Table of Contents
Commission Conference Agenda
April 4, 2017

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: March 23, 2017

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (L. Smith, Mouring) ALM
Division of Economics (Rome)
Division of Engineering (King)
Office of the General Counsel (Gervasi)

RE: Docket No. 160239-WS – Proposed amendment of Rule 25-30.445, F.A.C., General Information and Instructions Required of Water and Wastewater Utilities in an Application for a Limited Proceeding.

AGENDA: 04/04/17 – Regular Agenda – Rule Proposal – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

RULE STATUS: Proposal May Be Deferred

SPECIAL INSTRUCTIONS: None

Case Background

In 2014, the Florida Legislature enacted sections 367.072, Florida Statutes (F.S.), Petition to revoke certificate of authorization, and 367.0812, F.S., Rate fixing; quality of water service as criterion. Section 367.0812, F.S., requires that in fixing just, reasonable, compensatory, and not unfairly discriminatory rates, the Commission shall consider the extent to which a water utility provides service that meets secondary water quality standards as established by the Department of Environmental Protection (DEP). Section 367.0812(1)(c), F.S., requires the Commission to consider "[c]omplaints regarding the applicable secondary water quality standards filed by customers with the [C]ommission, the [DEP], the respective local governmental entity, or a county health department during the past 5 years."

The Commission implemented sections 367.072 and 367.0812, F.S., in 2015.[1] The Commission adopted Rule 25-30.091, Florida Administrative Code (F.A.C.), Petition to Revoke Water Certificate of Authorization, and amended Rule 25-30.440, F.A.C., Additional Engineering Information Required of Class A and B Water and Wastewater Utilities in an Application for Rate Increase, to require that when a utility applies for a rate increase, it must provide a copy of all customer complaints that it has received regarding DEP secondary water quality standards during the past five years. In addition, Rule 25-30.440(3), F.A.C., requires the submission of the most recent secondary water quality standards test results. Rule 25-30.443(1), F.A.C., Minimum Filing Requirements for Class C Water and Wastewater Utilities, makes Rule 25-30.440 applicable to Class C utilities seeking a rate increase, as well.

To promote clarity and consistency among Commission rules, staff is recommending that the Commission propose to amend Rule 25-30.445, F.A.C., to require that when applying for a limited proceeding, water and wastewater utilities must provide the same information pertaining to secondary water quality standards as are contained in Rule 25-30.440, F.A.C. Staff also recommends the elimination of the requirement contained in Rule 25-30.445(8), F.A.C., that a limited proceeding application shall not be filed for underearnings in lieu of a general rate case.

A Notice of Development of Rulemaking was published on July 27, 2016, in Volume 42, Number 145, of the Florida Administrative Register, after which time Utilities Inc., of Florida (UIF), the Office of Public Counsel (OPC), and Michael Smallridge submitted comments on the draft rule. On December 19, 2016, a second notice was issued to inform interested persons of staff's intent to include the elimination of the requirement in Rule 25-30.445(8), F.A.C., that a limited proceeding shall not be filed for underearnings in lieu of a general rate case. No further comments were received as a result of the second notice. No rule development workshop was requested and none was held.

The Commission has jurisdiction pursuant to sections 120.54, 350.127(2), 367.081, 367.0812, 367.0822, and 367.121, F.S.

[1] See Order No. PSC-15-0055-FOF-WS, issued January 21, 2015, in Docket No. 140205-WS (noticing the adoption of Rules 25-30.091 and 25-30.440, F.A.C.).

Discussion of Issues

Issue 1: Should the Commission propose the amendment of Rule 25-30.445, F.A.C., General Information and Instructions Required of Water and Wastewater Utilities in an Application for a Limited Proceeding?

Recommendation: Yes, the Commission should propose the amendment of Rule 25-30.445, F.A.C., as set forth in Attachment A. (Gervasi, King, L. Smith, Mouring, Rome)

Staff Analysis: Section 367.0812, F.S., requires that in fixing just, reasonable, compensatory, and not unfairly discriminatory rates, the Commission shall consider the extent to which a water utility provides service that meets secondary water quality standards as established by the Department of Environmental Protection (DEP). Section 367.0812(1)(c), F.S., requires the Commission to consider "[c]omplaints regarding the applicable secondary water quality standards filed by customers with the [C]ommission, the [DEP], the respective local governmental entity, or a county health department during the past 5 years."

Rule 25-30.440(11), F.A.C., Additional Engineering Information Required of Class A and B Water and Wastewater Utilities in an Application for Rate Increase, requires that when a utility applies for a rate increase, it must provide a copy of all customer complaints that it has received regarding DEP secondary water quality standards during the past five years. In addition, Rule 25-30.440(3), F.A.C., requires the submission of the most recent secondary water quality standards test results. Rule 25-30.443(1), F.A.C., Minimum Filing Requirements for Class C Water and Wastewater Utilities, makes Rule 25-30.440 applicable to Class C utilities seeking a rate increase, as well.

To promote clarity and consistency among Commission rules, and to assist the Commission in considering the extent to which a utility provides service that meets secondary water quality standards when evaluating an application for a limited proceeding, staff recommends that the Commission propose to amend Rule 25-30.445, F.A.C., to add Paragraph (4)(o), for Class A and B utilities, and Paragraph (5)(h), for Class C utilities, requiring that the minimum filing requirements (MFRs) for a limited proceeding application shall include: "1. A copy of all customer complaints that the utility has received regarding DEP secondary water quality standards during the past five years; and 2. A copy of the utility's most recent secondary water quality standards test results." Staff currently obtains this information via data requests after an application for limited proceeding is filed. By requiring this information as part of the limited proceeding MFRs, the number of data requests that would be necessary to process limited proceedings applications should be reduced, thereby streamlining the process for both staff and applicants. Utility ratepayers also should benefit from the Commission's consideration of secondary water quality standards prior to allowing a utility to move forward with a rate increase via a limited proceeding.

Staff also recommends that Rule 25-30.445(8), F.A.C., which requires that "[a] limited proceeding application shall not be filed for underearnings in lieu of a general rate case," should be eliminated. Paragraph (8) of the rule could potentially be interpreted to prohibit justifiable increases simply because a utility is in an underearnings position, or would be in an underearnings position if the costs being sought for recovery are incurred, and it suggests that unless a utility is earning within its authorized range, it would be prohibited from using the limited proceeding process. As such, Paragraph (8) unnecessarily restricts the use of the limited proceeding process, which was designed to save regulatory costs to the utility, its customers, and the Commission. Moreover, Paragraph (6)(b) of the rule provides that in evaluating whether a utility's request is appropriate for a limited proceeding, the Commission will consider "[w]hether the utility has not had a rate case in more than seven years and the requested rate increase exceeds 30 percent." Thus, Paragraph (6)(b) provides adequate safeguards to prevent utilities from inappropriately using the limited proceeding process to avoid a general rate case filing in which all costs of the utility would be fully evaluated.

Other non-substantive changes as shown in the attached draft rule are self-explanatory. For informational purposes, copies of the two forms incorporated by reference in the rule are also attached. Staff has not made any recommended changes to the forms. As shown on page 12, lines 11-13, of the draft rule, the Department of State will provide a hyperlink to these forms for inclusion in the rule, as required by section 120.54(1)(i)3.a., F.S., and Rule 1-1.013(6), F.A.C.

In its written comments, UIF states that it believes that the prior three years, rather than five years, of customer complaints is more consistent with prior Commission practice in file and suspend rate cases, and should be adequate in a limited proceeding to retain consistency. UIF also believes that the rule should include a specific deadline within which the Commission must act on a limited proceeding. UIF reasons that a limited proceeding is currently the only type of rate proceeding without a deadline, and that as a result, limited proceedings are being underutilized because utilities have no expectation on when rate relief will be forthcoming. UIF suggests that a five-month deadline is a reasonable time within which the Commission should be able to rule on a limited proceeding, and summarily suggests that a deadline will help to insulate the Commission from political involvement.

In its written comments, OPC agrees with staff's draft rule language. OPC believes that the inclusion of the staff recommended rule changes to the limited proceeding MFRs will provide a more complete record and additional transparency to the process. OPC states that customer input on these water quality issues plus the most recent test results will not only allow Commission staff to conduct a more thorough evaluation of the case, but will also allow all affected parties and the Commission to gain a greater understanding of issues that are important to water utility customers.

OPC strongly disagrees with UIF's suggestion to include a specific deadline for the Commission to act on limited proceedings. OPC states that both the Florida Legislature and the Commission have already identified instances where a deadline for the Commission to act is warranted. Chapter 367, F.S., requires an eight-month deadline for the Commission to act on petitions for rate relief through full administrative hearings, and a five-month deadline for the Commission to act on proposed agency action proceedings. And the Commission set a 90-day deadline to vote on a proposed agency action recommendation establishing rates in Rule 25-30.456, F.A.C., which addresses staff assistance in alternative rate setting. OPC argues that there are proceedings where flexibility is paramount and no deadline should be set. To OPC's knowledge, the lack of a deadline in limited proceedings does not present a hardship for any party, and UIF's comments are akin to "a solution in search of a problem."

Mr. Smallridge submitted comments on behalf of the eight utilities that he owns.[2] Mr. Smallridge states that five years is too long of a time to expect the utility to keep every customer complaint. He states that it is hard for some utilities to produce receipts from the past year, much less customer complaints from five years ago, and that a five-year timeframe would be "setting yourself up for failure." Mr. Smallridge further suggests that the new language on page 12, line 16 of the attached draft rule should specify "A Class A or B water utility's application for limited proceeding shall also include" instead of "A water utility's application for limited proceeding shall also include," to clarify who this provision of the rule applies to, similar to on page 13, line 21 of the draft rule, which states "A Class C water utility's application for limited proceeding shall also include[.]"

Staff disagrees with UIF's comment that the prior three years, rather than five years, of customer complaints is more consistent with prior Commission practice in file and suspend rate cases, and should be adequate in a limited proceeding to retain consistency. Staff also disagrees with Mr. Smallridge's comment that five years is too long of a time for a utility to keep these types of customer complaints. As noted above, the draft rule language is consistent with Rule 25-30.440(11), F.A.C., which requires that when a utility applies for a rate increase, it must provide a copy of all customer complaints that it has received regarding DEP secondary water quality standards during the past five years, and Rule 25-30.443(1), F.A.C., makes this requirement applicable to Class C utilities seeking a rate increase, as well. This rule requirement implements section 367.0812, F.S., which requires the Commission to consider the extent to which a water utility provides service that meets secondary water quality standards when fixing rates. Section 367.0812(1)(c), F.S., requires the Commission to consider "[c]omplaints regarding the applicable secondary water quality standards filed by customers with the [C]ommission, the [DEP], the respective local governmental entity, or a county health department <u>during the past 5 years</u>." (emphasis added). Moreover, as previously noted, staff currently obtains this information via data requests after an application for limited proceeding is filed. Therefore, only the timing of providing the secondary water quality standards information will be affected by the implementation of the rule amendment, not the nature of the information itself.

Staff further disagrees with UIF's suggestion to include a five-month deadline within which the Commission must act on a limited proceeding. Staff agrees with OPC that there are statutory deadlines imposed upon the Commission to act within a specified timeframe in certain types of cases, such as in file and suspend rate cases. There is no statutory deadline contained in section 367.0822, F.S., the limited proceedings statute. Moreover, applications for limited proceedings vary in scope and in complexity. Pursuant to section 367.0822, F.S., "[t]he [C]omission shall determine the issues to be considered during such a proceeding and may grant or deny any request to expand the scope of the proceeding to include other related matters." Thus, some limited proceedings take considerably longer to process than others, and it is important for the

[2] Those utilities include: Charlie Creek Utilities, LLC; Crestridge Utilities, LLC; East Marion Utilities, LLC; McLeod Gardens Utilities, LLC; Holiday Gardens Utilities, LLC; Orange Land Utilities, LLC; Pinecrest Utilities, LLC; and West Lakeland Wastewater, Inc.

Commission to have the flexibility to set its own deadlines to act on limited proceeding applications.[3]

Finally, with respect to Mr. Smallridge's comment to specify on page 12, line 16 of the attached draft rule that Paragraph (4)(o) applies to Class A and B utilities, the inclusion of this language is unnecessary because Paragraph (4) of the rule already specifies that "The following [MFRs] shall be filed . . . for a Class A or B water or wastewater utility," as shown on page 9, lines 24-25 of the attached draft rule. The new language of Paragraph (4)(o) of the draft rule is narrowed to water utilities because the inclusion in limited proceeding MFRs of water-related customer complaints and test results is inapplicable to wastewater only utilities.

Statement of Estimated Regulatory Costs

The Florida Administrative Procedure Act encourages an agency to prepare a Statement of Estimated Regulatory Costs (SERC). Section 120.54(3)(b), F.S. An agency must prepare a SERC if the proposed rule is likely to directly or indirectly increase regulatory costs in excess of $200,000 in the aggregate within one year after implementation of the rule, and shall consider the impact of the rule on small businesses, small counties, and small cities. Id.

Section 120.541(2)(a), F.S., requires a SERC to include an economic analysis showing whether the rule, directly or indirectly, is likely to: 1) have an adverse impact on economic growth, private sector job creation, employment, or investment; 2) have an adverse impact on business competitiveness; or 3) increase regulatory costs in excess of $1 million in the aggregate within five years after the implementation of the rule. Section 120.541(3), F.S., requires that if the adverse impact or regulatory costs of the rule exceed any of those criteria, the rule shall be submitted to the President of the Senate and Speaker of the House, and may not take effect until it is ratified by the Legislature.

The SERC prepared by staff is included as Attachment B to this recommendation. It indicates that the rule is not expected to adversely impact economic growth, private job sector employment, investment, and business competitiveness during the five-year period following its implementation, and that any transactional costs that might be incurred by affected entities would be de minimis. Based on the SERC, the recommended rules will not require legislative ratification.

---

[3] *Compare* Order No. PSC-06-0092-AS-WU, issued February 9, 2006, in Docket No. 000694-WU, *In Re: Petition by Water Management Services, Inc. for Limited Proceeding to Increase Water Rates in Franklin County* (approving settlement agreement for third and final phase of limited proceeding water rate increase after phases one and two had already been approved, to recover the cost of building a new water transmission main to connect the utility's wells on the mainland to its service territory on St. George Island, where application for limited proceeding was filed nearly six years earlier, on June 6, 2000) *with* Order No. PSC-14-0679-PAA-SU, issued December 9, 2014, in Docket No. 140106-SU, *In re: Application for limited proceeding rate increase in Polk County by West Lakeland Wastewater, Inc.* (granting 1.98 percent limited rate increase to recover additional customer billing costs and for operating permit renewal, where application for limited proceeding was filed less than seven months earlier, on May 20, 2014, and contained deficiencies that needed correction before application could be processed).

As required by section 120.541(2)(b)-(e), F.S., Attachment B also addresses the estimated number of individuals and entities likely to be required to comply with the rules, the estimated cost of implementing and enforcing the rules, the estimated transactional costs likely to be incurred by individuals and entities required to comply with the rules, and an analysis of the impact on small businesses, small counties, and small cities.

For the foregoing reasons, staff recommends that the Commission should propose the amendment of Rule 25-30.445, F.A.C., as shown on Attachment A.

Issue 2: Should this docket be closed?

Recommendation: Yes, if no requests for hearing or comments are filed, the rule amendments as proposed should be filed for adoption with the Secretary of State and the docket should be closed.

Staff Analysis: Unless comments or requests for hearing are filed, the rule amendments as proposed may be filed with the Secretary of State without further Commission action. The docket may then be closed. (Gervasi)

25-30.445 General Information and Instructions Required of Water and Wastewater Utilities in an Application for a Limited Proceeding.

(1) Each applicant for a limited proceeding shall provide the following general information to the Commission:

(a) The name of the applicant as it appears on the applicant's certificate and the address of the applicant's principal place of business;

(b) The type of business organization under which the applicant's operations are conducted; if the applicant is a corporation, the date of incorporation; the names and addresses of all persons who own 5 percent or more of the applicant's stock; or the names and addresses of the owners of the business.

(c) The number(s) of the Commission order(s), if any, in which the Commission most recently considered the applicant's rates for the system(s) involved.

(d) The address within the service area where the application is available for customer inspection during the time the rate application is pending.

(e) A statement signed by an officer of the utility that the utility will comply with the noticing requirements in Rule 25-30.446, F.A.C.

(2) In a limited proceeding application:

(a) Each schedule shall be cross-referenced to identify related schedules.

(b) Except for handwritten official company records, all data in the petition and application shall be typed.

(c) The original and seven copies shall be filed with the Office of Commission Clerk.

(3) A filing fee as required in Rule 25-30.020, F.A.C., shall be submitted at the time of application.

(4) The following minimum filing requirements shall be filed with the utility's application for limited proceeding for a Class A or B water or wastewater utility:

(a) A detailed statement of the reason(s) why the limited proceeding has been requested.

(b) If the limited proceeding is being requested to recover costs required by a governmental or regulatory agency, provide the following:

1. A copy of any rule, regulation, order or other regulatory directive that has required or will require the applicant to make the improvement or the investment for which the applicant seeks recovery.

2. An estimate by a professional engineer, or other person, knowledgeable in design and construction of water and wastewater plants, to establish the projected cost of the applicant's investment and the period of time required for completion of construction.

(c) A schedule that provides the specific rate base components for which the utility seeks recovery. Supporting detail shall be provided for each item requested, including:

1. The actual or projected cost(s);

2. The date the item will be or is projected to be placed in service;

3. Any corresponding adjustments that are required as a result of adding or removing the requested component(s) from rate base, which may include retirement entries; and

4. Any other relevant supporting information.

(d) If the utility's application includes a request for recovery of plant in service, accumulated depreciation and depreciation expense, supporting detail shall be provided by primary account as defined by the NARUC Uniform System of Accounts, in accordance with Rule 25-30.110, F.A.C.

(e) A calculation of the weighted average cost of capital shall be provided for the most recent 12-month period, using the mid-point of the range of the last authorized rate of return on equity, the current embedded cost of fixed-rate capital, the actual cost of short-term debt, the actual cost of variable-cost debt, and the actual cost of other sources of capital which were used in the last individual rate proceeding of the utility. If the utility does not have an authorized rate of return on equity, the utility shall use the current leverage formula pursuant to Section 367.081(4)(f), F.S.

(f) If the utility is requesting recovery of operating expenses, the following information shall be provided:

1. A detailed description of the expense(s) requested;

2. The total cost by primary account pursuant to the NARUC Uniform System of Accounts;

3. Supporting documentation or calculations; and

4. Any allocations that are made between systems, affiliates or related parties. If allocations are made, submit full detail that shows the total amount allocated, a description of the basis of the allocation methodology, the allocation percentage applied to each allocated cost, and the workpapers supporting the calculation of the allocation percentages.

(g) Calculations for all items that will create cost savings or revenue impacts from the implementation of the requested cost recovery items.

(h) If the utility includes any other items where calculations are required, supporting documentation shall be filed that reflects the calculations or assumptions made.

(i) A calculation of the revenue increase including regulatory assessment fees and income taxes, if appropriate.

(j) Annualized revenues for the most recent 12-month period using the rates in effect at the time the utility files its application for limited proceeding and a schedule reflecting this calculation by customer class and meter size.

(k) A schedule of current and proposed rates for all classes of customers.

(l) Schedules for the most recent 12-month period showing that, without any increased rates, the utility will earn below its authorized rate of return in accordance with Section 367.082, F.S. The schedules shall consist of a rate base, net operating income and cost of capital schedule with adjustments to reflect those consistent with the utility's last rate proceeding.

(m) If the limited proceeding is being requested to change the current rate structure, provide a copy of all workpapers and calculations used to calculate requested rates and allocations between each customer class. The test year <u>shall</u> ~~should~~ be the most recent 12-month period. In addition, the following schedules, which are incorporated herein by reference, from Form PSC/AFD 19-W (11/93), entitled "Class A Water and/or Wastewater Utilities Financial, Rate and Engineering Minimum Filing Requirements", <u>shall</u> ~~should~~ be provided. The schedules can be obtained from the Commission's Division of Accounting and Finance.

1. Schedule E-2, entitled "Revenue Schedule at Present and Proposed Rates<u>,</u>" <u>is available at [hyperlink]</u>.

2. Schedule E-14, entitled "Billing Analysis Schedules<u>,</u>" <u>is available at [hyperlink]</u>. Only two copies are required.

(n) Revised tariff sheets should not be filed with the application.

<u>(o) A water utility's application for limited proceeding shall also include:</u>

<u>1. A copy of all customer complaints that the utility has received regarding DEP secondary water quality standards during the past five years; and</u>

<u>2. A copy of the utility's most recent secondary water quality standards test results.</u>

(5) In addition to the requirements stated in subsections (1) through (3), the following minimum filing requirements shall be filed with the utility's application for limited proceeding for a Class C water or wastewater utility:

(a) A detailed statement of the reason(s) why the limited proceeding has been requested.

(b) If the limited proceeding is being requested to recover costs required by a governmental or regulatory agency, provide a copy of any rule, regulation, order or other regulatory directive that has required or will require the applicant to make the improvement or the investment for which the applicant seeks recovery.

(c) A schedule that provides the specific rate base components for which the utility seeks recovery, if known. Supporting detail shall be provided for each item requested, including:

1. The actual or projected cost(s);

2. The date the item will be or is projected to be placed in service;

3. Any corresponding adjustments, if known, that are required as a result of adding or removing the requested component(s) from rate base, which may include retirement entries; and

4. Any other relevant supporting information, if known.

(d) If the utility is requesting recovery of operating expenses, provide an itemized description of the expense(s), including the cost and any available supporting documentation or calculations.

(e) Provide a description of any known items that will create cost savings or revenue impacts from the implementation of the requested cost recovery items.

(f) A calculation of the revenue increase including regulatory assessment fees and income taxes, if applicable.

(g) Annualized revenues for the most recent 12-month period using the rates in effect at the time the utility files its application for limited proceeding and a schedule reflecting this calculation by customer class and meter size.

(h) A Class C water utility's application for limited proceeding shall also include:

1. A copy of all customer complaints that the utility has received regarding DEP secondary water quality standards during the past five years; and

2. A copy of the utility's most recent secondary water quality standards test results.

(6) In evaluating whether the utility's request is improper for a limited proceeding, the

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

Commission will consider factors such as:

(a) Whether the utility's filing includes more than 4 separate projects for which recovery is sought and the requested rate increase exceeds 30 percent. Corresponding adjustments for a given project are not subject to the above limitation;

(b) Whether the utility has not had a rate case in more than seven years and the requested rate increase exceeds 30 percent; or

(c) Whether the limited proceeding is filed as the result of the complete elimination of either the water or wastewater treatment process and the requested rate increase exceeds 30 percent.

(7) The utility shall provide a statement in its filing to the Commission which addresses whether the utility's rate base has declined or whether any expense recovery sought by the utility is offset by customer growth since its most recent rate proceeding or will be offset by future customer growth expected to occur within one year of the date new rates are implemented.

~~(8) A limited proceeding application shall not be filed for underearnings in lieu of a general rate case.~~

Rulemaking Authority 350.127(2), 367.121(1)(a) FS. Law Implemented 367.081, 367.0812, 367.0822, 367.121(1)(a), 367.145(2) FS. History–New 3-1-04, Amended___________

Revenue Schedule at Present and Proposed Rates

Florida Public Service Commission

Company:
Docket No.:
Test Year Ended:
Water [ ] or Sewer [ ]

Schedule: E-2
Page__of__
Preparer:

Explanation: Provide a calculation of revenues at present and proposed rates using the billing analysis. Explain any differences between these revenues and booked revenues. If a rate change occurred during the test year, a revenue calculation must be made for each period.

(1) Class/Meter Size	(2) Number Bills	(3) Consumption in MG	(4) Present Rate	(5) Revenues at Present Rates	(6) Proposed Rate	(7) Revenues at Proposed Rates
Residential						
5/8" x 3/4"						
M Gallons						
1" Etc.						
M Gallons Etc.						
Total Residential						
Average Bill						
General Service						
5/8" x 3/4"						
M Gallons						
1" Etc.						
M Gallons Etc.						
Total Gen. Serv.						
Average Bill						
List Other Classes As Above						
Totals						
Unbilled Revenues						
Other Revenue						
Misc. Serv. Charges						
Total Revenue						
Booked Revenue						
Difference (Explain)						

Rule 25-30.445, F.A.C., Form PSC/AFD 19-W (11/93)
Schedule: E-2

Billing Analysis Schedules

Florida Public Service Commission

Company:
Docket No.:
Test Year Ended:
Water [ ] or Sewer [ ]
Customer Class:
Meter Size:

Schedule: E-14
Page___of___
Preparer:

Explanation: Provide a billing analysis for each class of service by meter size. For applicants having master metered multiple dwellings, provide number of bills at each level by meter size or number of bills categorized by the number of units. Round consumption to nearest 1,000 gallons & begin at zero. If a rate change occurred during the test year, provide a separate billing analysis which coincides with each period.

(1) Consumpt. Level	(2) Number of Bills	(3) Cumulative Bills	(4) Gallons Consumed (1)x(2)	(5) Cumulative Gallons	(6) Reversed Bills	(7) Consolidated Factor [(1)x(6)]+(5)	(8) Percentage of Total
0							
1							
2							
3							

89

Rule 25-30.445, F.A.C., Form PSC/AFD 19-W (11/93)
Schedule: E-14

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:	January 31, 2017
TO:	Rosanne Gervasi, Senior Attorney, Office of the General Counsel
FROM:	C. Donald Rome, Jr., Public Utility Analyst II, Division of Economics
RE:	Statement of Estimated Regulatory Costs (SERC) for Proposed Amendments to Rule 25-30.445, Florida Administrative Code (F.A.C.).

The purpose of this rulemaking initiative is staff's recommendation of modifications to Commission Rule 25-30.445, F.A.C., General Information and Instructions Required of Water and Wastewater Utilities in an Application for a Limited Proceeding. Specifically, staff is recommending the addition of paragraphs 25-30.445(4)(o) and 25-30.445(5)(h), F.A.C., to require utilities seeking a limited proceeding to provide the following as part of the Minimum Filing Requirements (MFRs) submitted with the application: (a) a copy of all customer complaints that the utility has received regarding Department of Environmental Protection (DEP) secondary water quality standards during the past five years, and (b) a copy of the utility's most recent secondary water quality standards test results. Staff also recommends the elimination of the requirement in subsection 25-30.445(8), F.A.C., that a limited proceeding application shall not be filed for underearnings in lieu of a general rate case.

During the 2014 session, the Florida Legislature enacted Senate Bill 272 which was incorporated into Chapter 2014-68, Laws of Florida. Among other things, the legislation created new Section 367.0812, Florida Statutes (F.S.). Section 367.0812, F.S., requires that in fixing rates, the Commission shall consider the extent to which a utility provides water service that meets secondary water quality standards as established by DEP. In accordance with the 2014 statutory changes, the Commission adopted Rule 25-30.440(11), F.A.C., to require a copy of all customer complaints received by the utility during the past five years regarding secondary water quality standards when a Class A or B utility files for a rate increase. Rule 25-30.440(3), F.A.C., requires the submission of secondary standards test results, and Rule 25-30.443(1), F.A.C., requires Class C utilities to provide the information required by Rule 25-30.440, F.A.C., as part of its MFRs.

To promote clarity and consistency among Commission rules, staff is recommending the above mentioned addition of paragraphs 25-30.445(4)(o) and 25-30.445(5)(h), F.A.C., to require that utilities provide the same information pertaining to secondary water quality standards when filing MFRs with applications for a limited proceeding. This information is currently being collected by staff through data requests after the utility's application is filed. Staff believes that by providing additional clarity to Rule 25-30.445, F.A.C., the number of data requests that would be necessary during the limited proceeding process should be reduced, thereby streamlining the process for both staff and applicants.

Staff also recommends the elimination of the requirement in subsection 25-30.445(8), F.A.C., that a limited proceeding application shall not be filed for underearnings in lieu of a general rate case. As currently written, the rule potentially could be interpreted to suggest that unless a utility is earning within its authorized range, it would be prohibited from using the limited proceeding process. Staff recommends the elimination of the rule so as not to unnecessarily restrict the use of the limited proceeding process, which was designed to save regulatory costs to utilities, their customers, and the Commission.

The attached SERC addresses the considerations required pursuant to Section 120.541, F.S. No workshop was held in conjunction with the recommended rule revisions. No regulatory alternatives were submitted pursuant to Paragraph 120.541(1)(a), F.S. None of the impact/cost criteria established in Paragraph 120.541(2)(a), F.S., will be exceeded as a result of the recommended revisions.

cc: (Draper, Daniel, Shafer, King, Cibula, SERC file)

FLORIDA PUBLIC SERVICE COMMISSION
STATEMENT OF ESTIMATED REGULATORY COSTS
Rule 25-30.445, F.A.C.

1. Will the proposed rule have an adverse impact on small business? [120.541(1)(b), F.S.] (See Section E., below, for definition of small business.)

   Yes ☐ No ☒

For clarification, please see comments in Sections A(3) and E(1), below.

2. Is the proposed rule likely to directly or indirectly increase regulatory costs in excess of $200,000 in the aggregate in this state within 1 year after implementation of the rule? [120.541(1)(b), F.S.]

   Yes ☐ No ☒

If the answer to either question above is "yes", a Statement of Estimated Regulatory Costs (SERC) must be prepared. The SERC shall include an economic analysis showing:

A. Whether the rule directly or indirectly:

(1) Is likely to have an adverse impact on any of the following in excess of $1 million in the aggregate within 5 years after implementation of the rule? [120.541(2)(a)1, F.S.]

Economic growth	Yes ☐	No ☒
Private-sector job creation or employment	Yes ☐	No ☒
Private-sector investment	Yes ☐	No ☒

(2) Is likely to have an adverse impact on any of the following in excess of $1 million in the aggregate within 5 years after implementation of the rule? [120.541(2)(a)2, F.S.]

Business competitiveness (including the ability of persons doing business in the state to compete with persons doing business in other states or domestic markets)	Yes ☐	No ☒
Productivity	Yes ☐	No ☒
Innovation	Yes ☐	No ☒

1

(3) Is likely to increase regulatory costs, including any transactional costs, in excess of $1 million in the aggregate within 5 years after the implementation of the rule? [120.541(2)(a)3, F.S.]

Yes ☐ No ☒

Economic Analysis:
A summary of the recommended rule revisions is included in the attached memorandum to Counsel. Specific elements of the associated economic analysis are discussed below in Sections B through F of this SERC.

In accordance with statutory changes enacted during the 2014 legislative session, the Commission adopted Rule 25-30.440(11), Florida Administrative Code (F.A.C.), to implement provisions of Section 367.0812, Florida Statutes (F.S.), regarding the Commission's consideration during ratemaking proceedings of the extent to which a utility has met secondary water quality standards established by the Department of Environmental Protection (DEP). The Commission is required to consider complaints regarding applicable secondary water quality standards filed by customers with the Commission, DEP, the respective local governmental entity, or a county health department during the past five years (paragraph 367.0812(1)(c), F.S.).

To promote clarity and consistency among Commission rules, staff is suggesting amendments to subsections (4) and (5) of Rule 25-30.445, F.A.C., which would require utilities that apply for a limited proceeding to provide: (a) a copy of all customer complaints that the utility has received regarding DEP secondary water quality standards during the past five years, and (b) a copy of the utility's most recent secondary water quality standards test results. This information is currently being collected by staff through data requests during the course of limited proceedings; henceforth under the recommended rule revisions, utilities would provide the information as part of the Minimum Filing Requirements that accompany the utility's application for a limited proceeding.

Staff also recommends the elimination of the requirement in subsection 25-30.445(8), F.A.C., that a limited proceeding application shall not be filed for underearnings in lieu of a general rate case. As currently written, this rule potentially could be interpreted to suggest that unless a utility is earning within its authorized range, it would be prohibited from using the limited proceeding process.

As discussed in Section D below, additional transactional costs, if any, that potentially may be associated with the recommended rule revisions are expected to be de minimis. Therefore, staff believes that none of the impact/cost criteria established in Paragraph 120.541(2)(a), F.S., will be exceeded as a result of the recommended rule revisions.

B. A good faith estimate of: [120.541(2)(b), F.S.]

(1) The number of individuals and entities likely to be required to comply with the rule.

The recommended amendments to Rule 25-30.445, F.A.C., would affect 145 investor-owned water and wastewater utilities that serve approximately 175,000 Florida customers. Utilities which come under the jurisdiction of the Commission in the future also would be required to comply.

(2) A general description of the types of individuals likely to be affected by the rule.

The 145 investor-owned water and wastewater utilities are located in 37 counties.

C. A good faith estimate of: [120.541(2)(c), F.S.]

(1) The cost to the Commission to implement and enforce the rule.

☒ None. To be done with the current workload and existing staff.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

(2) The cost to any other state and local government entity to implement and enforce the rule.

☒ None. The rule will only affect the Commission.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

(3) Any anticipated effect on state or local revenues.

☒ None

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

D. A good faith estimate of the transactional costs likely to be incurred by individuals and entities (including local government entities) required to comply with the requirements of the rule. "Transactional costs" include filing fees, the cost of obtaining a license, the cost of equipment required to be installed or used, procedures required to be employed in complying with the rule, additional operating costs incurred, the cost of monitoring or reporting, and any other costs necessary to comply with the rule. [120.541(2)(d), F.S.]

☐ None. The rule will only affect the Commission

☐ Minimal. Provide a brief explanation.

☒ Other. Provide an explanation for estimate and methodology used.

Staff's suggested additions of paragraphs 25-30.445(4)(o) and 25-30.445(5)(h), F.A.C., would require utilities applying for a limited proceeding to include a copy of all customer complaints that the utility has received regarding DEP secondary water quality standards during the past five years and a copy of the utility's most recent secondary water quality standards test results as part of the Minimum Filing Requirements that accompany the limited proceeding application. Currently, staff obtains this information via a data request after the application is filed. Although the timing of providing the secondary water quality standards information would be affected, staff believes that potential additional transactional costs, if any, would be de minimis. Staff notes that since 2010, the Commission has received only six applications for a limited proceeding.

Staff believes that by providing additional clarity to Rule 25-30.445, F.A.C., the number of data requests that would be necessary during the limited proceeding process should be reduced, thereby streamlining the process for both staff and applicants. Utility ratepayers also should benefit from the Commission's consideration of secondary water quality standards prior to allowing a utility to move forward with a rate increase via a limited proceeding.

Staff's suggested deletion of subsection 25-30.445(8), F.A.C., would remove language stating that "a limited proceeding application shall not be filed for underearnings in lieu of a general rate case." As currently written, this rule potentially could be interpreted to suggest that unless a utility is earning within its authorized range, it would be prohibited from using the limited proceeding process. Staff recommends the elimination of this rule so as not to unnecessarily restrict the use of the limited proceeding process, which was designed to save regulatory costs to utilities, their customers, and the Commission. No additional transactional costs are anticipated as a result of this rule change. Staff further believes that subsection 25-30.445(6), F.A.C., provides adequate safeguards to prevent utilities from inappropriately using the limited proceeding process to avoid a general rate case filing in which all costs of the utility would be fully evaluated.

E. An analysis of the impact on small businesses, and small counties and small cities: [120.541(2)(e), F.S.]

(1) "Small business" is defined by Section 288.703, F.S., as an independently owned and operated business concern that employs 200 or fewer permanent full-time employees and that, together with its affiliates, has a net worth of not more than $5 million or any firm based in this state which has a Small Business Administration 8(a) certification. As to sole proprietorships, the $5 million net worth requirement shall include both personal and business investments.

☒ No adverse impact on small business. *[See clarification below.]*

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

While it is difficult to estimate the number of affected entities that would meet the definition of "Small Business" as defined in Section 288.703, F.S., it is reasonable to assume that many of the affected entities would meet the statutory definition and, therefore, potentially could incur additional transactional costs as discussed in Section D, above. However, as noted in Section D above, potential additional transactional costs associated with the recommended revisions, if any, are expected to be de minimis.

(2) A "Small City" is defined by Section 120.52, F.S., as any municipality that has an unincarcerated population of 10,000 or less according to the most recent decennial census. A "small county" is defined by Section 120.52, F.S., as any county that has an unincarcerated population of 75,000 or less according to the most recent decennial census.

☒ No impact on small cities or small counties

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

F. Any additional information that the Commission determines may be useful. [120.541(2)(f), F.S.]

☒ None.

<u>Additional Information:</u>

G. A description of any regulatory alternatives submitted and a statement adopting the alternative or a statement of the reasons for rejecting the alternative in favor of the proposed rule. [120.541(2)(g), F.S.]

☒ No regulatory alternatives were submitted.

☐ A regulatory alternative was received from

☐ Adopted in its entirety.

☐ Rejected. Describe what alternative was rejected and provide a statement of the reason for rejecting that alternative.

Item 2

FILED MAR 23, 2017
DOCUMENT NO. 03782-17
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: March 23, 2017

TO: Office of Commission Clerk (Stauffer)

CRR DAB MLC ALM

FROM: Division of Accounting and Finance (Richards, Buys, Cicchetti)
Office of the General Counsel (Mapp) KGM JSC

RE: Docket No. 170037-EI – Request for approval of change in rate used to capitalize allowance for funds used during construction (AFUDC) from 6.34% to 6.16%, effective January 1, 2017, by Florida Power & Light Company.

AGENDA: 04/04/17 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Florida Power & Light Company's (FPL or the Company) current Allowance for Funds Used During Construction (AFUDC) rate of 6.34 percent was approved on April 25, 2014, by Order No. PSC-14-0193-PAA-EI.[1] On February 17, 2017, FPL filed a petition seeking approval to decrease its AFUDC rate from 6.34 percent to 6.16 percent, effective January 1, 2017. The Commission has jurisdiction over this matter pursuant to Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

[1]Order No. PSC-14-0193-PAA-EI, issued April 25, 2014, in Docket No. 140035-EI, *In re: Request for approval of change of allowance for funds during construction (AFUDC)*, by Florida Power & Light Company, consummated by Order No. PSC-14-0267-CO-EI, issued May 27, 2014.

Discussion of Issues

Issue 1: Should the Commission approve FPL's request to decrease its AFUDC rate from 6.34 percent to 6.16 percent?

Recommendation: Yes. The appropriate AFUDC rate for FPL is 6.16 percent based on a 13-month average capital structure for the period ended December 31, 2016. (Richards)

Staff Analysis: FPL requested a decrease in its AFUDC rate from 6.34 percent to 6.16 percent. Rule 25-6.0141(2), Florida Administrative Code (F.A.C.), Allowance for Funds Used During Construction, provides the following guidance:

> (2) The applicable AFUDC rate shall be determined as follows:
>
> (a) The most recent 13-month average embedded cost of capital, except as noted below, shall be derived using all sources of capital and adjusted using adjustments consistent with those used by the Commission in the utility's last rate case.
>
> (b) The cost rates for the components in the capital structure shall be the midpoint of the last allowed return on common equity, the most recent 13-month average cost of short term debt and customer deposits and a zero cost rate for deferred taxes and all investment tax credits. The cost of long term debt and preferred stock shall be based on end of period cost. The annual percentage rate shall be calculated to two decimal places.

In support of the requested AFUDC rate of 6.16 percent, FPL provided its calculations and capital structure in Schedules A and B attached to its request. Staff reviewed the schedules and determined that the proposed rate was calculated in accordance with Rule 25-6.0141(2), F.A.C. The requested decrease in the AFUDC rate is due principally to a decrease in the cost rates of long term debt and short term debt, and an increase in the amount of zero-cost deferred income taxes in the capital structure. This decrease is modestly offset by a slight increase in the return on equity (ROE). The ROE increased from 10.50 percent to 10.55 percent in FPL's last rate case.[2]

Based on its review, staff believes that the requested decrease in the AFUDC rate from 6.34 percent to 6.16 percent is appropriate, consistent with Rule 25-6.0141, F.A.C., and recommends that it be approved.

[2]Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

Issue 2: What is the appropriate monthly compounding rate to achieve the requested 6.16 percent annual AFDUC rate?

Recommendation: The appropriate monthly compounding rate to maintain an annual rate of 6.16 percent is 0.499682 percent. (Richards)

Staff Analysis: FPL requested a monthly compounding rate of 0.499682 percent to achieve an annual AFUDC rate of 6.16 percent. In support of the requested monthly compounding rate of 0.499682 percent, FPL provided its calculations in Schedule C attached to its request. Rule 25-6.0141(3), F.A.C., provides a formula for discounting the annual AFUDC rate to reflect monthly compounding. The rule also requires that the monthly compounding rate be calculated to six decimal places.

Staff reviewed the Company's calculations and determined that they comply with the requirements of Rule 25-6.0141(3), F.A.C. Therefore, staff recommends that a discounted monthly AFUDC rate of 0.499682 percent be approved.

Issue 3: Should the Commission approve FPL's requested effective date of January 1, 2017, for implementing the revised AFUDC rate?

Recommendation: Yes. The revised AFUDC rate should be effective as of January 1, 2017, for all purposes. (Richards)

Staff Analysis: FPL's proposed AFUDC rate was calculated using a 13-month average capital structure for the period ended December 31, 2016. Rule 25-6.0141(5), F.A.C., provides that:

> The new AFUDC rate shall be effective the month following the end of the 12-month period used to establish that rate and may not be retroactively applied to a previous fiscal year unless authorized by the Commission.

The Company's requested effective date of January 1, 2017, complies with the requirement that the effective date does not precede the period used to calculate the rate, and therefore should be approved.

Issue 4: 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. (Mapp)

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, this docket should be closed upon the issuance of a consummating order.

Item 3

FILED MAR 27, 2017
DOCUMENT NO. 03833-17
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: March 27, 2017

TO: Office of Commission Clerk (Stauffer)

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

RE: Docket No. 170057-EI – Analysis of IOUs' hedging practices.

AGENDA: 04/04/17 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

This docket is the result of a comprehensive review of hedging practices that began in Docket No. 150001-EI. Duke Energy Florida, LLC (DEF), Florida Power & Light Company (FPL), Tampa Electric Company (TECO), and Gulf Power Company (Gulf) (collectively, IOUs) use hedging practices to buy a portion of the fuels used in their generating plants.[1]

[1]Pursuant to Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 160021-EI, *In re: Petition for rate increase by Florida Power & Light Company,* FPL agreed to a four–year moratorium on financial hedging through December 31, 2020. Pursuant to a settlement agreement approved in Order No. PSC-16-0547-FOF-EI, issued December 5, 2016, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor,* DEF, TECO, and Gulf agreed to a one-year moratorium on financial hedging through December 31, 2017. However, pursuant to a settlement agreement filed March 20, 2017, in Docket No. 160186-EI, *In re: Petition for rate increase by Gulf Power Company,* Gulf has agreed to an extension of its existing moratorium on financial hedging through December 31, 2020. This agreement is the subject of a hearing scheduled for April 4, 2017.

Order No. PSC-15-0586-FOF-EI[2] (2015 Fuel Order) provided a robust background on how the Commission's policy on hedging has developed over time, and describes the key actions the Commission has taken regarding the hedging programs that Florida's four largest IOUs use today. The information in the 2015 Fuel Order is summarized below.

Financial hedging involves using swap contracts or options, or both, to fix the price of fuel at the time the hedge instrument is executed for fuel to be delivered at a future date. Physical hedging involves using long-term fixed price contracts with suppliers, or physical possession of fuel, to fix the price of fuel over a period. Hedging allows utilities to manage the risk of volatile swings in the price of fuel. 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 financial 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),[3] the Commission approved the settlement of the issues. Specifically, the settlement 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 recover prudently incurred hedging costs through 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 the Commission and parties to the fuel docket to monitor utility hedging activities. As part of the annual final true-up filings in the fuel docket, utilities were required to state the volumes of fuel hedged, the type of hedging instruments used, the average length of the term of the hedge positions, and the fees associated with hedging transactions.

Although the Hedging Order allowed utilities flexibility in the development of risk management plans, the order 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 the proper oversight of hedging activities and for monitoring fuel price risk.

In tandem with Docket No. 011605-EI, staff conducted a review of internal controls for fuel procurement.[4] This study examined the practices, procedures, controls, and policies these companies followed when purchasing fossil fuels and wholesale energy. The study period looked

---

[2]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 inventive factor*.
[3]Order No. PSC-02-1484-FOF-EI (Hedging Order), issued October 30, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures*.
[4]Internal Controls of Florida's Investor-Owned Utilities for Fuel and Wholesale Energy Transactions, published in June 2002.

at data from 1998 through 2001. The study concluded that the Florida 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. Also, for the period studied, TECO and Gulf had little exposure to the volatility of natural gas prices due to their respective generation mixes.

The Commission reviewed its policy on hedging again in 2007 as part of the annual fuel cost recovery docket. Parties raised questions regarding the period for which the Commission was determining the prudent costs of hedging activities. The Commission deferred its decision on the prudence of 2007 hedging activity costs to 2008 in order to allow for sufficient review of the matter.

Following the 2007 fuel hearing, staff initiated two audits of the IOUs' hedging programs. Staff conducted a management audit that reviewed the IOUs' hedging programs to assess the costs and benefits realized since the implementation of the Hedging Order. Staff also reviewed the IOUs' accounting treatment of 2007 hedging activities to determine compliance with the risk management plans filed in 2006.

The management audit assessed the current and historical strategies of the fuel procurement hedging programs within each company, 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, staff examined the structure and performance of hedging natural gas and fuel oil through the use of physical purchases and financial instruments for the years 2003 through 2007. Staff collected information from each company's policies and procedures, organizational charts, risk management plans, and historical hedging transactions, and provided an analysis of each company. In June 2008, Commission staff issued a report titled Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities.

In its 2008 report, staff found that each company shared a universal goal of purchasing financial hedges for its fuel procurement, that is, to reduce the impacts of uncertain fuel prices on consumers. In their hedging activities, the companies were not attempting to speculate on price movements in the market. Rather, each was working to stabilize its annual fuel costs by initializing and settling financial hedging transactions through authorized financial counterparties. The volumes of gas and fuel oil hedged were less than the total volumes expected to be purchased. The balance of gas and fuel oil procured was purchased on the spot market. Overall, audit staff concluded that the use of financial hedges for fuel purchases provided a benefit to utility customers.

In response to the deferral of the determination of the prudent costs in the 2007 fuel hearing, on January 31, 2008, FPL filed a petition requesting that the Commission approve its proposed volatility mitigation mechanism (VMM) as an alternative to its then-current hedging program. The VMM proposal involved FPL collecting under recoveries of fuel costs over two years instead of one year, as is the current practice. On March 11, 2008, staff held a workshop to receive stakeholder input on this proposal.

By Order No. PSC-08-0316-PAA-EI,[5] the Commission clarified its Hedging Order in several areas. IOUs were required to file a Hedging Information Report by August 15th of each year. The Commission also specified that it would make a determination of the prudence of hedging activities for the twelve month period ending July 31, 2008. Staff held additional workshops 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] The Commission noted that its approval of the proposed guidelines demonstrated the Commission's support for hedging. The Commission also 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 approves the IOUs' risk management plans for hedging transactions the utility will enter the following year and beyond.

No other hedging-related orders have been issued to date, although since the issuance of these three orders, staff has presented hedging-related information to the Commission at Internal Affairs meetings.

Since the 1990s, natural gas-fired generation has become a large part of the generation mix of Florida's IOUs, and the increasing role for natural gas is expected to continue. Natural gas prices have been volatile over the years, with significant price spikes in 2000, 2003, 2005, and 2008. Since 2008, natural gas supply has increased significantly due to shale gas production. Since 2009, natural gas prices have averaged less than $4.00 per million British Thermal Units.

In its 2015 Fuel Order, the Commission addressed the following issues:

- Issue 1D: Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?

- Issue 1E: What changes, if any, should be made to the manner in which electric utilities conduct their natural gas financial hedging activities?

Within those issues were three, somewhat overlapping concerns: (1) the significant opportunity costs of hedging programs that the IOUs incurred as part of fuel costs paid by customers; (2) whether the volatility of natural gas prices has declined to the point where hedging is no longer effective or necessary; and (3) whether conditions in the natural gas market are stable and eliminate the need for hedging. The 2015 Fuel Order stated, in part:

[5]Order No. PSC-08-0316-PAA-EI (First Clarifying Order), 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 (Second Clarifying Order), issued October 8, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor*.

> [W]e find that the continuation of natural gas hedging process as outlined in our previous orders is in the customers' best interests.
>
> Our decision to continue hedging at this time is based on the evidence presented in this record which in large part consists of arguments to either completely eliminate hedging or to continue the procedures in place at this time. There was no written testimony from any party and very limited cross examination on possible changes to the manner in which the IOUs conduct natural gas financial hedging activities or alternatives to hedging: cost sharing of hedging gains and losses between the IOUs and ratepayers, alternative accounting treatment for recovery of gains and losses ("VMM program"), or imposing limits on the percentage of natural gas purchases hedged. All witnesses agreed 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. Notwithstanding our decision on hedging, we recognize that the cost of this program is significant by any measure for each Florida IOU and deserves further analysis. Therefore, we direct our staff, in conjunction with the parties to this docket, to explore possible changes to the current hedging protocol that will minimize potential losses to customers.[7]

In 2016, and to date in 2017, several filings and actions have taken place pertaining to the unresolved issues. These will be discussed primarily in the analysis for Issue 2. On February 21, 2017, a staff workshop was held to discuss natural gas hedging and related topics. On February 28, 2017, staff opened the instant docket to readdress the original 2 issues from the 2015 Order, which are currently identified below as Issues 1 and 2, respectively. An additional related issue (Issue 3) is included to address regulatory implementation matters. On March 6, 2017, all 4 IOUs filed post-workshop comments, along with the Sierra Club, the Florida Industrial Power Users Group (FIPUG), White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphates (White Springs), and the Office of Public Counsel (OPC).

The Commission has jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

[7] Order No. PSC-15-0586-FOF-EI, pp. 8-9.

Discussion of Issues

Issue 1: Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?

Recommendation: Yes. The purpose of hedging is to protect customers from large price increases and to minimize mark-to-market losses that occur when prices settle below projected levels. Fuel price hedging has benefits and risks. However, when executed in an economically efficient manner, staff believes that fuel price hedging activities are in consumers' best interest. (Barrett, Cicchetti)

Staff Analysis: Testimony and evidence was presented for this issue in the hearing for Docket No. 150001-EI, which is summarized below. In 2015, the IOUs favored continuing hedging activities because such activities are in customer's best interest, and most intervening parties advocated putting an end to hedging. Settlement agreements aside, these positions remain unchanged.

Summary of IOUs' position (from 2015)

Generally, the IOU witnesses in 2015 asserted that continuing natural gas financial hedging was in customers' best interest for two primary reasons:

1) Hedging is a tool every generating IOU in Florida uses to reduce the volatility of fuel rates over time.
2) Hedging a portion of their natural gas procurement provides a greater degree of fuel price certainty for customers.

Historically, the IOUs' hedging programs involved placing hedges in a non-speculative, structured manner for a certain percentage of natural gas over time whether prices were high or low, in accordance with the respective risk management plans under which each company operated. By placing hedges in this manner, the customers received a degree of price certainty for fuel purchases, which was achieved without the IOUs engaging in speculation to "out-guess" the market. Without such hedging, price certainty is gone, and customers have no protection against price swings. Without the protection from hedging a portion of natural gas purchases, significant swings in market prices could subject customers to large under and over recoveries and mid-course corrections.

In summary, because the hedging programs provide price stability to customers and a measure of protection against unanticipated dramatic price increases, the IOUs believe hedging should be continued and is in the customers' best interest.

Summary of Intervenor's position (from 2015)

OPC witnesses stated that the marginal benefit that customers received from hedging was vastly overshadowed by the historic hedging losses they have had to pay. Year over year losses from the IOUs' hedging programs demonstrate that the expectation that hedging gains and losses would offset one another did not occur. According to OPC, long term forecasts indicate an abundance of future supply coupled with slower growth in prices have led to lower price volatility for natural gas. Although the IOUs' hedging programs are designed to reduce the variability or volatility of fuel prices, external factors have already done this.

Commission Decision (from 2015)

In its 2015 Fuel Order, the Commission found that continuing natural gas hedging was in the customers' best interest, stating, in part:

> What this record clearly establishes is that without hedging, customers have a very significant exposure to natural gas price volatility due to a very dynamic natural gas market. Today natural gas prices are low and gas supply is forecasted to be abundant. However, demand for natural gas is increasing and is heavily influenced by weather and uncertain supply conditions.[8]

Analysis

In Order No. PSC-16-0547-FOF-EI (2016 Fuel Order),[9] the Commission found that resolving the hedging issues will, or may, involve looking at multiple options:

> As was requested by the parties to the Joint Stipulation, we hereby direct Commission staff to open a generic docket as soon as possible to allow all interested parties to engage in a workshop or workshops to consider all alternatives to prospectively resolving the hedging issues, including but not limited to the Gettings/Cicchetti approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether, with the goal of providing guidelines for risk management plans for 2018 and beyond that all stakeholders can either agree upon or not object to.[10]

Staff believes the "public interest" threshold is the first decision point the Commission should address. The February 21, 2017 workshop brought that consideration to the forefront.

February 21, 2017 Workshop and post-workshop comments

At the February 21, 2017 workshop, the IOUs collectively discussed a proposal to continue hedging. In post-workshop comments, the IOUs contend that the goals of hedging and the "public interest" consideration are closely related. If the Commission decides that the goal of hedging is to mitigate price spikes and to limit exposure to hedging transactions that result in losses, then the IOUs believe their current proposal accomplishes these objectives.[11] However, if the Commission decides that the goal of hedging is to mirror the market, the IOUs contend that hedging should be eliminated. As stated in FPL's post-workshop comments, a decision on the public interest and goal of hedging is imperative, and "there is no free lunch."

---

[8]Order No. PSC-15-0586-FOF-EI, p.8.
[9]Order No. PSC-16-0547-FOF-EI, p 3.
[10]Order No. PSC-16-0547-FOF-EI, p.3.
[11]At the February 21, 2017 workshop, the IOUs presented a joint proposal. Staff notes that the IOU's current proposal is addressed in Issues 2 and 3 of this memorandum.

In live comments at the workshop and in post-workshop written comments thereafter, OPC and FIPUG advocated the same general position stated in earlier documents, asserting that hedging should end. OPC advocated that other mechanisms are already available to address price volatility, as reflected in customer bills, and FIPUG asserted that it prefers to “pay at the pump.” White Springs believes that targeted-volume hedging should end, but stated that hedging is in the public interest. White Springs contended production advances and abundant reserves of natural gas are factors that have fundamentally impacted today’s market, and that the IOUs should develop hedging methods that systematically address fuel price trends and risks.

Conclusion

Staff believes the public interest decision is a threshold matter. The purpose of hedging is to minimize customer pain associated with energy price (consumer cost) increases. That is different than simply reducing volatility because customer pain is not symmetrical. The asymmetry is due to the fact that customer’s tolerance for upside cost exposure in rising-price markets is different than their tolerance for hedge losses in declining-price markets. Cost increases occur in rising cost markets where unfavorable outcomes, if unmitigated, can be severe. Hedge losses occur in declining cost markets, so outcomes are still beneficial, even if less so due to hedging. Fuel price hedging has benefits and risks. However, when executed in an economically efficient manner, staff believes that fuel price hedging activities are in customers’ best interest.

Issue 2: What changes, if any, should be made to the manner in which electric utilities conduct their natural gas financial hedging activities?

Recommendation: Consistent with the recommendation in Issue 1, staff believes that continuing fuel price hedging activities in an economically efficient manner is in the consumers' best interest and the Commission has the discretion to consider implementing changes to the manner in which the IOUs conduct their natural gas financial hedging activities. (Barrett, Cicchetti)

Staff Analysis: Similar to Issue 1, this issue also was presented in the hearing for Docket No. 150001-EI. In 2015, the record evidence for this issue was limited, with the IOUs advocating that no changes were warranted. OPC recommended that hedging be completely eliminated on a prospective basis. By advancing that position, OPC expressed that it was unnecessary to propose changes. With the exception of White Springs, the intervening parties largely supported OPC's position.

Commission Decision (2015)

In the 2015 Fuel Order, the Commission directed staff and the parties to more fully examine potential changes to the utilities' hedging programs:

> Our decision to continue hedging at this time is based on the evidence presented in this record which in large part consists of arguments to either completely eliminate hedging or to continue the procedures in place at this time. There was no written testimony from any party and very limited cross examination on possible changes to the manner in which the IOUs conduct natural gas financial hedging activities or alternatives to hedging: cost sharing of hedging gains and losses between the IOUs and ratepayers, alternative accounting treatment for recovery of gains and losses (VMM program), or imposing limits on the percentage of natural gas purchases hedged. All witnesses agreed 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. Notwithstanding our decision on hedging, we recognize that the cost of this program is significant by any measure for each Florida IOU and deserves further analysis. Therefore, we direct our staff, in conjunction with the parties to this docket, to explore possible changes to the current hedging protocol that will minimize potential losses to customers.[12]

Analysis

Staff believes this issue and the "public interest" issue (Issue 1) are inextricably related. Staff believes that if the Commission decides in Issue 1 that continuing fuel price hedging activities is in the consumers' best interest, then the Commission has a range of options from which it can choose so that electric utilities can continue natural gas financial hedging. However, if the Commission decides in Issue 1 that it does not support hedging in any manner, then staff believes this issue is moot.

[12]Order No. PSC-15-0586-FOF-EI, pp. 8-9.

Activity since the Commission's Decision (2015)

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 alternatives were proposed.

On April 22, 2016, Docket No. 160096-EI was opened to address a joint petition seeking approval of modifications to the IOUs' respective Risk Management Plans (Joint Petition). FPL, TECO, and Gulf sought approval of modifications to their respective 2016 Risk Management Plans, noting that the 2016 plans were approved in the 2015 Fuel Order. DEF did not join in seeking to modify its 2016 Risk Management Plan, because DEF believed its then-current Risk Management Plan afforded it the ability to meet the goals proposed by the other petitioners.

The Joint Petitioners proposed a two-step initiative to minimize potential losses to customers in periods of falling fuel prices. First, the Petitioners proposed reducing their hedging target ranges by up to 25 percent for procurement with hedging instruments.[13] Second, the Petitioners proposed shorter time horizons over which hedges are placed. In addition to the limited changes to the 2016 Risk Management Plans, the Petitioners proposed modifications to their 2017 Risk Management Plans, which were slated to be considered for approval at the November hearing in the Fuel Cost Recovery Clause docket (Docket No. 160001-EI). By Order No. PSC-16-0247-PAA-EI,[14] the Commission approved the Joint Petition.

On July 15, 2016, OPC timely filed a petition protesting Order No. PSC-16-0247-PAA-EI, formally requesting an evidentiary hearing. On July 28, 2016, Order No. PSC-16-0301-PCO-EI,[15] was issued to consolidate Docket Nos. 160001-EI and 160096-EI. Thereafter, in Docket No. 160001-EI (the 2016 fuel clause proceeding), the same two issues as originally proposed in 2015 were identified for resolution.

On September 23, 2016, staff witnesses Mark Anthony Cicchetti and Michael A. Gettings[16] provided testimony and exhibits to support a risk-responsive hedging program. Concurrent with the filings of staff witnesses Cicchetti and Gettings, OPC filed testimony and exhibits from witnesses Daniel J. Lawton and Tarik Noriega to advocate the substantially similar position expressed in 2015; that hedging should cease.

On September 30, 2016, the IOUs filed rebuttals to the testimony of staff witnesses Cicchetti and Gettings and OPC witnesses Lawton and Noriega.

---

[13] DEF agrees with and joined 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.

[14] Order No. PSC-16-0247-PAA-EI, issued June 27, 2016, in Docket No. 160096-EI, *In re: 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.*

[15] PSC-16-0301-PCO-EI, issued on July 28, 2016, jointly in Docket No. 160001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor, and also in* Docket No. 160096-EI, *In re: 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*.

[16] Mr. Gettings is a consultant who testified on behalf of staff in Docket No. 160001-EI about his suggested changes to the hedging practices followed by the IOUs in Florida.

On October 24, 2016, DEF, Gulf, TECO, OPC, the Florida Industrial Power Users Group (FIPUG), and the Florida Retail Federation (FRF) jointly filed a Stipulation and Agreement for Interim Resolution of Hedging Issues (Joint Stipulation) that provided that:

- DEF, Gulf, and TECO will implement a 100% moratorium on placing new hedges for all of 2017. The moratorium does not apply to hedging arrangements in place that were entered into pursuant to Risk Management Plans from prior years.

- DEF, Gulf, and TECO will withdraw their proposed Risk Management Plans for 2017.[17]

- DEF, Gulf, TECO, OPC, FIPUG, and FRF agree to cooperate with each other and Commission staff to engage in workshop(s) to consider all alternatives to resolving the pending hedging issues.

- DEF, Gulf, TECO, OPC, FIPUG, and FRF agree to negotiate in good faith to reach a settlement or other basis to dispose of the pending hedging issues on or before the anticipated due date for filing Risk Management Plans for 2018 (August 1, 2017). If these negotiations are unsuccessful, then DEF, Gulf, and TECO may submit Risk Management Plans for 2018, in advance of the expiration of the one year moratorium at the end of 2017.

The 2016 Fuel Order addressed the Joint Stipulation, and, in part, stated:

> Based on the evidence submitted in this docket, we hereby approve the Joint Stipulation and Agreement for Interim Resolution of Hedging issues, dated October 24, 2016 (the "Joint Stipulation"). Consistent with the Joint Stipulation, the parties have agreed to a moratorium on any new hedges effective immediately upon our approval of the stipulated positions offered on the hedging issues in this docket, with that moratorium extending through calendar year 2017. We therefore find that the hedging issues shall be deferred to the 2017 docket and the Joint Stipulation accepted as the replacement for the signatory companies' respective Risk Management Plans for 2017, rendering moot the company specific issues regarding their request for approval of their respective Risk Management Plans as filed for 2017. As was requested by the parties to the Joint Stipulation, we hereby direct Commission staff to open a generic docket as soon as possible to allow all interested parties to engage in a workshop or workshops to consider all alternatives to prospectively resolving the hedging issues, including but not limited to the Gettings/Cicchetti approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether, with the goal of providing guidelines for risk management plans for 2018 and beyond that all stakeholders can either agree upon or not object to.

. . .

[17]In separate filings, DEF, Gulf, and TECO withdrew their proposed Risk Management Plans for 2017.

> Consistent with our decision above, we accept the Joint Stipulation as the replacement for the signatory companies' respective Risk Management Plans for 2017, rendering moot the company specific issues regarding their request for approval of their respective Risk Management Plans as filed for 2017.[18]

Staff notes that although FPL was not a signatory to the Joint Stipulation, in a contemporaneous filing, FPL affirmed its support and agreement to follow the directives of the agreement.[19] In a separately docketed matter, FPL agreed to a four-year moratorium on financial hedging in a settlement agreement reached in FPL's 2016 rate case and other consolidated dockets (FPL Settlement). The Commission approved the FPL Settlement in Order No. PSC-16-0560-AS-EI.[20] Pursuant to the terms of the agreement, FPL will not execute any new natural gas financial hedges during the term of the agreement, which runs through December 31, 2020.

On January 10-12, 2017, a series of five conferences were scheduled between Mr. Gettings and interested stakeholders regarding possible changes to the hedging practices in Florida.[21] For the purposes of these conferences, Mr. Gettings developed an EXCEL-based risk-responsive model that used market data from the period 2001-2012. His model assumed a $2.5 billion fuel budget hedged in a risk-responsive fashion up to a maximum 65 percent of the fuel portfolio. Using these input variables, he graphically demonstrated the results of a risk-responsive hedging program compared to a targeted-volume hedging program. According to the findings, Mr. Gettings stated that the risk-responsive strategy produced market-average outcomes with mitigated peaks and valleys for that time period, compared to the targeted-volume hedging strategy, which produced a $1.1 billion loss.

On February 21, 2017, staff held a workshop to discuss natural gas hedging and related topics. During the workshop, the IOUs presented a proposal titled Out-of-The-Money (OTM) Call Options as an Alternative Form of Risk Responsive Hedging (IOU Proposal or OTM Call Options Approach). All of the IOUs, the Sierra Club, FIPUG, White Springs, and OPC filed post-workshop comments on March 6, 2017.

Goals of hedging for the Commission to consider

The Second Clarifying Order stated that the purpose of hedging is to "reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers."[22] Staff notes that this language has been cited frequently in various hedging-related pleadings since the inception of hedging. Staff believes this citation from the Second Clarifying Order is clearly associated with legacy hedging programs. As the discussion evolved about considering changes to hedging, staff believes the topic of "What should be the goals of hedging?" has been introduced, and needs to be addressed. As more fully explained in the analysis to follow, the discussion will present

[18]Order No. PSC-16-0547-FOF-EI, p.3.
[19]FPSC Document No. 08438-16.
[20]Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*
[21]During the January meetings, each IOU was allocated a 3 hour time period to allow subject matter experts the opportunity to engage directly with Mr. Gettings. The fifth and final 4 hour session was reserved for Intervenors, including the Office of Public Counsel.
[22]Second Clarifying Order at 16.

options the Commission may consider. Within that discussion, staff believes the options for such changes align with what, arguably, are newly defined goals of hedging.

Mr. Gettings testified that "the primary reason for hedging is to mitigate upside cost exposures, and the potential for hedge losses is an associated consequence which needs to be managed as well."[23] That testimony addressed a risk-responsive hedging approach that will be more fully explained below.

A second option for the Commission to consider was presented by the IOUs. The alternative presented by the IOUs revolves around two somewhat "new" goals of hedging:

1. To protect customers from large price increases, and
2. To minimize the losses that occur when natural gas prices decline from projected levels.

Staff believes the goals for hedging presented above by Mr. Gettings and the IOU's are essentially the same, but differ from the goal of simply "reducing volatility." In evaluating the options, it is important to note the distinction between "cost-risk" and "loss-risk." Cost-risk is associated with higher natural gas prices while loss-risk is associated with hedging losses in a declining-price market. Staff further believes that the most relevant question is, "What is the most economically efficient way to accomplish the goal of minimizing cost increases while minimizing hedge losses?" The analysis to follow will examine the nuances between the viewpoints set forth in the proposals of Mr. Gettings and the IOUs.

Options for the Commission to consider

Staff believes there are three primary options the Commission may consider in addressing this issue. The first option is the risk-responsive hedging approach, which was originally presented in staff-sponsored testimony and exhibits for the Fuel Clause hearing in 2016. The second option is the IOU Proposal presented at the February 2017 workshop. The third option is reinstatement of the hedging activities as conducted before the IOUs voluntarily suspended placing new hedges. This option is labeled the "status quo" option, although staff presents two variations that can be considered.

Option 1: The Risk-Responsive Hedging Approach

In Docket No. 160001-EI, Mr. Gettings provided testimony recommending that a risk-responsive hedging approach be implemented for fuel hedging. Mr. Gettings stated that mitigating upside costs as well as mitigating hedging losses is a different approach than simply reducing the price volatility exposure for customers, as was the goal of the legacy hedging methods. He used the term "customer pain" to refer to the customer's acceptance for bill fluctuations, asserting that the reactions for rising or falling prices are not symmetrical, as explained below:

> [Asymmetric pain] is due to the fact that tolerance for upside cost exposure in rising markets is different than the tolerance for hedge losses in downward

[23] Direct Testimony of Michael A. Gettings, appearing on behalf of the staff of the Florida Public Service Commission, filed on September 23, 2016, in Docket No. 160001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor* (Gettings Testimony) (FPSC Document No. 07781-17, Page 7).

> markets. Using a simple analogy for residential customers, taking a $500 better vacation with utility-bill savings would be a good thing and if utility hedge losses moderate those savings so that they are $300 rather than $500 it is still a good net outcome despite the $200 foregone savings. On the other hand, that same customer might struggle to meet necessary expenses if faced with an unmitigated $500 increase in utility costs, and that would be a very bad thing. Said differently, hedge losses occur in low-cost markets, so outcomes are still beneficial but less so; in low-cost markets customer impacts are constrained to discretionary choices regarding alternative uses of reduced savings. Cost increases occur in high-cost markets where unfavorable outcomes, if unmitigated, can be severe; also the customers' budget response is more likely to impact non-discretionary spending. So on balance, customers experience greater value from potential cost mitigation than they forego with potential hedge losses.[24]

In preparing his testimony, Mr. Gettings reviewed the 2017 Risk Management Plans, and noted that each IOU used a targeted-volume approach to accumulate hedges in accordance with a predetermined timeline. He testified that none of the 2017 Risk Management Plans provided information about how the IOUs measured risk in a quantitative fashion. Mr. Gettings observed that the accumulation of hedging losses since the natural gas pricing peak in 2008 was primarily due to hedging a targeted volume without a plan for responsive adjustments.

Mr. Gettings testified that a customer-focused risk-responsive hedging program would be an improvement over the targeted-volume approach. The risk-responsive program he recommends would use quantitative tools to measure volatility-related cost-risk and loss-risk, and the measurements would then serve as a basis for risk-responsive hedging decisions. Stated in a different manner, a risk-responsive hedging program would set Value at Risk (VAR) metrics for high and low tolerance bands, and formulate a strategy of prescribed responses to defend those tolerances against whatever risk conditions emerge.

Mr. Gettings stated that his recommended approach to a risk-responsive hedging program has four components:

1. A programmatic hedging portion for a low to moderate level of an IOUs fuel burn, 15 percent to 20 percent, for example.
2. A defensive hedging portion, with action boundaries when market prices are rising.
3. A contingent hedging portion, with action boundaries when market prices are declining.
4. A discretionary portion, which is very small, but available to take advantage of market opportunities. Mr. Gettings does not recommend using discretionary hedges and emphasizes that hedges should be executed based on a "risk-view" and not on a "market view."

[24]Direct Testimony of Michael A. Gettings, appearing on behalf of the staff of the Florida Public Service Commission, filed on September 23, 2016, in Docket No. 160001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor* (Gettings Testimony) (FPSC Document No. 07781-17, Page 5).

Mr. Gettings believes the dual goals of mitigating upside cost exposures, and actively managing the potential for hedge losses can be accomplished by following the risk-responsive (Option 1) approach. He recommended that hedging into a 36 month period is a good foundation for building a risk-responsive model, and emphasized that each IOU would have the flexibility to establish specific parameters, action limits, and boundaries to suit their risk profile. As noted above, Mr. Gettings provided a simulation for the period 2001-2012 using a basic risk-responsive strategy for a $2.5 billion dollar fuel burn compared to a 50 percent targeted-volume hedging strategy similar to the strategy employed by Florida IOUs over that period. The risk-responsive approach achieved essentially market price for natural gas while the targeted-volume approach achieved a $1.1 billion dollar loss.

Option 2: The IOU Proposal (OTM Call Options Approach)

The IOU Proposal was transmitted to staff as a PowerPoint file on February 20, 2017.[25] Penelope Rusk, an employee of TECO, was the chief spokesperson for the IOUs and conveyed their proposal as a PowerPoint presentation to the workshop attendees. The IOUs developed their plan to respond to what they believe are the new goals of hedging, which are to specify and constrain the cost threshold for upside price movement protection, and also maintain participation in declining-price markets. The IOUs believe their OTM Call Options Approach meets these goals of hedging in a simpler manner, without the complexity of multiple decision points required by the Gettings risk-responsive approach.

The IOU proposal defines an OTM Call Option as a "financial instrument that requires the purchaser to pay an up-front premium in return for the ability to receive payment if the future price of an underlying asset rises above a strike price that is higher than the current market for that asset.[26]" Although presented as a joint proposal, in practice each IOU would develop company-specific budgets for call options and thresholds that would be defined in Risk Management Plans. The decision points for each company would include setting price protection levels, the time horizon for options, and optioned volumes. From an accounting perspective, all call option premiums would be recorded as clause-recoverable fuel expenses. The IOUs characterize the cost of call options as akin to an "insurance premium" for protecting against price spikes. Staff believes examples will help illustrate the concept of call options in rising and falling markets.

Call Option Example Rising Price Market (Market Price > Option Price)

The IOU Proposal asserts that using OTM call options will protect against upward price movements because call options expiring "in the money" will provide price increase protection. Staff agrees, noting that understanding the concept of an "in the money" transaction is straightforward. "In the money" results when the option price is lower than the market price. However, the total price will include the commodity price plus a premium that was incurred in order to secure the option. The premium is incurred whether the option is exercised or not exercised. In this instance (the rising price market), the total option price is lower than the market price on the date the transaction is executed, which means the transaction was "in the money."

[25] Printed versions of the PowerPoint file were distributed on the day of the workshop (See FPSC Document Number 02730-17).
[26] FPSC Document Number 02730-17, Slide No. 5)

Call Option Example in a Falling Price Market (Option Price > Market Price)

The IOU Proposal asserts that call options expiring "out of the money" will not be exercised, and therefore, will not result in hedging losses beyond the up-front premium. Staff notes that in this scenario, the total price is not favorable to the market price on the date the transaction is executed, because the total price is higher than the market. The IOU Proposal asserts that since the option is not exercised, unfavorable hedging outcomes do not occur. However, just as in the rising market, staff observes that any time an option transaction is entered into, a premium is incurred in order to secure the option, whether the option was exercised or not exercised. In this instance (the falling price market), the fuel costs would consist of fuel purchased at a market price, plus the expense for the option premium when the option was entered into, even though the option was not exercised.

At the workshop and repeated in post-workshop filings, the IOUs stated that the risk-responsive approach is less favorable than their proposal for a number of reasons: First, the risk-responsive approach involves the use of a complex model each IOU would have to develop with significant administrative and implementation costs. Second, because this approach requires each IOU to establish cost/loss tolerances and formulate a strategy of prescribed responses, the IOUs may need to supplement their computing resources, and/or allocate a considerable amount of development time to implement that approach. In contrast, the IOUs contend that their recommended approach can be implemented quickly and easily. Third, the IOUs believe the risk-responsive approach sets up a possible conflict between contingent and defensive hedging triggers. Staff notes that possible conflicts between contingent and defensive hedging triggers are rare occurrences and the response, should that condition occur, would be addressed beforehand in the risk management plans. According to the IOUs, no such conflict would exist using the OTM Call Options approach. Fourth, the IOUs believe their proposal is more favorable than the risk-responsive approach because regulatory reporting will be substantially similar to what the IOUs are currently doing. Furthermore, the IOUs believe the regulatory reviews and audits will be easier to administer than under the risk-responsive approach. Finally, the IOUs believe the OTM Call Options approach will require fewer guidelines from the Commission to get up and running. These points were expressed in the workshop presentation, and reiterated in their post-workshop comments.

Observations from the Workshop

DEF, FPL, Gulf, and TECO individually contributed and presented portions of the IOU Proposal at the February 21, 2017 workshop.

DEF and FPL presented the results of modeling and analysis they performed in order to show what hypothetical results would have been achieved using an OTM Options method. DEF "back-tested" actual historical volume and hedging costs from 2013-2016, and FPL conducted a similar analysis using 2011-2016 data. In each time period evaluated, natural gas prices were relatively stable. In its model, DEF found that in 2013, 2015, and in 2016, the actual hedging results from programmatic hedging practices incurred higher costs than the (modeled) equivalent OTM Option amounts for those years. In 2014 the opposite occurred, as DEF found that the gross equivalent cost for option premiums was modeled to have greater cost than actual hedging costs incurred in that period. DEF states that its modeling demonstrates that call options protect against price increases above established cost price thresholds.

FPL's modeling was somewhat similar to DEF's, although staff notes that FPL used historical data for 2011-2016, and tested hypothetical results for hedging using a risk-responsive approach, compared to an OTM Call Option approach. For the hypothetical risk-responsive approach, FPL used a strategy modeling Defensive hedging up to a maximum 65 percent of the fuel burn. For the hypothetical OTM Call Option modeling, FPL used a 15 percent level for OTM Options covering 60 percent of the fuel burn, and the OTM cost total included the cost of option premiums. FPL stated the results of its modeling indicate:

1. The OTM Call Option Approach accomplishes an important goal: it provides a viable hedge against upside price risk while providing market price on the downside.
2. The OTM Call Option Approach shows significant cost advantages over the risk-responsive model when prices decline. The risk-responsive strategy had a slightly lower net gas cost in periods of rising prices.

The analyses Gulf and TECO performed were somewhat different from the analyses performed by DEF and FPL. Gulf provided graphs to show the relationship between market prices and call option prices. TECO did not back test, but instead presented information to demonstrate what OTM thresholds at 15 percent and 30 percent would look like using various theoretical 2018 market settlement prices. When it developed this data, TECO stated that the 2018 forward curve price of natural gas was $3.11/mmBtu (as of February 2017). For its modeling, TECO assumed call option premium costs of between $10-18 million were rolled into the final resulting price for OTM hedges. Using those thresholds, TECO's model indicated that:

1. If the final market settlement price ends up being lower than the OTM strike price, then the resulting price for the hedged natural gas will be above market.
2. If the final market settlement price ends up being above the OTM strike price, then the resulting price for the hedged natural gas will be below market, and premium cost increases will be limited.

An excerpt of the results of TECO's model is shown in Table 2-1 below:

Table 2-1
Modeled Results of Hypothetical OTM Call Options Approach from TECO

2018 Theoretical Market Settlement Price ($/mmBtu)	15 Percent OTM Call Options ($/mmBtu)	30 Percent OTM Call Options ($/mmBtu)
$2.50	$2.75	$2.64
$3.00	$3.25	$3.14
$3.50	$3.72	$3.64
$4.00	$3.72	$4.08
$4.50	$3.72	$4.08

Source: Excerpt of Slide No. 8 from IOU Proposal (FPSC Document Number 02730-17)

Joint Analysis (of Options 1 and 2)

On March 6, 2017, all 4 IOUs filed post-workshop comments, along with Sierra Club, FIPUG, White Springs, and OPC. These comments are summarized below:

OPC Comments

In its comments, OPC believes three threshold questions must be addressed before critiquing the Gettings approach (Option 1) or any hedging alternative. The questions OPC presented are as follows:

1. What should the Commission's volatility response policy (VRP) be as it relates to the price of natural gas recovered through the annual fuel adjustment clause?
2. Is there a lower cost or cost-free mechanism to mitigate fuel price volatility experienced by the customer?
3. How has natural gas price volatility decreased as a result of the discovery, production (fracking), and development of enormous natural gas reserves (supply) in recent years?

The OPC believes hedging was developed as a mitigation tool for price volatility, not expressly to provide fuel cost savings. Even without hedging, OPC believes the Commission already has access to VRP tools to address price volatility. The annual resetting of fuel cost recovery factors is one such tool, the mid-course correction process is another, and case-by-case considerations for spreading costs over extended time periods is another, according to OPC. OPC acknowledges that the Gettings approach might be more favorable than targeted-volume hedging, yet doubts whether the method would limit costs. OPC believes today's market is more mature and less prone to wide swings in volatility, due to ample, long-term supply reserves.

Sierra Club Comments

Although not squarely directed at Options 1 or 2, the Sierra Club believes the over-reliance on natural gas in Florida puts significant risk on all ratepayers, and financial mechanisms like these approaches are akin to "fixing pot-holes" as opposed to repaving the road. The Sierra Club believes the Commission should require the IOUs to invest in energy efficiency and generating sources that provide electricity without volatile fuel costs. According to the Sierra Club, the approach it recommends can limit ratepayer exposure to risk without relying on financial mechanisms.

White Springs and FIPUG Comments

White Springs and FIPUG offered general comments on hedging methods and results, but did not specifically comment on the Gettings approach (Option 1) or on the OTM Call Options Approach (Option 2).

Comments from the IOUs

As noted previously, the IOUs first challenged the risk-responsive approach (Option 1) in rebuttal testimony in September 2016. In the January 2017 series of conferences, subject matter experts from each IOU were given the opportunity to learn more about the risk-responsive approach, and directly questioned Mr. Gettings as they critically examined the EXCEL-based risk-responsive model developed specifically for those conferences. That model used historical data and parameters to graphically show how the hedging results he recommended under a risk-responsive hedging program compared to a targeted-volume hedging program. After actively participating in the January conferences, and thoroughly studying the risk-responsive approach, the IOUs collectively worked to develop an alternative to it, which resulted in their own proposal (OTM Call Options Approach, Option 2).

In post-workshop comments, the IOUs stated that the risk-responsive approach is considerably more complex than their own proposal. The IOUs believe the risk-responsive approach has merits, but does not completely eliminate hedging losses and involves many challenges for implementation and regulatory review. The IOUs contend that under risk-responsive hedging (Option 1), setting Company-specific action boundaries and risk-response protocols will be a significant undertaking; a task that no other IOU in the United States has undertaken. Staff notes this statement is inaccurate. Mr. Gettings has stated that IOUs in numerous states and Canada have deployed these methods but client confidentiality precludes disclosure of exactly which companies. IOUs in Pennsylvania, Indiana, Louisiana, and Washington, as well as public power companies in New York, Texas, California, the Carolinas, etc. have used these methods. It is true that the risk-responsive methodology has been more widely accepted by large public power companies, but the reason has nothing to do with effectiveness. As explained in Mr. Gettings' testimony, the reason is that prudence risk looms large in the IOU space, and barring an understanding with regulators, most IOUs prefer to adopt risk-blind methodologies.

Staff Analysis

On March 13, 2017, the Washington Utilities and Transportation Commission issued a Policy and Interpretive Statement on Local Distribution Companies' Natural Gas Hedging Practices (Washington Commission Statement) that endorsed the adoption of what is presented here as risk-responsive hedging (Option 1).[27] Staff believes this action has important implications for the instant matter before this body. Staff acknowledges that at the time the IOUs prepared their post-workshop comments, no regulatory body had ordered the implementation of hedging plans built around the concepts of a risk-responsive plan. In part, the Washington Commission Statement provides:

> The [Gettings] White Paper serves as a foundational document for the Commission's policy position on natural gas utility hedging practices. The White Paper provided the Commission with convincing evidence that strict programmatic hedging strategies disable utility capacity to adequately mitigate price risk to ratepayers. In describing the function of risk-responsive hedge strategies, which demonstrate the value of measuring and responding to changing market risk conditions, the White Paper provides guidance to lead the Companies toward more robust risk management programs.
>
> It is the Commission's explicit policy preference that the Companies employ risk-responsive hedge strategies. The singular programmatic hedging approach

[27]The Washington Commission Statement was filed in this docket on March 14, 2017 (FPSC Document Number 03531-17). This document refers to the July 25, 2015 publication from Mr. Gettings, *Natural Gas Utility Hedging Practices and Regulatory Oversight* (Gettings White Paper). Although the Gettings White Paper was not presented in its entirety as hearing evidence in Docket No. 160001-EI, staff witnesses Cicchetti and Gettings cited information from this published work.

> employed by many utilities fails to balance upside price risk with hedge loss risk in any meaningful way. An inflexible plan makes a utility's hedging less adaptable to changing conditions. Utilities must find a way to manage, simultaneously and continuously, upside price risk and downside hedging loss, and evaluate whether the "insurance" benefit justifies the cost.
>
> . . .
>
> The Companies should develop a framework for risk mitigation informed by quantitative metrics. Quantitative metrics allow utilities to measure, monitor market risk conditions, and facilitate identification of meaningful hedging responses. While we stop short of requiring use of the specific value-at-risk (VaR) methodology described in the White Paper, it is clear to us that each utility must develop robust analytical methods and incorporate these methods in their risk management frameworks.[28]

The IOUs contend that implementing the risk-responsive approach (Option 1) is complex and that ramp-up activities for implementing it would be costly, and take up to 2 years.[29] Staff observes that the Washington Commission Statement also acknowledged that implementing a risk-responsive hedging program will take time to get up and running, stating "the Commission expects that full implementation will take no longer than 30 months."[30]

In addition, the IOUs contend the risk responsive approach (Option 1) is not the best path forward because components of the plan involve discretionary transactions, which invites uncertainty in terms of regulatory reviews. The uncertainty comes about because individual IOUs participating in a common market may use that discretion by reacting to market signals in different ways. Staff notes that the Washington Commission Statement addressed the topic of uncertainty and prudence reviews as well, stating:

> Consistent with our intention not to be overly prescriptive about *how* the Companies develop more robust, risk-responsive hedge strategies, we decline here to be formulaic in suggesting how utilities ought to operate in a prudent manner. We adopt an affirmative policy that natural gas company hedging programs must adapt to constantly changing market risk conditions, and that utilities should seek to "[implement the most economically superior strategy] that produces a cost-mitigation tolerance with the smallest hedge-loss exposure."[31] The Companies must determine how best to achieve these objectives.
>
> Nevertheless, the Commission expects utilities to make reasonable progress in developing a more sophisticated risk management framework consistent with this policy statement. As we move forward, we are more likely to entertain arguments

[28]FPSC Document Number 03531-17, pp. 12-13.
[29]For example, in its post-workshop comments, Gulf estimates that it would incur $250K in non-recurring costs to implement the Cicchetti/Gettings approach, plus another $100K in recurring costs for staffing.
[30]FPSC Document Number 03531-17, p. 14.
[31]Gettings White Paper at 15.

> regarding the prudency of extraordinary hedging losses, particularly for companies that continue to rely upon a strict programmatic hedging approach. Therefore, continuing to maintain largely static hedge ratios without justification will become an increasingly risky proposition.
>
> In light of expert recommendation and comments filed in this proceeding, we determine that the Commission's existing prudence standard remains sufficient to evaluate decisions and subsequent outcomes related to hedging losses.[32]

In Florida, the Commission's process for prudence review is similarly structured to accommodate any modifications the Commission approves to the IOUs' methods of hedging.

Based on their modeling, the IOUs contend Option 2 will produce results similar to a risk-responsive plan, without the implementation challenges of the risk responsive approach (Option 1), or the regulatory review concern. To support this contention, FPL put forward the results of its comparative model during the February workshop. As noted previously, the risk-responsive model FPL compared to its OTM Plan used defensive hedging practices for up to a maximum of 65 percent of the fuel portfolio. For its hypothetical OTM Call Option models, FPL used a 15 percent level for OTM Options covering 60 percent of burn, and the OTM cost total included the cost of option premiums. FPL claims these results indicate that its OTM Call Option Approach provides a viable hedge against upside price risk while providing market price on the downside. In addition, FPL believes the OTM Call Option Approach shows significant cost advantages over the risk-responsive model when prices decline. The differences are less significant in a rising price environment, according to FPL.

Staff notes, however, that FPL's modeling may not be instructive for several reasons. First, during the time period FPL selected for its study presented in the workshop (2011-2016), the market prices for natural gas can be characterized as stable and low. During this time period, there were no significant peaks or valleys in the market. Staff notes, however, that in its post-workshop comments filed on March 6, 2017, FPL expanded its analysis to encompass the 2007-2016 period, as shown below in Table 2-2.

[32]FPSC Document Number 03531-17, p. 15.

Table 2-2
Comparative Results of OTM Call Option and Risk Responsive hedging approaches from FPL

Year	Market Settlement Prices ($/mmBtu)	Hypothetical Risk/Response Approach Results [with Defensive hedging up to 65% against price increases] ($/mmBtu)	Hypothetical OTM Call Options Approach [with 15% OTM Options covering 60% of burn and includes the cost of option premiums] ($/mmBtu)	Difference in Average Annual Cost between Hypothetical Risk/Response Approach Results and OTM Call Options Results ($/mmBtu)
2007	$6.86	$7.70	$7.49	($0.21)
2008	$9.03	$9.07	$9.15	$0.08
2009	$4.04	$5.56	$4.48	($1.08)
2010	$4.40	$5.17	$4.77	($0.40)
2011	$4.05	$4.47	$4.32	($0.15)
2012	$2.79	$3.52	$2.92	($0.60)
2013	$3.65	$3.92	$3.80	($0.11)
2014	$4.41	$4.28	$4.46	$0.18
2015	$2.66	$3.27	$2.78	($0.49)
2016	$2.46	$2.57	$2.58	$0.01
2007-2016 Average	$4.44	$4.95	$4.67	($0.28)

Source: Excerpt of Exhibit 1 from FPL's Post-workshop comments (FPSC Document Number 03145-17)

Staff believes FPL's expanded analysis is a more instructive comparison than what FPL presented at the workshop because it includes a period of higher volatility. Table 2-2 shows that FPL would have spent $374 million in 2007 and $1.7 billion over the ten-year period ending in 2016. That astronomical sum only provides rolling one-year hedge coverage. It is unlikely that any company would spend that amount of money in options premiums and it might not even be possible to find counterparties to execute that magnitude of options. The options market is far less liquid than the swap market. If in 2007, FPL's management, facing a prospective $374 million outlay, decided to limit it's expenditure to a more reasonable $100 million, the hedge ratio going into the price spike would have been a fraction of the numbers presented.

Further, a one-year hedge is of limited value. One can imagine the prudence discussion if $374 million were expended and prices did not rise substantially, but going into the next year prices increased dramatically before hedge coverage was secured. Extending option coverage to a two-year horizon would increase the options budget to well over twice the $374 million level because options for the second year would demand about twice the premium requirements. It is doubtful any firm would have an appetite for an approximately billion dollar option premium expenditure to cover two gas years. Staff believes that Table 2-2, taken on face value, illustrates the impracticality of the out-of-market option strategy.

Staff notes that the EXCEL-based model that Mr. Gettings developed for the January 2017 conferences used market data for the period 2001-2012, which is a broader analysis than FPL's expanded analysis, and encompassed at least two market peaks driven by weather-related events and a financial crisis. The OTM Call Options strategy is not risk-responsive. It deploys a predetermined budget on a calendar-based schedule and does not quantify and monitor risk. In addition, this strategy does not provide for real-time responses to potentially extreme cost outcomes. There has been no demonstration that the IOU-proposed OTM Call Options strategy can respond effectively to stressed cost environments.

In its post-workshop comments, TECO did not directly challenge the risk-responsive model as did FPL, but instead presented data comparing the difference between the performance of legacy hedging to a hypothetical 30% OTM model, as shown in Table 2-3 below:

Table 2-3
Comparative Results of 30% OTM Call Option proposal and legacy hedging approaches from TECO

Year	Hedging Results of Previous Swap Program ($)	Hypothetical OTM Call Options Proposal [with 30% OTM Options] ($)	Difference in Average Annual Cost between Previous Swap Program results and a 30% OTM Call Options Results ($)
2005	$53,231,770	$59,937,177	$6,705,407
2006	($54,482,120)	($9,849,134)	$44,632,986
2007	($59,691,520)	($49,825,107)	$9,866,413
2008	$18,147,375	($11,485,107)	($29,633,374)
2009	($193,185,985)	($30,692,292)	$162,493,693
2010	($67,840,710)	($27,561,549)	$40,279,161
2011	($33,889,480)	($12,723,142)	$21,166,338
2012	($61,518,120)	($6,566,356)	$54,951,764
2013	($3,256,370)	($8,181,402)	($4,925,032)
2014	$15,615,785	($3,245,652)	($18,861,437)
2015	($39,842,325)	($3,756,058)	$36,086,267
2016	($19,333,375	($5,401,428)	$13,931,947
2005-2016 Totals	($446,045,075)	($109,350,943)	$336,694,132

Source: Excerpt of TECO's Post-workshop comments (FPSC Document Number 03177-17)

Staff notes, however, that TECO does not provide information on what the options budget would have been for this period, or whether its impact was rolled into the totals shown.

Summary (Pros and Cons of Options 1 and 2)

To facilitate the Commission's consideration of the 3 options, staff presents a summary of the most and least favorable aspects of these options.

Pros of Option 1 (Risk-responsive approach)

1. Each IOU would have the flexibility to establish Value at Risk metrics to suit their risk profile.
2. Strategies could be structured to achieve the dual objectives of cost mitigation and hedge loss constraint.
3. Setting action boundaries "pre-plans" what actions will be taken when specific market conditions are encountered, and mitigates regulatory review concerns.
4. Monitoring risk tolerance levels and action boundaries engages executive oversight of hedging programs (more so than only hedging to a targeted volume).
5. The simulations of two major price spikes and a financial crisis between 2001 to 2011 indicate superior performance as to hedge loss mitigation as compared to the targeted-volume approach.
6. Risk-responsive strategies will significantly mitigate hedge losses in falling-price markets compared to targeted-volume approach.

Cons of Option 1 (Risk-responsive approach)

1. By and large, this is a new approach for Florida's IOUs. Each IOU would have to configure (or procure) resources in order to implement this option on the front end, and on an on-going basis. However, staff notes that given the dollars at stake, any administrative cost advantage of the OTM Call Option strategy is dwarfed by the potential economic advantages of a superior approach.
2. The set up time may be up to 2 years. One IOU (Gulf) estimated that its implementation cost would be $250,000.
3. Even though only a small portion of hedging under this plan is discretionary, the IOU faces a degree of uncertainty in regulatory reviews for this portion of hedging expenses. Although, as Mr. Gettings stated, discretionary hedges are not required and might never be used. Discretionary hedges are meant for seasoned managers to be able to take advantage of market opportunities. The Commission can prohibit discretionary hedges, if it so desires, in its annual review of the risk management plans.
4. OPC and other parties do not believe financial hedging is needed at all.

Pros of Option 2 (OTM Call Options approach)

1. Each IOU could implement this option without significant delay or expense. Transitioning from placing swaps to call options would not require the resources needed for implementing Option 1.
2. Having call options in-place benefits customers in rising markets, but only after price increases exceed premium investments. Call options provide a hedge against rising prices, and are akin to having an insurance policy to avoid large hedging losses because customers pay the market price plus the premiums even if the call options are not exercised.
3. In falling-price markets, customers will pay the market price for natural gas, plus the cost of option premiums, thereby avoiding significant hedge losses.

4. Minor or no changes are necessary for reporting and/or regulatory filings. Annual audits will be more straightforward than under Option 1.

Cons of Option 2 (OTM Call Options approach)

1. Option premiums add a "cost" to hedging regardless of which way the market moves. Although rising markets will mask, offset, or mitigate this cost, stable or declining markets will expose this cost.
2. Market activity (which is outside of the IOU's control) may drive up the price of call options. It is conceivable that in stressful market conditions, call options would be unavailable at any price.
3. A call option strategy is more limiting than a risk-responsive strategy.
4. The call option strategy is economically inferior to a risk-responsive, monitor-and-respond strategy. Loss-risk and cost-risk outcomes are superior under the risk-responsive approach in the most stressful market scenarios.
5. OPC and other parties do not believe financial hedging is needed at all.

Option 3: Resume Status Quo Hedging Practices (unrestricted or restricted)

In presenting the Commission with the choice to resume the current (or legacy) targeted volume hedging practices, staff is identifying two variations to this option. For purposes of this analysis, staff will use the terms "unrestricted" and "restricted" to generally describe whether the Commission decides to impose any specific parameters on the IOUs.

Prior to withdrawing their 2017 Risk Management Plans, staff notes that in April 2016, the IOUs proposed modifications to restrict the time horizons for hedges as well as to reduce the maximum hedge volumes for their in-place hedging programs. Recall also that prior to the February 2017 workshop, the risk-responsive approach (Option 1) was the principle alternative to the legacy targeted volume hedging practices.[33]

Staff believes that if the legacy hedging programs are resumed, the Commission may entertain making changes. As a result, the analysis discussing the resumption of status quo practices without modifications will assume that the Commission will not specify any time horizons for placing hedges, or place any limits on hedging volumes. Similarly, the analysis discussing the resumption of status quo practices with modifications presumes that the Commission reserves the right to specify limitations on time horizons for placing hedges, or on hedging volumes for each IOU.

Unrestricted

In the Second Clarifying Order, the Commission refined the guidelines for hedging and risk management plans.[34] Staff notes that the guidelines clarified the timing and content of the reports that summarize hedging activities, but allowed the IOUs to exercise discretion to create and implement flexible risk management plans. Staff believes this flexibility is primarily the time

[33] As noted earlier, Mr. Gettings developed an EXCEL-based risk-responsive model that compared the performance of targeted volume hedging strategy to his recommended strategy, finding that the targeted volume strategy produced a $1.1 billion loss for the study period.

[34] Order No. PSC-08-0667-PAA-EI (Second Clarifying Order), issued October 8, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor*.

horizons for hedges and hedge volumes that each IOU specifies in the confidential portions of their risk management plans. Without compromising any proprietary information from any party, staff can attest that this flexibility was evident in current and prior risk management plans from all four IOUs.

As noted in Issue 1, staff believes fuel price hedging has benefits and risks. As an alternative in addressing this issue, staff believes the Commission can consider the resumption of status quo hedging practices without any modifications.

Restricted

Since the issuance of the 2015 Fuel Order, the Commission has reviewed a substantial amount of hedging-related data and has evaluated the testimony and exhibits from subject matter experts. From a historical perspective, staff notes that DEF, FPL, Gulf, and TECO have all implemented targeted volume hedging programs that are tailored to Company-specific requirements. Stated differently, because of size, scale, fuel procurement needs, and other factors, hedging has not been implemented as a "one-size-fits-all" component of procurement. Nevertheless, staff believes modifications could be imposed in a manner that preserves the flexibility intended in the Second Clarifying Order.

Staff believes imposing a time horizon for placing hedges or placing limits on hedging volumes can be approached from the perspective of stating maximum allowable limits. Staff believes uncertainty rises as the maximum time horizons extend prospectively, and the same is true for hedging volumes. Staff believes the Commission should strike a balanced approach when considering modifications. Striking such a balance allows the Commission to set maximum common limits for all IOUs, while at the same time permitting an individual IOU to optimize its own hedging program to address its specific needs. Staff believes the following are reasonable modifications the Commission could implement in resuming targeted volume hedging practices:

1. Adjust the time horizon for placing hedges.
2. The maximum volume that IOUs may hedge is 50 percent of their projected burn.

Conclusion

Consistent with the recommendation in Issue 1, staff believes that continuing fuel price hedging activities in an economically efficient manner is in the consumers' best interest. The Commission has the discretion to consider implementing changes to the manner in which electric utilities conduct their natural gas financial hedging activities. Staff believes the Commission should not be overly prescriptive regarding the IOU's hedging strategies. However, staff believes the IOUs should have reasonable plans for dealing with market volatility and unexpected price shocks. Overall, the IOUs should strive to balance the risk of price spikes with customers' concerns about hedging losses. The historical reliance upon a strict programmatic, targeted-volume hedging strategy did not achieve such a balance.

Issue 3: If changes are made to the conduct of natural gas hedging activities, what regulatory implementation process is appropriate?

Recommendation: Staff believes the Commission's decision in Issue 2 will dictate what changes to the regulatory implementation process are needed, if any. (Barrett, Cicchetti)

Staff Analysis: Staff notes that Issues 1, 2, and 3 are all inter-related. As noted in the Case Background, natural gas hedging activities are described in annually-filed Risk Management Plans. These plans are filed on a prospective basis to detail each IOU's plan for hedging in the forward year.[35] Staff notes, however, that the 2017 Risk Management Plans were withdrawn, and the crux of this issue is whether 2018 Risk Management Plans, if any, can be reviewed, approved, and in-place to implement whatever decisions are made in Issues 1 and 2 of this recommendation. Pursuant to Order No. PSC-17-0053-PCO-EI,[36] the 2018 Risk Management Plans, if any, are due to be filed on July 27, 2017.

Staff believes that the discussion addressing regulatory implementation processes should encompass regulatory review and reporting requirements. During the January 2017 and February 2017 meetings, the IOUs expressed some general concerns about reporting and regulatory reviews, and, specifically, how any changes to the manner in which IOUs hedge would engage new and/or different regulatory reviews and reporting protocols. Before discussing any possible changes to regulatory implementation processes, staff will provide information on regulatory review and reporting steps that are currently in place.

Current Regulatory Reviews and Reporting

Regulatory review and reporting are closely related topics. Staff uses the term "reporting" to describe documents that the IOUs file with the Commission. As noted in the Case Background, the Hedging Order, first issued in 2002 and later clarified twice in separate orders in 2008, set forth certain reporting arrangements that are still in-place.[37] For the 2016 and prior Risk Management Plans, staff has consistently followed a 4-step regulatory review process summarized below:

1. After forward year Risk Management Plans are filed by each of the IOUs in the Fuel Cost Recovery Clause (Fuel Clause) docket, staff identifies a Company-specific issue for the approval of each plan.[38]

2. Through its approved Risk Management Plan, each IOU would conduct the hedging activities set forth therein. From a reporting standpoint, each IOU would capture the results of all hedging activities, and individually file bi-annual reports reflecting the

[35]In commodity trading documents, the term "forward year" is used to describe "the next" year. In the fuel cost recovery clause process, risk management plans are usually filed in the August/September time period each year, and are described using the applicable forward year. For example, the 2016 risk management plans carry "2016" in their titles, although the documents were filed in September of 2015, and were approved in the 2015 Order.
[36]Order No. PSC-17-0053-PCO-EI, issued February 20, 2017, in Docket No. 170001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor*.
[37]See footnotes 2, 3, and 4.
[38]For example, the 4 issues in the Fuel Clause hearing for approval of the forward year Risk Management Plan are structured as follows: "Should the Commission approve [Party Name]'s 20[XX] Risk Management Plan?"

hedging results over a historic 12 month period.[39] The Commission's review of hedging covers a 12-month period that runs from August 1 of the prior year to July 31 of the current year. Because of this reporting sequence, Commission staff and auditors review Risk Management Plans from the prior and current years.

3. On an annual basis, Commission staff and auditors review and analyze the hedging practices each IOU followed, as well as the results detailed in the bi-annual reports. Commission staff auditors offer testimony, with Company-specific audit reports attached as exhibits to their testimony.

4. Staff identifies a Company-specific issue to consider whether the IOU took prudent actions in following its approved Risk Management Plan.[40]

Staff believes the current review process summarized above has worked well for the Commission's purposes, and is adaptable to accommodate any decision that the Commission makes on Issue 2. Commission staff and auditors carefully review the hedging-related documents on a recurring, annual basis, and those reviews become the foundation for recommendations that come before the Commission on an annual basis during the Fuel Clause hearing.

Options for the Commission to consider

Consistent with the organization of Issue 2, staff believes this issue can be presented by examining the options identified in that issue.

Option 1: Risk-Responsive Hedging Approach

Under the risk-responsive model being considered, Mr. Gettings recommends that IOUs collect weekly data on their respective hedging activities, and compile the weekly data into quarterly reports that would be filed with the Commission.[41] Mr. Gettings believes the IOUs should reset action boundaries on an annual basis, and detail any and all changes in their Risk Management Plan filings. He believes the regulatory review should focus on whether a Risk Management Plan was followed, which is consistent with the staff's current objectives in reviewing hedging-related results.

During the January 2017 meetings and at the February 2017 workshop, the main implementation concern the IOUs expressed about the risk-responsive hedging approach was the cost and the complexity of building such a program from the ground up. In the workshop, representatives stated that the ramp-up time would be about 2 years, and that all such changes would appear in their Risk Management Plans for 2020.

[39]The bi-annual reports are generally filed in April and August of the current year, although the earlier filing captures result from the prior year. The April report captures data from the 5 month period of August 1 through December, 31 of the prior year. The August report captures data from the 7 month period of January 1 through July, 31 of the current year.

[40]For example, the four issues in the Fuel Clause hearing for attaching prudence for following approved Risk Management Plans are structured as follows: "Should the Commission approve as prudent [Party Name]'s actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in [Party Name]'s April 20[XX] and August 20[XX] hedging reports?"

[41]Mr. Gettings recommends that data be collected on a weekly basis, and the quarterly reports would be a roll-up of the results from 13 consecutive weekly reports.

Option 2: OTM Call Options Approach

As noted previously, the IOU Proposal was not addressed in testimony or exhibits, and came to the forefront very recently. Nonetheless, the IOUs contend that the OTM Call Options approach could be implemented very quickly, acknowledging that some transition would be necessary. The transition, however, would not impact any of the current swap transactions that were entered into pursuant to older, previously approved Risk Management Plans, as those transactions would be settled as new call options are placed. Until all such (older) hedging arrangements have been exercised, the reporting of hedging results would include both swaps and options. The current schedule for reporting hedging results (with bi-annual filings, and forward year Risk Management Plans filed in late July/early August) would work for the OTM Call Options approach, according to the IOU Proposal.

The most significant step for implementing the OTM Call Options approach would be setting up the Company-specific transitional goals and budgets applicable for these programs, while at the same time monitoring the swap transactions that are "rolling off." The IOU Proposal did not specify or recommend what goals or budgeted amounts would be appropriate for this year, or any future period.

Option 3: Resume Status Quo Hedging Practices (unrestricted or restricted)

If the Commission decides (in Issue 2) to resume status quo hedging practices in a modified or unmodified manner, staff believes no implementation process changes are necessary. Staff believes it is reasonable for the IOUs (except FPL) to file 2018 Risk Management Plans as scheduled. Staff believes the current schedule for reviewing the 2018 Risk Management Plans is adequate.

Joint Analysis (of Options 1 and 2)

In evaluating Option 1, staff believes the implementation concern the IOUs raised about the ramp-up time of 2 years is overstated. Staff believes a more realistic objective would be to treat 2018 as a transition period, with an aspiration to fully implement a risk-responsive hedging approach in time for the Risk Management Plans for 2019.

Staff believes the recommendation from Mr. Gettings to require the filing of 13-week (quarterly) reports is reasonable, and would not be costly, or burdensome for the IOUs to implement, if the Commission chooses to adopt it. As described above, the IOUs currently file hedging results (for a twelve month period) in two reports, and administratively, this recommended modification would alter the reporting period to thirteen weeks, which would introduce a requirement for the IOUs to file two new documents with the Commission. Staff believes, however, that staff and interested parties would benefit by having access to more current and more frequent data to evaluate.

Staff believes the recommendation from Mr. Gettings to require the filing of 13-week (quarterly) reports is reasonable, and could be implemented. Staff believes no other regulatory reporting changes are necessary, or recommended. Staff believes the review functions currently followed work well for the Commission's purposes and can be modified to accommodate a risk-responsive hedging approach.

Based on the assertions from the IOUs in the February 2017 presentation made about Option 2, staff agrees with the statement that the OTM Call Options approach could be implemented quickly. Although not placing new swap transactions at this time due to the 2017 moratorium, staff believes the hedging staff organizations that each IOU has at this time could transition to placing OTM Call Options, once program goals and budgets were established.

If the Commission decides (in Issue 2) that the OTM Call Options approach should be implemented, staff believes it is reasonable for the IOUs (except FPL) to address implementation matters in their 2018 Risk Management Plans. From a reporting perspective, staff believes no changes are needed.

Analysis (of Option 3)

If the Commission decides (in Issue 2) to resume status quo hedging practices in a modified or unmodified manner, staff believes no implementation process changes are necessary.

Conclusion

Staff believes the Commission’s decision in Issue 2 will dictate what changes to the regulatory implementation process are needed, if any.

Issue 4: 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: March 23, 2017

TO: Carlotta S. Stauffer, Commission Clerk, Office of Commission Clerk

FROM: Laura V. King, Division of Engineering, Chief of Reliability and Resource Planning

RE: Docket No. 160065-WU – Application for increase in water rates in Charlotte County by Bocilla Utilities, Inc.

Attached for filing is the revised recommendation in the above-named docket. This recommendation was deferred from the February 7, 2017 Commission Conference and is to be heard at the April 4, 2017 Commission Conference. There have been changes to Issues 1 through 5, and 12 through 14, with fall-out changes in several additional Issues. Staff sent its fourth data request to the Utility February 13, 2017, with responses due February 20, 2017. The Utility responded in part February 20, 2017, and in full March 10, 2017. Staff sent its fifth data request February 27, 2017, with responses due March 6, 2017. The Utility responded in part March 7, 2017, and in full March 8, 2017. The changes to staff's recommendation were made to reflect information contained in these data request responses.

EXE Approval ____________

ARH:pz

Attachment

Revised 3/23/17

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: March 23, 2017

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Hill, Graves, King)
Division of Accounting and Finance (Frank, Norris)
Division of Economics (Hudson, Johnson)
Office of the General Counsel (Leathers, Crawford)

RE: Docket No. 160065-WU – Application for increase in water rates in Charlotte County by Bocilla Utilities, Inc.

AGENDA: 04/04/17 – Regular Agenda – Proposed Agency Action – Except for Issue Nos. 21 and 23 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Polmann

CRITICAL DATES: 04/04/17 (5-Month Effective Date Waived Through April 4, 2017)

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

Bocilla Utilities, Inc. (Bocilla or Utility) is a Class B utility providing water service to approximately 400 water customers in Charlotte County. Effective February 12, 2013, Bocilla was granted water Certificate No. 662-W.[1] Bocilla's rates have never been established for ratemaking purposes by the Florida Public Service Commission (Commission or PSC).

On May 24, 2016, Bocilla filed its application for the rate increase at issue. The Utility requested that the application be processed using the Proposed Agency Action (PAA) procedure. The test year established for interim and final rates is the 12-month period ended December 31, 2015.

The Utility's application did not initially meet the minimum filing requirements (MFRs). On June 23, 2016, staff sent Bocilla a letter indicating deficiencies in the filing of its MFRs. The Utility filed a response to staff's deficiency letter which satisfied the MFRs on July 19, 2016, and thus the official filing date was established as July 19, 2016, pursuant to Section 367.083, Florida Statutes (F.S.).

The Utility asserts that it is requesting an increase to recover reasonable and prudent costs for providing service and a reasonable rate of return on investment, including pro forma plant improvements. Bocilla is requesting final rates designed to generate annual revenues of $552,015. This represents a revenue increase of $161,000 (41.17 percent). The Utility requested interim rates, which were granted on August 29, 2016.[2] This recommendation addresses Bocilla's requested final rates. The 5-month effective date has been waived by the Utility through April 4, 2017. The Commission has jurisdiction pursuant to Section 367.081 and 367.091, F.S.

---

[1] Order No. PSC-13-0228-PAA-WU, issued May 29, 2013, in Docket No. 130067-WU, *In re: Application for grandfather certificate to operate water utility in Charlotte County by Bocilla Utilities, Inc.*
[2] Order No. PSC-16-0364-PCO-WU, issued August 29, 2016, in Docket No. 160065-WU, *In re: Application for increase in water rates in Charlotte County by Bocilla Utilities, Inc.*

Discussion of Issues

Issue 1: Is the quality of service provided by Bocilla satisfactory?

Recommendation: Yes. Staff recommends that the quality of Bocilla's product and the condition of the water treatment facilities is satisfactory. It appears that the Utility has attempted to address customers' concerns. Therefore, staff recommends that the overall quality of service for the Bocilla water system in Charlotte County is satisfactory. (Hill)

Staff Analysis: Pursuant to Rule 25-30.433(1), Florida Administrative Code (F.A.C.), in water rate cases, the Commission shall determine the overall quality of service provided by a Utility. This is derived from an evaluation of three separate components of the Utility's operations. These components are the quality of the Utility's product, the operational conditions of the Utility's plant and facilities, and the Utility's attempt to address customer satisfaction. Bocilla's compliance with the Department of Environmental Protection (DEP) regulations, and customer comments or complaints received by the Commission, are also reviewed. The rule further states that sanitary surveys, outstanding citations, violations, and consent orders on file with DEP and the county health department over the preceding three-year period shall be considered. Additionally, Section 367.0812(1), 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 DEP.

Quality of Utility's Product

Bocilla's service area is located in Charlotte County. Bocilla purchases all of its water from the Englewood Water District (EWD). Staff's evaluation of Bocilla's water quality consisted of a review of the Utility's compliance with DEP standards. On October 23, 2014, the Utility provided affirmation to DEP that it removed its water treatment facility from service and became a consecutive user.

As a consecutive water user, Bocilla only maintains its distribution system and no longer operates supply wells. In addition, the secondary standards of the Utility's water are not regulated by DEP. On December 12, 2016, DEP communicated to the Utility that its bacteriological test results were satisfactory. During the test year it was determined that nitrification issues were causing odor and color issues. The Utility exercised extensive flushing to address the issue. The Utility also worked with DEP and the Florida Rural Water Association to determine a cost effective resolution to the nitrification issue. In order to address nitrification as well as bio-film buildup in its system, Bocilla installed a chloramine feed system on March 20, 2017.

Operating Conditions of the Utility's Plant and Facilities

On December 1, 2016, DEP conducted a compliance evaluation inspection of Bocilla's facilities. Based on the information provided during the inspection, DEP determined that Bocilla's facilities were in compliance with DEP rules and regulations. Giving consideration to DEP's inspection results, staff recommends that the operating conditions of Bocilla's facilities are satisfactory. Staff performed a site visit on October 4, 2016. During the visit, plant components appeared to be well maintained, with the exception of some salt water corrosion on some components identified by the Utility to be repaired or replaced, as described in Issues 5 and 12.

The Utility's Attempt to Address Customer Satisfaction

In order to determine the Utility's attempt to address customer satisfaction, staff reviewed customer complaints and comments from five sources: the Commission's Consumer Activity Tracking System (CATS), complaints filed with DEP, complaints filed with the Utility, complaints raised during the customer meeting, and all correspondence submitted to the Commission Clerk regarding this rate case. A summary of all complaints and comments received is shown in Table 1-1 below.

Table 1-1
Number of Complaints by Source

Subject of Complaint	PSC's Records (CATS) (test year and 4 prior years)	Utility's Records (test year and 4 prior years)	DEP (test year and 4 prior years)	Docket Correspondence	Customer Meeting
Billing Related	2				1
Opposing Rate Increase				6	7
Water Quality		1		3	5
Quality of Service				3	4
Boil Water Notice				3	4
Water Pressure				5	1
Total*	2	1	0	20	22

* A customer comment may appear twice in this table if it meets multiple categories

Staff reviewed the Commission's complaint records from January 1, 2011, through December 31, 2015, and found two complaints. Based on staff's review, both complaints were related to billing and both complaints have been closed. Staff also requested complaints against the Utility filed with DEP for the 2015 test year and four years prior. DEP indicated that it has not received any complaints against the Utility during the requested time frame. The Utility recorded one complaint for this time period regarding its quality of service. The one complaint addressed the color of the water. As previously noted, the Utility is installing a chloramine feed system to address color and odor issues. Based on the records of the Utility and the Commission, it appears that the Utility has responded in a timely manner to each of these complaints.

A customer meeting was held in Englewood, Florida, on October 5, 2016. Approximately 30 of the Utility's customers attended the meeting and 9 spoke. The subjects of the complaints included (1) billing issues, (2) affordability of the rate increase, (3) water quality/odor/color, (4) responsiveness of the Utility, (5) the boil water notice procedure, and (6) insufficient water pressure. As previously addressed, the Utility is installing a chloramine feed system to address color and odor issues. Regarding the customer complaints about the Utility's boil water notice, staff has reviewed the Utility's boil water notice procedure and believes that it is in compliance with Section 381.0062(2)(j), F.S. The Utility provided records of previously distributed boil water notices which fit these requirements. Regarding water pressure concerns, the Utility stated that, outside of low pressure events related to damage to the system, its pressure is maintained using its pressure boost station. The Utility also provided a certified fire flow report which indicates adequate pressure for fire protection.

Staff received a petition with signatures from 128 customers dated March 2, 2017, and additional petition pages with 15 customer signatures dated March 6, 2017. The petition stated that the undersigned urged the Commission to decrease, not increase, water rates. In this petition, 72 customers commented on the affordability of the rate increase, eight commented on the quality of the water, one commented on the water pressure, and three commented on insufficient support for the rate increase. The remaining customers signed the petition without comment.

Staff believes that the Utility's attempts to address customer satisfaction should be considered satisfactory. Staff's conclusion is based on the low number of complaints received by the Commission, DEP, and the Utility as well as the Utility's responsiveness to customer concerns.

Conclusion

Based on review of DEP records, staff recommends that the quality of Bocilla's product and the condition of its facilities is satisfactory. Additionally, it appears that the Utility has attempted to address customers' concerns. Therefore, staff recommends that the overall quality of service for the Bocilla water system in Charlotte County is satisfactory.

Issue 2: Should the audit adjustments to rate base to which the Utility and staff agree be made?

Recommendation: Yes. Accumulated amortization of Contributions-in-aid-of-Construction (CIAC) should be decreased by $44,625, and CIAC amortization expense should be decreased by $3,538. Further, Operations and Maintenance (O&M) expense should be decreased by $5,048. (Frank, Hill)

Staff Analysis: Staff's audit report was filed on September 1, 2016. Bocilla's response to the audit was received October 10, 2016. In its response to the staff audit report of the Utility, Bocilla and staff agreed to the audit adjustments as set forth in the tables below.

Table 2-1
Description of Audit Adjustments

Audit Adjustments	Description of Adjustments
Finding 6	Reflect appropriate accumulated amortization of CIAC.
Finding 8	Reflect the removal of unsupported and out-of-period costs, as well as the reclassification of certain amounts.

Source: Staff Audit

In its response to Audit Finding 6, the Utility disagreed with audit staff's calculation of accumulated amortization of CIAC to reflect the retirement of the water treatment plant. Staff agrees with Bocilla and has reflected the removal of the retired plant based on the correct amortization rates. Additionally, the Utility's response to Audit Finding 8 included invoices to support some of the expenses that were removed as unsupported. Staff verified and included the appropriate supported amounts. However, one invoice provided was out-of-period and another should have been capitalized. Based on the audit adjustments agreed to by Bocilla, staff recommends that the adjustments set forth in Table 2-2 below, be made to rate base and net operating income.

Table 2-2
Adjustments to Rate Base and Net Operating Income (NOI)

Audit Adjustments	Accum. Amort. of CIAC	O&M Expense	CIAC Amort. Expense
Finding 6	($44,625)		$3,538
Finding 8		($5,048)	

Source: Staff Audit and Utility's Response to Audit

Issue 3: Should the full amount of the original cost study provided by the Utility be accepted as a factor in determining Utility Plant in Service?

Recommendation: No. Staff recommends that the original cost study is sufficient to support the amount of Utility Plant in Service (UPIS) presented in the MFRs; however, errors and discrepancies discovered by staff suggest that the original cost study is not sufficiently reliable to support the higher plant values. Staff recommends that UPIS balances should be based on the MFRs, with adjustments described below. Accordingly, UPIS should be increased by $9,848. A corresponding adjustment should be made to decrease accumulated depreciation by $49,695 and depreciation expense by $1,025. (Hill, Norris)

Staff Analysis: In its response to the audit, Bocilla contested Audit Finding 2 and the corresponding adjustments to accumulated depreciation reflected in Audit Finding 5. In regards to Audit Finding 2, audit staff reduced the average plant balance of Account 331 – Transmission & Distribution Mains to reflect the removal of unsupported plant additions totaling $577,798. As detailed in Audit Finding 1, the Utility was unable to locate any records prior to 2007. Thus the majority of the unsupported plant additions are prior to 2007. The Utility acknowledged this factor in its audit response and stated that it was having an original cost study prepared to substantiate the costs that the Utility was unable to support. Additionally, there were physical assets such as pumping equipment, which were neither supported by records nor reflected in the Utility's current books. On its own initiative, Bocilla decided to contract for an original cost study to determine a value for UPIS that better reflects the original cost of the Utility's investment in assets to serve customers for all plant additions prior to and including 2014. The procedure for determining original cost consists of identifying the existence of the assets, estimating their specifications, and calculating the likely historical cost of these assets at the time they were placed into utility service.

The referenced source for cost information for the study was the Engineer's Estimate of Reproduction Cost prepared by Giffels-Webster Engineers, Inc. Costs of each component were calculated based on recent water utility construction, such as a Sarasota County Utilities project. In preparing the subsequent original cost study, Management & Regulatory Consultants, Inc. adjusted these costs using the Handy-Whitman Water Utility Index. The index uses historical trends to indicate how each type of utility component has changed in price, and was used to convert the recent cost references to the year each component was placed into service for Bocilla. Staff believes that the described methodology is reasonable for establishing original cost of service. Although staff believes that the methodology for establishing original cost of service is reasonable, staff has several concerns regarding the overall reliability of the original cost study for estimating costs. Staff's concerns are discussed in detail below.

Staff sent four rounds of information requests regarding the original cost study. Staff has identified in Bocilla's responses several errors in component costs, installation dates, and depreciation methodology. The errors in component costs are summarized in Table 3-1 below. The original cost study did not include known plant additions (meter installations) for the year 2015. The Utility explained that it did not reflect the addition of the new meters because the meters were replacements and not for new customers. Treating plant additions in this manner misrepresents UPIS as well as accumulated depreciation. Information provided by the Utility, in response to requests from staff, suggests that plant was installed during time periods that reflect no additions in the original cost study. Additionally, staff found that the original cost study did not use the correct group depreciation methodology when calculating accumulated depreciation.

Table 3-1
Description of Original Cost Study Errors

Error	Description of Error
U-17 understated by $500, U-18 understated by $500, U-19 overstated by $500	Staff requested additional information about the meter installation, U-19. In its response, Bocilla discovered that water service (short side) U-17 should be $800 instead of $300, water service (long side) U-18 should be $1,000 instead of $500, and meter installed U-19 should be $500 instead of $1,000. These discrepancies are based on a response from Giffels-Webster Engineers, Inc. to Bocilla. This error does not impact total UPIS but does affect accumulated depreciation because these components have different depreciation rates.
U-19 overstated by $135	U-19 represents the installation price of a meter, as estimated by Giffels-Webster Engineers, Inc. In response to staff's third data request, the Utility stated that the actual cost to install a meter is $365. This value, modified using the Handy-Whitman Index, more accurately estimates the historical cost of installing a meter. This error overstates UPIS by $35,350.
Remove U-16 $19,267.44 from 2004	U-16 represents the assets related to an interconnect to supply Knight Island Utilities (KIU) with water it purchases from EWD. As such, it should be considered a non-utility asset.
Remove U-15 $878.36 from 1991	Staff requested additional information about directional drill U-15, at which point the Utility discovered that this item was already accounted for in another line item and should be removed.
Reclassify boost station assets to appropriate NARUC Account	The Utility included all assets from the interconnect project in the Transmission and Distribution account. The assets that belong in the Pumping Equipment account should be reclassified so that appropriate depreciation rates will be applied.

Although staff has concerns regarding the original cost study, staff believes that the information provided can reasonably be used to conclude that the plant in service for transmission and distribution is at or above the amount contained in the Utility's MFRs. Based on the original cost study, plant in service for transmission and distribution totaled $1,465,171. This total is nearly 35 percent greater than what the Utility included in its MFRs. Furthermore, due to a lack of records, the audit only traced additions back to 2007. The original cost study shows additions totaling more than $1 million prior to 2007. However, staff recommends that the use of the original cost study be limited to substantiating the balance of Account 331 – Transmission & Distribution Mains, not supporting a higher UPIS balance.

Furthermore, the staff audit report is still relevant for the three additional plant accounts that comprise the Utility's test year average balance. Additionally, information received during staff's inquiry of the original cost study necessitates further adjustments. Staff's recommended adjustments to test year plant are discussed below.

Account 331 – Transmission & Distribution Mains

Staff's October 4, 2016 site inspection included a boost station which was not identified in the Utility's MFRs. The Utility provided additional documentation for these assets and all costs associated with the Englewood Water District interconnect (Englewood Project). In its MFRs, Bocilla recorded the entire cost of the Englewood Project in Account 441 – Transmission & Distribution Mains as a plant addition of $363,809 in 2014 and $97,256 in 2015 for a total amount of $461,065. This amount reflects a 64 percent allocation of costs, due to the KIU agreement discussed below, totaling $717,616 and an additional $1,791 of costs directly attributed to Bocilla. The Englewood Project is comprised of three distinct components: a subaqueous crossing, an interconnect, and a boost station. However, the Utility recorded the boost station as part of the total interconnect project instead of isolating that amount to record in Account 311 – Pumping Equipment.

Staff identified several adjustments which should be made to the total cost of the Englewood Project. Staff believes the total cost of the project should be reduced by $51,717 to reflect the removal of unsupported costs, including capitalized construction interest and a bank penalty. Staff notes that both of these items should be been removed regardless of support due to the nature of each expense. This total also reflects the removal of the costs directly attributed to Bocilla totaling $1,791. Additionally, the total cost of the project should be reduced by $11,261 to reflect the removal of legal and engineering expenses associated with work unrelated to the Englewood Project, such as filing index applications with the Commission and the Utility's 2013 certificate docket. In total staff believes the total cost of the Englewood Project should be reduced by $62,978 ($51,717 + $11,261), resulting in a total cost of $656,429 ($719,407 - $62,978).

Staff is recommending that the total cost of the Englewood Project should first be partially allocated to KIU, and should then be classified into the proper National Association of Regulatory Utility Commissioners (NARUC) accounts. KIU is a utility which purchases water from EWD, but all water it purchases in this way flows through Bocilla infrastructure. The Englewood Project assets, as well as certain pro forma projects discussed in Issue 5, all directly benefit KIU. The Utility agrees that 64 percent of the value of these assets, with the exception of the subaqueous crossing as discussed below, should be allocated to Bocilla, and that 36 percent should be allocated to KIU based on the relative Equivalent Residential Connection (ERC) capacities of Bocilla and KIU, 715 and 400, respectively. Review of Bocilla's support documentation verified that the costs associated with the subaqueous crossing were equally and individually assumed by Bocilla and KIU. Bocilla had previously maintained that KIU's allocation of the Englewood Project was 36 percent of the total cost, as reflected in the Utility's MFRs. However, the KIU Interconnect agreement furnished by the Utility specified equal funding for that component. Staff reflected this detail in its allocation of the Englewood Project's costs and did not apply the 36 percent allocation to the costs associated with the subaqueous crossing. Further, staff identified the costs associated with the boost station in order to reclassify these costs to the correct NARUC account of Account 311 – Pumping Equipment. The costs associated with the boost station totaled $129,863. Table 3-2 below, illustrates staff's allocation calculation of the Englewood Project.

Table 3-2
Allocation of Englewood Project Costs

	Unallocated Costs	Allocation Percentage	Bocilla Allocated Costs
Account 311 – Pumping Equipment			
Boost Station	$129,863	64 %	$83,112
Account 331 – Transmission & Distribution Mains			
Interconnect	$449,979	64 %	$287,987
Subaqueous Crossing	76,586	N/A	76,586
Total	$526,565		$364,573
Total Project	$656,428		$447,685

Staff's recommended allocation of costs from the Englewood Project result in an increase of $83,112 to Account 311 – Pumping Equipment and a decrease of $96,493 to Account 331 – Transmission & Distribution Mains. However a corresponding adjustment is necessary to reflect the average balance of Account 331 – Transmission & Distribution Mains based on staff's recommended adjustments. As such, Account 331 – Transmission & Distribution Mains should be increased by $29,956 to reflect the appropriate average balance. The net effect is an increase of $16,575 ($83,112 - $96,493 + $29,956).

Account 334 – Meters

Staff believes an adjustment to Account 334 – Meters is necessary based on its review and consideration of the original cost study. Bocilla's MFRs reflect a 2015 plant addition of $35,880 to Account 334 – Meters for 104 meters. However, staff was never able to obtain documentation supporting the full amount of the addition. In lieu of the total actual costs, it appears that the Utility applied a per unit cost of $345 to the 104 meters, based on a full scale replacement of each component, including a backflow preventer in order to calculate the total cost of $35,880 ($345 x 104). Staff requested the complete documentation to support the total and reviewed all documentation retained by audit staff. Staff was particularly concerned with obtaining the complete documentation due to an invoice indicating that several of the meters were actually for KIU. Including capitalized labor, staff calculated a total cost of $22,428 for 104 meters, which is a reduction of $13,452. However, due to the meters being an addition during the test year, the adjustment to the average plant balance only reflects half. As such, staff recommends that UPIS be decreased by $6,726 to reflect the actual cost of the documented meter additions.

Account 302 – Franchise

This plant account was verified by audit staff with no adjustments noted. However, the Utility had not recorded any accumulated depreciation. Based on Audit Finding 5, accumulated depreciation should be increased by $3,062.

Conclusion

Staff recommends that the original cost study is sufficient to support the amount of UPIS presented in the MFRs, but that errors and discrepancies discovered by staff suggest that the original cost study is not sufficiently reliable to support the higher plant values. Staff recommends that UPIS balances should be based on the MFRs, with adjustments described above. Accordingly, UPIS should be increased by $9,848. Staff recalculated the corresponding accumulated depreciation for the adjusted plant accounts. Including the adjustment from Audit Finding 5, as previously discussed, accumulated depreciation should be decreased by $49,695 and depreciation expense should be decreased by $1,025.

Issue 4: Should further adjustments be made to the Utility's rate base?

Recommendation: Yes. UPIS should be reduced by $44,000 to remove double counting of land. Land should be also reduced by $44,000 to reflect the removal of land from rate base. CIAC should be increased by $83 associated with the meter installation charges collected by the Utility. Corresponding adjustments should be made to increase both accumulated amortization of CIAC and CIAC amortization expense by $8 and to decrease property taxes by $3,179. (Frank, Hill)

Staff Analysis: Staff has reviewed the test year rate base components along with other support documentation. As such, staff believes further adjustments are necessary to Bocilla's rate base, as discussed below.

Land

In its MFRs, the Utility double counted $44,000 for land in its rate base. As such, staff decreased plant by $44,000 to remove the duplicate amount for land. Further, Bocilla no longer operates the plant for which this land was used, and agrees with staff that the land should be removed from rate base. Accordingly, land should be decreased by $44,000 to reflect the removal of land from rate base. A corresponding adjustment should be made to remove the real estate taxes associated with the land. Therefore, property taxes should be decreased by $3,179.

CIAC

In its MFRs, the Utility recorded $458,848 of CIAC. Staff learned during a conference call with Bocilla and the Office of Public Counsel (OPC) that the Utility had been incorrectly recording meter installation charges as revenues. Although, the Utility provided staff a breakdown of meter installations dating back to 1993, Bocilla's plant balance only reflects meter replacements for existing customers during the test year. Therefore, all meter installation charges prior to the test year should not be reflected in CIAC except for one during 2015 reflected on the Utility's breakdown of meter installations. Accordingly, CIAC should be increased by $83 associated with a meter installation charge that was previously recorded in test year revenues by Bocilla. Corresponding adjustments should be made to increase both accumulated amortization of CIAC and CIAC amortization expense by $8.

Issue 5: Should any adjustments be made to the Utility's pro forma plant?

Recommendation: Yes. The appropriate amount of pro forma plant additions is $139,708. This results in a decrease of $50,067 from the Utility's requested amount. Therefore, UPIS should be increased by $139,708. Corresponding adjustments should also be made to increase accumulated depreciation by $11,709 and increase depreciation expense by $11,709. Additionally, property taxes should be increased by $2,136. (Hill, Frank)

Staff Analysis: The Utility did not reflect any pro forma plant requests in its original filing. However, in subsequent data requests, Bocilla requested the inclusion of seven pro forma projects. The amount of the pro forma plant additions totaled $189,775. The Utility provided invoices and justification for each of the plant additions. Based on its review of Bocilla's requested pro forma plant, staff recommends several adjustments to the Utility's proposed pro forma plant as summarized below.

The pro forma plant additions include $10,964 for a boost station rebuild, $12,850 for a boost station control package, $11,400 for the 6" valve replacement, $10,060 for looping dead end lines, $14,721 for a chloramine feed system, and $22,102 per year for four years for a meter replacement program. Bocilla requested $41,371 for a new utility truck as a pro forma expense. However, staff believes a vehicle asset should be considered a pro forma plant item. Therefore, staff will address the new truck in this issue and remove the requested amount from pro forma O&M expenses.

The Utility has stated that all projects will be completed in 2017 with the exception of the meter replacement program which is a four-year program. Based on staff's review, the proposed additions will improve the reliability of Bocilla's system or improve the quality of the Utility's product. Staff's recommended adjustments to the Utility's requested pro forma plant additions are discussed below.

Boost Station Rebuild

In total, the Utility requested $10,964 to rebuild its boost station. According to a probable cause report funded by Bocilla, this repair was necessary due to improper exercising of fire hydrants. Bocilla further states that Charlotte County firefighters were seen operating a fire hydrant at the time the damage was caused. Charlotte County has declined to accept responsibility for this event, and Bocilla has stated that "any legal action would incur more cost than the repairs."

Bocilla's support for the amount of the repair included a request of $1,560 for 700 hand-delivered boil water notices and $3,105 for the engineer's probable cause report that it obtained while attempting to recover repair expenses from Charlotte County. The engineer's probable cause report is an appropriate non-recurring expense to be included in pro forma O&M expenses, as discussed in Issue 12. However, staff believes that both items are not appropriate to capitalize and reduced the recommended pro forma plant by $4,665 for a total of $6,299. As discussed in Issue 3, this project is associated with assets that benefit KIU and should reflect a 36 percent allocation to KIU. Therefore staff reduced the recommended pro forma plant by $2,268 (36 percent x $6,299) for a total recommended increase of $4,031 to plant.

Boost Station Control Package

Based on the most recent update of this project, the Utility requested $12,850 for a control package for its boost station. The current control system is no longer supported by the manufacturer, and supporting the control system internally would cost over 50 percent of the cost of a new system. Additional functionality, greater reliability, and lower maintenance costs justify the additional cost of the new system. As discussed in Issue 3, this project is associated with assets that benefit KIU and should reflect a 36 percent allocation to KIU. Therefore, staff reduced the recommended pro forma plant by $4,626 (36 percent x $12,850) for a total recommended increase of $8,224 to plant.

Chloramine Feed System

At the point of connection to EWD, the water purchased by Bocilla passes DEP requirements for chlorine or chloramine residuals. However, once the water reaches the point of use at some customer residences, periodic tests reveal that disinfection residuals are at times insufficient, and formation of nitrites and bio-films have impacted the quality of those customers' water. Bocilla has worked with the Florida Rural Water Association to design a chloramine feed system to address this problem while controlling engineering costs. The designs of this and related systems have changed since the MFRs were filed. The amount the Utility has supported with invoices is now $14,721 based on an updated bid by DMK Associates Inc. As discussed in Issue 3, KIU directly benefits from certain Bocilla assets and it is appropriate to allocate 36 percent of the value of those assets to KIU. The chloramine feed system benefits KIU in this way, and so $5,300 (36% x $14,721) should be removed and $9,421 should be approved.

Meter Replacement

Bocilla requested $26,449 per year to replace 100 meters each year for a period of four years. The Utility noted that many of the meters are near the end of their useful life and it is more economical to purchase the materials needed in bulk. Section 367.081(2)(a)2.a., F.S., states that "the commission shall consider utility property... to be constructed within a reasonable time in the future, not to exceed 24 months after the end of the historic base year... unless a longer period is approved by the Commission, to be used and useful in the public service, if such property is needed to serve current customers...." Because this pro forma plant item is needed to serve current customers, staff recommends that this property be allowed in rate base even though it lies outside of the 24-month window. In its most recent update for the project, Bocilla reduced its request to $22,102 per year for four years. Based on documentation provided by the Utility, staff recommends that the Commission approve a total of $55,200 for this program over four years. Staff's recommended amount is based on the replacement of 240 meters at an estimated cost of $230 per meter over a four-year period. As discussed in Issue 3, the MFRs did not show any balance in Account 334 – Meters. Because staff is recommending that the Original Cost Study is not reliable enough to establish original plant in service, there is no retirement associated with the meter replacements.

Conclusion

In total, staff recommends an increase of $139,708 ($4,031 + $8,224 + $9,421 + $55,200 + $11,400 + $10,060 + $41,371). This results in a decrease of $50,067 from the Utility's requested amount. There are no associated retirements to the pro forma projects. Therefore, UPIS should be increased by $139,708. Corresponding adjustments should also be made to increase accumulated depreciation by $11,709 and increase depreciation expense by $11,709. Additionally, property taxes should be increased by $2,136.

Issue 6: What is the used and useful (U&U) percentage of the Utility's water transmission and distribution system?

Recommendation: Bocilla's water transmission and distribution system should be considered 100 percent U&U. There appears to be no excessive unaccounted for water (EUW), therefore, staff recommends that no adjustment be made to operating expenses for purchased water. (Hill)

Staff Analysis: Bocilla's water transmission and distribution system should be considered 100 percent U&U. There appears to be no EUW, therefore, staff is not recommending an adjustment be made to operating expenses for purchased water, as discussed below.

Excessive Unaccounted for Water

Rule 25-30.4325(1)(e), F.A.C., defines EUW as "unaccounted for water in excess of 10 percent of the amount produced." Unaccounted for water is all water that is produced that is not sold, metered, or accounted for in the records of the Utility. EUW is calculated by subtracting both the gallons used for other services, such as flushing, and the gallons sold to customers from the total gallons pumped for the test year. The Utility purchased 30,892,000 gallons of water and sold 24,936,000 gallons of water to customers. The Utility recorded 720,000 gallons of water used for normal flushing and 3,650,000 gallons of water used for flushing to achieve DEP required chlorine residuals. The result ([30,892,000 - 24,936,000 - 720,000 - 3,650,000] / 30,892,000) for unaccounted for water is 5.13 percent, not in excess of 10 percent and so there is no EUW.

Transmission & Distribution System Used & Useful

Bocilla purchases water from EWD through an interconnection. This interconnection is equivalent to a single well, and so it should be considered 100 percent U&U pursuant to Rule 25-30.4325(4), F.A.C.[3] There are no large undeveloped parcels in Bocilla's territory; however, there are undeveloped lots interspersed throughout the distribution system. All lines are required to serve existing customers, and no portions of the distribution system could be isolated as not U&U; therefore, Bocilla's transmission and distribution system should be considered 100 percent U&U.

Conclusion

Bocilla's water transmission and distribution system should be considered 100 percent U&U. There appears to be no EUW, therefore, staff recommends that no adjustment be made to operating expenses for purchased water.

[3]Order No. PSC-14-0626-PAA-WU, issued October 29, 2014, in Docket No. 130265-WU, *In re: Application for staff-assisted rate case in Charlotte County by Little Gasparilla Water Utility, Inc.*

Issue 7: What is the appropriate working capital allowance?

Recommendation: The appropriate working capital allowance is $44,993. As such, the working capital allowance should be decreased by $473. (Frank)

Staff Analysis: Rule 25-30.433(2), F.A.C., requires Class B utilities to use the formula method, or one-eighth of O&M expenses, to calculate the working capital allowance. The Utility has properly filed its allowance for working capital using the formula method. Staff has recommended adjustments to Bocilla's O&M expenses. As a result, staff recommends working capital of $44,993. This reflects a decrease of $473 to the Utility's requested working capital allowance of $45,466.

Issue 8: What is the appropriate rate base for the test year period ended December 31, 2015?

Recommendation: Consistent with staff's other recommended adjustments, the appropriate rate base for the test year ended December 31, 2015, is $744,524. (Frank)

Staff Analysis: In its MFRs, the Utility requested a rate base of $690,154. Based on staff's previously recommended adjustments, the appropriate rate base is $744,524. The schedule for rate base is attached as Schedule No. 1-A, and the adjustments are shown on Schedule No. 1-B.

Issue 9: What is the appropriate return on equity?

Recommendation: Based on the Commission's leverage formula currently in effect, the appropriate return on equity (ROE) is 11.16 percent with an allowed range of plus or minus 100 basis points. (Frank)

Staff Analysis: The ROE included in the Utility's MFRs is 10.50 percent. Based on the current leverage formula in effect and an equity ratio of 21.58 percent, the appropriate ROE is 11.16 percent.[4] Staff recommends an allowed range of plus or minus 100 basis points be recognized for ratemaking purposes.

[4]Order No. PSC-16-0254-PAA-WS, issued June 29, 2016, in Docket No. 160006-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 10: What is the appropriate weighted average cost of capital based on the proper components, amounts, and cost rates associated with the capital structure for the test year ended December 31, 2015?

Recommendation: The appropriate weighted average cost of capital for the test year ended December 31, 2015, is 6.03 percent. (Frank)

Staff Analysis: In its filing, Bocilla requested an overall cost of capital of 5.97 percent. The Utility's capital structure consists of long-term debt, common equity, and deferred income taxes. In addition to the recommended cost rate for common equity discussed in Issue 9, staff believes an adjustment is necessary to the cost rate for long-term debt. In its filing, Bocilla reflected a cost rate of 5.00 percent for long-term debt. However, the Utility subsequently stated that no adjustments were made to reflect the removal of the non-utility funds from the loan balance. The Utility also stated that the cost rate does not take into account the closing costs of the loan. Staff reviewed the loan statement and based on the stated interest rate and issuance costs associated with this long-term debt, staff recommends that the appropriate cost rate for this long-term debt is 4.75 percent.

The Utility provided the closing statement for a loan totaling $1,005,226. The stated purpose of the loan was to fund the Englewood Project. However, the loan also paid off the balances of two existing loans. As discussed in Issue 3, two components of the Englewood Project, an interconnect and boost station, are allocated between Bocilla and KIU. The third component, a subaqueous crossing, was equally funded by the two Utilities. Although Bocilla secured the funding and commenced the project, KIU has a specific agreement with Bocilla to pay for its allocation of the Englewood Project costs. Therefore, staff believes an adjustment should be made to reflect a percent of the loan amount attributable to KIU.

Staff determined KIU'S allocation of the debt by isolating the amount of the loan that was associated with funding the allocated components of the project, not including the subaqueous crossing as it was equally funded. This results in a reduction of $219,673 to the average balance of the long-term debt. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ended December 31, 2015, including the aforementioned adjustments, staff recommends a weighted average cost of capital of 6.03 percent. Schedule No. 2 details staff's recommended overall cost of capital.

Issue 11: What is the appropriate amount of test year revenues?

Recommendation: The appropriate test year revenues for Bocilla's water system are $398,153. (Johnson)

Staff Analysis: In its MFRs, Bocilla's adjusted test year revenues were $395,395. The water revenues include $397,988 of annualized service revenues, $2,168 of miscellaneous revenues and a deduction of $4,761 for credits to customers. In review of the Utility's adjusted test year billing data, staff found that the Utility used the incorrect number of gallons for each rate block in calculating annualized revenues. Based on the audit, staff made the adjustments to reflect the appropriate number of gallons used in each rate block. Therefore, the test year service revenues for Bocilla should be $398,103 which results in a small increase of $115 ($398,103 - $397,988).

Staff also made adjustments to miscellaneous revenues for Bocilla. The Utility recorded monies received from service availability charges as miscellaneous revenues instead of CIAC. Therefore, staff decreased miscellaneous revenues by $1,292 for an allowance for funds prudently invested (AFPI) charge and $165 for a meter installation charge. In addition, the Utility included $711 in its miscellaneous revenues for other charges. However, according to the staff's audit, Bocilla only billed two initial connection charges of $25. Therefore, staff reduced miscellaneous revenues by $661 ($711-$50). The total reduction to miscellaneous revenues is $2,118 ($1,292+$165+$661). For the reasons outlined above, the miscellaneous revenues for the Utility should be $50 ($2,168-$2,118). In addition, the Utility gave $4,761 in credits to customers who had abnormally high usage and met the Utility's criteria for a credit. Staff did not include these credits in test year revenues. Staff believes this a business decision and the burden should not be carried by the general body of ratepayers. Based on the above, the appropriate test year revenues for Bocilla are $398,153 ($398,103 + $50). Table 11-1 below, represents a summary of staff's adjustments for test year revenues.

Table 11-1
Test Year Revenues

	Water
Service Revenues	
Utility Annualized Service Revenues	$397,988
Staff's Adjustment	$115
Total Service Revenues	$398,103
Miscellaneous Revenues	
Utility Recorded Miscellaneous Revenues	$2,168
Staff's Miscellaneous Revenue Adjustments	($2,118)
Total Miscellaneous Revenues	$50
Total Test Year Revenues	$ 398,153

Issue 12: Should any adjustments be made to the Utility's pro forma expenses?

Recommendation: Yes. Bocilla's requested pro forma O&M expenses should be reduced by $29,402. A corresponding adjustment should be made to increase payroll taxes by $765. (Hill, Frank)

Staff Analysis: In its filing, the Utility requested $55,719 for pro forma expenses. Based on its review of Bocilla's requested pro forma expenses, staff recommends several adjustments to the Utility's proposed expenses as summarized below.

Salaries & Wages – Employees
In its filing, the Utility requested an additional $10,400 ($25 x 416 hours) a year for its administrative employee to work one extra day a week. However, in response to staff's first data request, Bocilla stated that this figure was an error and that only 400 additional hours is being requested. Given the amount of responsibilities for this position as described by the Utility, and the difficulty Bocilla has had keeping adequate records, staff believes one additional day per week for the part-time administrative employee is reasonable. Staff reduced this expense by $400 ($10,400 - $10,000) to reflect the corrected request. The Utility did not include in its request the corresponding increase in payroll taxes to reflect the additional time. Therefore, staff made a corresponding adjustment to increase payroll taxes by $765.

Regulatory Commission Expense – Other
In its MFRs, Bocilla requested $16,024 for the loss on the early abandonment of the water treatment plant. Subsequently, the Utility withdrew its request. Thus, staff recommends the removal of the $16,024.

Contractual Services – Accounting
In its filing, the Utility requested $4,200 for Contractual Services – Accounting. In response to a data request, Bocilla stated that it presently does not utilize any monthly accounting services, but is requesting that $350 per month be authorized as the Utility does not have the accounting expertise to perform the necessary monthly accruals to derive monthly financial statements. The Utility points to its poor record keeping as evidence for its need of accounting services. Bocilla further asserted that accruals are done at the end of the year and are being performed for free by one of the board of directors. The Utility asserts that it is not a reasonable business practice to have a director provide this service for free, and as such should be done monthly as a paid function. Given the need for proper record keeping, staff recommends no adjustment to the requested $4,200 for Contractual Services – Accounting.

New Utility Truck
In its MFRs, Bocilla requested $7,200 for the lease of a new truck to replace an older truck currently being used. It also made a corresponding request of $2,500 for maintenance and gas and $2,600 for insurance associated with the new truck. As discussed in Issue 5, staff capitalized the full amount of the new truck to plant after the Utility decided to purchase rather than lease it. Therefore, staff reduced O&M expense by $7,200 to reflect the removal of the lease expense. The Utility also requested $2,500 for maintenance and gas for the new vehicle and mileage reimbursements for its employees who may need to use personal vehicles for work. Staff believes because the Utility utilized a truck and reimbursed employees' fuel during

the test year, test year expenses should adequately reflect the costs of gas and maintenance and reimbursements for personal vehicles. Therefore, staff disallowed the requested $2,500 for additional maintenance and gas. In response to a staff data request, the Utility provided an updated estimate for insurance expense of $2,018. Staff believes because there was $1,470 for test year insurance expense, an additional $548 ($2,018 - $1,470) is reasonable to reflect the estimate for the insurance on the new vehicle. Accordingly, staff recommends that the requested pro forma amount be reduced by $2,052 ($2,600 - $548). In total, staff recommends a decrease of $11,752 ($7,200 + $2,500 + $2,052) to pro forma expenses associated with the purchase of a new truck.

Contractual Services – Engineering

The test year already includes 26.25 of the 50 hours requested for lead, copper, and chlorine control services, therefore, the requested $6,750 should be reduced by $3,544. Additionally, as discussed above in Issue 5, staff expensed the probable cause report associated with the boost station rebuild and amortized it over five years, pursuant to Rule 25-30.433(8), F.A.C. This results in an increase of $397. In total, staff recommends a decrease of $3,146 ($3,544 - $397).

Chloramine Feed System Chemicals, Operation & Maintenance

At the time it filed its MFRs, the Utility was undergoing an iterative design process for its chloramine feed system. It has now provided estimated chemical expenses of $2,649. Staff notes that this total includes the chemicals needed to treat water consumed by KIU. In its response to staff's fourth data request, the Utility stated that 46 percent of the flows through this system can be attributable to KIU, and so staff recommends that the requested chemical expense be reduced to $1,430, or 54 percent of the requested amount. Since this is a pro forma addition, O&M should be increased by $490 for estimated repairs and maintenance associated with the feed system.

Fire Hydrant Maintenance and Exercise Program

The Utility requested $4,650 over two years for maintenance of its fire hydrants. Maintenance will consist of sand blasting and painting half of the 62 hydrants each year to extend their lives. Bocilla has stated that the harsh salt water environment has led to the need to replace fire hydrants before their estimated useful life and that performing this maintenance will extend the life of the existing hydrants and save replacement costs, which are between $2,500 and $3,000. The Utility stated that it is critical to perform this maintenance for all hydrants within the next two years to prevent incurring these replacement costs. Staff believes that the first round of maintenance is prudent, but that more justification is required to approve an ongoing 2-year maintenance cycle. Staff therefore recommends that the $4,650 should be amortized over two years. Bocilla has also requested $3,720 to exercise its fire hydrants twice yearly to ensure proper function. This is in response to a recent loss of life due to a fire in Bocilla's territory and increased concern about fire protection. Staff recommends that this program is prudent and that the cost calculations submitted by Bocilla for this activity reflects the actual cost of components and labor not already included in salary expense.

Conclusion

Based on the above, staff recommends that the Utility's requested pro forma expenses be reduced by $29,402 (-$400 - $16,024 - $11,752 - $3,146 + $1,430 + $490). A corresponding adjustment should be made to increase payroll taxes by $765.

Issue 13: Should any adjustments be made to the Utility's salaries and wages expense?

Recommendation: Yes. Salaries and wages expense should be reduced by $13,896. Pensions and benefits should be decreased by $1,510. A corresponding adjustment should be made to reduce payroll taxes by $1,103. (Frank)

Staff Analysis: Based on its review of test year salaries and wages expense, staff recommends several adjustments to the Utility's proposed expense as summarized below.

Salaries & Wages – Employees

In its MFRs, Bocilla reflected a total expense of $104,866 for employee salaries and wages. The Utility has one full-time operator, which the Utility allocates 20 percent of the operator's salary to KIU. Bocilla also has a part-time meter reader/distribution worker, a part time administrative employee, and a part-time sub-contractor. In an effort to examine the reasonableness of the Utility's salary levels, staff used multiple resources including the American Water Works Associations' (AWWA) 2015 Compensation Survey and believes all employee compensation falls within a reasonable range. Given the intensive description of job duties and no additional benefits included for the part-time positions, staff believes the salary levels are reasonable.

Staff believes there should be a 20 percent allocation to KIU for the operator's annual bonus. This results in a decrease of $510 ($2,550 x 20%). Further, staff believes the operator's pensions and benefits should also reflect a 20 percent allocation to KIU. The operator is the only employee receiving pensions and benefits. Therefore, the allocation results in a decrease of $1,510 ($7,548 x 20%) to the total amount of the Utility's pensions and benefits. In total, staff recommends reducing employees' salaries and wages expense by $510.

Salaries & Wages – Officers

In its MFRs, the Utility reflected an expense of $88,061 for the officer's salary. This amount reflects a 10 percent allocation for the officer's time spent on KIU activities. The total salary of the officer is $97,846. In response to staff data requests, Bocilla stated that the officer's duties have increased since removing the water treatment plant from service. The Utility stated that this was not anticipated, but nitrification and bio-films generated from chloramine treated water have presented many additional problems that require continuous flushing.

According to Bocilla, the officer is responsible for overseeing and protecting a publicly regulated water supply 24 hours a day, 365 days a year. The Utility estimated the officer's total time per month tending to utility operations is 160 to 200 hours. Staff used the AWWA 2015 Compensation Survey (CS) to examine the reasonableness of the officer's starting salary of $97,846. Staff compared the job description of the officer to a general manager in the AWWA to account for the overall oversight responsibility of the officer. According to the AWWA, the midpoint salary range for a water utility general manger is $88,844. As such, staff believes that this is a reasonable level for the officer's salary. Staff recommends reducing the officer's total salary by $9,002 to reflect the AWWA midpoint salary range for a general manager.

Further, staff believes that the Utility's ten percent allocation of officer's salary for non-utility activities does not reasonably reflect the officer's time spent on KIU business. Due to poor record keeping of the officer's time, the Utility was unable to provide staff with recorded hours for time associated with KIU. Staff believes that 20 percent, consistent with the Utility's suggested allocated time for the operator, of the officer's time is more reasonable given the amount of billing calculations and employee management that is involved with KIU. Therefore, staff believes that 20 percent of the officer's salary should be allocated to KIU. This decreases the recommended salary level by $17,769 ($88,844 x 20%). This results in a recommended officer's salary of $71,075 ($88,844 - $17,769). In total, staff recommends decreasing the Utility's requested officer's salary by $16,986 ($88,061 - $71,075).

Staff increased officer's salaries and wages expense by $10,800 for directors' fees reclassified from miscellaneous expenses. The Utility's board of directors consists of three directors who meet once a week for an hour and receive $3,600 each annually. Staff believes it is excessive to have three directors meet weekly for a water reseller Utility with only one full-time employee. Staff recommends decreasing each director's fee to $100 a month for a total reduction of $7,200. This results in a net increase of $3,600 ($10,800 - $7,200).

In total, staff recommends reducing officer's salaries and wages expense by $13,386 (-$16,986 + $3,600).

Conclusion

Based on the above, staff recommends that the Utility's salaries and wages expense be reduced by $13,896 ($510 + $13,386). Pensions and benefits should be decreased by $1,510. A corresponding adjustment should be made to reduce payroll taxes by $1,103.

Issue 14: Should further adjustments be made to the Utility's O&M expense?

Recommendation: Yes. O&M expense should be further decreased by $18,520. (Frank)

Staff Analysis: Based on its review of test year O&M expense, staff recommends several adjustments to the Utility's O&M expense as summarized below.

Purchased Power

In its filing, Bocilla reflected an expense of $4,549 for Purchased Power in the test year. Staff removed $1,131 from test year expenses related to charges for the abandoned water treatment plant. Staff also removed $365 for a deposit which was reimbursed to the Utility. In its response to staff's second data request, the Utility stated it has no objection to the above adjustments to Purchased Power. Purchased Power is also affected by the KIU relationship discussed in Issues 3 and 12. As a result, Purchased Power should also be reduced by $1,078 to account for KIU's 46 percent share of pumping costs. In total, staff recommends a reduction of $2,574 ($1,131 + $365 + $1,078).

Contractual Services – Engineering

Staff and the Utility agree that an expense of $1,463 for well plugging is not recurring in nature and should be amortized over five years. The net adjustment to Contractual Services – Engineering should be a decrease of $1,170.

Contractual Services – Legal

In its MFRs, the Utility reflected an expense of $654 for Contractual Services – Legal in the test year. A $360 bill for legal services was also included as part of the Utility's rate case expense. As such, staff removed $360 from Contractual Services – Legal as duplicative costs already reflected in rate case expense.

Transportation Expenses

In its filing, the Utility reflected an expense of $5,454 for transportation expenses in the test year. Staff reclassified barge fees totaling $13,320 from miscellaneous expense. Although the Utility's office is located on the mainland, the infrastructure is located on a barrier island which requires a barge fee for transportation from the mainland to the island. In an effort to verify the actual costs of barging, staff requested the contract between Bocilla and Palm Island Transit, the transit company. The Utility provided a contract between Palm Island Transit and Islander Management Group, LLC (IMG), which in turn bills Bocilla for the barging. Staff compared the invoices from IMG to the contract agreement to verify the costs. The Utility also provided a new contract between Palm Island Transit and Bocilla. The contract allows for 50 round trips per month for a monthly rate of $950 and $19 for each additional trip. Staff recommends using the new contract total of $11,400 ($950 x 12 months) plus $1,140 ($19 x 60) to reflect additional trips based on an average of 60 additional trips per year. This results in a decrease of $780 ($13,320 - $12,540). In total, staff recommends a net increase of $12,540 ($13,320 - $780) to transportation expenses.

Insurance – Workman's Comp

In its MFRs, the Utility reflected an expense of $4,383 for workman's comp expense in the test year. Staff reduced this expense by $442 to reflect a 20 percent allocation to KIU for the operator's workman's comp. Staff also reduced this expense by $263 for capitalized overhead associated with the meter replacement program. In total, staff reduced workman's comp by $705 (-$442 - $263).

Advertising Expense

In its MFRs, the Utility recorded $375 for advertising expense in the test year. This expense comprised of rotary club membership fees. As such, staff removed $375 for non-utility expense.

Salaries & Wages – Employees

Staff made adjustments to correct capitalized employee time spent replacing meters for the meter replacement program. Staff decreased the sub-contractor's expense by $3,480 and increased the distribution worker's expense by $2,960. This results in a net decrease of $520 ($2,960 - $3,480).

Miscellaneous Expenses

In its MFRs, the Utility recorded $46,378 for miscellaneous expense in the test year. Staff reduced miscellaneous expense by $13,320 to remove barge fees addressed above in transportation expense. Staff also reduced miscellaneous expense by $10,800 to reclassify director's fees to officer's salaries and wages expense. Staff also removed $1,237 related to meter replacements and capitalized the expense to plant. This results in a total reduction of $25,357 ($13,320 + $10,800 + $1,237).

Conclusion

Based on the above, staff recommends that O&M expense be further decreased by $18,520 (-$2,574 - $1,170 - $360 + $12,540 - $705 - $375 - $520 - $25,357).

Issue 15: What is the appropriate amount of rate case expense?

Recommendation: The appropriate amount of rate case expense is $99,588. This expense should be recovered over four years for an annual expense of $24,897. Therefore, annual rate case expense should be increased by $3,797. (Frank)

Staff Analysis: In its MFRs, Bocilla requested $84,400 for current rate case expense. Staff requested an update of the actual rate case expense incurred, with supporting documentation, as well as the estimated amount to complete the case. On March 7, 2017, the Utility submitted its last revised estimate of rate case expense, through completion of the PAA process, which totaled $117,328.

Table 15-1
Bocilla's Initial and Revised Rate Case Expense Request

	MFR B-10 Estimated	Actual	Additional Estimated	Revised Total
Friedman & Friedman, PA	$38,000	$28,688	$4,635	$33,323
Englewood Management Group, LLC	30,000	55,587	8,175	63,762
DMK Engineering	8,100	3,375	3,775	7,150
M&R Consultants	0	2,100	0	2,100
Giffels-Webster, Inc.	0	6,905	0	6,905
Filing Fee	4,000	2,000	0	2,000
Bocilla In-house	1,600	1,838	250	2,088
Customer Notices	1,200	0	0	0
Travel	1,500	0	0	0
Total	$84,400	$100,493	$16,835	$117,328

Source: MFR Schedule B-10 and Utility responses to staff data requests

Pursuant to Section 367.081(7), F.S., the Commission shall determine the reasonableness of rate case expense and shall disallow all rate case expense determined to be unreasonable. Staff has examined the requested actual expenses, supporting documentation, and estimated expenses as listed above for the current rate case. Based on its review, staff believes the following adjustments to Bocilla's rate case expense estimate are appropriate.

Coenson & Friedman, P.A. (C&F)

In its MFRs, the Utility included $38,000 in legal fees to complete the rate case. Bocilla provided documentation detailing this expense through March 1, 2017. The actual fees and costs totaled $26,247 with an estimated $4,635 to complete the rate case, totaling $30,882.

C&F's actual expenses included the $2,000 filing fee. However, the Utility also included $2,000 in its MFR Schedule B-10, under "Public Service Commission – Filing Fee." Staff has left the filing fee under the filing fee line item and has removed the entry from legal fees to avoid double recovery of this fee.

According to invoices, the law firm of C&F billed the Utility $504 related to the correction of MFR deficiencies. The Commission has previously disallowed rate case expense associated with correcting MFR deficiencies because of duplicate filing costs.[5] Consequently, staff recommends an adjustment to reduce C&F's actual legal fees by $504.

C&F's estimate to complete the rate case includes fees for 12.5 hours at $370/hr. and an additional $10 for photocopies, totaling $4,635. Staff has reviewed the estimate to complete and believes this amount is reasonable. Therefore, staff made no further adjustments.

Englewood Management Group, LLC (EMG)
In its MFRs, the Utility included $30,000 in accounting fees to complete the rate case. Bocilla provided documentation detailing this expense through December 14, 2016. The actual fees and costs totaled $55,587 with an estimated $8,000 to complete the rate case, totaling $63,587. Staff reviewed the invoices and found that a total of $1,133 occurred before the test year. Staff notes that certain line items on these invoices referred to work with C&F that did not appear on any of C&F's rate case expense invoices. Also, lines items indicated work involving the correction of books and records to make the test year accurate. Staff believes it is the Utility's responsibility to keep accurate books and records. As such, staff removed $1,133 from rate case expense. Staff further found that $1,806 was related to work to correct deficiencies. As mentioned above, it is Commission practice to disallow rate expense associated with correcting deficiencies. Therefore, staff recommends an adjustment to reduce EMG's actual accounting fees by $1,806. Also, included in the invoices was $583 for traveling. Staff believes this cost is inappropriate since the consultant is on the board of directors and lives near the Utility.

EMG's estimate to complete the rate case includes fees totaling $7,500 (50 hours at $150/hr.) and an additional $675 in costs for attending the Commission Conference. The estimate to complete included 18 hours for responding to staff requests and analysis for staff consideration in drafting final order. After the last estimate to complete was provided by Bocilla, invoices for 11.5 hours were submitted for EMG related to responding to staff requests. Therefore, staff removed 11.5 hours from the estimated 18 hours for responding to staff's requests. Staff also removed 8 hours for review of the Final Order as duplicative of another line item for an estimate of 4 hours to review the Commission's PAA Order. Further, staff removed 4 hours associated with miscellaneous items that may arise as unreasonable. As a result, staff reduced EMG's estimate to compete by $3,525 (23.5 hours x $150/hr.). In addition to EMG's estimated time to complete, Bocilla estimated $675 for lodging, meals, and travel costs for EMG to attend the Commission Conference. In an effort to be consistent with other consultants' estimated travel costs, staff reduced this estimate to $575 to reflect $200 for a hotel reservation, $50 for meals, and $325 for mileage (650 miles x $0.50/mile). This results in a decrease of $100 ($675 - $575). Staff recommends a total decrease of $3,625 ($3,525 + $100) to the estimate to

[5]Order Nos. PSC-05-0624-PAA-WS, issued June 7, 2005, in Docket No. 040450-WS, *In re: Application for rate increase in Martin County by Indiantown Company, Inc.;* and PSC-01-0326-FOF-SU, issued February 6, 2001, in Docket No. 991643-SU, *In re: Application for increase in wastewater rates in Seven Springs System in Pasco County by Aloha Utilities, Inc.*

complete. In total, staff recommends that accounting fees for EMG be reduced by $7,147 ($3,522 + $3,625).

DMK Engineering

The Utility provided one invoice related to preparing MFRs, responding to data requests, and audit facilitation totaling $3,375. Bocilla also provided an estimate to complete the rate case which includes $560 for responding to data requests and $2,640 ($165/hr x 16 hrs.) for traveling and attending the Commission Conference. The estimate to complete also includes $575 in costs for lodging, meals, and mileage. Staff believes these expenses are reasonable. As such, staff recommends no adjustment to actual and estimated rate case expense for DMK Engineering.

M&R Consultants

In its MFRs, the Utility did not include any estimated rate case expense associated with accounting services provided by M&R Consultants. However, Bocilla subsequently provided an invoice for fees related to the original cost study totaling $2,100. In its response to staff's second data request, the Utility stated that the costs of obtaining the original cost study will not be submitted as costs of the rate case. Therefore, staff recommends reducing this expense by $2,100.

Giffels-Webster, Inc.

In its MFRs, Bocilla did not include any estimated rate case expense associated with accounting services provided by Giffels-Webster, Inc. However, the Utility subsequently provided two invoices for fees related to the original cost study totaling $6,905. As mentioned above, Bocilla stated that the costs of obtaining the original cost study will not be submitted as costs of the rate case. Therefore, staff recommends reducing this expense by $6,905.

Filing Fee

The Utility included $4,000 in its MFR Schedule B-10 for the filing fee. However, the filing fee for this rate case was $2,000. As such, staff reduced the filing fee expense by $2,000.

In-House

In its MFRs, the Utility did not include any estimated rate case expense for in-house employees. However, in response to staff's data requests, the Utility provided $1,838 for rate case work done by their part-time administrative employee. Further, Bocilla provided an estimate to complete for the President to attend the Commission Conference. This estimate includes hotel and meals totaling $250. Staff believes these expenses are reasonable and recommend no adjustment to in-house rate case expense.

Customer Notices

In its MFRs, the Utility included estimated costs of $1,200 for printing and shipping. Bocilla is responsible for sending out three notices: the initial notice, customer meeting notice, and notice of the final rate increase. The Commission has historically approved recovery of noticing and postage, despite the lack of supporting documentation, based on a standard methodology to estimate the total expense using the number of customers and the estimated per unit cost of envelopes, copies, and postage.[6] As such, staff estimated the postage cost for the notices to be approximately $564 (400 customers x $0.47 x 3 notices). Staff estimates envelope costs to be $72 (400 customers x $0.06 per envelope x 3 notices) and copying costs to be $280 (400 customers x $0.10 per copy x 7 pages).[7] Based on these components, the total cost for customer notices and postage is $916 ($564 + $72 + $280). Accordingly, staff recommends rate case expense be decreased by $284 ($1,200 - $916).

Travel

In its MFRs, the Utility included an estimated $1,500 for travel costs. However, Bocilla subsequently provided documentation detailing estimated travel costs for C&F and EMG's rate case expense. Staff addresses travel costs for these consultants above. As such, staff reduced travel costs by $1,500 to avoid double recovery.

Conclusion

Based upon the adjustments discussed above, staff recommends the Utility's revised rate case expense of $117,328 be decreased by $18,940 to reflect staff's adjustments, for a total of $99,588. A breakdown of staff's recommended rate case expense is as follows:

Table 15-2
Staff Recommended Rate Case Expense

Description	MFR Estimated	Utility Revised Act.& Est.	Staff Adjustment	Recom. Total
Legal Fees	$38,000	$33,323	($2,504)	$31,323
Accounting Consultant Fees	30,000	63,762	(7,147)	56,615
Engineering Consultant Fees	8,100	16,155	(9,005)	7,150
Filing Fee	4,000	2,000	0	2,000
Bocilla In-house	1,600	2,088	0	2,088
Customer Notices	1,200	0	(284)	916
Travel	$1,500	0	0	0
Total	$84,400	$117,328	($18,940)	$99,588

Source: MFR Schedule B-10 and responses to staff data requests

[6]Order No. PSC-14-0025-PAA-WS, issued January 10, 2014, in Docket No. 120209-WS, *In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida.*
[7]The initial notice sent by the Utility was three pages, and the customer notice was one page. Staff anticipates that the final notice will be approximately three pages.

In its MFRs, Bocilla requested total rate case expense of $84,400. When amortized over four years, this represents an annual expense of $21,100. The recommended total rate case expense of $99,588 should be amortized over four years; pursuant to Section 367.0816, F.S.[8] This represents an annual expense of $24,897. Based on the above, staff recommends that annual rate case expense be increased by $3,797 ($24,897 - $21,100) compared to the original request in the MFRs.

[8]Section 367.0816, F.S., was repealed pursuant to Ch. 2016-226, Laws of Florida, effective July 1, 2016. However, the Statute was in effect when Bocilla's application was filed, and therefore shall remain applicable in this case.

Issue 16: What is the appropriate revenue requirement for the test year ended December 31, 2015?

Recommendation: Staff recommends the following revenue requirement be approved.

Test Year Revenue	$ Increase	Revenue Requirement	% Increase
$398,153	$82,665	$480,818	20.76%

(Frank)

Staff Analysis: In its filing, the Utility requested a revenue requirement to generate annual revenue of $547,770. This requested revenue requirement represents a revenue increase of $152,375, or approximately 38.54 percent. Consistent with recommendations concerning rate base, cost of capital, and operating income issues, staff recommends the appropriate revenue requirement should be $480,818. This represents an increase in revenues of $82,665 (or 20.76 percent). This increase will allow the Utility the opportunity to recover its operating expenses and earn a 6.03 percent return on its investment in water rate base. The schedule for operating income is attached as Schedule No. 3-A, and the adjustments are shown on Schedule No. 3-B.

Issue 17: What are the appropriate rate structures and rates for Bocilla's water system?

Recommendation: The recommended rate structure and monthly water rates are attached to this recommendation as 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. (Johnson)

Staff Analysis: Bocilla is located on a barrier island in Charlotte County and provides water service to approximately 400 residential customers. Typically, staff evaluates the seasonality of a utility's customers based on the percentage of bills at zero gallons, which is 11 percent. However, for Bocilla, a portion of the customers are in residence periodically throughout each month rather than a few months out of the year. Therefore, staff believes it is appropriate to evaluate the seasonality based on the percentage of bills at the 1,000 gallon level, which is 30 percent. As a result, it appears that the customer base is somewhat seasonal. The average residential water demand is 5,125 gallons per month. The average water demand excluding zero gallon bills is 5,738 gallons per month. The Utility's current water system rate structure for residential and general service customers consists of a base facility charge (BFC) and a three-tier inclining block rate structure. The rate blocks are: (1) 0-6,000 gallons; (2) 6,001-12,000 gallons; and (3) all usage in excess of 12,000 gallons per month. In addition, the Utility currently has a bulk water rate for service to an emergency interconnection with an adjacent exempt utility and a private fire protection rate in accordance with Rule 25-30.465 F.A.C.

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.

The Utility's proposed rate structure includes a revenue allocation to the BFC of 56.11 percent. Typically, unless the Utility's customer base is highly seasonal, the Commission allocates no greater than 40 percent of the water revenue to the BFC. Staff believes a BFC allocation of 48 percent will send the appropriate conservation pricing signals to target discretionary usage and also provide revenue stability to address the moderate amount of seasonal usage in Bocilla's customer base.

The average person per household served by the Utility 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 instead of 6,000 gallons. Staff recommends the BFC and three-tier gallonage charge rate structure, which includes a gallonage charge for non-discretionary usage for residential water customers, should be continued. However, the rate tiers should be: (1) 0-3,000 gallons (non-discretionary); (2) 3,001-

12,000 gallons; and (3) all usage in excess of 12,000 gallons per month. Approximately 23 percent of the customer demand exceeds 12,000 gallons per month. Further, based on the recommended revenue increase of approximately 21 percent as well as the seasonal nature of Bocilla's customer base, the reduction in residential demand is expected to be insignificant. Staff recommends a BFC and uniform gallonage charge rate structure for general service water customers. The Utility has no customers for bulk water; therefore, staff recommends that Bocilla's bulk water tariff be canceled. The Utility's private fire protection rates should be updated in accordance with Rule 25-30.465 F.A.C.

Table 17-1 below, contains staff's recommended rate structure and rates as well as alternative rate structures, which include varying BFC allocations and rate blocks. Alternative I results in a more even distribution of the rate increase to all customers regardless of demand, but does not send the appropriate pricing signals to target discretionary usage. Alternative II maintains the existing tiers (0 – 6,000, 6,001-12,000, 12,000+) but provides a greater increase for non-discretionary demand than the staff recommended rate structure. The staff recommended rate structure mitigates the rate impact for non-discretionary demand while sending a significant pricing signal for demand in excess of 12,000 gallons per month.

Table 17-1
Staff's Recommended and Alternative Water Rate Structures and Rates

	RATES AT TIME OF FILING	STAFF RECOMMENDED RATES 48% BFC	ALTERNATIVE I 56% BFC	ALTERNATIVE II 49% BFC
Residential				
5/8" x 3/4" Meter Size	$46.24	$47.50	$54.64	$47.81
Charge per 1,000 gallons				
0-6,000 gallons	$4.62			$7.61
6,001 – 12,000 gallons	$7.76			$9.52
Over 12,000 gallons	$12.32			$19.04
0 – 3,000 gallons		$6.93	$6.25	
3,001 – 12,000 gallons		$8.66	$7.81	
Over 12,000 gallons		$17.32	$15.62	
3,000 Gallons	$60.10	$68.29	$73.39	$70.64
6,000 Gallons	$73.96	$94.27	$96.82	$93.47
12,000 Gallons	$120.52	$146.23	$143.68	$150.59

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.

Issue 18: Should Bocilla's request to implement a late payment charge be approved?

Recommendation: Yes. Bocilla's request to implement a late payment charge of $7.12 should be approved. Bocilla should be required to file a proposed customer notice and tariff to reflect the Commission-approved charge. 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 10 days after the date of the notice. (Johnson)

Staff Analysis: The Utility is requesting a $7.12 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. The Utility indicated that four late payment notices are processed per hour. The hourly salary for the employee that processes late payment notices is $24.50 per hour. Based on the labor and four late payment notices per hour, the labor cost per notice is $6.15. The cost basis for the Utility's requested and staff's recommended late payment charge is shown below, in Table 18-1.

Table 18-1
Late Payment Cost Justification

	Staff's Recommended
Labor	$6.15
Printing	0.50
Postage	0.47
Total	$7.12

Source: Utility's cost justification and staff's calculation

Since the late 1990s, the Commission has approved late payment charges ranging from $2.00 to $7.00.[9] Staff recommends that the Utility's requested late payment charge of $7.12 is consistent with previously approved late payment charges and should be approved. The purpose of this charge is not only to provide an incentive for customers to make timely payment, thereby

[9]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.*

reducing the number of delinquent accounts, but also to place the cost burden of processing delinquent accounts solely upon those who are the cost causers.

Based on the above, Bocilla's request to implement a late payment charge of $7.12 should be approved. Bocilla should be required to file a proposed customer notice and tariff to reflect the Commission-approved charge. 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 10 days after the date of the notice.

Issue 19: Should the Utility's approved service availability policy and charges be revised?

Recommendation: Yes. Bocilla's existing wastewater system capacity charge should be discontinued. Staff recommends a new meter installation charge of $365 and a main extension charge of $1,279 per ERC. The Utility's existing AFPI charge should be collected from the remaining 315 ERCs the system was originally designed to serve. The approved service availability charges may only be collected from new connections to the Utility's water system. The approved service availability charges should be effective for service rendered on or after the stamped approval date of the tariff pursuant to Rule 25-30.475, F.A.C. (Johnson)

Staff Analysis: Bocilla's existing service availability charges shown on Table 19-1 were originally approved by Charlotte County and were subsequently grandfathered in when Charlotte County transferred jurisdiction to the Commission in 2013. The charges include a meter installation charge of $165, a system capacity charge of $3,000 per ERC, and an AFPI charge.

Rule 25-30.580, F.A.C., establishes guidelines for designing service availability charges. Pursuant to the rule, the maximum amount of contributions-in-aid-of construction (CIAC), net of amortization, should not exceed 75 percent of the total original cost, net of accumulated depreciation, of the Utility's facilities and plant when the facilities and plant are at their designed capacity. The minimum amount of CIAC should not be less than the percentage of such facilities and plant that is represented by the water transmission and distribution system and sewage collection systems.

Meter Installation Charge

A meter installation charge is designed to recover the cost of the meter and the installation. The Utility's current meter installation charges are $165 for the 5/8" x 3/4" meter and actual cost for all other meter sizes. Based on the cost justification provided for the meter replacement program, staff believes it is appropriate to update the Utility's existing meter installation charges. Staff believes the requested meter installation charge of $365 is reasonable.

Main Extension Charge

A system capacity charge is a single service availability charge that includes the cost of both plant and lines. For a Utility that receives donated lines from a developer, an individual customer connecting to those lines should only be responsible for a service availability charge that reflects plant costs. Therefore, separate charges are typically developed to reflect the customer's share of plant costs (plant capacity charges) and the cost of lines in lieu of donated lines (main extension charges).

Based on the original cost study, the cost of the water distribution system is $914,370 and the lines have a design capacity of 715 ERCs. Therefore, staff recommends that the Utility's service availability charges be revised to include a main extension charge of $1,279 per ERC ($914,370/715). Staff's recommended main extension charge is consistent with the guidelines in Rule 25-30.580, F.A.C., which require that, at a minimum, the cost of the Utility's lines should be contributed.

Staff reviewed the contribution level of Bocilla's water system and found that the current contribution level is 33 percent, which is less than the 75 percent maximum guideline provided in Rule 25-30.580, F.A.C. The minimum amount of CIAC should not be less than the percentage of such facilities and plant that is represented by the water distribution system. Based on staff's review, the recommended main extension charge would allow the Utility to be approximately 75 percent contributed at full capacity. As a result, staff recommends that Bocilla's system capacity charge be discontinued.

AFPI Charge

Bocilla also has an AFPI charge that was originally approved by Charlotte County. An AFPI charge is designed to allow the Utility to recover, from new connections, a portion of the depreciation, property taxes, and return on investment associated with non-used and useful plant that is not included in rates. The costs are typically accumulated on a monthly basis for up to five years. The Bocilla AFPI charges accrued from 1992 to 1995. While the plant associated with those charges was subsequently retired in 2014, the Utility is entitled to continue to recover the costs incurred from 1992 to 1995 from future connections. A new customer connecting to the system today would pay the maximum charge of $1,292.31 per ERC. Staff recommends that the Utility be authorized to continue collecting an AFPI charge of $1,292.31 per ERC from the remaining 315 ERCs the system was designed to serve.

Conclusion

Based on the above, Bocilla's existing wastewater system capacity charge should be discontinued. Staff recommends a new meter installation charge of $365 and a main extension charge of $1,279 per ERC. The Utility's existing AFPI charge should be collected from the remaining 315 ERCs the system was originally designed to serve. The approved service availability charges may only be collected from new connections to the Utility's water system. The approved service availability charges should be effective for service rendered on or after the stamped approval date of the tariff pursuant to Rule 25-30.475, F.A.C.

Table 19-1
Current and Recommended Service Availability Charges

	Current Charge	Recommended Charge
Meter Installation Charge 5/8"x3/4"	$165.00	$365.00
Main Extension Charge Per ERC	$0.00	$1,279.00
System Capacity Charge	$3,000.00	$0.00
AFPI Charge	$1,292.31	$1,292.31

Issue 20: What are the appropriate initial customer deposits for Bocilla?

Recommendation: The appropriate water initial customer deposit should be $171 for the residential 5/8 inch x 3/4 inch 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. (Johnson)

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 a utility and, ultimately, the general body of ratepayers. Historically, the Commission has set initial customer deposits equal to two times the average estimated bill. Currently, Bocilla does not have initial customer deposits in place. Based on the average water demand, the appropriate initial customer deposit should be $171 to reflect an average residential customer bill for two months.

Based on the above, staff recommends that the appropriate water initial customer deposit should be $171 for the residential 5/8 inch x 3/4 inch 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.

Issue 21: What is the appropriate amount by which rates should be reduced four years after the established effective date to reflect the removal of the amortized rate case expense as required by Section 367.0816, F.S.?[10]

Recommendation: The water rates should be reduced as shown on Schedule No. 4 to remove rate case expense grossed-up for regulatory assessment fees (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. Bocilla 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 the Utility 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. (Johnson, Frank)

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 rates. The reduction will reflect the removal of revenue associated with the amortization of rate case expense, the associated return in working capital, and the gross-up for RAFs. This results in a reduction of $26,267.

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. Bocilla 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 the Utility 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.

[10]Section 367.0816, F.S., was repealed pursuant to Ch. 2016-226, Laws of Florida, effective July 1, 2016. However, the Statute was in effect when Bocilla's application was filed, and therefore shall remain applicable in this case.

Issue 22: In determining whether any portion of the interim water revenue increase granted should be refunded, how should the refund be calculated, and what is the amount of the refund, if any?

Recommendation: The appropriate refund amount should be calculated by using the same data used to establish final rates, excluding rate case expense and other items not in effect during the interim period. The revised revenue requirements for the interim collection period should be compared to the amount of interim revenues granted. This results in a refund of 11.3 percent for water. The refund should be made with interest in accordance with Rule 25-30.360(4), F.A.C. The Utility should be required to submit proper refund reports pursuant to Rule 25-30.360(7), F.A.C. The Utility should treat any unclaimed refunds as Contributions in Aid of Construction (CIAC) pursuant to Rule 25-30.360(8), F.A.C. Further, the letter of credit should be released upon staff's verification that the required refunds have been made. (Frank)

Staff Analysis: The Commission authorized Bocilla to collect interim water rates, subject to refund, pursuant to Section 367.082, F.S. The approved interim revenue requirement for water of $464,122 represented an increase of $65,159 or 16.33 percent.

According to Section 367.082, F.S., any refund should be calculated to reduce the rate of return of the Utility during the pendency of the proceeding to the same level within the range of the newly authorized rate of return. Adjustments made in the rate case test period that do not relate to the period that interim rates are in effect should be removed. Rate case expense is an example of an adjustment which is recovered only after final rates are established.

In this proceeding, the test period for establishment of interim and final rates is the 12-month period ended December 31, 2015. Bocilla's approved interim rates did not include any provisions for pro forma or projected operating expenses or plant. The interim increase was designed to allow recovery of actual interest expense, and the lower limit of the last authorized range for equity earnings.

To establish the proper refund amount, staff calculated adjusted interim period revenue requirements utilizing the same data used to establish final rates. Rate case expense was excluded because this item is prospective in nature and did not occur during the interim collection period. Using the principles discussed above, staff calculated an adjusted interim revenue requirement of $411,621 for water. The adjusted water interim revenue requirement of $411,621 is lower than the interim revenue requirement of $464,122, resulting in a refund of 11.3 percent.

The refund should be made with interest in accordance with Rule 25-30.360(4), F.A.C. The Utility should be required to submit proper refund reports pursuant to Rule 25-30.360(7), F.A.C. The Utility should treat any unclaimed refunds as Contributions in Aid of Construction (CIAC) pursuant to Rule 25-30.360(8), F.A.C. Further, the letter of credit should be released upon staff's verification that the required refunds have been made.

Issue 23: Should the Utility be required to notify, within 90 days of an effective order finalizing this docket, that it has adjusted its books for all the applicable NARUC Uniform System of Accounts (USOA) associated with the Commission approved adjustments?

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. Bocilla should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA accounts 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 deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days. (Frank)

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. Bocilla should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA accounts 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 deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days.

Issue 24: 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, and the Utility has provided staff with proof that the adjustments for all the applicable NARUC USOA primary accounts have been made. Once these actions are complete, this docket should be closed administratively. (Leathers)

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, and the Utility has provided staff with proof that the adjustments for all the applicable NARUC USOA primary accounts have been made. Once these actions are complete, this docket should be closed administratively.

Bocilla Utilities, Inc. **Schedule No. 1-A**
Schedule of Water Rate Base **Docket No. 160065-WU**

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$1,230,651	($47,895)	$1,182,756	$105,557	$1,288,313
2	Land and Land Rights	44,000	0	44,000	(44,000)	0
3	Non-used and Useful Components	0	0	0	0	0
4	Construction Work in Progress	42	0	42	0	42
5	Accumulated Depreciation	(358,888)	9,780	(349,108)	37,986	(311,122)
6	CIAC	(460,348)	1,500	(458,848)	(83)	(458,931)
7	Amortization of CIAC	232,960	(7,114)	225,846	(44,617)	181,229
8	Working Capital Allowance	0	45,466	45,466	(473)	44,993
9	**Rate Base**	$688,417	$1,737	$690,154	$54,370	$744,524

Bocilla Utilities, Inc. **Adjustments to Rate Base**		**Schedule No. 1-B** **Docket No. 160065-WU**
	Explanation	**Water**
	Plant In Service	
1	Reflect appropriate test year plant. (Issue 3)	$9,848
2	To remove duplicative land. (Issue 4)	(44,000)
3	Reflect appropriate pro forma Plant. (Issue 5)	139,708
	Total	$105,557
	Land	
	To remove non-used and useful land. (Issue 4)	($44,000)
	Accumulated Depreciation	
1	Reflect appropriate test year accum. depr. (Issue 3)	$49,695
2	Reflect appropriate pro forma accumulated depr. (Issue 5)	(11,709)
	Total	$37,986
	CIAC	
	Retirements related to meter hook-up charges. (Issue 5)	($83)
	Accumulated Amortization of CIAC	
1	Agreed upon Audit Finding 6. (Issue 2)	($44,625)
2	Reflect meter installation via hook-up charges. (Issue 5)	8
	Total	($44,617)
	Working Capital	
	Reflect the appropriate working capital amount. (Issue 7)	($473)

Bocilla Utilities, Inc. **Schedule No. 2**
Capital Structure-Simple Average **Docket No. 160065-WU**

	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	$1,005,226	$0	$1,005,226	$0	$1,005,226	82.30%	5.00%	4.12%
2	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
3	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
4	Common Equity	216,151	0	216,151	0	216,151	17.70%	10.50%	1.86%
5	Customer Deposits	0	0	0	0	0	0.00%	0.00%	0.00%
6	Deferred Income Taxes	12,122	0	12,122	0	12,122	0.00%	0.00%	0.00%
7	**Total Capital**	$1,233,499	$0	$1,233,499	$0	$1,233,499	100.00%		5.97%
Per Staff									
8	Long-term Debt	$1,005,226	($219,673)	$785,553	($211,191)	$574,362	77.14%	4.75%	3.66%
9	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
10	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
11	Common Equity	216,151	0	216,151	(58,111)	158,040	21.23%	11.16%	2.37%
12	Customer Deposits	0	0	0	0	0	0.00%	0.00%	0.00%
13	Deferred Income Taxes	12,122	0	12,122	0	12,122	1.63%	0.00%	0.00%
14	**Total Capital**	$1,233,499	($219,673)	$1,013,826	($269,302)	$744,524	100.00%		6.03%

	LOW	HIGH
RETURN ON EQUITY	10.16%	12.16%
OVERALL RATE OF RETURN	5.82%	6.25%

Bocilla Utilities, Inc.
Statement of Water Operations

Schedule No. 3-A
Docket No. 160065-WU

	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:**	$391,017	$156,753	$547,770	($149,617)	$398,153	$82,665 20.76%	$480,818
	Operating Expenses							
2	Operation & Maintenance	363,729	60,795	424,524	(64,579)	359,945		359,945
3	Depreciation (net of CIAC Amort.)	14,743	0	14,743	14,214	28,957		28,957
4	Taxes Other Than Income	44,538	6,857	51,395	(8,114)	43,281	3,720	47,001
5	Income Taxes	0	0	0	0	0	0	0
6	**Total Operating Expense**	423,010	67,652	490,662	(58,479)	432,183	3,720	435,903
7	**Operating Income**	($31,993)	$89,101	$57,108	($91,138)	($34,030)	$78,945	$44,915
8	**Rate Base**	$688,417		$690,154		$744,524		$744,524
9	**Rate of Return**	-4.65%		8.27%		-4.57%		6.03%

Bocilla Utilities, Inc.
Adjustment to Operating Income

Schedule 3-B
Docket No. 160065-WU

	Explanation	Water
	Operating Revenues	
1	Remove requested final revenue increase.	($152,375)
2	Reflect appropriate amount of annualized revenues. (Issue 11)	2,758
	Total	($149,617)
	Operation and Maintenance Expense	
1	Agreed upon Audit Finding 8. (Issue 2)	($5,048)
2	Reflect appropriate pro forma O&M expenses. (Issue 12)	(29,402)
3	Reflect appropriate salaries & wages expense. (Issue 13)	(13,896)
4	Reflect appropriate pensions and benefits. (Issue 13)	(1,510)
5	Reflect appropriate test year expense adjustments. (Issue 14)	(18,520)
6	Reflect appropriate amount of rate case expense. (Issue 15)	3,797
	Total	($64,579)
	Depreciation Expense - Net	
1	Agreed upon Audit Finding 6. (Issue 2)	$3,538
2	Reflect appropriate test year depr. expense. (Issue 3)	(1,025)
3	Reflect meter installation via hook-up charges. (Issue 4)	(8)
4	Reflect appropriate pro forma depreciation exp. (Issue 5)	11,709
	Total	$14,214
	Taxes Other Than Income	
1	RAFs on revenue adjustments above.	($6,733)
2	Reflect appropriate test year property taxes. (Issue 4)	(3,179)
3	Reflect appropriate pro forma property taxes (Issue 5)	2,136
4	Reflect appropriate pro forma payroll taxes. (Issue 12)	765
5	Reflect appropriate payroll tax expense. (Issue 13)	(1,103)
	Total	($8,114)

Bocilla Utilities, Inc.
TEST YEAR ENDED December 31, 2015
MONTHLY WATER RATES

SCHEDULE NO. 4
DOCKET NO. 160065-WU

	RATES AT TIME OF FILING	COMMISSION APPROVED INTERIM	UTILITY REQUESTED RATES	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential and General Service					
Base Facility Charge by Meter Size					
5/8"X3/4"	$46.24	$53.83	$63.60	$47.50	$2.63
3/4"	N/A	N/A	N/A	$71.25	$3.95
1"	$115.60	$134.58	$159.00	$118.75	$6.58
1-1/2"	$231.18	$269.15	$318.00	$237.50	$13.16
2"	$369.85	$430.64	$508.00	$380.00	$21.05
3"	$693.55	$861.28	$954.00	$760.00	$42.10
4"	$1,155.93	$1,345.75	$1,590.00	$1,187.50	$65.79
6"	$2,324.85	$2,691.50	$3,180.00	$2,375.00	$131.58
8"	$3,699.02	$4,306.40	$5,088.00	$3,800.00	$210.52
Charge per 1,000 gallons - Residential					
0 - 6,000 gallons	$4.62	$5.38	$6.35	N/A	N/A
6,001 - 12,000 gallons	$7.76	$9.03	$10.71	N/A	N/A
Over 12,000 gallons	$12.32	$14.34	$17.00	N/A	N/A
0 - 3,000 gallons	N/A	N/A	N/A	$6.93	$0.38
3,001 - 12,000 gallons	N/A	N/A	N/A	$8.66	$0.48
Over 12,000 gallons	N/A	N/A	N/A	$17.32	$0.96
Charge per 1,000 gallons - General Service				$10.17	$0.56
0 - 6,000 gallons	$4.62	$5.38	$6.35	N/A	N/A
6,001 - 12,000 gallons	$7.76	$9.03	$10.71	N/A	N/A
Over 12,000 gallons	$12.32	$14.34	$17.00	N/A	N/A
Typical Residential 5/8" x 3/4" Meter Bill Comparison					
3,000 Gallons	$60.10	$69.97	$82.65	$68.29	
6,000 Gallons	$73.96	$86.11	$101.70	$94.27	
12,000 Gallons	$120.52	$140.29	$165.96	$146.23	

Item 5

FILED MAR 23, 2017
DOCUMENT NO. 03780-17
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: March 23, 2017

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Knoblauch, M.Watts)
Division of Accounting and Finance (Galloway)
Division of Economics (Bruce)
Office of the General Counsel (Mapp)

RE: Docket No. 160238-WS – Application of B & C Water Resources, L.L.C. and D & E Water Resources, L.L.C. for transfer of majority organizational control.

AGENDA: 04/04/17 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

B & C Water Resources, L.L.C. (B&C) and D & E Water Resources, L.L.C. (D&E) (collectively, the "Utilities") are Class C utilities. B&C serves approximately seven customers in Baker and Union Counties. D&E, whose service territory is in Flagler and Volusia Counties, currently is not serving any customers. The Florida Public Service Commission (Commission) granted Water Certificate No. 626-W to B&C by Order No. PSC-04-1256-PAA-WU, issued December 20, 2004.[1] The Commission granted Water and Wastewater Certificate Nos. 635-W

[1]Order No. PSC-04-1256-PAA-WU, issued on December 20, 2004, in Docket No. 041040-WU, *In re: Application for certificate to operate water utility in Baker and Union Counties by B & C Water Resources, L.L.C.*

and 545-S, to D&E by Order No. PSC-07-0274-PAA-WS, issued April 2, 2007.[2] B&C provides water service to its customers through seven wells, which serve individual hunting lodges that are retained for seasonal use. D&E, which also possesses seven wells, currently is not serving any customers.

B&C's 2015 Annual Report shows gross revenues of $2,335 and a negative net operating income of $23,511. D&E's 2015 Annual Report shows gross revenues of $0 and a negative net operating income of $10,085. Portions of B&C's service area lie in both the Suwannee River Water Management District and the St. Johns River Water Management District (SJRWMD). D&E's service area lies solely in the SJRWMD.

On November 15, 2016, B&C and D&E filed a joint application for transfer of majority organizational control. Staff identified several deficiencies in a letter to the Utilities on December 20, 2016. The Utilities' response on January 20, 2017, satisfied all of these deficiencies.

This recommendation addresses the Utilities' application for a transfer of majority organizational control. The transfer also involves the merger of Plum Creek Manufacturing Holding Company (Plum Creek or Seller), of which B&C and D&E are wholly owned subsidiaries, into Weyerhaeuser NR Company (Weyerhaeuser or Buyer). The Commission has jurisdiction pursuant to Sections 367.071 and 367.091, Florida Statutes (F.S.).

[2]Order No. PSC-07-0274-PAA-WS, issued on April 2, 2007, in Docket No. 060694-WS, *In re: Application for certificates to provide water and wastewater service in Flagler and Volusia Counties by D & E Water Resources, L.L.C.*

Discussion of Issues

Issue 1: Should the application for transfer of majority organizational control of B&C in Baker and Union Counties and D&E in Flagler and Volusia Counties from Plum Creek to Weyerhaeuser be approved?

Recommendation: Yes. The transfer of majority organizational control from Plum Creek to Weyerhaeuser is in the public interest and should be approved effective the date of the Commission vote. The resultant order should serve as the water and wastewater certificates, with the territories described in Attachment A for B&C and Attachment B for D&E. The Utilities' existing rates and charges should remain in effect until a change is authorized by the Commission in a subsequent proceeding. For the Utilities', the tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), Florida Administrative Code, (F.A.C.). (Knoblauch, Galloway, Bruce)

Staff Analysis: This application is for the transfer of majority organization control of B&C in Baker and Union Counties and D&E in Flagler and Volusia Counties on the parent level from Plum Creek to Weyerhaeuser. Based on staff's review, the application is in compliance with the governing statute, Section 367.071, F.S., and Rule 25-30.037(4), F.A.C., concerning applications for transfer of majority organizational control.

Noticing and Territory

B&C and D&E provided notices of the application pursuant to Section 367.071, F.S., and Rule 25-30.030, F.A.C. No objections to the transfers were filed with the Commission, and the time for doing so has expired. The notices contained a description of the territory for B&C and D&E, which is appended to this recommendation as Attachments A and B, respectively.

Technical and Financial Ability

Pursuant to Rules 25-30.037(2)(l) and (m), F.A.C., the application contains statements describing the technical and financial ability of the Buyer to provide service. The Utilities appear to be in compliance with applicable environmental standards, and, according to the application, there will be no change in the day-to-day operational management of the systems. Therefore, staff believes that the Buyer has demonstrated the technical ability to provide service to the existing service territory.

The transfer application also states that the Buyer has sufficient financial assets to ensure the continuing operation of the Utilities. Staff reviewed the financial statements of the Buyer and believes they have the financial capability to provide any necessary funding.

Rates and Charges

B&C's water rates were last approved in an original certificate case in 2004.[3] However, B&C's bulk raw water class of service and revised service availability charges were approved in 2008.[4] B&C's existing rates and charges for water are shown on Schedule No. 1. D&E's water and wastewater rates were last approved in an original certificate case in 2007.[5] D&E's existing rates and charges are shown on Schedule No. 2. Rule 25-9.044(1), F.A.C., provides that, in the case of a change of ownership or control of a utility, the rates, classifications, and regulations of the former owner must continue unless authorized to change by this Commission. Therefore, staff recommends that B&C's and D&E's existing rates and charges remain in effect until a change is authorized by this Commission in a subsequent proceeding.

Conclusion

Based on the above, staff recommends that the transfer of the majority organizational control from Plum Creek to Weyerhaeuser is in the public interest and should be approved effective the date of the Commission vote. The resultant order should serve as the water and wastewater certificates, with the territories described in Attachment A for B&C and Attachment B for D&E. The Utilities' existing rates and charges should remain in effect until a change is authorized by the Commission in a subsequent proceeding. For the Utilities, the tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C.

---

[3] Order No. PSC-04-1256-PAA-WU, issued December 20, 2004, in Docket No. 041040-WU, *In re: Application for certificate to operate water utility in Baker and Union counties by B & C Water Resources, L.L.C.*

[4] Order No. PSC-08-0800-TRF-WU, issued December 3, 2008, in Docket No. 080197-WU, *In re: Application for approval of a new bulk raw water classification of service and approval of revised service availability policy and charges in Baker and Union Counties by B & C Water Resources, L.L.C.*

[5] Order No. PSC-07-0274-PAA-WS, issued April 2, 2007, in Docket No. 060694-WS, *In re: Application for certificates to provide water and wastewater service in Flagler and Volusia Counties by D & E Water Resources, L.L.C.*

Issue 2: Should this docket be closed?

Recommendation: Yes. If the Commission approves staff's recommendation in Issue 1, this docket should be closed. (Mapp)

Staff Analysis: If the Commission approves staff's recommendation in Issue 1, this docket should be closed.

B & C WATER RESOURCES, L.L.C.

WATER SERVICE TERRITORY

SERVING ONLY BAKER COUNTY, FLORIDA

TOWNSHIP 3 SOUTH, RANGE 19 EAST: All of Section 23, lying South of U.S. Highway 90; All of Section 24, lying South of U.S. Highway 90; All of Section 25; All of Section 26, lying South of U.S. Highway 90; All of Section 27, lying South of U.S. Highway 90; All of Section 28, lying South of U.S. Highway 90; All of Section 34; All of Section 35; All of Section 36
TOWNSHIP 3 SOUTH, RANGE 20 EAST: All of Section 11; All of Section 13; All of Section 15; All of Section 16; All of Section 17, lying South of U.S. Highway 90; All of Section 18, lying South of U.S. Highway 90; All of Section 20; All of Section 21; All of Section 22; All of Section 23; All of Section 25, lying West of County Road 229; All of Section 26; All of Section 27; All of Section 29; All of Section 30; All of Section 31; All of Section 33; All of Section 35
TOWNSHIP 3 SOUTH, RANGE 21 EAST: All of Section 29; All of Section 30; All of Section 31; All of Section 32
TOWNSHIP 4 SOUTH, RANGE 19 EAST: All of Section 1; All of Section 2; All of Section 3; All of Section 4; All of Section 9; All of Section 10; All of Section 11; All of Section 12; All of Section 13; All of Section 14; All of Section 15; All of Section 16
TOWNSHIP 4 SOUTH, RANGE 20 EAST: All of Section 6; All of Section 7; All of Section 12; All of Section 13; All of Section 14; All of Section 15; All of Section 16; All of Section 18
TOWNSHIP 4 SOUTH, RANGE 21 EAST: All of Section 4; All of Section 5; All of Section 6; All of Section 7; All of Section 8; All of Section 9; All of Section 10, lying East of County Road 121; All of Section 11, lying East of County Road 121; All of Section 12; All of Section 13; All of Section 14; All of Section 15; All of Section 16; All of Section 17; All of Section 18
TOWNSHIP 4 SOUTH, RANGE 22 EAST: All of Section 7; All of Section 18

SERVING ONLY UNION COUNTY, FLORIDA

TOWNSHIP 4 SOUTH, RANGE 19 EAST: All of Section 21; All of Section 22; All of Section 23; All of Section 24; All of Section 25; All of Section 26; All of Section 27; All of Section 28; The east 1/2 of Section 32; All of Section 33; All of Section 34; All of Section 35; All of Section 36
TOWNSHIP 4 SOUTH, RANGE 20 EAST: All of Section 19; All of Section 20; All of Section 21; All of Section 22; All of Section 23; All of Section 24; All of Section 25; All of Section 26; All of Section 27; All of Section 28; All of Section 29; All of Section 30; All of Section 31; All of Section 32; All of Section 33; All of Section 34; All of Section 35; All of Section 36
TOWNSHIP 4 SOUTH, RANGE 21 EAST: All of Section 19; All of Section 20; All of Section 21; All of Section 22; All of Section 23; All of Section 24; All of Section 25; All of Section 26; The Northeast 1/4, the North 1/2 of the Southeast 1/4 and the Southwest 1/4 of the Northwest 1/4; Section 27; The North 1/2, the Northwest 1/4 of the Southeast 1/4 and the

Northeast 1/4 of the Southwest 1/4; The North 1/2 of Section 28; All of Section 29; All of Section 30; All of Section 31; Section 32: the West 1/2; All of Section 36
TOWNSHIP 4 SOUTH, RANGE 22 EAST: All of Section 19; All of Section 30
TOWNSHIP 5 SOUTH, RANGE 18 EAST: All of Section 12; All of Section 13; All of Section 14; All of Section 15; All of Section 22; All of Section 23; All of Section 24; All of Section 25; All of Section 26; All of Section 27; All of Section 34; All of Section 35, lying North of County Road 238; All of Section 36, lying North of County Road 238
TOWNSHIP 5 SOUTH, RANGE 19 EAST: All of Section 1; All of Section 2; All of Section 3; All of Section 4; All of Section 5; All of Section 7; All of Section 8; All of Section 9; All of Section 10; All of Section 11; All of Section 12; All of Section 13; All of Section 14; All of Section 15; All of Section 16; All of Section 17; All of Section 18; All of Section 19; All of Section 20; All of Section 21; All of Section 22; All of Section 23; All of Section 24; All of Section 25, lying North of County Road 100; All of Section 27; All of Section 28; All of Section 29; All of Section 30; All of Section 31, lying North of County Road 238; All of Section 32; lying North of County Road 238; All of Section 33; All of Section 34; All of Section 35
TOWNSHIP 5 SOUTH, RANGE 20 EAST: All of Section 1, lying South of County Road 16; All of Section 2; All of Section 3; All of Section 4; All of Section 5; All of Section 6; All of Section 7; All of Section 8; All of Section 9; All of Section 10; All of Section 11; All of Section 12; All of Section 13; All of Section 14; All of Section 15; All of Section 16; All of Section 17; All of Section 18; All of Section 19; All of Section 20; All of Section 21, lying North of County Road 121; All of Section 22, lying North of County Road 121; All of Section 23, lying North of County Road 121; All of Section 28; The Southeast 1/4 of the Northwest 1/4 of Section 29 lying South of County Road 238 and the North 1/2 of the Northwest 1/4 of Section 29; The North 1/2 of Section 30; The Southeast 1/4 and the East 1/2 of the Southwest 1/4 of Section 32; All of Section 33; All of Section 34; All of Section 35
TOWNSHIP 5 SOUTH, RANGE 21 EAST: All of Section 6; All of Section 7; The West 1/4 and the Northwest 1/4 of Southeast 1/4 of Section 8; All of Section 17, lying South of County Road 121 and State Highway 16; Section 18: The South 1/2 of the Southeast 1/4 lying East of County Road 229 and the East 2/3 of the Northeast 1/4 of the Southeast 1/4; All of Section 19, lying North of County Road 229; All of Section 20, lying North of County Road 229; All of Section 29; All of Section 30
TOWNSHIP 6 SOUTH, RANGE 20 EAST: All of Section 2, lying North of County Road 100; All of Section 3; All of Section 4; All of Section 5; All of Section 6; All of Section 8; All of Section 9; All of Section 10; All of Section 16; All of Section 18

FLORIDA PUBLIC SERVICE COMMISSION
Authorizes

B & C Water Resources, L.L.C.
Pursuant to
Certificate Number 626-W

to provide water service in Baker and Union Counties in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Orders of this Commission in the territory described by the Orders of this Commission. This authorization shall remain in force and effect until superseded, suspended, cancelled or revoked by Order of this Commission.

Order Number	Date Issued	Docket Number	Filing Type
PSC-04-1256-PAA-WU	12/20/04	041040-WU	Original Certificate
*	*	160238-WS	Transfer Majority Organizational Control

***Order Number and date to be provided at time of issuance**

D & E WATER RESOURCES, L.L.C.
DESCRIPTION OF TERRITORY SERVED
Water and Wastewater Service Area
Volusia and Flagler Counties

DESCRIPTION: PARCEL 1

A parcel of land lying in Sections 10 and 15, Township 13 South, Range 30 East, Flagler County, Florida, and more particularly described as follows:

From a Point of Reference being the Southwest corner of said Section 10, bear S86°53'34"E along the South line of said Section 10 a distance of 249.50 feet to the Southerly right-of-way of County Road 304; thence N41°37'15"E along the said Southerly right-of-way line of County Road 304 a distance of 1385.48 feet to an intersection with the Easterly right-of-way line of the Florida Power & Light right-of-way (300' R/W) being the Point of Beginning of this description; thence continue N41°37'15"E 2818.53 feet; thence N41°27'55"E 1173.68 feet to a point along said Southerly right-of-way line of County Road 304, said point being the Southwest corner of Official Records Book 360, Pages 74 thru 76 as recorded in the records of Flagler County, Florida; thence leaving said Southerly right-of-way line of County Road 304 along the Southerly line of said Official Records Book 360, Pages 74 thru 76 S86°54'03"E 1371.88 feet; thence S01°25'22"E 359.06 feet; thence S41°27'55"W 1763.90 feet; thence S 41°37'15"W 3630.65 feet to a point on the Easterly right-of-way line of the Florida Power & Light right-of-way (300' R/W); thence along said Easterly right-of-way line N16°50'03"W 1548.88 feet to the Southerly line of County Road 304 and the Point of Beginning of this description.

LESS & EXCEPT THE FOLLOWING DESCRIPTION:

A 10.00 acre parcel of land lying in Section 10, Township 13 South, Range 30 East, Flagler County, Florida and more particularly described as Follows:

From a Point of Reference being the Southwest corner of Section 10, bear S86°53'34"E along the South line of said Section 10 a distance of 249.50 feet to the Southerly right-of-way of County Road 304; thence N41°37'15"E along the said Southerly right-of-way of County Road 304 a distance of 1385.48 feet to an intersection with the Easterly right-of-way line of the Florida Power & Light right-of-way (300' R/W); thence continue N41°37'15"E along the Southerly line of County Road 304 a distance of 330.00 feet to the Point of Beginning of this description; thence continue N41°37'15"E along said right-of-way line a distance of 330.00 feet; thence S48°22'45"E a distance of 1320.00 feet; thence S41°37'15"W a distance of 330.00 feet; thence N48°22'45"W a distance of 1320.00 feet to the Southerly line of County Road 304 and the Point of Beginning.

DESCRIPTION: PARCEL 2

PARCEL 2 – TRACT "A"

A parcel of land lying in Sections 10, 11, 12, 13, 14 and 15, Township 13 South, Range 30 East, Flagler County, Florida and being a portion of the subdivision of BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida and being more particularly described as follows:

BEGIN at the Southeast corner of Section 12, Township 13 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 12, N 01°53'47" W, a distance of 5329.76 feet to the Northeast corner of said Section 12; thence departing said East line and on the North line of said Section 12, S 89°22'13" W, a distance of 5046.45 feet to the Northwest corner of said Section 12, the same being the Northeast corner of aforesaid Section 11, Township

13 South, Range 30 East, Flagler County, Florida; thence on the North line of said Section 11, S 89°35'41" W, a distance of 5413.22 feet to the Northwest corner of said Section 11; thence departing said North line and on the West line of said Section 11, S 1°14'45" E, a distance of 669.38 feet to the Northwest corner of Tract 6, Block B of Section 11, Township 13 South, Range 30 East of BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida; thence departing said West line and on the North line of said Tract 6, Block B, of Section 11, N 89°33'02" E, a distance of 676.64 feet to the Northeast corner of said Tract 6, Block B, of Section 11; thence departing said North line and on the East line of Tract 6, Block B and the East line of Tract 7, Block Ball in Section 11, Township 13 South, Range 30 of said BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida, S 01°14'43" E, a distance of 1337.72 feet to the Southeast corner of said Tract 7, Block B, of Section 11; thence departing said East lines and on the South line of said Tract 7, Block B, of Section 11, S 89°27'44" W, a distance of 676.61 feet to the Southwest corner of said Tract 7, Block B, of Section 11; thence departing the South line of said Tract 7, Block B, of Section 11 and on the West line of said Tract 7, Block B, of Section 11, the same being the East line of Section 10, Township 13 South, Range 30 East, Flagler County, Florida, N 01°14'45" W, a distance of 530.41 feet to the Southeast corner of a parcel of land as described in Official Records Book 700, Page 124 of the Public Records of Flagler County, Florida; thence departing said East and West lines and on the Southeasterly line of said parcel of land as described in Official Records Book 700, Page 124 of the Public Records of Flagler County, Florida, S 41°36'27" W, a distance of 1766.36 feet; thence continue on said Southeasterly line, S 41°45'47" W, a distance of 3627.29 feet to the Southwesterly corner of said parcel of land as described in Official Records Book 700, Page 124 of the Public Records of Flagler County, Florida, said corner being on the East line of a Florida Power & Light Company Right of Way as described in Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing said Southeast line and on the East line of said Florida Power & Light Company Right of Way as described in Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida, S 16°41'34" E, a distance of 1738.79 feet to a point on the North line of Tract 11, Block B of Section 15, Township 13 South, Range 30 East of aforesaid BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida; thence departing said East line and on the North line of said Tract 11, Block B, of Section 15, S 86°41'51" E, a distance of 594.56 feet to the Northeast corner of said Tract 11, Block B, of Section 15; thence departing said North line and on the East line of said Tract 11, Block B, of Section 15, S 01°51'03" E, a distance of 669.29 feet to the Southeast corner of said Tract 11, Block B, of Section 15; thence departing said East line and on the South line of said Tract 11, Block B, of Section 15, N 86°43'47" W, a distance of 412.04 feet to a point on the East line of aforesaid Florida Power & Light Company Right of Way as described in Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing said South line and on the East line of said Florida Power & Light Company Right of Way as described in Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida through the following courses: S 16°41'34" E, a distance of 1659.46 feet; thence N 73°18'26" E, a distance of 50.00 feet; thence S 16°41'34" E, a distance of 119.71 feet; thence S 26°20'10" W, a distance of 119.71 feet; thence N 63°39'50" W, a distance of 50.00 feet; thence S 26°20'10" W, a distance of 1002.58 feet to a point on the South line of Section 15, Township 13 South, Range 30

East, Flagler County, Florida, thence on said South line of said Section 15, S 86°52'11" E, a distance of 3150.33 feet to the Southeast corner of said Section 15; thence departing said South line, S 29°34'48" W, a distance of 71.00 feet to a point on the South Maintained Right of Way line of "Relay Road 9" (a Private Road) ; thence on the South Maintained Right of Way line of said "Relay Road 9", through the following courses: N 89°20'27" E, a distance of 2753.49 feet; thence N 89°58'57" E, a distance of 542.17 feet; thence N 88°58'33" E, a distance of 2108.33 feet to a point on the East Maintained Right of Way line of "Relay Road 12" (a Private Road); thence departing said South Maintained Right of Way line of "Relay Road 9" on the East Maintained Right of Way line of said "Relay Road 12", N 0°28'30" W, a distance of 3482.39 feet to a point on the South Maintained Right of Way line of "Relay Road 10" (a Private Road) and the beginning of a curve concave Southeasterly having a radius of 125.00 feet and a central angle of 43°32'07"; thence departing the East Maintained Right of Way line of said "Relay Road 12" and on the South Maintained Right of Way line of said "Relay Road 10" and on the arc of said curve a distance of 94.98 feet said arc being subtended by a chord which bears N 21°17'33" E, a distance of 92.71 feet to the curves end; thence continue on the South Maintained Right of Way line of said "Relay Road 10" through the following courses: N 43°03'37" E, a distance of 72.28 feet; thence N 50°30'25" E, a distance of 122.34 feet; thence N 69°30'14" E, a distance of 120.05 feet; thence N 71°53'35" E, a distance of 136.22 feet; thence N 65°23'52" E, a distance of 107.59 feet; thence N 57°13'53" E, a distance of 117.33 feet; thence N 50°33'04" E, a distance of 536.84 feet; thence N 40°48'31" E, a distance of 180.65 feet; thence N 43°22'12" E, a distance of 60.92 feet; thence N 49°37'12" E, a distance of 97.92 feet; thence N 56°23'41" E, a distance of 1669.02 feet; thence N 58°51'52" E, a distance of 92.42 feet; thence N 64°08'46" E, a distance of 91.58 feet; thence N 72°44'28" E, a distance of 368.38 feet; thence N 79°56'35" E, a distance of 101.54 feet; thence S 80°49'49" E, a distance of 71.54 feet; thence S 66°51'48" E, a distance of 176.65 feet; thence S 68°39'11" E, a distance of 110.07 feet; thence S 78°54'10" E, a distance of 142.60 feet; thence S 85°45'53" E, a distance of 1250.31 feet to the POINT OF BEGINNING.

Together with:

PARCEL 2 – TRACT "B"

A parcel of land lying in Sections 12, 13, 22, 23, 24, 25, 26, 27, 34 and 35, Township 13 South, Range 30 East, Flagler County, Florida and lying in Sections 2, 3, 10, 11, 14 and 15, Township 14 South, Range 30 East, Flagler County, Florida and being a portion of the subdivision of BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida and being more particularly described as follows:

COMMENCE at the Northeast corner of Section 13, Township 13 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 13, S 2°12'01" E, a distance of 78.26 feet to the POINT OF BEGINNING; thence continue along the East line of said Section 13, S 2°12'01" E, a distance of 5224.92 feet to the Northeast corner of Section 24, Township 13 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 24, S 1°39'56" E, a distance of 5330.16 feet to the Northeast corner of Section 25, Township 13 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 25, S 1°55'02" E, a distance of 2672.59 feet to the East Quarter corner of said Section 25; thence continue on said East line S 2°00'45" E, a distance of 2694.96 feet to the Southeast corner of said Section 25; thence departing the East line of said Section 25, S 89°06'20" W, a distance of 5358.28 feet to a point on the Westerly Maintained Right of Way line of "Relay Road 12" (a Private Road); thence on the Westerly Maintained Right of Way line of said "Relay Road 12", through the following courses: S 1°37'59" E, a distance of 4479.07 feet; thence S 3°49'05" E, a distance of 587.46 feet; thence S 1°26'24" E, a distance of 5497.16 feet; thence S 1°13'51" W, a distance of 858.47 feet; thence departing said Westerly Maintained Right of Way line of "Relay Road 12", and on the Westerly line of the Halifax Basin, through the following courses: S 2°06'48" E, a distance of 1987.94 feet; thence S 86°19'18" W, a distance of 1062.98 feet; thence S 89°49'00" W, a distance of 1750.63 feet; thence S 88°10'03" W, a distance of 1114.30 feet; thence S 0°50'04" E, a distance of 4253.61 feet; thence departing said Westerly line of the Halifax Basin, S 89°21'12" W, a distance of 1585.74 feet to a point on the Centerline of the Maintained Right of Way of "Relay Road 5" (a Private Road); thence on the Centerline of the Maintained Right of Way of said "Relay Road 5", through the following courses: N 45°09'48" W, a distance of 504.10 feet; thence N 29°46'37" W, a distance of 1621.36 feet; thence N 34°58'17" W, a distance of 196.85 feet; thence N 25°49'43" W, a distance of 172.43 feet; thence N 2°36'37" W, a distance of 134.60 feet; thence N 15°20'26" E, a distance of 159.07 feet; thence N 49°10'50" E, a distance of 162.05 feet; thence N 57°33'48" E, a distance of 1491.56 feet; thence N 40°48'02" E, a distance of 154.68 feet; thence N 8°48'44" E, a distance of 157.25 feet; thence N 0°22'30" W, a distance of 1045.82 feet; thence N 5°38'10" W, a distance of 897.04 feet; thence N 7°58'50" W, a distance of 811.14 feet; thence N 2°34'49" W, a distance of 645.45 feet; thence N 6°39'36" E, a distance of 550.91 feet; thence N 19°14'57" E, a distance of 230.24 feet; thence N 48°26'49" E, a distance of 247.18 feet; thence N 36°28'10" E, a distance of 243.07; thence N 10°45'32" E, a distance of 233.99 feet to a point on the Centerline of the Maintained Right of Way of "Relay Road 4" (a Private Road); thence departing the Centerline of the Maintained Right of Way of "Relay Road 5" and on the Centerline of the Maintained Right of Way of said "Relay Road 4" through the following courses: N 89°00'18" W, a distance of 599.18 feet; thence S 87°04'43" W, a distance of 1051.01 feet; thence S 80°05'16" W, a distance of 1282.86 feet; thence S 76°39'33" W, a distance of 800.98 feet; thence S 81°15'55" W, a distance of 285.07 feet; thence S 76°58'32" W, a distance of 512.51 feet to a point on the Easterly Right of Way line of a Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing the Centerline of the Maintained Right of Way of said "Relay Road 4" and on the Easterly Right of Way line of said Florida Power and Light Company Right of Way through the following courses: N 22°02'08" W, a distance of 3116.10 feet; thence N 0°26'57" W, a distance of 6500.00 feet; thence N 1°04'34" W, a distance of 5200.00 feet; thence N 1°46'19" W, a distance of 2600.57 feet; thence N 26°20'10" E, a distance of 4134.17 feet to the North line of Section 22, Township 13 South, Range 30 East, Flagler County, Florida; thence departing the Easterly Right of Way line of said Florida Power and Light Company Right of Way and on the North line of said Section 22, S 86°52'11" E, a distance of 3150.33 feet to the Northeast corner of said Section 22; thence departing said North line, S 29°34'48" W, a distance of 71.00 feet to a point on the South Maintained Right of Way line of "Relay Road 9" (a Private Road) ; thence on the South Maintained Right of Way line of said "Relay Road 9", through the following courses: N 89°20'27" E, a distance of 2753.49 feet; thence N 89°58'57" E, a distance of 542.17 feet; thence N 88°58'33" E, a distance of 2108.33 feet to a point on the East Maintained Right of Way line of "Relay Road 12" (a Private Road); thence departing said South Maintained Right of Way line of "Relay Road 9" on the East Maintained Right of Way line of said "Relay Road 12", N 0°28'30" W, a distance of 3482.39 feet to a point on the South Maintained Right of Way line of "Relay Road 10" (a Private Road) and the beginning of a curve concave Southeasterly having a radius of 125.00 feet and a central angle of 43°32'07"; thence departing the East Maintained Right of Way line of said "Relay Road 12" and on the South Maintained Right of Way line of said "Relay Road 10" and on the arc of said curve a distance of 94.98 feet said arc being subtended by a chord which bears N 21°17'33" E, a distance of 92.71 feet to the curves end; thence continue on the South Maintained Right of Way line of said "Relay Road 10" through the following courses: N 43°03'37" E, a distance of 72.28 feet; thence N 50°30'25" E, a distance of 122.34 feet; thence N 69°30'14" E, a distance of 120.05 feet; thence N 71°53'35" E, a distance of 136.22 feet; thence N 65°23'52" E, a distance of 107.59 feet; thence N 57°13'53" E, a distance of 117.33 feet; thence N 50°33'04" E, a distance of 536.84 feet; thence N 40°48'31" E, a distance of 180.65 feet; thence N 43°22'12" E, a distance of 60.92 feet; thence N 49°37'12" E, a distance of 97.92 feet; thence N 56°23'41" E, a distance of 1669.02 feet; thence N 58°51'52" E, a distance of 92.42 feet; thence N 64°08'46" E, a distance of 91.58 feet; thence N 72°44'28" E, a distance of 368.38 feet; thence N 79°56'35" E, a distance of 101.54 feet; thence S 80°49'49" E, a distance of 71.54 feet; thence S 66°51'48" E, a distance of 176.65 feet; thence S 68°39'11" E, a distance of 110.07 feet; thence S 78°54'10" E, a distance of 142.60 feet; thence S 85°45'53" E, a distance of 1250.31 feet to the POINT OF BEGINNING.

Together with:

PARCEL 2 - TRACT "C"

A parcel of land lying in Sections 35 and 36, Township 13 South, Range 30 East, Flagler County, Florida and lying in Sections 1, 2, 11, 12 and 14, Township 14 South, Range 30 East, Flagler County, Florida and being more particularly described as follows:

BEGIN at the Northeast corner of Section 36, Township 13 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 36, S 01°52'15" E, a distance of 5249.16 feet to the Southeast corner of said Section 36, the same being the Northeast corner of Section 1, Township 14 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 1, S 00°14'28" E, a distance of 5296.99 feet; to the Southeast corner of said Section 1, the same being the Northeast corner of Section 12, Township 14 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 12, S 01°56'03" E, a distance of 5259.13 feet to the Southeast corner of said Section 12; thence departing said East line and on the South line of said Section 12, S 87°56'12" W, a distance of 5264.99 feet to the Southwest corner of said Section 12 the same being the Northeast corner of Section 14, Township 14 South, Range 30 East, Flagler County, Florida; thence departing said South line and on the East line of said Section 14, S 00°33'38" E, a distance of 5294.00 feet to the Southeast corner of said Section 14; thence departing said East line and on the South line of said Section 14, S 88°56'35" W, a distance of 795.54 feet; thence departing said South line N 0°43'27" W, a distance of 3483.72; thence S 89°21'12" W, a distance of 3183.19 feet; thence N 0°50'04" W, a distance of 4253.61 feet; thence N 88°10'03" E, a distance of 1114.30 feet; thence N 89°49'00" E, a distance of 1750.63 feet; thence N 86°19'18" E, a distance of 1062.98 feet; thence N 02°06'48" W, a distance of 1987.94 feet to a point on the Westerly Maintained Right of Way line of said "Relay Road 12" (a Private Road); thence on the Westerly Maintained Right of Way line of said "Relay Road 12", through the following courses: N 01°13'51" E, a distance of 858.47 feet; thence N 01°26'24" W, a distance of 5497.16 feet; thence N 03°49'05" W, a distance of 587.46 feet; thence N 01°37'59" W, a distance of 4479.07 feet; thence departing said Westerly Maintained Right of Way line of said "Relay Road 12", N 89°06'20" E, a distance of 5358.28 to the POINT OF BEGINNING.

Together with:

PARCEL 2 - TRACT "D"

A parcel of land lying in Sections 2, 3, 9, 10, 11, 14, 15, 16, 21, 22 and 23, Township 14 South, Range 30 East, Flagler County, Florida, and being more particularly described as follows:

BEGIN at the Southeast corner of Section 21, Township 14 South, Range 30 East, Flagler County, Florida; thence on the South line of said Section 21, S 89°49'43" W, a distance of 347.16 feet to a point on the Easterly Right of Way line of a Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing said South line and on the Easterly Right of Way line of said Florida Power and Light Company Right of Way through the following courses: N 1°00'03" W, a distance of 785.64 feet; thence N 0°50'45" W, a distance of 11098.95 feet; thence N 42°58'43" E, a distance of 3248.83 feet; thence S 47°01'17" E, a distance of 50.00 feet; thence N 42°58'43" E, a distance of 131.86 feet; thence N 22°02'08" W, a distance of 131.86 feet; thence S 67°57'52" W, a distance of 50.00 feet; thence N 22°02'08" W, a distance of 2248.01 feet to a point on the Centerline of the Maintained Right of Way of "Relay Road 4" (a Private Road); thence departing the Easterly Right of Way line of said Florida Power and Light Company Right of Way and on the Centerline of the Maintained Right of Way of said "Relay Road 4" through the following courses: thence N 76°58'32" E, a distance of 512.51 feet; thence N 81°15'55" E, a distance of 285.07 feet; thence N 76°39'33" E, a distance of 800.98 feet; thence N 80°05'16" E, a distance of 1282.86 feet; thence N 87°04'43" E, a distance of 1051.01 feet; thence S 89°00'18" E, a distance of 599.18 feet to a point on the Centerline of the Maintained Right of Way of "Relay Road 5" (a Private Road); thence departing the Centerline of the Maintained Right of Way of "Relay Road 4" and on the Centerline of the Maintained Right of Way of said "Relay Road 5", through the following courses: S 10°45'32" W, a distance of 233.99 feet; thence S 36°28'10" W, a distance of 243.07 feet; thence S 48°26'49" W, a distance of 247.18 feet; thence S 19°14'57" W, a distance of 230.24 feet; thence S 6°39'36" W, a distance of 550.91 feet; thence S 2°34'49" E, a distance of 645.45 feet; thence S 7°58'50" E, a distance of 811.14 feet; thence S 5°38'10" E, a distance of 897.04 feet; thence S 0°22'30" E, a distance of 1045.82 feet; thence S 8°48'44" W, a distance of 157.25 feet; thence S 40°48'02" W, a distance of 154.68 feet; thence S 57°33'48" W, a distance of 1491.56 feet; thence S 49°10'50" W, a distance of 162.05 feet; thence S 15°20'26" W, a distance of 159.07 feet; thence S 2°36'37" E, a distance of 134.60 feet; thence S 25°49'43" E, a distance of 172.43 feet; thence S 34°58'17" E, a distance of 196.85 feet; thence S 29°46'37" E, a distance of 1621.36 feet; thence S 45°09'48" E, a distance of 504.10 feet; thence departing the Centerline of the Maintained Right of Way of said "Relay Road 5", N 89°21'12" E, a distance of 4768.94 feet; thence S 0°43'27" E, a distance of 3483.72 feet to a point on the North line of Section 23, Township 14 South, Range 30 East, Flagler County, Florida; thence on said North line, S 88°56'35" W, a distance of 870.72 feet to the Northeast corner of the West 3/4 of the Northwest 1/4 of the Northeast 1/4 of said Section 23; thence departing said North line and on the East line of the West 3/4 of the Northwest 1/4 of the Northeast 1/4 of said Section 23, S 1°10'11" E, a distance of 1318.43 feet to the Southeast corner of the West 3/4 of the Northwest 1/4 of the Northeast 1/4 of said Section 23; thence departing said East line and on the South line of the West 3/4 of the Northwest 1/4 of the Northeast 1/4 of said Section 23, S 89°11'22" W, a distance of 1002.43 feet to the Southwest corner of the West 3/4 of the Northwest 1/4 of the Northeast 1/4 of said Section 23; thence departing said South line and on the East line of the Northwest 1/4 of said Section 23, S 0°59'18" E, a distance of 1313.31 feet to the Southeast corner of the Northwest 1/4 of said Section 23; thence departing said East line and on the South line of the Northwest 1/4 of said Section 23, S 89°30'49" W, a distance of 2670.27 feet to the Southwest corner of the Northwest 1/4 of said Section 23; thence departing said South line and on the West line of said Section 23, S 1°57'19" E, a distance of 2685.77 feet to the Southwest corner of said Section 23, the same being the Southeast corner of Section 22, Township 14 South, Range 30 East, Flagler County, Florida; thence departing said West line and on the South line of said Section 22, S 89°38'58" W, a distance of 5292.80 feet to the POINT OF BEGINNING.

Together with:

PARCEL 2 – TRACT "E"

A parcel of land lying in Sections 13, 23 and 24, Township 14 South, Range 29 East, Flagler County, Florida, and lying in Sections 32 and 33, Township 13 South, Range 30 East, Flagler County, Florida and lying in Sections 3, 4, 5, 8, 9, 10, 16, 17, 18, 19, 20 and 21, Township 14 South, Range 30 East, Flagler County, Florida and being more particularly described as follows:

COMMENCE at the Southeast corner of Section 21, Township 14 South, Range 30 East, Flagler County, Florida; thence on the South line of said Section 21, S 89°49'43" W, a distance of 647.19 feet to a point on the Westerly Right of Way line of a Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida for the POINT OF BEGINNING; thence continue on the South line of said Section 21, S 89°49'43" W, a distance of 4718.82 feet to the Southeast corner of Section 20, Township 14 South, Range 30 East, Flagler County, Florida; thence on the South line of said Section 20, S 88°47'01" W, a distance of 5298.64 feet to the Southeast corner of Section 19, Township 14 South, Range 30 East, Flagler County, Florida; thence on the South line of said Section 19, S 89°19'45" W, a distance of 5297.80 feet to the Southeast corner of Section 24, Township 14 South, Range 29 East, Flagler County, Florida; thence on the South line of said Section 24, S 89°23'20" W, a distance of 5207.14 feet to a point on the Easterly Right of Way line of State Road 11 (a variable width Right of Way per Florida Department of Transportation Right of Way Maps Section 7305-1237); thence departing said South line and on the Easterly Right of Way line of said State Road 11 through the following courses: N 20°24'51" W, a distance of 2930.37 feet to the beginning of a curve concave Easterly having a radius of 1309.89 feet and a central angle of 46°49'53"; thence on the arc of said curve a distance of 1070.65 feet said arc being subtended by a chord which bears N 03°00'06" E, a distance of 1041.10 feet to the curves end; thence N 26°25'02" E, a distance of 943.90 feet to a point on the Southerly Maintained Right of Way line of an Un-Named Forest Management Road (a Private Road); thence departing said Easterly Right of Way line of said State Road 11 and on the Southerly and Easterly Maintained Right of Way line of said Un-Named Forest Management Road through the following courses: N 85°32'18" E, a distance of 478.40 feet; thence N 82°31'02" E, a distance of 145.70 feet; thence N 88°08'58" E, a distance of 914.53 feet; thence S 67°41'49" E a distance of, 483.36 feet; thence S 68°05'09" E, a distance of 382.72 feet; thence N 89°06'42" E, a distance of 421.46 feet; thence S 71°40'23" E, a distance of 183.41 feet; thence N 75°42'29" E, a distance of 479.29 feet; thence N 70°18'39" E, a distance of 1173.27 feet; thence N 1°19'52" W, a distance of 84.93 feet; thence N 29°56'34" W, a distance of 72.33 feet; thence N 60°26'33" W, a distance of 182.44 feet; thence N 28°46'19" W, a distance of 279.51 feet; thence N 7°10'19" W, a distance of 208.33 feet; thence N 54°45'50" W, a distance of 165.66 feet; thence N 59°13'06" W, a distance of 130.55 feet; thence N 40°38'00" W, a distance of 201.78 feet; thence N 7°14'45" W, a distance of 142.69 feet; thence N 30°27'17" W, a distance of 348.70 feet; thence N 41°04'25" W, a distance of 63.36 feet; thence N 61°19'01" W, a distance of 77.91 feet; thence N 19°47'15" W, a distance of 98.52 feet; thence N 28°13'06" W, a distance of 50.52 feet; thence N 47°22'23" W, a distance of 68.18 feet; thence N 9°23'57" W, a distance of 105.09 feet; thence N 33°52'10" W, a distance of 274.06 feet; thence N 52°54'53" W, a distance of 189.54 feet; thence N 29°25'35" W, a distance of 212.63 feet; thence N 40°17'46" W, a distance of 50.15 feet; thence N 72°29'31" W, a distance of 93.59 feet; thence N 24°05'07" W, a distance of 62.87 feet; thence N 10°24'23" W, a distance of 111.71 feet; thence N 15°15'51" W, a distance of 127.93 feet; thence N 28°38'04" W, a distance of 514.83 feet; thence departing said Southerly and Easterly Maintained Right of Way line of said Un-Named Forest Management Road, N 89°50'18" E, a distance of 3111.09 feet to a point on the Southerly Maintained Right of Way line of "Relay Road 41" (a Private Road); thence on the Southerly Maintained Right of Way line said "Relay Road 41" and its Easterly projection, through the following courses: N 84°05'49" E, a distance of 640.34 feet; thence N 87°04'31" E, a distance of 1376.85 feet; thence N 85°37'18" E, a distance of 3308.37 feet to a point on the Easterly Maintained Right of Way line of "Relay Road 14" (a Private Road); thence on the Easterly Maintained Right of Way line of said "Relay Road 14", through the following courses: N 1°38'24" W, a distance of 2408.29 feet; thence N 1°36'22" W, a distance of 2795.88 feet; thence N 1°30'45" W, a distance of 2591.53 feet; thence N 1°35'50" W, a distance of 3207.05 feet; thence N 2°03'07" W, a distance of 2009.45 feet to the Southwest corner of Section 32, Township 13 South, Range 30 East, Flagler County, Florida; thence departing the Easterly Maintained Right of Way line of said "Relay Road 14", N 88°46'57" E, a distance of 687.93 feet to a point on the Centerline of the Maintained Right of Way of "Relay Road 21" (a Private Road); thence on the Centerline of the Maintained Right of Way of said "Relay Road 21" through the following courses: N 0°25'59" E, a distance of 150.18 feet; thence N 6°37'03" W, a distance of 536.01 feet; thence N 11°16'14" W, a distance of 606.06 feet to the beginning of a curve concave Southeasterly having a radius of 335.85 feet and a central angle of 71°05'56"; thence on the arc of said curve a distance of 416.76 feet said arc being subtended by a chord which bears N 24°16'44" E, a distance of 390.53 feet to the curves end; thence N 59°49'42" E, a distance of 438.34 feet to the beginning of a curve concave Northwesterly having a radius of 267.00 feet and a central angle of 71°26'49"; thence on the arc of said curve a distance of 332.94 feet said arc being subtended by a chord which bears N 24°06'18" E, a distance of 311.79 feet to the curves end; thence N 11°37'07" W, a distance of 1223.86 feet to the beginning of a curve concave Southeasterly having a radius of 233.00 feet and a central angle of 116°23'25"; thence on the arc of said curve a distance of 473.31 feet said arc being subtended by a chord which bears N 46°34'36" E, a distance of 396.03 feet to the curves end; thence S 75°13'42" E, a distance of 1327.37 feet; thence S 78°01'36" E, a distance of 518.35 feet; thence S 63°38'56" E, a distance of 2303.63 feet; thence S 72°22'36" E, a distance of 146.11 feet to the beginning of a curve concave Southwesterly having a radius of 85.00 feet and a central angle of 69°39'15; thence on the arc of said curve a distance of 103.33 feet said arc being subtended by a chord which bears S 37°32'58" E, a distance of 97.09 feet to the curves end; thence S 2°43'21" E, a distance of 1294.37 feet; thence S 19°28'38" E, a distance of 248.00 feet; thence S 2°20'20" E, a distance of 463.96 feet; thence departing the Centerline of the Maintained Right of Way of "Relay Road 21", S 88°49'10" E, a distance of 1177.70 feet; thence N 46°39'50" E, a distance of 221.07 feet; thence N 14°37'45" E, a distance of 307.75 feet; thence N 63°32'28" E, a distance of 422.87 feet; thence S 85°26'12" E, a distance of 400.06 feet; thence S 75°16'42" E, a distance of 235.73 feet; thence S 47°50'56" E, a distance of 357.80 feet; thence S 27°30'57" E, a distance of 347.29 feet; thence S 71°45'23" E, a distance of 188.69 feet; thence S 40°04'33" E, a distance of 712.94 feet; thence S 27°24'47" E, a distance of 424.67 feet; thence S 5°17'48" E, a distance of 526.22 feet; thence S 61°46'39" E, a distance of 265.05 feet; thence N 16°56'59" E, a distance of

208.92 feet; thence N 12°16'37" E, a distance of 321.13 feet; thence N 20°34'25" E, a distance of 394.57 feet; thence N 63°59'11" E, a distance of 237.48 feet; thence N 40°36'39" E, a distance of 302.36 feet; thence N 71°39'06" E, a distance of 147.23 feet; thence S 68°11'27" E, a distance of 403.35 feet to a point on the Westerly Right of Way line of a Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence on the Westerly Right of Way line of said Florida Power and Light Company Right of Way through the following courses: S 0°26'57" E, a distance of 1278.44 feet; thence S 89°33'03" W, a distance of 100.00 feet; thence S 0°26'57" E, a distance of 69.06 feet; thence S 22°02'08" E, a distance of 69.06 feet; thence N 67°57'52" E, a distance of 100.00 feet; thence S 22°02'08" E, a distance of 5280.14 feet; thence S 42°58'43" W, a distance of 3178.33 feet; thence N 47°01'17" W, a distance of 50.00 feet; thence S 42°58'43" W, a distance of 120.11 feet; thence S 0°50'45" E, a distance of 120.11 feet; thence N 89°09'15" E, a distance of 50.00 feet; thence S 0°50'45" E, a distance of 11120.02 feet; thence S 1°00'03" E, a distance of 781.70 feet to the POINT OF BEGINNING.

Together with:

PARCEL 2 – TRACT "F"

A parcel of land lying in Sections 12, 13 and 24, Township 14 South, Range 29 East, Flagler County, Florida, and lying in Sections 5, 6, 7, 8, 17 and 18, Township 14 South, Range 30 East, Flagler County, Florida and being more particularly described as follows:

COMMENCE at the Northeast Corner of Section 6, Township 14 South, Range 30 East, Flagler County, Florida for the POINT OF BEGINNING; thence on the North line of said Section 6, S 89°45'33" W, a distance of 2593.13 feet to a point on the Easterly Right of Way line of State Road 11 (a variable width Right of Way per Florida Department of Transportation Right of Way Maps Section 7305-1237) said point being on a curve concave Southeasterly having a radius of 2939.79 feet and a central angle of 26°32'24"; thence departing said North line and on the Easterly Right of Way line of said State Road 11 and on the arc of said curve a distance of 1361.74 feet said arc being subtended by a chord which bears S 13°08'50" W, a distance of 1349.60 feet to the curves end; thence continue on said Easterly Right of Way line through the following courses: S 26°25'02" W, a distance of 2034.28 feet; thence S 63°34'58" E, a distance of 47.50 feet; thence S 26°25'02" W, a distance of 15200.38 feet to a point on the Southerly Maintained Right of Way line of an Un-Named Forest Management Road (a Private Road); thence departing the Easterly Right of Way line of said State Road 11 and on the Southerly and Easterly Maintained Right of Way line of said Un-Named Forest Management Road through the following courses: N 85°32'18" E, a distance of 478.40 feet; thence N 82°31'02" E, a distance of 145.70 feet; thence N 88°08'58" E, a distance of 914.53 feet; thence S 67°41'49" E a distance of, 483.36 feet; thence S 68°05'09" E, a distance of 382.72 feet; thence N 89°06'42" E, a distance of 421.46 feet; thence S 71°40'23" E, a distance of 183.41 feet; thence N 75°42'29" E, a distance of 479.29 feet; thence N 70°18'39" E, a distance of 1173.27 feet; thence N 1°19'52" W, a distance of 84.93 feet; thence N 29°56'34" W, a distance of 72.33 feet; thence N 60°26'33" W, a distance of 182.44 feet; thence N 28°46'19" W, a distance of 279.51 feet; thence N 7°10'19" W, a distance of 208.33 feet; thence N 54°45'50" W, a distance of 165.66 feet; thence N 59°13'06" W, a distance of 130.55 feet; thence N 40°38'00" W, a distance of 201.78 feet; thence N 7°14'45" W, a distance of 142.69 feet; thence N 30°27'17" W, a distance of 348.70 feet; thence N 41°04'25" W, a distance of 63.36 feet; thence N 61°19'01" W, a distance of 77.91 feet; thence N 19°47'15" W, a distance of 98.52 feet; thence N 28°13'06" W, a distance of 50.52 feet; thence N 47°22'23" W, a distance of 68.18 feet; thence N 9°23'57" W, a distance of 105.09 feet; thence N 33°52'10" W, a distance of 274.06 feet; thence N 52°54'53" W, a distance of 189.54 feet; thence N 29°25'35" W, a distance of 212.63 feet; thence N 40°17'46" W, a distance of 50.15 feet; thence N 72°29'31" W, a distance of 93.59 feet; thence N 24°05'07" W, a distance of 62.87 feet; thence N 10°24'23" W, a distance of 111.71 feet; thence N 15°15'51" W, a distance of 127.93 feet; thence N 28°38'04" W, a distance of 514.83 feet; thence departing said Southerly and Easterly Maintained Right of Way line of said Un-Named Forest Management Road, N 89°50'18" E, a distance of 3111.09 feet to a point on the Southerly Maintained Right of Way line of "Relay Road 41" (a Private Road); thence on the Southerly Maintained Right of Way line said "Relay Road 41" and its Easterly projection, through the following courses: N 84°05'49" E, a distance of 640.34 feet; thence N 87°04'31" E, a distance of 1376.85 feet; thence N 85°37'18" E, a distance of 3308.37 feet to a point on the Easterly Maintained Right of Way line of "Relay Road 14" (a Private Road); thence on the Easterly Maintained Right of Way line of said "Relay Road 14", through the following courses: N 1°38'24" W, a distance of 2408.29 feet; thence N 1°36'22" W, a distance of 2795.88 feet; thence N 1°30'45" W, a distance of 2591.53 feet; thence N 1°35'50" W, a distance of 3207.05 feet; thence N 2°03'07" W, a distance of 2009.45 feet to the POINT OF BEGINNING.

Together With:

PARCEL 2 - TRACT "G"

A parcel of land lying in Sections 32 and 33, Township 13 South, Range 30 East, Flagler County, Florida and lying in Section 4, Township 14 South, Range 30 East, Flagler County, Florida and being more particularly described as follows:

BEGIN at the Northwest corner of Section 32, Township 13 South, Range 30 East, Flagler County, Florida; thence on the North line of said Section 32, N 88°43'17" E, a distance of 5344.33 feet to the Northwest corner of Section 33, Township 13 South, Range 30 East, Flagler County, Florida; thence departing the North line of said Section 32 and on the North line of said Section 33, N 89°02'16" E, a distance of 5327.65 feet to a point on the Westerly Right of Way line of a Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing said North line and on the Westerly Right of Way line of said Florida Power and Light Company Right of Way through the following courses; S 1°04'34" E, a distance of 1032.17 feet; thence S 0°26'57" E, a distance of 5227.11 feet; thence departing said Westerly Right of Way line, N 68°11'27" W, a distance of 403.35 feet; thence S 71°39'06" W, a distance of 147.23 feet; thence S 40°36'39" W, a distance of 302.36 feet; thence S 63°59'11" W, a distance of 237.48 feet; thence S 20°34'25" W, a distance of 394.57 feet; thence S 12°16'37" W, a distance of 321.13 feet; thence S 16°56'59" W, a distance of 208.92 feet; thence N 61°46'39" W, a distance of 265.05 feet; thence N 5°17'48" W, a distance of 526.22 feet; thence N 27°24'47" W, a distance of 424.67 feet; thence N 40°04'33" W, a distance of 712.94 feet; thence N 71°45'23" W, a distance of 188.69 feet; thence N 27°30'57" W, a distance of 347.29 feet; thence N 47°50'56" W, a distance of 357.80 feet; thence N 75°16'42" W, a distance of 235.73 feet; thence N 85°26'12" W, a distance of 400.06 feet; thence S 63°32'28" W, a distance of 422.87 feet; thence S 14°37'45" W, a distance of 307.75 feet; thence S 46°39'50" W, a distance of 221.07 feet; thence N 88°49'10" W, a distance of 1177.70 feet; thence N 2°20'20" W, a distance of 463.96 feet; thence N 19°28'38" W, a distance of 248.00 feet; thence N 2°43'21" W, a distance of 1294.37 feet to a point on the Centerline of the Maintained Right of Way of "Relay Road 21" (a Private Road) said point being on a curve concave Southwesterly having a radius of 85.00 feet and a central angle of 69°39'15"; thence on the Centerline of the Maintained Right of Way of said "Relay Road 21" and the arc of said curve, a distance of 103.33 feet said arc being subtended by a chord which bears N 37°32'58" W, a distance of 97.09 feet to the curves end; thence continue on the Centerline of the Maintained Right of Way of said "Relay Road 21" through the following courses: N 72°22'36" W, a distance of 146.11 feet; thence N 63°38'56" W, a distance of 2303.63 feet; thence N 78°01'36" W, a distance of 518.35 feet; thence N 75°13'42" W, a distance of 1327.37 feet to the beginning of a curve concave Southeasterly, having a radius of 233.00 feet and a central angle of 116°23'25"; thence on the arc of said curve a distance of 473.31 feet said arc being subtended by a chord which bears S 46°34'36" W, a distance of 396.03 feet to the curves end; thence S 11°37'07" E, a distance of 1223.86 feet to the beginning of a curve concave Northwesterly, having a radius of 267.00 feet and a central angle of 71°26'49"; thence on the arc of said curve a distance of 332.94 feet said arc being subtended by a chord which bears S 24°06'18" W, a distance of 311.79 feet to the curves end; thence S 59°49'42" W, a distance of 438.34 feet to the beginning of a curve concave Southeasterly, having a radius of 335.85 feet and a central angle of 71°05'56"; thence on the arc of said curve a distance of 416.76 feet said arc being subtended by a chord which bears S 24°16'44" W, a distance of 390.53 feet to the curves end; thence S 11°16'14" E, a distance of 606.06 feet; thence S 6°37'03" E, a distance of 536.01 feet; thence S 0°25'59" W, a distance of 150.18 feet; thence departing the Centerline of the Maintained Right of Way of said "Relay Road 21", S 88°46'57" W, a distance of 687.93 feet to the Southwest corner of aforesaid Section 32, Township 13 South, Range 30 East, Flagler County, Florida; thence on the West line of said Section 32, N 1°27'57" W, a distance of 5551.65 feet to the POINT OF BEGINNING.

Together With:

PARCEL 2 - TRACT "H"

A parcel of land lying in Sections 21 and 28, Township 13 South, Range 30 East, Flagler County, Florida and being more particularly described as follows:

Commence at the Northeast corner of Section 21, Township 13 South, Range 30 East, Flagler County, Florida; thence on the East line of said Section 21, S 01°38'28" E, a distance of 2912.85 feet the POINT OF BEGINNING; thence continue on said East line, S 01°38'28" E, a distance of 730.84 feet to a point on the Westerly line of a Florida Power & Light Company Right of Way as described in Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing said East line and on the Westerly Right of Way line of said Florida Power & Light Company Right of Way as described in Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida through the following courses: S 26°20'10" W, 81.11 feet; thence N 63°39'50" W, a distance of 100.00 feet; thence S 26°20'10" W, a distance of 75.03 feet; thence S 01°46'19" E, 75.03 feet; thence N 88°13'41" E, a distance of 100.00 feet; thence S 01°46'19" E, a distance of 2623.85 feet; thence S 01°04'34" E, a distance of 4164.37 feet to a point on the South line of Section 28, Township 13 South, Range 30 East, Flagler County, Florida; thence departing said Westerly Right of Way line and on the South line of said Section 28, S 89°02'16" W, a distance of 5327.65 feet to the Southwest corner of said Section 28; thence departing said South line and on the West line of said Section 28, N 01°44'05" W, a distance of 5336.53 feet to the Northwest corner of said Section 28, the same being the Southwest corner of aforesaid Section 21; thence on the West line of said Section 21, N 00°36'48" W, a distance of 2959.76 feet to a point on the South line of a parcel of land as described in Official Records Book 1325, Page 871 of the Public Records of Flagler County, Florida; thence on said South line through the following courses: N 89°23'12" E, a distance of 2873.95 feet; thence S 43°02'23" E, a distance of 383.63 feet to the beginning of a curve concave Southwesterly having a radius of 25.00 feet and a central angle of 66°53'45"; thence on the arc of said curve a distance of 29.19 feet said arc being subtended by a chord which bears S 09°35'31" E, a distance of 27.56 feet to the curves end and a point of reverse curvature a curve concave Northeasterly having a radius of 54.00 feet and a central angle of 156°53'45"; thence on the arc of said curve a distance of 147.87 feet said arc being subtended by a chord which bears S 54°35'31" E, a distance of 105.81 feet to the curves end; thence N 46°57'37" E, a distance of 54.00 feet; thence S 43°02'23" E, a distance of 325.77 feet; thence N 89°25'06" E, a distance of 1908.32 to the POINT OF BEGINNING.

Together With:

PARCEL 2 - TRACT "I"

A parcel of land lying in Sections 10, 15, 16 and 22, Township 13 South, Range 30 East, Flagler County, Florida and being a portion of the subdivision of BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida and being more particularly described as follows:

BEGIN at the Southeast corner of Section 16, Township 13 South, Range 30 East, Flagler County, Florida; thence on the South line of said Section 16, N 89°36'11" W, a distance of 2671.24 feet to the Southwest corner of the Southeast 1/4 of said Section 16; Thence departing said South line and on the West line of the Southeast 1/4 of said Section 16, N 1°32'31" W, a distance of 1328.92 feet to the Northeast corner of the South 1/2 of the Southwest 1/4 of said Section 16; thence departing said West line and on the North line of the South 1/2 of the Southwest 1/4 of said Section 16, N 89°55'51" W, a distance of 805.85 feet to the Southeasterly Right of Way line of State Road 304 (a variable width Right of Way per Florida Department of Transportation Right of Way Maps Section 73510-2601); thence departing said North line and on the Southeasterly Right of Way line of said State Road 304 through the following courses: N 41°47'02" E, a distance of 828.22 feet; thence S 48°12'58" E, a distance of 25.00 feet; thence N 41°47'02" E, a distance of 2771.95 feet to a point on the North line of the Southeast 1/4 of the Northeast 1/4 of aforesaid Section 16; thence departing said Southeasterly Right of Way line and on the North line of the Southeast 1/4 of the Northeast 1/4 of said Section 16, N 89°38'48" E, a distance of 979.85 feet to the Southwest corner of the Northwest 1/4 of the Northwest 1/4 of Section 15, Township 13 South, Range 30 East, Flagler County, Florida; thence departing said North line and on the West line of the Northwest 1/4 of the Northwest 1/4 of said Section 15, N 1°38'39" W, a distance of 1057.12 feet to the Southeasterly Right of Way line of State Road 304 (a variable width Right of Way per Florida Department of Transportation Right of Way Maps Section 73510-2601); thence departing said West line and on the Southeasterly Right of Way line of said State Road 304, N 41°45'47" E, a distance of 1395.30 feet to a point on the Westerly Right of Way line of a Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing the Southeasterly Right of Way line of said State Road 304 and on the Westerly Right of Way line of said Florida Power and Light Company Right of Way, S 16°41'34" E, a distance of 2994.33 feet to a point on the North line of the South 1/2 of Track 10, Block B of the subdivision of BUNNELL DEVELOPMENT COMPANY'S LAND at BUNNELL FLORIDA as recorded in Plat Book 1, Page 1, of the Public Records of Flagler County, Florida; thence departing said Westerly Right of Way line and on the North line of the South 1/2 of said Track 10, Block B, N 86°41'51" W, a distance of 414.48 feet to the Northwest corner of the of the South 1/2 of said Track 10, Block B; thence departing said North line and on the West line of the South 1/2 of said Track 10, Block B, S 1°44'51" E, a distance of 669.93 feet to the Southwest corner of said

Track 10, Block B; thence departing said West line and on the South line of said Track 10, Block B, S 86°43'47" E, a distance of 598.21 feet to a point on the Westerly Right of Way line of aforesaid Florida Power and Light Company Right of Way as recorded in, Official Records Book 215, Page 141 of the Public Records of Flagler County, Florida; thence departing said South line and on the Westerly Right of Way line of said Florida Power and Light Company Right of Way through the following courses: S 16°41'34" E, a distance of 1750.17 feet; thence S 26°20'10" W, a distance of 5062.48 feet to a point on the West line of Section 22, Township 13 South, Range 30 East, Flagler County, Florida; thence departing said Westerly Right of Way line and on the West line of said Section 22, N 1°38'28" W, a distance of 3643.68 feet to the Point of Beginning.

Together With

PARCEL 2 - TRACT "J"

A parcel of land lying in Sections 31 and 32, Township 14 South, Range 30 East, Sections 3,4,9,10,11,13,14 and 15, Township 15 South, Range 30 East and in Sections 17 and 18, Township 15 South, Range 31 East, all lying and being in Volusia County, Florida and being more particularly described as follows:

Commence at the Northeast corner of Section 32, Township 14 South, Range 30 East, Volusia County, Florida; thence on the North line of said Section 32, S 89° 26' 37" W, a distance of 929.66 feet to a point 20 feet West of the centerline of a Forest Management Road locally known as Forest Management Road "B", said point being the POINT OF BEGINNING; thence departing said North line and on a line 20 feet West of the centerline of aforesaid Forest Management Road "B" through the following courses, S 29° 00' 58" W, a distance of 710.66 feet; thence S 44° 52' 43" W, a distance of 438.82 feet; thence S 35° 05' 04" W, a distance of 724.86 feet; thence S 35° 16' 31" W, a distance of 697.29 feet; thence S 34° 25' 28" W, a distance of 638.85 feet; thence S 05° 09' 02" E, a distance of 654.24 feet; thence S 00° 07' 38" W, a distance of 157.15 feet; thence S 13° 13' 29" W, a distance of 121.87 feet; thence S 16° 22' 41" W, a distance of 711.44 feet; thence S 02° 05' 12" W, a distance of 406.43 feet; thence S 06° 45' 50" E, a distance of 912.39 feet; thence S 06° 53' 15" E, a distance of 852.23 feet to the Northerly Right of Way line of State Road 40, a 200 feet wide Right of Way per Florida Department of Transportation Right of Way Map, Section 79100-2503; thence on said Northerly Right of Way line of State Road 40, S 74° 23' 23" W, a distance of 3070.73 feet to a point at the beginning of a curve concave to the North having a radius of 5661.65 feet and a central angle of 07° 46' 30"; thence departing the Northerly Right of Way line of aforesaid State Road 40 and on the meander line between an existing pine plantation and jurisdictional wetland, in a Northwesterly direction, a distance of 2272 feet, more or less to a point hereafter referred to as "Point A" said "Point A" being 20 feet East of the centerline of a Forest Management Road locally known as Forest Management Road "A" and said "Point A" bearing N 50° 15' 49" W, a distance of 2075.89 feet from the aforementioned beginning of curve; thence departing said meander line and on a line 20 feet East of the centerline of aforesaid Forest Management Road "A" through the following courses, N 16° 44' 18" E, a distance of 71.03 feet; thence N 10° 38' 13" W, a distance of 1352.46 feet; thence N 10° 40' 05" W, a distance of 1291.34 feet; thence N 13° 34' 29" W, a distance of 344.53 feet; thence N 21° 33' 25" W, a distance of 1169.70 feet; thence N 21° 56' 54" W, a distance of 653.58 feet; thence N 21° 36' 29" W, a distance of 769.11 feet; thence N 40° 46' 37" W, a distance of 527.19 feet to a point on the North line of Section 31, Township 14 South, Range 30 East, Volusia County, Florida; thence on the North line of said Section 31, N 89° 26' 37" E, a distance of 3865.19 feet to the Northeast corner of said Section 31, the same being the Northwest corner of aforesaid Section 32, Township 14 South, Range 30

East, Volusia County, Florida; thence on the North line of said Section 32, N 89° 26' 37" E, a distance of 4349.80 feet to the POINT OF BEGINNING.

Together With:

PARCEL 2 – TRACT "K"

Commence at the Southeast corner of Section 17, Township 15 South, Range 31 East, Volusia County, Florida; thence on the South line of said Section 17, S 88° 39' 52" W, a distance of 5311.55 feet to the Southwest corner of said Section 17, the same being the Southeast corner of Section 18, Township 15 South, Range 31 East, Volusia County, Florida; thence on the South line of said Section 18, S 88° 39' 52" W, a distance of 5316.86 feet to the Southwest corner of said Section 18, the same being the Southeast corner of Section 13, Township 15 South, Range 30 East, Volusia County, Florida; thence on the South line of said Section 13, S 88° 59' 03" W, a distance of 828.38 feet to a point on the Westerly line of a Florida Power and Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida, said point being the POINT OF BEGINNING; thence continue on the South line of said Section 13, S 88° 59' 03" W, a distance of 4483.97 feet to the Southwest corner of said Section 13, the same being the Southeast corner of Section 14, Township 15 South, Range 30 East, Volusia County, Florida; thence on the South line of said Section 14, S 88° 42' 00" W, a distance of 2638.88 feet to the Southeast corner of the Southwest 1/4 of said Section 14; thence continue on the South line of said Section 14, S 88° 44' 35" W, a distance of 2633.47 feet to the Southwest corner of said Section 14, the same being the Southeast corner of Section 15, Township 15 South, Range 30 East, Volusia County, Florida; thence on the South line of the East 1/2 of said Section 15, S 89° 24' 13" W, a distance of 2668.10 feet to the Southwest corner of the East 1/2 of said Section 15; thence departing said South line and on the West line of the East 1/2 of said Section 15, N 00° 27' 35" W, a distance of 1339.92 feet to the Southeast corner of the East 1/2 of the Northeast 1/4 of the Southwest 1/4 of said Section 15; thence departing said West line and on the South line of the East 1/2 of the Northeast 1/4 of the Southwest 1/4 of said Section 15, S 89° 21' 21" W, a distance of 667.60 feet to the Southwest corner of the East 1/2 of the Northeast 1/4 of the Southwest 1/4 of said Section 15; thence departing said South line and on the West line of the East 1/2 of the Northeast 1/4 of the Southwest 1/4 of said Section 15, N 00° 29' 03" W, a distance of 1339.36 feet to the Northwest corner of the East 1/2 of the Northeast 1/4 of the Southwest 1/4 of said Section 15; thence departing said West line and on the South line of the Northwest 1/4 of said Section 15, S 89° 18' 30" W, a distance of 2004.51 feet to the Southwest corner of the Northwest 1/4 of said Section 15; thence departing said South line and on the West line of the Northwest 1/4 of said Section 15, N 00° 33' 27" W, a distance of 2681.18 feet to the Northwest corner of said Section 15, the same being the Southeast corner of Section 9, Township 15 South, Range 30 East, Volusia County, Florida; thence departing said West line and on the South line of the East 1/2 of said Section 9, S 88° 52' 36" W, a distance of 2610.14 feet to the Southwest corner of the East 1/2 of said Section 9; thence departing said South line and on the West line of the East 1/2 of said Section 9, N 01° 34' 25" W, a distance of 5270.67 feet to the Northwest corner of the East 1/2 of said Section 9, the same being the Southwest corner of the East 1/2 of Section 4, Township 15 South, Range 30 East, Volusia County, Florida; thence on the West line of the East 1/2 of said Section 4, N 00° 16' 16" W, a distance of 2972.04 feet to a point on the Southerly Right of Way line of State Road 40, a 200 feet wide Right of Way per Florida Department of Transportation Right of Way Map, Section 79100-2503, said point being on a curve concave to the North having a radius of 5861.65 feet and a central angle of 06° 51' 35"; thence departing said West line and on said Southerly Right of Way line of State Road 40 and on the arc of said curve a distance of 701.78 feet, said arc being subtended by a chord which bears N 77° 49' 10" E, a distance of 701.36 feet to the curves end; thence continue on said Southerly Right of Way line of State Road 40, N 74° 23' 23" E, a distance of 3071.83 feet to a point 20 feet West of the centerline of a Forest Road locally known as Forest Management Road "B"; thence departing the Southerly Right of Way line of State Road 40 and on a line 20 feet West of the centerline of aforesaid Forest Management Road "B" through the following courses, S 18° 33' 39" E, a distance of 937.03 feet; thence S 18° 45' 34" E, a distance of 709.38 feet; thence S 18° 32' 13" E, a distance of 496.41 feet; thence S 26° 53' 00" E, a distance of 89.78 feet; thence S 49° 23' 17" E, a distance of 103.20 feet; thence S 59° 04' 17" E, a distance of 279.13 feet; thence S 52° 23' 12" E, a distance of 124.74 feet; thence S 32° 27' 25" E, a distance of 231.99 feet; thence S 32° 03' 38" E, a distance of 241.75 feet; thence S 34° 35' 32" E, a distance of 598.98 feet; thence S 39° 26' 42" E, a distance of 171.82 feet; thence S 44° 13' 57" E, a distance of 1374.87 feet; thence S 40° 58' 25" E, a distance of 1023.75 feet; thence S 40° 57' 20" E, a distance of 1522.12 feet; thence S 41° 52' 28" E, a distance of 1301.42 feet; thence S 22° 14' 32" E, a distance of 113.06 feet; thence S 12° 01' 10" E, a distance of 1003.87 feet; thence S 11° 38' 03" E, a distance of 700.17 feet to a point on the North line of Section 14, Township 15 South, Range 30 East, Volusia County, Florida; thence on the North line of said Section 14, N 88° 55' 30" E, a distance of 3990.49 feet to Northeast corner of said Section 14, the same being the Northwest corner of Section 13, Township 15 South, Range 30 East, Volusia County, Florida; thence on the North line of said Section 13, N 89° 22' 49" E, a distance of 3305.64 feet to a point on the Westerly line of the aforesaid Florida Power and Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida; thence departing said North line and on the Westerly line of said Florida Power and Light Company Right of Way, S 21° 25' 08" E, a distance of 1264.30 feet ; thence continue on the Westerly line of said Florida Power and Light Company Right of Way, S 10° 39' 05" E, a distance of 4200.89 feet to the POINT OF BEGINNING.

Together With:

PARCEL 2 – TRACT "L"

Commence at the Southeast corner of Section 17, Township 15 South, Range 31 East, Volusia County, Florida; thence on the South line of said Section 17, S 88° 39' 52" W, a distance of 1327.89 feet to the Southeast corner of the Southwest 1/4 of the Southeast 1/4 of said Section 17 and the POINT OF BEGINNING; thence continue on the South line of said Section 17, S 88° 39' 52" W, a distance of 3983.66 feet to Southwest corner of said Section 17, the same being the Southeast corner of Section 18, Township 15 South, Range 31 East, Volusia County, Florida; thence on the South line of said Section 18, S 88° 39' 52" W, a distance of 5316.86 feet to the Southwest corner of said Section 18, the same being the Southeast corner of Section 13, Township 15 South, Range 30 East, Volusia County, Florida; thence on the South line of said Section 13, S 88° 59' 03" W, a distance of 524.08 feet to a point on the Easterly line of a Florida Power and Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida; thence departing said South line and on the Easterly line of said Florida Power and Light Company Right of Way, N 10° 39' 05" W, a distance of 351.79 feet; thence continue on the Easterly line of said Florida Power and Light Company Right of Way, N 10° 13' 38" W, a distance of 4090.33 feet ; thence continue on the Easterly line of said Florida Power and Light Company Right of Way, N 21° 25' 07" W, a distance of 1002.42 feet to the North line of aforesaid Section 13, Township 15 South, Range 30

East, Volusia County, Florida; thence departing said Easterly line of said Florida Power and Light Company Right of Way and on the North line of said Section 13, N 89° 22' 49" E, a distance of 1593.79 feet to the Northeast corner of said Section 13, the same being the Northwest corner of aforesaid Section 18, Township 15 South, Range 31 East, Volusia County, Florida; thence on the North line of said Section 18, N 89° 07' 44" E, a distance of 5266.05 feet to the Northeast corner of said Section 18, the same being the Northwest corner of aforesaid Section 17, Township 15 South, Range 31 East, Volusia County, Florida; thence on the North line said Section 17, N 88° 46' 28" E, a distance of 1334.66 feet to the Northeast corner of the West 1/2 of the Northwest 1/4 of said Section 17; thence departing said North line and on the East line of the West 1/2 of the Northwest 1/4 of said Section 17, S 01° 25' 22" E, a distance of 2633.79 feet to the Southeast corner of the West 1/2 of the Northwest 1/4 of said Section 17; thence departing said East line and on the South line of the West 1/2 of the Northwest 1/4 of said Section 17, S 88° 43' 11" W, a distance of 1331.27 feet to the Southwest corner of the West 1/2 of the Northwest 1/4 of said Section 17; thence departing said South line and on the West line of said Section 17, S 01° 29' 47" E, a distance of 1317.54 feet to the Northwest corner of the South 1/2 of the Southwest 1/4 of said Section 17; thence departing said West line and on the North line of the South 1/2 of the Southwest 1/4 of said Section 17 and on the North line of the Southwest 1/4 of the Southeast 1/4 of said Section 17, N 88° 41' 31" E, a distance of 3988.73 feet to the Northeast corner of the Southwest 1/4 of the Southeast 1/4 of said Section 17; thence departing said North lines and on the East line of the Southwest 1/4 of the Southeast 1/4 of said Section 17, S 01° 16' 32" E, a distance of 1315.61 feet to the POINT OF BEGINNING.

DESCRIPTION: PARCEL 3

PARCEL 3 - TRACT "A"

A parcel of land lying in Section 36, Township 14 South, Range 29 East, Section 31, Township 14 South, Range 30 East and in Sections 4 and 5, Township 15 South, Range 30 East, all lying and being in Volusia County, Florida and being more particularly described as follows:

BEGIN at the Northwest corner of Section 31, Township 14 South, Range 30 East, Volusia County, Florida; thence on the North line of said Section 31, N 89° 26' 37" E, a distance of 1414.27 feet to a point 20 feet East of the centerline of a Forest Management Road locally known as Forest Management Road "A"; thence departing the North line of said Section 31 and on a line 20 feet East of the centerline of aforesaid Forest Management Road "A" through the following courses: S 40°46'37" E, a distance of 527.19 feet; thence S 21°36'29" E, a distance of 769.11 feet; thence S 21°56'54" E, a distance of 653.58 feet; thence S 21°33'25" E, a distance of 1169.70 feet; thence S 13°34'29" E, a distance of 344.53 feet; thence S 10°40'05" E, a distance of 1291.34 feet; thence S 10°38'13" E, a distance of 1352.46 feet; thence S 16°44'18" W, a distance of 71.03 feet to a point hereafter referred to as "POINT A"; thence returning to the POINT OF BEGINNING proceed on the North line of Section 36, Township 14 South, Range 29 East, Volusia County, Florida, S 89°38'06" W, a distance of 2993.67 feet; to a point on the Easterly Right of Way Line of State Road 11 (a 200 foot right of way, per Florida Department of Transportation Right of Way Maps Sections 7909-104 & 79100-2901); thence departing said North line and on said Easterly Right of Way Line, S 4°38'21" E, a distance of 5362.16 feet to a point on the South line of aforesaid Section 36, Township 14 South, Range 29 East, Volusia County, Florida; thence departing said Easterly Right of Way Line and on the South line of said Section 36 the same being the North Line of the Northwest 1/4 of Section 5, Township 15 South, Range 30 East, Volusia County, Florida, N 88°46'28" E, a distance of 1497.46 feet to the Northwest corner of the Northeast 1/4 of Section 5, Township 15 South, Range 30 East, Volusia

County, Florida; thence continue on the South Line of aforesaid Section 36 the same being the North Line of the Northeast 1/4 of Section 5, Township 15 South, Range 30 East, Volusia County, Florida, N 89°06'19" E, a distance of 1320.86 feet; thence departing said North and South lines, S 0°02'24" E, a distance of 2447.12 feet to a point on the Northerly Limited Access Right of Way Line of State Road 40 (per Florida Department of Transportation Right of Way Maps Sections 79100-2503); thence on said Northerly Limited Access Right of Way Line and Northerly Right of Way Line of State Road 40 through the following courses: N 82°09'53" E, a distance of 633.43 feet; thence S 7°50'07" E, 50.00 feet a point on the Northerly Right of Way Line of State Road 40 (a 200 foot right of way, per Florida Department of Transportation Right of Way Maps Sections 79100-2503); thence continue on said Northerly Right of Way Line of State Road 40 through the following courses: N 82°09'53" E, a distance of 3245.96 feet to the beginning of a curve concave Northwesterly having a radius of 5661.65 feet and a central angle of 7°46'30"; thence on the arc of said curve a distance of 768.28 feet said arc being subtended by a chord that bears N 78°16'38" E, a distance of 767.69 feet to the curves end and a point on a meandering line between an existing pine plantation and wetland said point bearing S 50°15'49" E, a distance of 2075.89 feet from aforesaid "POINT A"; thence departing the Northerly Right of Way Line of State Road 40 and on said meander line between an existing pine plantation and wetland, Northwesterly, a distance of 2272 feet, more or less to aforesaid "POINT A" to close.
LESS Maintained Right of Way for Clifton Cemetery Road, a County Maintained Right of Way.

Together With:

PARCEL 3 – TRACT "B"

A parcel of land lying in Sections 28, 29, 32 and 33, Township 14 South, Range 30 East, and in Sections 2 and 3, Township 15 South, Range 30 East, all lying and being in Volusia County, Florida and being more particularly described as follows:

Begin at the Northwest corner of Section 28, Township 14 South, Range 30 East, Volusia County, Florida; thence on the North line of said Section 28, N 89°49'43" E, a distance of 4718.82 feet to a point on the Westerly Right of Way Line of a Florida Power & Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida; thence departing the North line of said Section 28 and on the Westerly Right of Way Line of said Florida Power & Light Company Right of Way through the following courses: S 1°00'03" E, a distance of 6622.81 feet; thence S 88°59'57" W, a distance of 100.00 feet; thence S 1°00'03" E, a distance of 68.01 feet; thence S 21°24'53" E, a distance of 68.01 feet; thence N 68°35'07" E, a distance of 100.00 feet; thence S 21°24'53" E, a distance of 2921.78 feet to a point on the Northerly Right of Way Line of State Road 40 (a 200 foot right of way, per Florida Department of Transportation Right of Way Map Sections 79100-2503); thence departing said Westerly Right of Way Line and on the Northerly Right of Way Line of said State Road 40, S 74°23'23" W, a distance of 8883.67 feet to a point 20 feet West of the centerline of a Forest Management Road locally known as Forest Management Road "B"; thence departing the Northerly Right of Way Line of said State Road 40 on a line 20 feet West of the centerline of aforesaid Forest Management Road "B" through the following courses: N 6°53'15" W, a distance of 852.23 feet; thence N 6°45'50" W, a distance of 912.39 feet; thence N 2°05'12" E, a distance of 406.43 feet; thence N 16°22'41" E, a distance of 711.44 feet; thence N 13°13'29" E, a distance of 121.87 feet; thence N 0°07'38" E, a distance of 157.15 feet; thence N 5°09'02" W, a distance of 654.24 feet; thence N 34°25'28" E, a distance of 638.85 feet; thence N 35°16'31" E, a distance of 697.29 feet; thence N 35°05'04" E, a distance of 724.86 feet; thence N 44°52'43" E, a distance of 438.82 feet; thence N 29°00'58" E, a distance of 710.66 feet to a point on the South Line of

Section 29, Township 14 South, Range 30 East, Volusia County, Florida; thence on the South Line of said Section 29, N 89°26'37" E, a distance of 269.52 feet to the Southwest corner of the East 1/2 of the East 1/4 of said Section 29; thence departing the South line of said Section 29 and on the West Line of the East 1/2 of the East 1/4 of said Section 29, N 1°07'29" W, a distance of 5409.16 feet to the Northwest corner of the East 1/2 of the East 1/4 of said Section 29; thence departing said West Line and on the North line of the East 1/2 of the East 1/4 of said Section 29, N 88°47'01" E, a distance of 662.33 feet to the POINT OF BEGINNING.

Together With:

PARCEL 3 – TRACT "C"

A parcel of land lying in Sections 27, 28, 33 and 34, Township 14 South, Range 30 East, all lying and being in Volusia County, Florida and being more particularly described as follows:

Begin at the Northeast corner of Section 27, Township 14 South, Range 30 East, Volusia County, Florida; thence on the East Line of said Section 27, S 0°43'05" E, a distance of 5281.63 feet to the Southeast corner of said Section 27, the same being the Northeast corner of Section 34, Township 14 South, Range 30 East, Volusia County, Florida; thence departing the East Line of said Section 27 and on the East Line of said Section 34, S 0°50'04" E, a distance of 2995.90 feet to a point on the Northerly Right of Way Line of State Road 40 (a 200 foot right of way, per Florida Department of Transportation Right of Way Map Sections 79100-2503); thence departing said East Line and on the Northerly Right of Way Line of said State Road 40 the same being on a curve concave Southerly having a radius of 2925.76 feet and a central angle of 18°35'49"; thence on the arc of said curve a distance of 949.64 feet, said arc being subtended by a chord that bears S 83°41'17" W, a distance of 945.48 feet to the curves end; thence continue on the Northerly Right of Way Line of said State Road 40, S 74°23'23" W, a distance of 3756.48 feet to a point on the Easterly Right of Way Line of a Florida Power & Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida; thence departing the Northerly Right of Way Line of State Road 40 and on the Easterly Right of Way Line of said Florida Power & Light Company Right of Way through the following courses: N 21°24'53" W, a distance of 2948.26 feet; thence N 1°00'03" W, a distance of 6614.46 feet to a point on the North Line of Section 28, Township 14 South, Range 30 East, Volusia County, Florida; thence departing said Easterly Line and on the North Line of said Section 28, N 89°49'43" E, a distance of 347.16 feet to the Northeast corner of said Section 28, the same being the Northwest corner of aforesaid Section 27, Township 14 South, Range 30 East, Volusia County, Florida; thence departing the North Line of aforesaid Section 28 and on the North line of said Section 27, N 89°38'58" E, 5292.80 feet to the POINT OF BEGINNING.

Together With:

PARCEL 3 – TRACT "D"

A parcel of land lying in Sections 33 and 34, Township 14 South, Range 30 East, and in Sections 1,2,3,10,11 and 12, Township 15 South, Range 30 East, all lying and being in Volusia County, Florida and being more particularly described as follows:

BEGIN at the Southeast corner of Section 11, Township 15 South, Range 30 East, Volusia County, Florida; thence on the South line of said Section 11, S 88°55'30" W, a distance of 3990.49 feet to a point 20 feet West of the centerline of a Forest Management Road locally known as Forest Management Road "B"; thence departing the South line of said Section 11 and on a line 20 feet West of the centerline of aforesaid Forest Management Road "B" through the following courses: N 11°38'03" W, a distance of 700.17 feet; thence N 12°01'10" W, a distance of 1003.87 feet; thence N 22°14'32" W, a distance of 113.06 feet; thence N 41°52'28" W, a distance of 1301.42 feet; thence N 40°57'20" W, a distance of 1522.12 feet; thence N 40°58'25" W, a distance of 1023.75 feet; thence N 44°13'57" W, a distance of 1374.87 feet; thence N 39°26'42" W, a distance of 171.82 feet; thence N 34°35'32" W, a distance of 598.98 feet; thence N 32°03'38" W, a distance of 241.75 feet; thence N 32°27'25" W, a distance of 231.99 feet; thence N 52°23'12" W, a distance of 124.74 feet; thence N 59°04'17" W, a distance of 279.13 feet; thence N 49°23'17" W, a distance of 103.20 feet; thence N 26°53'00" W, a distance of 89.78 feet; thence N 18°32'13" W, a distance of 496.41 feet; thence N 18°45'34" W, a distance of 709.38 feet; thence N 18°33'39" W, a distance of 937.03 feet to a point on the Southerly Right of Way Line of State Road 40 (a 200 foot right of way, per Florida Department of Transportation Right of Way Map Sections 79100-2503); thence on said Southerly Right of Way Line of State Road 40, N 74°23'23" E, a distance of 8902.90 feet to a point on the Westerly Right of Way Line of a Florida Power & Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida; thence departing the Southerly Right of Way Line of said State Road 40 and on the Westerly Right of Way Line of said Florida Power & Light Company Right of Way through the following courses, S 21°24'53" E, a distance of 8620.26 feet; thence S 60°43'11" W, a distance of 197.04 feet; thence S 00°54'18" W, a distance of 3253.41 feet to a point on the South line of Section 12, Township 15 South, Range 30 East, Volusia County, Florida; thence departing the Westerly Right of Way line of said Power & Light Company Right of Way and on the South line of said Section 12, S 89°22'49" W, a distance of 1775.66 to the POINT OF BEGINNING.

Together With:

PARCEL 3 – TRACT "E"

A parcel of land lying in Sections 34 and 35, Township 14 South, Range 30 East, Sections 1, 2, and 12, Township 15 South, Range 30 East and in Section 7, Township 15 South, Range 31 East, all lying and being in Volusia County, Florida and being more particularly described as follows: BEGIN at the Northeast corner of Section 12, Township 15 South, Range 30 East, Volusia County, Florida; thence on the East line of said Section 12, S 00°40'00" E, a distance of 2650.44 feet to the Northwest Corner of the South 1/2 of Section 7, Township 15 South, Range 31 East, Volusia County, Florida; thence departing said East line and on the North line of the South 1/2 of said Section 7, N 89°19'09" E, a distance of 5278.30 feet to the Northeast corner of the South 1/2 of said Section 7; thence departing said North line and on the East line of the South 1/2 of said Section 7, S 00°41'03" E, a distance of 2409.52 feet; to the Northeast corner of the South 230 feet of said Section 7 as recorded in Official Records Book 2622, Page 1169 of the Public Records of Volusia County, Florida; thence departing said East line and on the North line of the South 230 feet of said Section 7, S 89°07'44" W, a distance of 5267.09 feet to the Northwest corner of the South 230 feet of said Section 7; thence departing said North line and on the West line of the South 1/2 of said Section 7, N 00°56'56" W, a distance of 1275.69 feet to a point on the Easterly Right of Way Line of a Florida Power & Light Company Right of Way as recorded in Official Records Book 2452, Page 540 of the Public Records of Volusia County, Florida; thence departing said West line and on said Easterly Right of Way Line of said Florida Power & Light Company Right of Way through the following courses: N 35°48'21" W, a distance of 1384.61 feet; thence S 90°00'00" W, a distance of 1795.79 feet; thence N 21°24'53" W, a distance of 1273.78 feet; thence N 22°17'46" W, a distance of 3904.12 feet; thence N 21°24'53" W, a distance of 4287.20 feet to a point on the Southerly Right of Way Line of State Road 40 (a 200 foot right of way, per Florida Department of Transportation Right of Way Map Sections 79100-2503); thence departing the Easterly Right of Way Line of said Florida Power & Light

Company Right of Way and on the Southerly Right of Way Line of said State Road 40 through the following courses: N 74°23'23" E, a distance of 3736.15 feet to the beginning of a curve concave Southerly having a radius of 2725.76 feet and a central angle of 23°10'10"; thence on the arc of said curve a distance of 1102.25 feet said arc being subtended by a chord that bears N 85°58'28" E, a distance of 1094.76 feet to the curves end; thence S 82°26'27" E, a distance of 1305.72 feet to a point on the West line of PLANTATION PINES (an unrecorded subdivision); thence departing said Southerly Right of Way line and on the West line of said PLANTATION PINES (an unrecorded subdivision) S 00°40'09" E, a distance of 1721.08 feet to the Northeast corner of Section 1, Township 15 South, Range 30 East, Volusia County, Florida; thence on the East line of said Section 1, the same being the West line of aforesaid PLANTATION PINES (an unrecorded subdivision), S 00°40'38" E, a distance of 5300.64 feet to the POINT OF BEGINNING.

Together With:

PARCEL 3 – TRACT "F"

A parcel of land lying in Sections 5 and 8, Township 15 South, Range 31 East, all lying and being in Volusia County, Florida and being more particularly described as follows:

Begin at the Northwest corner of Section 5, Township 15 South, Range 31 East, Volusia County, Florida, thence on the North Line of said Section 5, N 89°36'29" E, a distance of 1319.85 feet to the Northeast corner of the West 1/2 of the Northwest 1/4 of said Section 5; thence departing said North Line and on the East Line of the West 1/2 of the Northwest 1/4 of said Section 5, S 0°43'40" E, a distance of 2635.16 feet to the Southeast corner of the West 1/2 of the Northwest 1/4 of said Section 5, said corner being on the North Line of the Southwest 1/4 of said Section 5; thence departing said East Line and on the North Line of the Southwest 1/4 of said Section 5, N 89°26'21" E, a distance of 1321.45 feet to the Northeast corner of the Southwest 1/4 of said Section 5; thence departing said North Line and on the East line of the Southwest 1/4 of said Section 5, S 0°45'47" E, a distance of 2631.54 feet to the Southeast corner of the Southwest 1/4 of said Section 5, the same being the Northeast corner of the Northeast 1/4 of the Northwest 1/4 of Section 8, Township 15 South, Range 31 East, Volusia County, Florida; thence on the East Line of the Northeast 1/4 of the Northwest 1/4 of said Section 8, S 0°56'00" E, a distance of 1310.73 feet to the Southeast corner of the Northeast 1/4 of the Northwest 1/4 of said Section 8; thence departing said East Line and on the South Line of the Northeast 1/4 of the Northwest 1/4 of said Section 8, S 89°04'11" W, a distance of 1326.03 feet to the Southwest corner of the Northeast 1/4 of the Northwest 1/4 of said Section 8 the same being the Northeast corner of the Southwest 1/4 of the Northwest 1/4 of said Section 8; thence departing said South Line and on the East Line of the Southwest 1/4 of the Northwest 1/4 of said Section 8, S 0°48'30" E, a distance of 1315.24 feet to the Southeast corner of the Southwest 1/4 of the Northwest 1/4 of said Section 8; thence departing said East Line and on the South Line of the Southwest 1/4 of the Northwest 1/4 of said Section 8, S 88°52'31" W, a distance of 1328.91 feet to the Southwest corner of the Northwest 1/4 of said Section 8; thence departing said South Line and on the West Line of the Northwest 1/4 of said Section 8 the same being on the East Line of PLANTATION PINES (an unrecorded subdivision), N 0°41'03" W, a distance of 2639.52 feet to the Northwest Corner of said Section 8, the same being the Southwest corner of the Southwest 1/4 of aforesaid Section 5; thence on the West line of the Southwest 1/4 said Section 5, the same being on the East Line of aforesaid PLANTATION PINES (an unrecorded subdivision), N 0°41'17" W, a distance of 2639.58 feet to the Southwest corner of the West 1/2 of the Northwest 1/4 of said Section 5; thence on the West Line of the West 1/2 of the Northwest 1/4 of said Section 5, the same being on the East Line of aforesaid PLANTATION PINES (an unrecorded subdivision), N 0°41'34" W, a distance of 2639.04 feet to the POINT OF BEGINNING.

FLORIDA PUBLIC SERVICE COMMISSION
Authorizes
D & E Water Resources, L.L.C.
Pursuant to
Certificate Number 635-W

to provide water service in Flagler and Volusia Counties in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Orders of this Commission in the territory described by the Orders of this Commission. This authorization shall remain in force and effect until superseded, suspended, cancelled or revoked by Order of this Commission.

Order Number	Date Issued	Docket Number	Filing Type
PSC-07-0274-PAA-WS	04/02/07	060694-WS	Original Certificate
*	*	160238-WS	Transfer Majority Organizational Control

***Order Number and date to be provided at time of issuance**

FLORIDA PUBLIC SERVICE COMMISSION
Authorizes
D & E Water Resources, L.L.C.
Pursuant to
Certificate Number 545-S

to provide wastewater service in Flagler and Volusia Counties in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Orders of this Commission in the territory described by the Orders of this Commission. This authorization shall remain in force and effect until superseded, suspended, cancelled or revoked by Order of this Commission.

Order Number	Date Issued	Docket Number	Filing Type
PSC-07-0274-PAA-WS	04/02/07	060694-WS	Original Certificate
*	*	160238-WS	Transfer Majority Organizational Control

***Order Number and date to be provided at time of issuance**

B & C Water Resources, LLC.
Monthly Water Rates

Residential and General Service
Base Facility Charge by Meter Size

5/8" x 3/4"	$12.61
3/4"	$18.92
1"	$31.53
1 1/2"	$63.05
2"	$100.88
Charge per 1,000 gallons	$2.94

Bulk Raw Water

Base Facility Charge	$2,529.42
Charge per 1,000 gallons	$0.08

Miscellaneous Service Charges

Initial Connection Charge	$15.00
Normal Reconnection Charge	$15.00
Violation Reconnection Charge	$15.00
Premises Visit Charge (in lieu of disconnection)	$10.00

Service Availability Charges

Meter Installation Charge

5/8" x 3/4"	$200.00
3/4"	$250.00
1"	$300.00
1 1/2"	$450.00
2"	$600.00

Plant Capacity Charge

Residential – per ERC (350 gpd)	$293.66
General Service per ERC (350 gpd)	$293.66
All others per gallon	$0.84
Bulk Raw Water Service per ERC (350gpd)	$311.14
All others per gallon	$0.89

D & E Water Resources, LLC.
Monthly Water and Wastewater Rates

Residential and General Service	**Water Rates**	**Wastewater Rates**
Base Facility Charge by Meter Size		
5/8" x 3/4"	$15.39	$22.34
3/4"	$23.09	$33.51
1"	$38.48	$55.85
1 1/2"	$76.95	$111.70
2"		$178.72
Charge per 1,000 gallons	$4.14	
10,000 gallon cap		$6.80

Miscellaneous Service Charges

	Water	**Wastewater**
Initial Connection Charge	$20.00	$20.00
Normal Reconnection Charge	$20.00	$20.00
Violation Reconnection Charge	$20.00	Actual Cost
Premises Visit Charge (in lieu of disconnection)	$20.00	$20.00

Service Availability Charge

Plant Capacity Charge	**Water**	**Wastewater**
Residential – per ERC (350 gpd)	$980.06	
Residential – per ERC (300 gpd)		$2,094.46
All others per gallon		$6.98

Item 6

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: March 23, 2017

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Ollila) A.O. EJD PD
Office of the General Counsel (Leathers)

RE: Docket No. 170029-GU – Petition for approval of modifications to extension of facilities and area extension program tariffs, by Florida City Gas.

AGENDA: 04/04/17 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 04/04/17 (60-Day Suspension Date Waived by the Company Until the 04/04/17 Agenda Conference)

SPECIAL INSTRUCTIONS: None

Case Background

On February 2, 2017, Florida City Gas (FCG or Company) filed a petition for approval of modifications to its existing Extension of Facilities (applicable to general tariff extension customers) and Area Extension Program (AEP) tariffs. In accordance with Rule 25-7.054, Florida Administrative Code, (F.A.C.), the tariffs apply to new customers that require an extension of gas distribution facilities in order to receive service. The proposed tariff modifications will allow FCG to require certain general tariff extension customers and AEP customers to commit to receive natural gas service at a defined minimum annual volume and to pay for the minimum annual volume even if it had not been reached, i.e., a take or pay commitment, in order to receive service.

In a February 7, 2017 email (subsequently filed in the docket), FCG waived the 60-day suspension deadline, pursuant to Section 366.06(3), Florida Statutes (F.S.), until the April 4, 2017 Agenda Conference. FCG responded to staff's first data request on March 3, 2017. On March 17, 2017, the Company filed revised responses to staff's data request and revised tariff pages. The proposed tariff pages as revised are contained in Attachment 1 of this recommendation. The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, F.S.

Discussion of Issues

Issue 1: Should the Commission approve FCG's proposed tariff modifications, as revised on March 17, 2017, to the Extension of Facilities and AEP tariffs?

Recommendation: Yes, the Commission should approve FCG's proposed tariff modifications, as revised on March 17, 2017, to the Extension of Facilities and AEP tariffs effective April 4, 2017. (Ollila)

Staff Analysis:

Current Extension of Facilities Tariffs

Rule 25-7.054(3), F.A.C., provides that extensions of gas facilities are made at no cost to the customer when the capital investment necessary to extend service is equal to or less than the Maximum Allowable Construction Cost (MACC). FCG's tariff defines the MACC as six times the estimated annual gas revenue less the cost of gas (margin revenues).[1] If the required capital investment exceeds the MACC, then the customer must pay the difference between the MACC and the capital costs as an Aid to Construction (ATC) pursuant to FCG's "Extensions of mains and services above free limit" tariff provision. This tariff provision is shown on Page 1 of 3 of Attachment 1.

FCG stated that during 2012-2016 over 4,400 customers (or on average 880 customers per year) paid ATC costs. The capital investment to serve a new customer may include gas mains, service lines, and regulators.

The AEP tariff is designed to provide FCG with an alternate optional method to recover its capital investment to provide natural gas service to customers in a discrete geographic area who do not have gas service available.[2] The AEP tariff provides for the determination of a charge applicable to all gas customers located in the geographic area over a 10-year amortization period. The AEP charge is applied on a per therm basis in addition to all other tariffed charges. The AEP charge is calculated by a formula based on the amount of investment required and the projected gas sales and resulting revenues collected from customers in the AEP area.

The AEP tariff requires FCG to recalculate and true-up the AEP charge on the third anniversary of the date when the facilities to provide gas service were placed into service, or on the date when 80 percent of the originally forecast annual load is connected, whichever comes first. The Company can true-up the AEP charge only once, and the new charge will be applied prospectively over the remainder of the amortization period.

The AEP tariff includes a provision that the length of the amortization period may be modified upon Commission approval. In 2012, FCG extended its facilities pursuant to the AEP tariff to serve a large commercial customer, a citrus producer (Glades project). In 2016, the Commission approved a delay of the true-up and an extension of the amortization period for two years

[1] Order No. PSC-95-0506-FOF-GU, issued April 24, 1995, in Docket No. 950206-GU, *In re: Petition for approval of tariffs governing extension of facilities by City Gas Company of Florida.*
[2] Ibid.

because the project had not developed as projected.[3] Other than the Glades project, FCG has used the AEP tariff nine times since its 1995 implementation.

FCG's Proposed Take or Pay Provision

The proposed tariff modifications provide FCG with the option to require a take or pay provision from a general tariff extension customer or an AEP customer. The proposed take or pay provision would require the customer to agree to commit to a minimum volume of natural gas each year.

FCG explained that it views the proposed take or pay provision as another tool to mitigate the risk associated with high-cost extensions. The Company asserted that its ability to fully recover its investment may be compromised when a customer's actual gas volumes are significantly less than the customer's estimate of gas volumes used to calculate the MACC and there are minimal or no opportunities to true-up the calculation. FCG asserted that a take or pay provision will add another layer of protection to reduce the risk to the general body of ratepayers from stranded investment. The Company also asserted that a take or pay provision will encourage potential customers to provide business information that will result in a realistic, rather than an inflated, calculation of potential gas volumes.

FCG stated that the process to determine whether a minimum take or pay requirement is necessary is the same for general tariff extension customers or AEP customers. FCG identified three factors it would use to evaluate whether the take or pay provision should be required. The factors are the overall capital investment necessary to extend service, the customer's use for natural gas, and whether the business is a start-up or established business with verifiable consumption data that can be used to substantiate the annual natural gas use estimates (risk assessment). According to the Company, lower risk businesses are those that have existing natural gas use, are implementing equipment with known gas usage, or can provide verifiable usage data, such as data from an affiliate. A higher risk potential customer might be a new business that has new equipment, projected high volumes, and little or no business or gas usage experience. According to the Company, the "ultimate" factor is the impact to the Company and its ratepayers if the new customer's volumes are less than projections.

The minimum volume commitment will not be set above the amount used to calculate the MACC. A customer's specific annual volume commitment would be identified in a schedule that is contained in the gas extension contract. Each year, on the anniversary date of the account, FCG will audit the actual billed volume of natural gas and compare it to the take or pay schedule in the gas extension contract. If the volume is less than the requirement, the Company would bill for the volume shortfall using the applicable charges associated with the customer's tariff rate for general service extension customers. For an AEP customer, the billing of the volume shortfall would also include the applicable AEP surcharge. The minimum volume commitment is six years for general tariff extension customers and ten years for AEP customers. FCG stated that it does not anticipate frequent use of the take or pay provision for general tariff extension customers or AEP customers.

---

[3] Order No. PSC-16-0066-PAA-GU, issued February 5, 2016, in Docket No. 150232-GU, *In re: Petition for approval of variance from area extension program (AEP) tariff to delay true-up and extend amortization period, by Florida City Gas.*

The Company explained that the Glades project prompted it to review its general tariff extension and AEP tariffs and to consider whether changes to the tariffs might reduce or mitigate future difficulties with lower-than-expected usage. In response to staff's data request, FCG stated that there had been at least one prior situation where a take or pay provision would have been useful as the expected gas volumes did not materialize due to an unintentional error by the customer concerning the customer's installed equipment specifications. FCG also stated that there is a potential project currently under consideration in an existing AEP area with the customer being amenable to a take or pay provision. The Company asserts that the proposed revisions are in the public interest and will protect existing ratepayers while facilitating the expansion of service to new customers.

Conclusion

Staff believes that a take or pay provision for general tariff extension customers and AEP customers is reasonable and appropriate because it will limit the risk to the general body of ratepayers. Therefore, staff recommends that the Commission approve FCG's proposed tariff modifications to the Extension of Facilities and AEP tariffs effective April 4, 2017.

Issue 2: Should this docket be closed?

Recommendation: If Issue 1 is approved the tariffs should become effective on April 4, 2017. If a protest is filed within 21 days of the issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order. (Leathers)

Staff Analysis: If Issue 1 is approved the tariffs should become effective on April 4, 2017. If a protest is filed within 21 days of the issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order.

RULES AND REGULATIONS (Continued)

11. EXTENSION OF FACILITIES

A. Free Extensions of Mains and Services: The maximum capital investment required to be made by the Company for main and service facilities without cost to the Customer shall be defined as the Maximum Allowable Construction Cost ("MACC"). The MACC shall equal six times the annual Margin Revenues estimated to be derived from the facilities. However, customers initially served under the Residential Standby Generator Service ("RSG") and Commercial Standby Generator Service ("CSG") Rate Schedules shall not be eligible for extension allowances, even if additional load is added at a later date, but such Customers may be eligible to receive refunds of amounts paid to the Company for extensions under B.(2) below.

B. Extensions of Mains and Services Above Free Limit: When the cost of the extension required to provide service is greater than the free limit specified above, the Company may require a non-interest bearing advance in Aid to Construction ("ATC") equal to the cost in excess of such free limit provided that:

(1) At the end of the first year following construction, the Company shall refund to the person paying the ATC or their assigns an amount equal to the excess, if any, of the MACC as recalculated using actual gas revenues, less the actual cost of gas, over the estimated MACC used to determine the amount of the ATC.

(2) For each additional Customer taking service at any point on the extension within a period of five (5) years from date of construction, the Company shall refund to the person paying the ATC or their assigns an amount by which the MACC for the new Customer exceeds the cost of connecting the Customer, provided that an additional main extension shall have not been necessary to serve the additional Customer.

(3) The aggregate refund to any Customer made through the provisions of (a) and (b) above shall at no time exceed the original ATC of such Customer.

(4) The extension shall at all times be the property of the Company and any un-refunded portion of the ATC at the end of five (5) years shall be credited to the plant account of the Company.

(5) The Company may require a commitment by a customer to take or pay for a minimum volume of gas as deemed appropriate by the Company given the circumstances of facility cost and/or the service requirements of a particular customer. In no instance will the minimum volume commitment be set at a level that exceeds the volume amount used to calculate the MACC for the customer, nor will the volume commitment term exceed six (6) years.

RULES AND REGULATIONS (Continued)

11. EXTENSION OF FACILITIES (Continued)

C. Area Extension Program Charge: Notwithstanding the provisions of Sections A and B when facilities are to be extended to serve single or multiple delivery points in a discrete geographic area, the Company may require an Area Extension Program Charge ("AEP"). The Company, in its sole discretion, may require this charge when:

(1) The cost of the project facilities required to provide service through the area is greater than the aggregate MACC for the Customers to be served; and

(2) The Company reasonably forecasts Margin Revenues plus the AEP during the period ending ten years from when the mains required to serve the project facilities are placed in service (the Amortization Period), that are sufficient to recover the cost of the project facilities.

The AEP, which shall be stated on a per therm basis, shall apply with respect to all natural gas sold or transported to Company Customers located within the applicable discrete geographic area during the Amortization Period.

The AEP will be calculated by dividing (1) the amount of additional revenue required in excess of the Company's applicable tariff rates by (2) the volume of gas reasonably forecast to be sold or transported to Customers within the applicable discrete geographic area during the Amortization Period. The additional revenue required is that amount determined necessary to recover the excess cost of the facilities, including the Company's allowed cost of capital.

AEP collected shall be used specifically to amortize the cost of the project facilities within the applicable discrete geographic area that are in excess of the MACC. If the AEP collected is sufficient before the expiration of the Amortization Period to fully amortize the excess costs, including provision for the accumulated cost of capital, the AEP for that area shall terminate immediately, and the Company shall promptly credit the affected Customers for amounts over collected, if any.

Upon the earlier of (1) the third anniversary of the date when the project facilities are placed in service and (2) the date on which 80% of the originally forecast annual load is connected, the Company will reassess the amount of additional revenue required to recover the unamortized excess cost of the facilities and the calculation of the AEP. The resulting adjustment of the AEP (whether upward or downward) will be applied over the remainder of the Amortization Period.

The Company may require a commitment by a customer to take or pay for a minimum volume of gas as deemed appropriate by the Company given the circumstances of facility cost and/or the service requirements of a particular customer. In no instance will the minimum volume commitment be set at a level that exceeds the volume amount used to calculate the MACC for the customer, nor will the volume commitment term exceed ten (10) years.

Issued by: Carolyn Bermudez
Vice President, Southern Operations

Effective

The Company may enter into a guaranty agreement with the party or parties requesting the extension, whereby that party or parties agree to pay to the Company any unamortized balance remaining at the end of the Amortization Period. The Company's rights under the guaranty agreement will not be considered when calculating the AEP.

The length of the Amortization Period may be modified upon the specific approval of the Florida Public Service Commission.

RULES AND REGULATIONS (Continued)

11. EXTENSION OF FACILITIES (Continued)

D. General

The Company will own control and maintain all service pipes, regulators, vents, meters, meter connections, valves and other appurtenances from the main to the outlet side of the meter.

The extension of facilities provisions shall not require the Company to extend its mains across private property or in streets that are not at established grade; nor prohibit the Company from making extensions of mains of greater length than required herein.

Item 7

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: March 23, 2017

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Friedrich, Hudson)
Division of Accounting and Finance (Vogel)
Division of Engineering (Buys, Knoblauch)
Office of the General Counsel (Tan)

RE: Docket No. 160143-WU – Application for staff-assisted rate case in Hardee County by Charlie Creek Utilities, LLC.

AGENDA: 04/04/17 – Proposed Agency Action- Except Issue Nos. 10, 11, and 18 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: 11/01/17 (15-Month Effective Date (SARC))

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

Charlie Creek Utilities, LLC, (Charlie Creek or utility) is a Class C utility providing water service to approximately 144 residential and one general service customer in Hardee County. Rates were last established for this utility when its original certificate was granted on January 25, 2016.[1] The rates and charges Charlie Creek had in effect prior to the current owner acquiring the water system were approved simultaneously with the utility's original certificate. Charlie Creek is currently owned by Michael Smallridge and operated under Florida Utility Services 1, LLC (FUS1).

On June 3, 2016, Charlie Creek filed an application for a staff assisted rate case (SARC). Staff selected the test year ended December 31, 2015, for the instant case. According to Charlie Creek's 2015 annual report, total gross revenues were $68,259 and total operating expenses were $71,773. On February 14, 2017, a petition, with 20 signatures, opposing the rate increase was received by the Commission. The Commission has jurisdiction in this rate case pursuant to Sections 367.0812, 367.0814, 367.081(8) and 367.091, Florida Statutes (F.S.).

[1]Order No. PSC-16-0043-PAA-WU, issued January 25, 2016, in Docket No. 150186-WU, *In re: Application for certificate to operate a water utility in Hardee County by Charlie Creek Utilities, LLC.*

Discussion of Issues

Issue 1: Is the quality of service provided by Charlie Creek Utilities, LLC satisfactory?

Recommendation: Yes. The overall quality of service provided by Charlie Creek Utilities, LLC should be considered satisfactory. (Knoblauch)

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. Overall quality of service is derived from an evaluation of three separate components of the utility 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 Florida Department of Environmental Protection (FDEP) and the county health department over the preceding three-year period shall be considered. Furthermore, 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 FDEP.

Quality of Utility's Product

In evaluation of Charlie Creek's product quality, staff reviewed the utility's compliance with FDEP primary and secondary drinking water standards. Primary standards protect public health, while secondary standards regulate contaminants that may impact the taste, odor, and color of drinking water.

Staff reviewed chemical analyses of samples dated June 26, 2012, and July 27, 2015. All results were in compliance with the FDEP primary and secondary water quality standards. These chemical analyses are performed every three years. The next scheduled analysis should take place in 2018.

Staff additionally reviewed customer complaints regarding the quality of Charlie Creek's product. At the customer meeting held in Wauchula, FL on January 19, 2017, two customers discussed concerns regarding the quality of water, including low pressure, water outages, a sulfur odor, low chlorine levels, and a white substance in the pipes. As of the filing date of this recommendation, five customers provided written comments expressing similar concerns.

The utility has stated that there are ongoing efforts to complete the maintenance and repairs needed to update the system and address the calcium and odor concerns. To address the white substance customers had observed, the utility is engaging an engineer in efforts to manage calcification problems in the system. Staff believes the utility's efforts to address the calcification are reasonable considering the customer's complaints. Additionally, the utility stated that the buildup of calcium can also be attributed to the low pressure problems customers have experienced.

One customer at the customer meeting stated that they contacted the utility about a lack of chlorine in the water, and the utility responded that they had run out of chlorine. The customer suggested that additional monitoring of the water quality should be completed on a monthly or bimonthly basis.

Addressing chlorine level concerns, the utility stated they had never run out of chlorine and this may have occurred under the previous owner. The utility disagreed that additional water quality monitoring is necessary as the water test results are in compliance with the FDEP requirements and additional testing would result in an added expenses for the customers.

Staff also requested copies of complaints filed with the utility during the test year and four years prior to the test year. The utility indicated that no formal complaints were filed during the test year, but the utility had received customer calls in relation to an odor from the water. In response, the utility installed two flushing valves in order to help with the hydrogen sulfide that was causing the odor.

In 2012, a customer complaint was filed with FDEP which related to a possible calcium buildup in the lines. Calcium is a secondary contaminant and is not considered an immediate health risk; however, the customer was advised to contact FDEP if there were any further concerns. No other product quality complaints were received. Based on staff's review, giving consideration to the utility's current compliance with FDEP standards, Charlie Creek's product should be considered satisfactory. Furthermore, it appears that the utility is addressing the product quality concerns raised by its customers.

Operating Condition of the Utility's Plant and Facilities

Charlie Creek's service area is located in Wauchula, Florida, in Hardee County, and is within the Southwest Florida Water Management District (SWFWMD). The water treatment system has two wells and the raw water is treated with liquid chlorine for disinfection purposes. The utility's water system has two storage tanks totaling 11,000 gallons and is pumped into a 6,000 gallon hydropneumatic tank before entering the distribution system.

On February 12, 2014, FDEP conducted a sanitary survey. One deficiency was identified, stemming from the utility not meeting minimum requirements for a community over 350 in population. To meet the minimum requirements, the utility was required to submit an Emergency Preparedness Plan, perform remediation measures to one well, and repair or replace its generator. The utility made the necessary improvements and the system was found to be in compliance on May 6, 2014. Staff did not identify any issues or concerns during its January 19, 2017, site visit. Based on the operating condition of Charlie Creek'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 the utility's attempt to address customer satisfaction. A summary of all complaints and comments received during the test year and four years prior are shown in Table 1-1.

Table 1-1
Number of Complaints by Source

Subject of Complaint	PSC's Records (CATS)	Utility's Records	FDEP	Docket Correspondence	Customer Meeting
Improper Billing/ Billing Related			1	3	
Quality of Water			1	3	2
Condition of Facilities				4	2
Improper Disconnect	2				
Outages	1			2	2
Total*	3	0	2	12	6

Source: Document Nos. 00915-17, 01687-17, 01810-17, and 0083-17
*A complaint may appear more than one time in this table if it meets multiple categories.

As part of staff's evaluation of customer satisfaction, staff held a customer meeting to receive customer comments concerning Charlie Creek's quality of service. The utility mailed the customer meeting notice to its customers on January 4, 2017, advising them of the time, place, and purpose of the meeting, as well as the procedures for filing comments with the Commission.

Four customers attended the customer meeting, two of which provided comments. As previously discussed in this issue, both customers reported problems associated with the water quality. The first customer additionally cited several instances when contacting the utility, their concerns were not properly addressed or they were provided with erroneous information. Moreover, the customer described an occurrence involving a water line break resulting in multiple day outages, and a customer provided personal equipment to assist the utility in repairing the line. The second customer echoed many of the same concerns, such as water outages. Additionally, both customers believed that more customers were not present at the customer meeting due to a misunderstanding of the rate increase and the impact it would have on customers' bills.

Charlie Creek provided a written response to the oral comments made at the customer meeting. In its response the utility indicated that, since the utility was acquired in 2014, it has made efforts to upgrade customer safety and convenience. The utility stated that it is holding annual meetings with customers to discuss utility related issues and has implemented an option to pay bills over the phone or online.

Regarding the water main break, the utility stated that Charlie Creek personnel initially repaired the water main following the break, but discovered that there was additional damage when the water pressure in the system remained low. A customer of Charlie Creek volunteered their equipment; however, due to the extent of the leak, a contractor was hired to complete the repairs. The utility asserted that customers were not out of water for several days; however, the pressure was low and a precautionary boil water notice was issued.

Other issues raised in the written comments received by the Commission included estimated water usage, lack of flushing, frequent breaks in water lines, difficulties in contacting the utility, poor customer service, and a delayed response by the utility when repairing leaks. As previously discussed, the utility has started holding annual meetings with its customers to discuss utility related issues. Additionally, the utility explained that several customer meters have been replaced to improve billing accuracy.

Staff reviewed the Commission's complaint records from January 1, 2011, through March 3, 2017, and found three complaints. Two of the complaints have been closed. The remaining complaint involved an improper disconnection of service.

Examining FDEP records over a five year period including the test year and the four years prior, one complaint was received on February 22, 2012. The customer stated that particles were present in their water, there was a leak on the purveyor's side, and they believed meters were not being correctly read. FDEP personnel contacted the utility's operator and owner who addressed the customer's concerns and the complaint was closed on February 23, 2012.

Based on the utility's response to customers' oral concerns expressed in connection with the customer meeting, the small number of complaints filed with the Commission, as well as the lack of those filed with FDEP, 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 Charlie Creek should be considered satisfactory.

Issue 2: What are the used and useful percentages (U&U) of Charlie Creek Utilities, LLC's water treatment plant (WTP) and distribution system?

Recommendation: Charlie Creek's WTP should be considered 50 percent U&U. The water distribution system should be considered 55 percent U&U. There appears to be no excessive unaccounted for water (EUW); therefore, staff is not recommending an adjustment be made to operating expenses for chemicals and purchased power. (Knoblauch)

Staff Analysis: Charlie Creek's water system is served by two 4-inch wells rated at 125 gallons per minute (gpm) and 350 gpm, and the WTP permitted capacity is 133,000 gallons per day (gpd). The raw water is treated by chlorination prior to entering the water distribution system. The WTP has two useable storage tanks totaling 11,000 gallons in capacity. There is an existing fire flow stand pipe, but no fire hydrants are present. The distribution system is composed of varying sizes of galvanized and PVC pipes. Staff notes that there have been no prior rate cases for this utility before the Commission; therefore, the U&U percentages for the WTP, storage facilities, and the distribution system have not been previously established.

Water Treatment Plant Used and Useful

Pursuant to Rule 25-30.4325, F.A.C., the U&U calculations are defined for a water treatment system and storage facilities. For a water treatment plant with more than one well and storage capacity, the U&U is described by the following equation: ([Peak Demand + Fire Flow + Growth – Excessive Unaccounted for Water]/Firm Reliable Capacity).

The peak demand is the single maximum day in the test year where there is no unusual occurrences and is measured in gallons per day (gpd). From the flow data provided on the utility's Monthly Operating Reports (MORs), the peak demand was found to be 60,000 gpd. There is no fire flow for the utility. Based on recent data growth in connections appears to be zero. As discussed below, no EUW has been identified for this system.

The firm reliable capacity is defined for systems with more than one well as the pumping capacity of all wells combined, excluding the largest individual well. For Charlie Creek, this yields a value of 125 gpm, or 120,000 gpd. Since DEP rates the treatment facilities at a capacity of 133,000 gpd, the well-based capacity is not constrained by treatment capacity. The final calculation of U&U for Charlie Creek is 50 percent ([60,000 + 0 + 0 – 0] / 120,000).

Excessive Unaccounted for Water

Rule 25-30.4325, F.A.C., defines EUW as unaccounted for water in excess of 10 percent of the amount produced. Unaccounted for water is all water produced that is not sold, metered, or accounted for in the records of the utility. In determining whether adjustments to plant and operating expenses are necessary in accordance with Rule 25-30.4325(10), F.A.C., staff considers several factors. These factors include the causes of EUW, any corrective action taken, and the economical feasibility of a proposed solution. EUW is calculated by subtracting both the gallons sold to customers and the gallons used for other services, such as flushing, from the total gallons pumped for the test year.

Based on the MORs filed by the utility, Charlie Creek produced 14,534,000 gallons of water from January 1, 2015 to December 31, 3015. However, in response to staff's data request, the utility found tabulation errors in their MORs and provided the corrected pumped water data. The total gallons pumped using the corrected data for 2015 was found to be 8,099,000 gallons.

Based on the audit report completed by staff, the utility sold 8,294,049 gallons of water to customers. Additionally, the utility documented 233,000 gallons of water that were expended for other uses as recorded in the 2015 Annual Report. The resulting unaccounted for water is -5.3 percent ([8,099,000 – 8,294,049 – 233,000] / 8,099,000).

The utility believes the reason more water was sold than pumped was due to several factors. During the first several months of operation in 2015, the utility identified and replaced forty-three faulty water meters, representing approximately 30 percent of its customer base. At the end of 2016, a total of ninety-two meters had been replaced. When determining the amount of water sold to customers with faulty meters, the utility estimated usages and utilized past usages from their billing system.

Charlie Creek also found inaccuracies with the master meters at both wells. On February 17, 2017, the Florida Rural Water Association (FRWA) tested both well's master meters and found one meter to be outside the acceptable range of accuracy. The primary well's master meter was found to be running 8.3 percent slower than the test meter, but it was within accuracy tolerance. The second well's master meter was found to be running 11.1 percent faster than the test meter and was not within acceptable accuracy tolerance. However, the second well had undergone repairs in 2015 following the transfer of the system and was not operational until November 2016, thus it did not contribute to the amount of water pumped. Considering the results from the FRWA and the age of each meter, the utility plans to replace both master meters for improved accuracy in the amount of water pumped. Staff believes the replacement of the master meters is prudent.

Staff considered an additional analysis of the unaccounted for water by taking into account the inaccuracy of the primary well's master meter. Using the FRWA's findings of the primary well's master meter, the amount of water pumped was adjusted accordingly and the unaccounted for water was found to be less than 10 percent. Therefore, considering all of these factors, staff recommends that no adjustment be made to operating expenses for chemicals and purchased power due to the EUW.

Storage Used and Useful

The utility has two useable storage tanks with a capacity of 11,000 gallons. According to Rule 25-30.4325(8), F.A.C., usable storage capacity less than or equal to the peak day demand shall be considered 100 percent used and useful. As discussed above, the peak day demand was found to be 60,000 gallons per day, thus, the storage should be considered 100 percent U&U.

Water Distribution System Used and Useful

The equation for calculating U&U for the water distribution system is given by: ([Number of Test Year Connections + Growth] / Capacity of the System). Based on customer bills, the audit report identified 144 residential connections and 1 general service connection during the test year. The capacity of the system is 266 lots; therefore, the water distribution system is 55 percent U&U ([145 + 0] / 266).

Summary

Based on staff's analysis, Charlie Creek's water treatment plant should be considered 50 percent U&U, storage U&U should be considered 100 percent, and the water distribution system should be considered 55 percent U&U. There appears to be no EUW; therefore, staff is not recommending an adjustment be made to operating expenses for chemicals and purchased power.

Issue 3: What is the appropriate average test year rate base for Charlie Creek Utilities, LLC?

Recommendation: The appropriate average test year water rate base for Charlie Creek is $26,617. (Vogel)

Staff Analysis: Charlie Creek's net book value has never been established by the Commission, due in part to the lack of original documentation from the previous owner, during the original certificate audit.

Charlie Creek's current ownership manages and owns other utilities in Florida and, as of January 1, 2015, has been recording common costs on FUS1 books. These costs, which include salaries, transportation, and office supplies, have been allocated among all of the utilities receiving services from FUS1. Staff used allocations based on customer count and all utilities owned and managed by FUS1 at the time of the audit. All new allocation adjustments are based on ERC count and the current utilities owned or managed by FUS1 as of September 26, 2016. The new allocation for Charlie Creek from FUS1 is 7.29 percent. The test year ended December 31, 2015, was used for the instant case. A summary of each water rate base component and recommended adjustments are discussed below.

Utility Plant in Service (UPIS)

The UPIS balance to begin the test year was $0 as the utility's prior owner's records were destroyed. For the test year, the utility recorded water UPIS of $3,044. Staff capitalized major repairs at the plant originally expensed to Accounts 620 and 636. These repairs include two pump repairs, one for $504 and the second for $640. The utility originally booked these costs as expenses, but staff believes these repairs will not be recurring and did extend the useful life of the assets; therefore, the costs should be capitalized. The utility's improvements being capitalized also include replacing a control box, refurbishing well #2 pumping equipment, installing a flush point, and installing a starter on well #1. The utility also installed meters, but did not book the labor and installation costs for these meters. Therefore, staff has increased UPIS by $360. Staff also increased this account by $1,070 to include the purchase of a lawn mower.

As discussed in Issue 2, the utility also included the purchase and installation of two master meters. The utility also purchased and installed two gate valves along with the necessary sampling expenses. These additions totaled $1,472 and $2,223 (1,833 + 390), respectively. Staff has also included an averaging adjustment of negative $7,393. Staff's adjustments to UPIS result in a net increase of $4,349. Therefore, staff recommends that the appropriate UPIS balance is $7,393. These recommended adjustments to UPIS are detailed in Table 3-1.

Table 3-1
Adjustments made to UPIS

	Adjustment Description	Water
1.	To capitalize the purchase of a 30 gpd pump.	$590
2.	To capitalize the replacement of a control box.	508
3.	To capitalize the refurbishment of well pumping equipment.	2,156
4.	To capitalize the installation of a 2-inch flush point.	1,800
5.	To capitalize the installation of a starter for a well.	418
6.	To capitalize non-recurring pump repairs and new impeller.	1,144
7.	To include the installation cost of replaced meters.	360
8.	To include the purchase of a new lawn mower.	1,070
9.	To include pro forma replacement of two gate valves and sampling.	2,223
10.	To include pro forma purchase and installation of two master meters.	1,472
	Subtotal	$11,741
	Averaging Adjustment	(7,393)
	Net Increase to UPIS	$4,349
	Existing UPIS	3,044
	Test Year UPIS	$7,393

UPIS - Allocated

The utility did not record a balance in UPIS – Allocated. Due to the utility's relationship with FUS1, staff has included allocated common plant from FUS1. Staff's audit included total FUS1 balances for Office Furniture & Equipment, Transportation Equipment, and Tools, Shop, and Garage Equipment of $21,770. After applying Charlie Creek's 7.29 percent allocation, staff increased UPIS – Allocated by $1,588. Staff also included an averaging adjustment of negative $69. Therefore, staff recommends that the appropriate UPIS - Allocated balance is $1,518.

Land & Land Rights

The utility recorded a test year land balance of $12,050. No adjustments are necessary; therefore, staff recommends that the Land & Land Rights balance remain $12,050

Non-Used and Useful (non-U&U) Plant

The utility did not record a test year non-U&U plant balance for water. As discussed in Issue 2, staff determined the WTP to be 50 percent U&U and the water distribution system to be 55 percent U&U.

Staff has applied the U&U percentage to WTP average plant balances and to the associated average accumulated depreciation balances. Staff has increased non-U&U WTP by $1,120 for average plant and decreased the associated average depreciation by $75. Staff has applied the U&U percentage to the water distribution average plant balances and to the associated average accumulated depreciation balances. Staff has increased non-U&U water distribution system by $905 for average plant and decreased the associated average depreciation by $38. Staff's adjustments to non-U&U plant are an increase of $2,025 and staff's adjustments to associated average depreciation are a decrease of $112. Therefore, staff recommends non-U&U plant of $1,912.

Contributions in Aid of Construction (CIAC)

The utility did not record CIAC balances. Due to the lack of original cost for transmission and distribution plant, staff cannot determine an amount for CIAC. Commission audit staff found no additions in the test year and determined that no adjustments are necessary. Staff recommends CIAC of zero.

Accumulated Depreciation

Charlie Creek recorded a test year accumulated depreciation balance of $179. Staff recalculated accumulated depreciation using the prescribed rates set forth in Rule 25-30.140, F.A.C., and depreciation associated with plant additions and retirements and has increased water by $98. Staff has decreased this account by $215 for water to reflect the simple average. As discussed in Issue 2, the utility requested pro forma items. Staff has included $152 for the average accumulated depreciation associated with the pro forma items. Staff's total adjustments to this account are a decrease of $36. Staff's adjustments to this account results in an Accumulated Depreciation balance of $215.

Accumulated Depreciation- Allocated

The utility did not record a test year balance for Accumulated Depreciation – Allocated. Staff has included in this account accumulated depreciation for plant associated with FUS1's common plant that has been allocated to Charlie Creek. Staff has included $58 to Accumulated Depreciation - Allocated. Staff has also included an averaging adjustment of $21 for each account. Therefore, staff's adjustments to this account results in an Accumulated Depreciation – Allocated balance of $37.

Accumulated Amortization of CIAC

As stated above, staff recommends a CIAC balance of zero; therefore, the balance of Accumulated Amortization of CIAC should also be zero.

Working Capital Allowance

Working capital is defined as the short-term investor-supplied funds that are necessary to meet operating expenses. 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 $7,820 (based on O&M expense of $62,557 /8).

Rate Base Summary

Based on the foregoing, staff recommends that the appropriate average test year rate base for Charlie Creek is $26,617. 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 return on equity and overall rate of return for Charlie Creek Utilities, LLC?

Recommendation: The appropriate return on equity (ROE) is 11.16 percent with a range of 10.16 percent to 12.16 percent. The appropriate overall rate of return is 6.28 percent. (Vogel)

Staff Analysis: According to staff's audit, Charlie Creek's test year capital structure reflected common equity of $15,931, long term debt of $8,660 and customer deposits of $2,555.

Staff has decreased common equity by $15,931 to remove revenue earned from the previous owner and to reflect an adjustment made by the utility based on the transfer audit performed in Docket 150186-WU. Staff decreased the customer deposits balance by $599, to reflect the utility's customer deposit log. The utility's capital structure has been reconciled with staff's recommended rate base. The appropriate ROE for the utility is 11.16 percent based upon the Commission-approved leverage formula currently in effect.[2] Staff recommends an ROE of 11.16 percent, with a range of 10.16 percent to 12.16 percent, and an overall rate of return of 6.28 percent. The ROE and overall rate of return are shown on Schedule No. 2.

---

[2]Order No. PSC-16-0254-PAA-WS, issued June 29, 2016, in Docket No. 160006-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 are the appropriate test year revenues for Charlie Creek Utilities, LLC?

Recommendation: The appropriate test year revenues for Charlie Creek's water system are $65,621. (Friedrich)

Staff Analysis: Charlie Creek recorded total test year revenues of $68,259. The water revenues included $63,582 of service revenues and $4,677 of miscellaneous revenues. Based on staff's review of the utility's billing determinants and the service rates that were in effect during the test year, staff determined test year service revenues should be $59,656. This results in a decrease of $3,926 ($63,582-$59,656) to service revenues. In addition, staff made adjustments to miscellaneous revenues. Based on staff's review of the number of miscellaneous service occurrences during the test year and the utility's tariff approved miscellaneous service charges, staff determined miscellaneous revenues should be $5,965. This results in an increase of $1,288 ($5,965-$4,677). Based on the above, the appropriate test year revenues for Charlie Creek's water system are $65,621.

Issue 6: What is the appropriate amount of operating expense for Charlie Creek Utilities, LLC?

Recommendation: The appropriate amount of operating expense for Charlie Creek is $69,063. (Vogel)

Staff Analysis: Charlie Creek recorded operating expense of $71,632 for the test year ended December 31, 2015. The test year O&M expenses have been reviewed, including invoices, canceled checks, and other supporting documentation. Staff has also included an allocated portion of FUS1's operating expenses for the test year ended December 31, 2015. Staff used allocations based on customer count and all utilities owned and managed by FUS1 at the time of the audit. All incremental allocation increases are based on ERC count as of September 26, 2016. The new allocation for Charlie Creek from FUS1 is 7.29 percent. Staff has made several adjustments to the utility's operating expenses as summarized below.

Salaries and Wages- Employees (601)

Charlie Creek recorded salaries and wages – employees expense of $12,876. Staff received a compensation survey completed by OCBOA Consulting, LLC (OCBOA) regarding the salaries of FUS1 employees. The utility requested an increase in salaries based on the survey. Staff analyzed the results of the compensation survey and properly allocated the salary adjustments for Charlie Creek. Staff's adjustments and analysis of the compensation study are consistent with those approved in East Marion Utilities, LLC (East Marion), a sister utility, by the Commission at the February 7, 2017 Commission Conference.[3] Staff continues to believe that the amounts approved are appropriate at this time. Staff's allocation of salaries is detailed in Table 6-1.

Table 6-1
Adjustments made to Salaries and Wages – Employees based on the OCBOA Compensation Survey

Title	Requested	Current Salary	Allocation %	Allocated Salary
Chief Financial Off.	$55,500	$54,366	7.29	$3,964
Operation Supervisor	39,000	39,000	7.29	2,844
Office Manager	39,500	39,500	7.29	2,880
Cust. Serv. Rep.	34,000	34,000	7.29	2,479
Part-time Billing	10,400	10,400	7.29	758
Total				$12,927

Source: Utility's request based on Compensation Survey from OCBOA

Staff has increased this expense by $51 to account for the increase in salaries and to properly allocate the salary expense. Staff's total adjustments result in an increase of $51. Therefore, staff is recommending salaries and wages – employees expense of $12,927.

Salaries and Wages- Officers (603)

Charlie Creek recorded salaries and wages – officers expense of $5,700. Based on the adjustments approved at the February 7, 2017 Commission Conference, staff has decreased this

[3]Docket No. 150257-WS, *In re: Application for staff-assisted rate case in Marion County, by East Marion Utilities, LLC.*

expense by $398. This represents a recommended total President salary of $72,704 to be allocated over all FUS1 utilities, as previously approved. The utility has not provided any additional information regarding this account and staff does not believe any additional increases are appropriate at this time. Therefore, staff is recommending salaries and wages – officers expense of $5,302

Employee Pensions and Benefits (604)

Charlie Creek recorded employee pensions and benefits expense of $1,838. Staff has decreased this expense by $260 to include the appropriate amount of benefits expense for the test year. Staff has increased this account by $122 to reflect the incremental allocation increase. Staff's adjustments result in a decrease of $138. Therefore, staff is recommending employee pensions and benefits expense of $1,700.

Purchased Power (615)

The utility recorded purchased power expense of $3,790. Staff has decreased this expense by $18 to remove an out of period expense. Staff increased this expense by $392 to include a previously unrecorded invoice. Staff's net adjustments are an increase of $374. Therefore, staff recommends purchased power expense of $4,164.

Fuel for Power Production (616)

The utility recorded fuel for power production expense of $496. Staff has reclassified this expense to Account 650. Therefore, staff's adjustments result in a decrease of $496. Therefore, staff recommends fuel for power production expense of $0.

Chemicals (618)

Charlie Creek recorded chemicals expense of $1,994. Staff has decreased this account by $165, to remove a double entry. Staff's total adjustments result in a decrease of $165. Therefore, staff recommends chemicals expense of $1,829.

Materials & Supplies (620)

The utility recorded materials & supplies expense of $2,926. Staff has decreased this account by $1,144 to remove capitalized expenses relating to pump repairs during the test year. The utility, in its audit response, requested inclusion of these expenses in O&M. Staff believes these expenses should be capitalized as they are non-recurring. Staff has increased this account by $369 to include an allocated invoice not previously included. Staff also increased this account by $155 to reflect the incremental allocation increase. Staff's total adjustments result in a decrease of $620. Therefore, staff recommends materials & supplies expense of $2,306.

Contractual Services- Other (636)

Charlie Creek recorded Contractual Services – Other expense of $16,705. As discussed in Issue 1, calcification of the water distribution system has caused quality of service issues associated with water color and water pressure. The utility has engaged an engineering consultant to address the calcification issue which has also caused water meters and appurtenances to fail. Based on information provided by Charlie Creek, correcting the calcification issue will likely improve the utility's quality of service. Charlie Creek provided an invoice of $4,197 for the scope of services to be completed by the engineering consultant. The utility attempted to obtain multiple bids, but due to the rural location of the utility, no other engineering firm was able to provide a bid. Staff believes the engineering analysis and its costs are prudent and reasonable. Staff recommends the following adjustments to Contractual Services – Other.

Table 6-2
Adjustments made to Contractual Services - Other

	Adjustment Description	Water
1.	To capitalize the purchase of a 30 gpd pump.	($590)
2.	To capitalize the replacement of a control box.	(508)
3.	To capitalize the refurbishment of well pumping equipment.	(2,156)
4.	To capitalize the installation of a 2-inch flush point.	(1,800)
5.	To capitalize the installation of a starter for a well.	(418)
6.	To remove a duplicate invoice.	(528)
7.	To include an allocated invoice not previously included.	33
8.	To reflect the incremental allocation increase.	76
9.	To reflect an increase in water operations expense of $25/month.	300
10.	To include pro forma replacement of two check valves.	86
11.	To include pro forma sampling expense for a main repair.	390
12.	To include pro forma main repair.	400
13.	To include pro forma piping supplies.	216
14.	To include pro forma calcification analysis, amortized over five years.	839
	Total	($3,660)

Source: Audit Control No. 16-182-4-1, Audit Response, and Responses to Staff's Data Requests

Based on the adjustments shown above, staff's net adjustment is a decrease of $3,660. Staff recommends Contractual Services – Other expense of $13,045.

Rent Expense (640)

Charlie Creek recorded rent expense of $1,258. Staff has decreased this account by $104 to reflect the annualized lease agreement with FUS1. Staff has increased this account by $89 to reflect the incremental allocation increase based on ERCs. Staff's adjustments result in a net decrease of $15. Therefore, staff recommends rent expense of $1,243.

Transportation Expense (650)

Charlie Creek recorded transportation expense of $1,309. Staff has increased this account by $295 to reflect the appropriate allocated expenses for transportation. Staff has decreased this account by $122 to remove a truck loan from expenses. Staff has decreased this account by $27 to remove unsupported expenses. Staff has reclassified an account balance from Account 616 for $496, increasing this account balance by $496. Finally, staff increased this expense by $151 to reflect the incremental allocation increase. Staff's total adjustments result in an increase of $793. Staff recommends transportation expense of $2,102.

Insurance Expense (655)

Charlie Creek recorded insurance expense of $1,935 for the test year. Staff has decreased this expense by $301 to remove the health insurance premiums duplicated in Account 604. Staff recommends insurance expense for the test year of $1,634.

Regulatory Commission Expense (665)

Charlie Creek did not record regulatory commission expense for the test year. Staff has determined the filing fees, noticing fees, and postage for the instant case to be $1,259. Staff has also included $887 to reflect amortized filing and legal fees from the transfer, not previously included. Staff has amortized these amounts over four years. Therefore, staff recommends regulatory commission expense of $536.

Bad Debt Expense (670)

Charlie Creek recorded a bad debt expense estimation of $350 for the test year. Staff has increased this account by $1,615 to reflect the actual bad debt expense per an Aging Account Report. The utility did not have three years of records to compare. However, the Aging Account Report included approximately 6 months of 2016 data totaling $883. Staff believes approximately 18 months of data is a valid representation of bad debt expense for this utility. Therefore, staff recommends bad debt expense of $1,965.

Miscellaneous Expense

Charlie Creek recorded miscellaneous expense of $7,159. Staff recommends the following adjustments to miscellaneous expense:

Table 6-3
Adjustments made to Miscellaneous Expense

	Adjustment Description	Water
1.	To remove bank fees for non-sufficient funds and closing costs.	($105)
2.	To remove transfer filing fees and amortize into Acct. 665.	(750)
3.	To remove a portion of the purchase fee for the utility.	(100)
4.	To include customer convenience fees.	758
5.	To remove interest payments for a loan.	(407)
6.	To move expenses relating to original certification to Acct. 665.	(137)
7.	To include expenses relating to an annual customer meeting.	199
8.	To remove unsupported expenses.	(123)
9.	To reflect the test year allocation of expenses from FUS1.	17
10.	To remove equipment expenses included in Acct. 640.	(179)
11.	To reflect the appropriate amount of utility expenses from FUS1.	(170)
12.	To include amortized closing costs of a loan, amortized over 5 years.	20
13.	To reflect the incremental allocation increase.	279
14.	To include pro forma roof repair, amortized over five years.	219
	Total	($479)

Source: Audit Control No. 16-182-4-1, Audit Response, and Invoices provided by utility

Staff's total adjustments decrease this account by $479. Therefore, staff recommends miscellaneous expense of $6,680.

Operation and Maintenance Expenses Summary

Based on the above adjustments, staff recommends that the O&M expense balance is $62,557. Staff's recommended adjustments to O&M expense are shown on Schedule Nos. 3-A through 3-C.

Depreciation Expense (Net of Amortization of CIAC)

Charlie Creek recorded depreciation expense of $179 during the test year. Staff recalculated depreciation expense using the prescribed rates set forth in Rule 25-30.140, F.A.C. Staff increased depreciation expense by $98 to reflect the appropriate depreciation expense. Staff increased depreciation expense by $249 to include the appropriate depreciation of allocated plant. Staff increased depreciation expense by $152 to include depreciation expense for pro forma plant. Staff decreased depreciation expense by $112 to reflect the U&U adjustment to plant. The appropriate amount of amortization of CIAC is $0. Staff's total adjustment is an increase of $387, resulting in a net depreciation expense of $566.

Taxes Other Than Income (TOTI)

Charlie Creek recorded a TOTI balance of $5,993 for the test year. Staff has recalculated the utility's property taxes using the updated 2015 rates and has decreased this account $4,278. The utility had included the 2013 and 2014 property tax payment in this account. Staff increased this account to include payroll taxes of $1,251. Staff has increased this account by $2,953, to reflect the appropriate test year Regulatory Assessment Fees (RAFs) based on adjusted test year revenues. Staff increased TOTI by $74 to reflect the pro forma plant addition. Staff also decreased TOTI by $490 to remove property taxes associated with non-U&U property. Staff's adjustments to TOTI result in a net decrease of $490.

In addition, as discussed in Issue 8, revenues have been increased by $9,697 to reflect the change in revenue required to cover expenses and allow the recommended operating margin. As a result, TOTI should be increased by $436 to reflect RAFs of 4.5 percent on the change in revenues. This adjustment results in a net decrease of $54. Staff recommends TOTI of $5,939

Operating Expense Summary

The application of staff's recommended adjustments to Charlie Creek's test year operating expenses results in operating expenses of $69,063. Operating expenses are shown on Schedule Nos. 3-A. The related adjustments are shown on Schedule Nos. 3-B and 3-C.

Issue 7: Should the Commission utilize the operating ratio methodology as an alternative method of calculating the water revenue requirement for Charlie Creek Utilities, LLC? If so, what is the appropriate margin?

Recommendation: Yes, the Commission should utilize the operating ratio methodology for calculating the water revenue requirement for Charlie Creek. The margin should be 10 percent of O&M expense. (Vogel)

Staff Analysis: Section 367.0814(9), F.S., provides that the Commission may, by rule, establish standards and procedures for setting rates and charges of small utilities using criteria other than those set forth in Sections 367.081(1), (2)(a), and (3), F.S. Rule 25-30.456, F.A.C., provides an alternative to a staff-assisted rate case as described in Rule 25-30.455, F.A.C. As an alternative, utilities with total gross annual operating revenue of less than $275,000 per system may petition the Commission for staff assistance using alternative rate setting.

Charlie Creek did not petition the Commission for alternative rate setting under the aforementioned rule, but staff believes the Commission should employ the operating ratio methodology to set rates in this case. The operating ratio methodology is an alternative to the traditional calculation of revenue requirements. Under this methodology, instead of applying a return on the utility's rate base, the revenue requirement is based Charlie Creek's O&M expenses plus a margin. This methodology has been applied in cases in which the traditional calculation of the revenue requirement would not provide sufficient revenue to protect against potential variances in revenues and expenses.

By Order No. PSC-96-0357-FOF-WU,[4] the Commission, for the first time, utilized the operating ratio methodology as an alternative means for setting rates. This order also established criteria to determine the use of the operating ratio methodology and a guideline margin of 10 percent of O&M expense. This criterion was applied again in Order No. PSC-97-0130-FOF-SU.[5] Most recently, the Commission approved the operating ratio methodology for setting rates in Order No. PSC-16-0126-PAA-WU.[6]

By Order No. PSC-96-0357-FOF-WU, the Commission established criteria to determine whether to utilize the operating ratio methodology for those utilities with low or non-existent rate base. The qualifying criteria established by Order No. PSC-96-0357-FOF-WU and how they apply to the utility are discussed below:

1) <u>Whether the utility's O&M expense exceeds rate base</u>. The operating ratio method substitutes O&M expense for rate base in calculating the amount of return. A utility generally would not benefit from the operating ratio method if rate base exceeds O&M expense. In the instant case, rate base is less than the level of O&M expense. The utility's primary risk resides with covering

---

[4]Issued March 13, 1996, in Docket No. 950641-WU, *In re: Application for staff-assisted rate case in Palm Beach County by Lake Osborne Utilities Company, Inc.*
[5]Issued February 10, 1997, in Docket No. 960561-SU, *In re: Application for staff-assisted rate case in Citrus County by Indian Springs Utilities, Inc.*
[6]Issued March 28, 2016, in Docket No. 140220-WU, *In re: Application for staff-assisted rate case in Polk County by Sunrise Utilities, LLC.*

its operating expense. Based on the staff's recommendation, the adjusted rate base for the test year is $26,617, while adjusted O&M expenses are $62,557.

2) Whether the utility is expected to become a Class B utility in the foreseeable future. Pursuant to Section 367.0814(9), F.S., the alternative form of regulation being considered in this case only applies to small utilities with gross annual revenue of $275,000 or less. Charlie Creek is a Class C utility and the recommended revenue requirement of $75,318 is substantially below the threshold level. The utility's service area has not had any significant growth in the last five years. Therefore, it appears the utility will not become a Class B utility in the foreseeable future.

3) Quality of service and condition of plant. As discussed in Issue 1, the overall quality of service provided by Charlie Creek Utilities, LLC should be considered satisfactory.

4) Whether the utility is developer-owned. The current utility owner is not a developer.

5) Whether the utility operates treatment facilities or is simply a distribution and/or collection system. The issue is whether or not purchased water and/or wastewater costs should be excluded in the computation of the operating margin. Charlie Creek operates a water treatment plant.

Based on staff's review of the utility's situation relative to the above criteria, staff recommends that Charlie Creek is a viable candidate for the operating ratio methodology.

By Order Nos. PSC-96-0357-FOF-WS and PSC-97-0130-FOF-WU, the Commission determined that a margin of 10 percent shall be used unless unique circumstances justify the use of a greater or lesser margin. The important question is not what the return percentage should be, but what level of operating margin will allow the utility to provide safe and reliable service and remain a viable entity. The answer to this question requires a great deal of judgment based upon the particular circumstances of the utility.

Several factors must be considered in determining the reasonableness of a margin. First, the margin must provide sufficient revenue for the utility to cover its interest expense. Staff believes the margin will sufficiently cover the interest expense for Charlie Creek.

Second, the operating ratio method recognizes that a major issue for small utilities is cash flow; therefore, the operating ratio method focuses more on cash flow than on investment. In the instant case, the utility's primary risk resides with covering its operating expense. A traditional calculation of the revenue requirement may not provide sufficient revenue to protect against potential variances in revenues and expenses. Under the rate base methodology, the return to Charlie Creek would be $1,597. With the large number of necessary repairs and improvements made to the system in its first year under this owner and the potential need for additional repairs, staff does not believe the $1,597 would provide the financial cushion necessary to successfully operate this utility.

Third, if the return on rate base method was applied, a normal return would generate such a small level of revenue that in the event revenues or expenses vary from staff's estimates, Charlie Creek could be left with insufficient funds to cover operating expenses. Therefore, the margin should provide adequate revenue to protect against potential variability in revenues and expenses. If the utility's operating expenses increase or revenues decrease, Charlie Creek may not have the funds required for day-to-day operations. Staff determined that a 10 percent margin would be sufficient in this case.

In conclusion, staff believes the above factors show that the utility needs a higher margin of revenue over operating expenses than the traditional return on rate base method would allow. Therefore, in order to provide Charlie Creek with adequate cash flow to provide some assurance of safe and reliable service, staff recommends application of the operating ratio methodology at a margin of 10 percent of O&M expense for determining the revenue requirements.

Issue 8: What is the appropriate revenue requirement for Charlie Creek Utilities, LLC?

Recommendation: The appropriate revenue requirement is $75,318, resulting in an annual increase of $9,697 (14.78 percent). (Vogel)

Staff Analysis: Charlie Creek should be allowed an annual increase of $9,697 (14.78 percent). This will allow the utility the opportunity to recover its expenses as well as a 10 percent margin on O&M expenses for its water systems. The calculations are shown in Tables 8:

Table 8-1
Water Revenue Requirement

Adjusted O&M Expense	$62,557
Operating Margin (%)	10.00%
Operating Margin ($)	$6,256
Adjusted O&M Expense	62,557
Depreciation Expense (Net)	566
Taxes Other Than Income	5,503
Test Year RAFs	436
Revenue Requirement	$75,318
Less Adjusted Test Year Revenues	65,621
Annual Increase	$9,697
Percent Increase	14.78%

Issue 9: What are the appropriate rate structure and rates for Charlie Creek Utilities, LLC?

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. (Friedrich)

Staff Analysis: Charlie Creek is located in Hardee County within the SWFWMD and provides water service to approximately 145 residential and one general service customer. Approximately 10.49 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 4,788 gallons per month. The utility's current water system rate structure for residential and general service customers consists of a base facility charge (BFC) based on meter size and a two-tier inclining block rate structure. The rate blocks are: (1) 0-3,000 gallons and (2) all usage in excess of 3,000 gallons per month.

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 order to design gallonage charges that will send the appropriate pricing signals to target non-discretionary usage, staff believes 40 percent of the revenue requirement should be recovered through the BFC. At the 40 percent BFC allocation, the percentage increase in price increases as consumption increases, which is one of the rate design goals. In addition, the average number of people per household served by the water system is two and one half; therefore, based on the number of persons per household, 50 gallons per day per person, and the number of days per month, the non-discretionary usage threshold should be 4,000 gallons per month instead of 3,000 gallons. Staff recommends a BFC and a two-tier gallonage charge rate structure for residential customers. The rate tiers should be: (1) 0-4,000 gallons and (2) all usage in excess of 4,000 gallons per month. Staff recommends a BFC and uniform gallonage charge rate structure for general service customers.

Further, based on the recommended revenue increase of approximately 16.3 percent excluding miscellaneous revenues, the residential consumption can be expected to decline by 292,000 gallons, resulting in anticipated average residential demand of 4,619 gallons per month. Staff recommends a 3.5 percent reduction in total test year residential gallons for rate setting purposes and corresponding reductions of $13 for purchased power, $6 for chemical expense, and $1 for RAFs to reflect the anticipated repression. These adjustments result in a post repression revenue requirement of $69,333. The recommended rate structure and monthly water rates are shown on Schedule No. 4. Additionally, staff evaluated alternative rate structures with varying BFC allocations and found that the alternatives were not in accordance with the rate design parameters.

Based on the above, 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 10: What is the appropriate amount by which rates should be reduced in four years after the published effective date to reflect the removal of the amortized rate case expense as required by Section 367.081(8), F.S.?

Recommendation: The water rates should be reduced as shown on Schedule Nos. 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 367.081(8), F.S. Charlie Creek 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 the utility 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. (Vogel, Friedrich)

Staff Analysis: Section 367.081(8), 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 rates. The reduction will reflect the removal of revenue associated with the amortization of rate case expense, the associated return in working capital, and the gross-up for RAFs. The total reduction is $617.

Based on the above, the water rates should be reduced as shown on Schedule Nos. 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 367.081(8), F.S. Charlie Creek 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 the utility 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.

Issue 11: Should the recommended rates be approved for Charlie Creek Utilities, LLC on a temporary basis, subject to refund with interest, 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 with interest, in the event of a protest filed by a party other than the utility. Charlie Creek 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's Office of Commission Clerk no later than the 20th of each 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. (Vogel)

Staff Analysis: This recommendation proposes an increase in water 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. Charlie Creek 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.

Charlie Creek 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 $6,586. 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 express approval of the Commission;
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; and
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.

Should the recommended rates be approved by the Commission on a temporary basis, Charlie Creek should maintain a record of the amount of the security, 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's Office of Commission Clerk no later than the 20th of each 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 the miscellaneous service charges of Charlie Creek Utilities, LLC be revised?

Recommendation: Yes. Charlie Creek's miscellaneous service charges should be revised. The charges should be effective on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. In addition, the approved charges 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. (Friedrich)

Staff Analysis: Section 367.091, F.S., authorizes the Commission to approve and change miscellaneous service charges. The utility requested that staff evaluate its existing miscellaneous service charges. The staff recommended salaries have been utilized in order to determine the administrative and field labor component of miscellaneous services. Staff has also utilized the mileage provided by the utility and the IRS mileage rate to calculate the transportation costs associated with administering the miscellaneous services. In addition, the utility has requested that miscellaneous service charges be grossed up to reflect the appropriate RAFs. The Commission has previously approved miscellaneous service charges that are grossed up to reflect the appropriate RAFs.[7] Below in Table 12-5 are the utility's current and staff's recommended miscellaneous service charges rounded up to the nearest tenth.

Initial Connection

The initial connection charge is levied for service initiation at a location where service did not exist previously. A Charlie Creek representative makes one trip when performing the service of an initial connection. Based on labor and transportation to and from the service territory, staff recommends initial connection charges of $56.50 for normal hours and $60.10 for after hours. Staff's calculation is shown below in Table 12-1.

Table 12-1
Initial Connection Charge Calculation

Activity	Normal Hours Cost	Activity	After Hours Cost
Labor (Administrative) ($18.00/hr x1/4hr)	$4.50	Labor (Administrative) ($18.00/hr x1/4hr)	$4.50
Labor (Field) ($20.31/hr x 1/3 hr)	$6.77	Labor (Field) ($30.47/hr x 1/3 hr)	$10.16
Transportation ($0.535/mile x 80 miles-to/from)	$42.80	Transportation ($0.535/mile x 80 miles-to/from)	$42.80
Mark up for RAFs (4.5%)	$2.43	Mark up for RAFs (4.5%)	$2.59
Total	$56.50	Total	$60.05

Source: Utility's cost justification documentation.

[7]Order Nos. PSC-99-2378-TRF-WU, in Docket No. 990763-WU, dated December 6, 1999, *In re: Tariff filing by Floralino Properties, Inc. requesting approval of premises visit charge for visits requested by customers in Pasco County* and PSC-17-0092-PAA-WU, in Docket No. 160144-WU, dated March 13, 2017, *In re: Application for transfer of Certificate No. 288-W in Pasco County from Orangeland Water Supply to Orange Land Utilities, LLC*

Normal Reconnection Charge

A normal reconnection charge is levied for the transfer of service to a new customer account at a previously served location, or reconnection of service subsequent to a customer requested disconnection. A normal reconnection requires two trips, which includes one to turn service on and the other to turn service off.

Based on labor and transportation to and from the service territory, staff recommends that the normal reconnection charge should be $104.80 for normal hours and $110.30 for after hours. Staff's calculations are shown below in Table 12-2.

Table 12-2
Normal Reconnection Charge Calculation

Activity	Normal Hours Cost	Activity	After Hours Cost
Labor (Administrative) ($18.00/hr x1/4hr)	$4.50	Labor (Administrative) ($18.00/hr x1/4hr)	$4.50
Labor (Field) ($20.31/hr x 1/4 hr x 2)	$10.16	Labor (Field) ($30.74/hr x 1/4hr x 2)	$15.37
Transportation ($0.535/mile x 80 miles-to/from x 2)	$85.60	Transportation ($0.535/mile x 80 miles-to/from x 2)	$85.60
Mark up for RAFs (4.5%)	$4.51	Mark up for RAFs (4.5%)	$4.75
Total	$104.77	Total	$110.22

Source: Utility's cost justification documentation

Violation Reconnection Charge

The violation reconnection charge is levied prior to reconnection of an existing customer after discontinuance of service for cause. The service performed for violation reconnection requires two trips, which includes one trip to turn off service and a subsequent trip to turn on service once the violation has been remedied. Based on labor and transportation to and from the service territory, staff recommends violation reconnection charges of $104.80 for normal hours and $110.30 for after hours. Staff's calculations are shown below in Table 12-3.

Table 12-3
Violation Reconnection Charge Calculation

Activity	Normal Hours Cost	Activity	After Hours Cost
Labor (Administrative) ($18.00/hr x1/4hr)	$4.50	Labor (Administrative) ($18.00/hr x1/4hr)	$4.50
Labor (Field) ($20.31/hr x 1/4 hr x 2)	$10.16	Labor (Field) ($30.74/hr x 1/4 hr x 2)	$15.37
Transportation ($0.535/mile x 80 miles-to/from) x 2	$85.60	Transportation ($0.535/mile x 80 miles-to/from) x 2	$85.60
Mark up for RAFs (4.5%)	$4.51	Mark up for RAFs (4.5%)	$4.75
Total	$104.77	Total	$110.22

Source: Utility's cost justification documentation.

Premises Visit

The premises visit charge is levied when a service representative visits premises at the customer's request for complaint resolution and the problem is found to be the customer's responsibility. In addition, the premises visit can be levied when a service representative visits a premises for the purpose of discontinuing service for nonpayment of a due and collectible bill, and does not discontinue service because the customer pays the service representative or otherwise makes satisfactory arrangements to pay the bill. A premises visit requires one trip.

Based on labor and transportation to and from the service territory, staff recommends a premises visit charges of $56.50 for normal hours and $60.10 for after hours. Staff's calculations are shown below in Table 12-4.

Table 12-4
Premises Visit Charge Calculation

Activity	Normal Hours Cost	Activity	After Hours Cost
Labor (Administrative) ($18.00/hr x1/4hr)	$4.50	Labor (Administrative) ($18.00/hr x1/4hr)	$4.50
Labor (Field) ($20.31/hr x 1/3 hr)	$6.77	Labor (Field) ($30.74/hr x 1/3 hr)	$10.16
Transportation ($0.535/mile x 80 miles-to/from)	$42.80	Transportation ($0.535/mile x 80 miles-to/from)	$42.80
Mark up for RAFs (4.5%)	$2.43	Mark up for RAFs (4.5%)	$2.59
Total	$56.50	Total	$60.05

Source: Utility's cost justification documentation.

Below, in Table 12-5, are the Utility's requested and staff's recommended miscellaneous service charges.

Table 12-5
Miscellaneous Service Charges

	Current		Staff Recommended	
	Normal Hours	After Hours	Normal Hours	After Hours
Initial Connection Charge	$20.00	$40.00	$56.50	$60.10
Normal Reconnection Charge	$10.00	$20.00	$104.80	$110.30
Violation Reconnection Charge	$20.00	$20.00	$104.80	$110.30
Premises Visit Charge (in lieu of Disconnection)	$10.00	$20.00	$56.50	$60.10

Conclusion

Charlie Creek's miscellaneous service charges should be revised. The charges should be effective on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. In addition, the approved charges 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 13: Should the request of Charlie Creek Utilities, LLC to implement a late payment charge be approved?

Recommendation: Yes. Charlie Creek's request to implement a $5.25 late payment charge should be approved. The utility should be required to file a proposed customer notice and tariff to reflect the Commission-approved charge. The approved charge should be effective 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 10 days after the date of the notice. (Friedrich)

Staff Analysis: The utility is requesting a $5.25 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, F.S. In its cost justification, Charlie Creek's total cost for a late payment charge is $5.28, but Charlie Creek is requesting this charge to be rounded down to $5.25. Since the 1990s, the Commission has approved late payment charges ranging from $2.00 to $7.00.[8] The purpose of this charge is to provide an incentive for customers to make timely payments and to place the cost burden of processing delinquent accounts solely upon those who are cost causers. Staff believes Charlie Creek's requested late payment charge of $5.25 is appropriate. Charlie Creek's labor cost of $4.75 accounts for the office personnel time to search, determine, and process delinquent accounts. The provided justification by Charlie Creek also includes costs for supplies and postage for printing and sending out late payment notices. Charlie Creek's cost basis for the late payment charge is shown below in Table 8-1.

Table 13-1
Late Payment Charge Cost Justification

Activity	Cost
Labor	$4.75
Supplies	$0.06
Postage	$0.47
Total Cost	$5.28

Source: Utility's cost justification documentation

[8]Order Nos. PSC-01-2101-TRF-WS, in Docket No. 011122-WS, issued October 22, 2001, *In re: Tariff filing to establish a late payment charge in Highlands County by Damon Utilities, Inc.*; PSC-08-0255-PAA-WS, in Docket No. 070391-WS, issued April 24, 2008, *In re: Application for certificates to provide water and wastewater service in Sumter County by Orange Blossom Utilities, Inc.*; PSC-09-0752-PAA-WU, in Docket No. 090185-WU, issued November 16, 2009, *In re: Application for grandfather certificate to operate water utility in St. Johns County by Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility.*; 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.*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.*

Based on the above, Charlie Creek's request to implement a $5.25 late payment charge should be approved. The utility should be required to file a proposed customer notice and tariff to reflect the Commission-approved charge. The approved charge should be effective 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 10 days after the date of the notice.

Issue 14: Should the Commission approve Charlie Creek Utilities, LLC's request to implement a convenience charge of $3.43?

Recommendation: Yes. Charlie Creek's request for approval of a convenience charge of $3.43 for customers who opt to pay their bill by debit or credit card should be approved. The convenience charge should be effective on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. In addition, the approved charge 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. (Friedrich)

Staff Analysis: Section 367.091, 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 $3.43 convenience charge and provided cost justification as required by Section 367.091, F.S. The utility's cost analysis breakdown for its requested charge is shown below in Table 7-1.

Table 14-1
Convenience Charge Cost Justification

Activity	Cost
Labor	$0.54
Ink and Paper per Transaction	$0.06
Credit Card Machines	$2.83
Total	$3.43

Source: Utility's cost justification documentation

The charge is designed to recover the cost of supplies, administrative labor, and equipment. Staff believes that the utility's requested charge of a $3.43 convenience charge is reasonable for customers who opt to pay their water bill by debit or credit card. The utility's requested charge benefits the customers by allowing them to expand their payment options. Furthermore, this fee will insure the utility's remaining customers do not subsidize those customers who choose to pay using this option. A convenience charge of $3.43 for Orange Land Utilities, LLC, a sister utility of Charlie Creek, was approved recently by the Commission.[9]

Based on the above, staff recommends that Charlie Creek's request for approval of a convenience charge of $3.43 for customers who opt to pay their bill by debit or credit card should be approved. The convenience charge should be effective on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. In addition, the approved charge 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.

[9] Order No. PSC-17-0092-PAA-WU, in Docket No. 160144-WU, dated March 13, 2017, In re: *Application for transfer of Certificate No. 288-W in Pasco County from Orangeland Water Supply to Orange Land Utilities, LLC.*

Issue 15: Should Charlie Creek Utilities, LLC's request for a $50 meter tampering charge be approved?

Recommendation: Yes. Charlie Creek's request to implement a $50 meter tampering charge should be approved. The charge should be effective for services rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. In addition, the approved charge should not be implemented until staff has approved the proposed customer notice and the notice has been received by the customers. Charlie Creek should provide proof of the date notice was given within 10 days of the date of the notice. (Friedrich)

Staff Analysis: The utility requested a $50 charge to recover the cost of changes in piping on equipment necessary as a result of meter tampering. Rule 25-30.320(2)(i), F.A.C., provides that a customer's service may be discontinued without notice in the event of tampering with the meter or other facilities furnished or owned by the utility. In addition, Rule 25-30.320(2)(j), F.A.C., provides that a customer's service may be discontinued in the event of an unauthorized or fraudulent use of service. The rule allows the utility to require the customer to reimburse the utility an amount reasonably estimated as the deficiency in revenue resulting from the customer's fraudulent use before restoring service.

Pursuant to Rule 25-30.345, F.A.C., a utility may charge a reasonable fee to defray the cost of restoring service that was discontinued for proper cause as specified in Rule 25-30.320, F.A.C. The Commission has previously approved a meter tampering charge of $50 for sister utilities of Charlie Creek. The utility provided the appropriate cost justification pursuant to Section 367.091, F.S. Staff believes this is reasonable and consistent with prior Commission decisions and should be approved. However, the charge is appropriate only where an investigation reveals evidence of meter tampering.

Based on the above, staff recommends that Charlie Creek's request to implement a $50 meter tampering charge should be approved. The charge should be effective for services rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. In addition, the approved charge 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 16: What are the appropriate initial customer deposits for Charlie Creek Utilities, LLC?

Recommendation: The appropriate water initial customer deposit should be $76 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. (Friedrich)

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. Currently, the utility has an initial customer deposit of $65 for the residential 5/8" x 3/4" meter size and two times the average customer bill for all other meter sizes. Based on the staff recommended water rates and post repression average residential demand, the appropriate initial customer deposit should be $76 for water to reflect an average residential customer bill for two months

Staff recommends that the appropriate water initial customer deposit should be $76 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.

Issue 17: Should the existing plant capacity charge of Charlie Creek Utilities, LLC, be discontinued?

Recommendation: Yes. Charlie Creek's existing plant capacity charge should be discontinued. The utility's existing plant capacity charge should be discontinued. (Friedrich)

Staff Analysis: The current service availability charges for Charlie Creek were approved in Docket No. 150186-WU with the utility's original certificate.[10] The utility's service availability charges consist of meter installation charges based on meter size and a plant capacity charge of $750. Rule 25-30.580, F.A.C., establishes guidelines for designing service availability charges. Pursuant to the rule, the maximum amount of contributions-in-aid-of construction (CIAC), net of amortization, should not exceed 75 percent of the total original cost, net of accumulated depreciation, of the Utility's facilities and plant when the facilities and plant are at their designed capacity. The minimum amount of CIAC should not be less than the percentage of such facilities and plant that is represented by the water transmission and distribution system.

Staff's recommended rate base consists of plant improvements and additions by the current owner. The recommended rate base does not include values for the distribution system or CIAC. Therefore, based on staff's recommended rate base the utility's current contribution level is zero percent.

If the utility continues to collect the current plant capacity charge of $750 per equivalent residential connection (ERC), the contribution level would exceed the utility's plant in service balance. Due to the relatively small amount of rate base and the number ERCs that can be served by the utility, staff recommends that the plant capacity charge be discontinued. This would allow the utility to maintain a minimum level of investment on which to earn a return in a future rate proceeding. Based on the above, Charlie Creek's existing plant capacity charge should be discontinued.

---

[10]Order No. PSC-16-0043-PAA-WU, issued January 25, 2016, in Docket No. 150186-WU, In Re: *Application for certificate to operate a water utility in Hardee County by Charlie Creek Utilities, LLC*

Issue 18: Should the utility be required to notify the Commission in writing that it has adjusted its books in accordance with the Commission's decision?

Recommendation: Yes. Charlie Creek should be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision. Charlie Creek should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all applicable NARUC USOA primary accounts 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. (Vogel)

Staff Analysis: Charlie Creek should be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision. Charlie Creek 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 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 19: Should this docket be closed?

Recommendation: No. Except for the granting of temporary rates in the event of protest, the four year rate reduction, and proof of adjustments of books and records, which are final actions 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 will 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, and the utility has provided staff with proof that the adjustments for all the applicable NARUC USOA primary accounts have been made. Once the above actions are completed this docket will be closed administratively. (Tan)

Staff Analysis: Except for the granting of temporary rates in the event of protest, the four year rate reduction, and proof of adjustments of books and records, which are final actions 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 will be issued 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 will 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, and the utility has provided staff with proof that the adjustments for all the applicable NARUC USOA primary accounts have been made. Once the above actions are completed this docket will be closed administratively.

CHARLIE CREEK UTILITIES, LLC **SCHEDULE NO. 1-A**
TEST YEAR ENDED 12/31/15 **DOCKET NO. 160143-WU**
SCHEDULE OF WATER RATE BASE

DESCRIPTION	BALANCE PER UTILITY	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$3,044	$4,349	$7,393
UTILITY PLANT IN SERVICE- ALLOCATED	0	1,518	1,518
LAND & LAND RIGHTS	12,050	0	12,050
NON-USED AND USEFUL COMPONENTS	0	(1,912)	(1,912)
CIAC	0	0	0
ACCUMULATED DEPRECIATION	(179)	(36)	(215)
ACCUMULATED DEPRECIATION- ALLOCATED	0	(37)	(37)
AMORTIZATION OF CIAC	0	0	0
WORKING CAPITAL ALLOWANCE	0	7,820	7,820
WATER RATE BASE	$14,915	$11,702	$26,617

CHARLIE CREEK UTILITIES, LLC TEST YEAR ENDED 12/31/15 ADJUSTMENTS TO RATE BASE		SCHEDULE NO. 1-B DOCKET NO. 160143-WU
		WATER
	UTILITY PLANT IN SERVICE	
1.	To reflect the correct records of plant in service.	$6,976
2.	To include pro forma plant additions.	4,765
3.	Averaging adjustment.	(7,393)
	Total	$4,349
	UTILITY PLANT IN SERVICE – ALLOCATED	
1.	To allocated common plant from FUS1.	$1,588
2.	Averaging adjustment.	(69)
	Total	$1,518
	NON-USED AND USEFUL PLANT	
1.	To reflect non-used and useful plant.	($2,025)
2.	To reflect non-used and useful Accumulated Depreciation.	112
	Total	($1,912)
	ACCUMULATED DEPRECIATION	
1.	Depreciation adjustment per Rule 25-30.140 F.A.C.	($98)
2.	To reflect pro forma plant replacements depreciation.	(152)
3.	Averaging adjustment.	215
	Total	($36)
	ACCUMULATED DEPRECIATION – ALLOCATED	
1.	To reflect the appropriate Accumulated Depreciation – Allocated.	($58)
2.	Averaging adjustment.	21
	Total	($37)
	WORKING CAPITAL ALLOWANCE	
	To reflect 1/8 of test year O&M expenses.	$7,820

CHARLIE CREEK UTILITIES, LLC **SCHEDULE NO. 2**
TEST YEAR ENDED 12/31/15 **DOCKET NO. 160143-WU**
SCHEDULE OF CAPITAL STRUCTURE

	CAPITAL COMPONENT	PER UTILITY	SPECIFIC ADJUST-MENTS	BALANCE BEFORE PRO RATA ADJUSTMENTS	PRO RATA ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON EQUITY	$15,931	($15,931)	$0	$0	$0	0.00%	11.16%	0.00%
2.	RETAINED EARNINGS	0	0	0	0	0	0.00%	0.00%	0.00%
3.	LONG-TERM DEBT	8,660	0	8,660	16,001	24,661	92.65%	6.62%	6.13%
4.	SHORT-TERM DEBT	0	0	0	0	0	0.00%	0.00%	0.00%
5.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
6.	CUSTOMER DEPOSITS	2,555	(599)	1,956	0	1,956	7.35%	2.00%	0.15%
7.	TOTAL	$27,146	($16,530)	$10,616	$14,867	$26,617	100.00%		6.28%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	10.16%	12.16%
OVERALL RATE OF RETURN	6.28%	6.28%

CHARLIE CREEK UTILITIES, LLC TEST YEAR ENDED 12/31/15 SCHEDULE OF WATER OPERATING INCOME					SCHEDULE NO. 3-A DOCKET NO. 160143-WU
	TEST YEAR PER UTILITY	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1. **OPERATING REVENUES**	$68,259	($2,638)	$65,621	$9,697 14.78%	$75,318
OPERATING EXPENSES:					
2. OPERATION & MAINTENANCE	$65,460	($2,903)	$62,557	$0	$62,557
3. DEPRECIATION (NET)	179	387	566	0	566
4. AMORTIZATION	0	0	0	0	0
5. TAXES OTHER THAN INCOME	5,993	(490)	5,503	436	5,939
6. INCOME TAXES	0	0	0	0	0
7. **TOTAL OPERATING EXPENSES**	$71,632	($3,006)	$68,626	$436	$69,063
8. **OPERATING INCOME/(LOSS)**	($3,373)		($3,005)		$6,256
9. **WATER O&M EXPENSES**	$65,460		$62,557		$62,557
10. **OPERATING MARGIN**					10.00%

CHARLIE CREEK UTILITIES, LLC TEST YEAR ENDED 12/31/15 ADJUSTMENTS TO OPERATING INCOME		SCHEDULE NO. 3-B DOCKET NO. 160143-WU Page 1 of 3
		WATER
	OPERATING REVENUES	
1.	To reflect the appropriate test year revenues.	($3,926)
2.	To adjust miscellaneous revenues for test year.	1,288
	Subtotal	($2,638)
	OPERATION AND MAINTENANCE EXPENSES	
1.	Salaries and Wages – Employees (601)	
	a. To include the new salary adjustment with proper allocation.	$51
2.	Salaries and Wages – Officers (603)	
	b. To include the new salary adjustment with proper allocation.	($398)
3.	Employee Pension & Benefits (604)	
	a. To reflect appropriate amount of benefit expense.	($260)
	b. To reflect new allocations.	122
	Subtotal	($138)
4.	Purchased Power (615)	
	a. To remove an out of period expense.	($18)
	b. To include a previously unrecorded expense.	392
	Subtotal	$374
5.	Fuel for Purchased Power (616)	
	To remove undocumented expenses.	($496)
6.	Chemicals (618)	
	a. To remove a duplicate expense.	($165)
7.	Materials & Supplies (620)	
	a. To remove capitalized expenses relating to pump repairs.	($1,144)
	b. To include an invoice not previously included.	369
	c. To reflect new allocations.	155
	Subtotal	($620)

CHARLIE CREEK UTILITIES, LLC TEST YEAR ENDED 12/31/15 ADJUSTMENTS TO OPERATING INCOME	SCHEDULE NO. 3-B DOCKET NO. 160143-WU Page 2 of 3
	WATER
8. Contractual Services - Other (636)	
a. To remove capitalized expenses discussed in Table 6-2.	($590)
b. To capitalize the replacement of a control box.	(508)
c. To capitalize the refurbishment of well pumping equipment.	(2,156)
d. To capitalize the installation of a 2-inch flush point.	(1,800)
e. To capitalize the installation of a starter for a well.	(418)
f. To remove an invoice duplicated in two months.	(528)
g. To include an allocated invoice not previously included.	33
h. To reflect the new allocations.	76
i. To reflect an increase in water operations expense of $25/month.	300
j. To include pro forma replacement of two check valves.	86
k. To include pro forma sampling expense after main repair.	390
l. To include pro forma main repair.	400
m. To include pro forma piping supplies for main repair.	216
n. To include pro forma engineering analysis for calcification.	839
Subtotal	($3,660)
9. Rent Expense (640)	
a. To reflect the appropriate allocated expenses from FUS1.	($104)
b. To reflect the new allocations.	89
Subtotal	($15)
10. Transportation Expense (650)	
a. To reflect the appropriate expenses for the test year.	$295
b. To remove a truck loan.	(122)
c. To remove unsupported allocated expenses from FUS1.	(27)
d. To reclassify fuel expenses from Account 619.	496
e. To reflect the new allocations.	151
Subtotal	$793
11. Insurance Expense (655)	
To remove health insurance premiums included in Account 604.	(301)
12. Regulatory Commission Expense (665)	
a. To include rate case expense.	$315
b. To include amortized filing and legal fees from the transfer.	222
Subtotal	$536
13. Bad Debt Expense (670)	
To reflect the appropriate bad debt expense for the test year.	$1,615

	CHARLIE CREEK UTILITIES, LLC TEST YEAR ENDED 12/31/15 ADJUSTMENTS TO OPERATING INCOME	SCHEDULE NO. 3-B DOCKET NO. 160143-WU Page 3 of 3
		WATER
14.	Miscellaneous Expense (675)	
	a. To remove bank fees.	($105)
	b. To reallocate filing fees to Acct. 665.	(750)
	c. To remove purchase fee for the utility.	(100)
	d. To include fees for customer's convenience fees.	758
	e. To remove interest payments for a loan.	(407)
	f. To reallocate expenses relating to original certification to Acct. 665.	(137)
	g. To include expenses relating to an annual customer meeting.	199
	h. To remove unsupported expenses.	(123)
	i. To reflect the appropriate allocation of expenses.	17
	j. To remove equipment expenses included in Acct. 640.	(179)
	k. To reflect the appropriate amount of utility expenses from FUS1.	(170)
	l. To include amortized closing cost of a loan, amortized over five years.	20
	m. To reflect the new allocations.	279
	n. To include pro forma roof repair.	219
	Subtotal	($479)
	TOTAL OPERATION & MAINTENANCE ADJUSTMENTS	($2,903)
	DEPRECIATION EXPENSE	
1.	To reflect test year depreciation calculated per Rule 25-30.140, F.A.C.	$98
2.	To reflect appropriate depreciation expense from allocated plant.	249
3.	To include depreciation expense for pro forma plant.	152
4.	To reflect used and useful depreciation expense.	(112)
	Total	$387
	TAXES OTHER THAN INCOME	
1.	To correct property tax expense.	($4,278)
2.	To reflect payroll taxes.	1,251
3.	To reflect the appropriate test year RAFs.	2,953
4.	To reflect the property tax for pro forma plant and test year additions.	74
5.	To reflect non-used and useful property tax.	(490)
	Total	($490)

CHARLIE CREEK UTILITIES, LLC TEST YEAR ENDED 12/31/15 ANALYSIS OF WATER OPERATION AND MAINTENANCE EXPENSE			SCHEDULE NO. 3-C DOCKET NO. 160143-WU
	TOTAL PER UTILITY	STAFF ADJUST-MENTS	TOTAL PER STAFF
(601) SALARIES AND WAGES - EMPLOYEES	$12,876	$51	$12,927
(603) SALARIES AND WAGES - OFFICERS	5,700	(398)	5,302
(604) EMPLOYEE PENSIONS AND BENEFITS	1,838	(138)	1,700
(610) PURCHASED WATER	0	0	0
(615) PURCHASED POWER	3,790	374	4,164
(616) FUEL FOR POWER PRODUCTION	496	(496)	0
(618) CHEMICALS	1,994	(165)	1,829
(620) MATERIALS AND SUPPLIES	2,926	(620)	2,306
(630) CONTRACTUAL SERVICES - BILLING	0	0	0
(631) CONTRACTUAL SERVICES - PROFESSIONAL	1,592	0	1,592
(633) CONTRACTUAL SERVICES – TESTING	5,532	0	5,532
(636) CONTRACTUAL SERVICES - OTHER	16,705	(3,660)	13,045
(640) RENTS	1,258	(15)	1,243
(650) TRANSPORTATION EXPENSE	1,309	793	2,102
(655) INSURANCE EXPENSE	1,935	(301)	1,634
(665) REGULATORY COMMISSION EXPENSE	0	536	536
(670) BAD DEBT EXPENSE	350	1,615	1,965
(675) MISCELLANEOUS EXPENSE	7,159	(479)	6,680
	$65,460	($2,903)	$62,557

CHARLIE CREEK UTILITIES, LLC. TEST YEAR ENDED 12/31/15 MONTHLY WATER RATES			SCHEDULE NO. 4 DOCKET NO. 160143-WU
	UTILITY CURRENT RATES	**STAFF RECOMMENDED RATES**	**4 YEAR RATE REDUCTION**
Residential and General Service			
Base Facility Charge by Meter Size			
5/8"X3/4"	$15.00	$15.89	$0.14
3/4"	$22.50	$23.84	$0.21
1"	$37.50	$39.73	$0.35
1-1/2"	$75.00	$79.45	$0.71
2"	$120.00	$127.12	$1.13
3"	$240.00	$254.24	$2.26
4"	$375.00	$397.25	$3.54
6"	$750.00	$794.50	$7.07
Charge per 1,000 gallons - Residential			
0 - 3,000 gallons	$3.50	N/A	N/A
Over 3,000 gallons	$4.50	N/A	N/A
0 - 4,000 gallons	N/A	$4.72	$0.04
Over 4,000 gallons	N/A	$5.90	$0.05
Charge per 1,000 gallons - General Service		$5.19	$0.05
0 – 3,000 gallons	$3.50	N/A	
Over 3,000 gallons	$4.50	N/A	
Typical Residential 5/8" x 3/4" Meter Bill Comparison			
4,000 Gallons	$30.00	$34.77	
6,000 Gallons	$39.00	$46.57	
8,000 Gallons	$48.00	$58.57	