BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

Docket No. 150009-EI

In re: Fuel and Capacity Clause

Docket No. 150001-EI

Submitted for Filing: March, 2 2015

DUKE ENERGY FLORIDA, INC.'S PETITION TO END THE FIXED LEVY NUCLEAR PROJECT RATE COMPONENT OF THE NUCLEAR COST RECOVERY CLAUSE CHARGES CONSISTENT WITH THE REVISED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT, SECTION 366.93, FLORIDA STATUTES, AND RULE 25-6.0423, F.A.C.

Duke Energy Florida, Inc. ("DEF" or the "Company") petitions the Florida Public Service Commission ("PSC" or the "Commission") to approve deferral of collection of the approximate \$54 million currently involved in litigation until such time as the litigation is finalized, approve annual collection of or accrual until such time as the litigation is finalized of the carrying costs on the deferred amount as required under Section 366.93, Florida Statutes, and to end the fixed Levy Nuclear Project ("LNP") rate component of the Company's Nuclear Cost Recovery Clause ("NCRC") charges, set at \$3.45/1,000 kWh (for the residential customer) in the Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") approved by the Commission in Order No. PSC-13-0598-FOF-EI, included in support of this Petition as Attachment A, and set the Levy portion of the bill to zero for the remainder of 2015 effective with the first monthly billing cycle that occurs at least 10 days after Commission approval, and to approve the Revised Tariff sheet included as Attachment B to this Petition which reflects this change. DEF's Petition is consistent with the 2013 Settlement Agreement, the nuclear cost recovery statute, Section 366.93, Florida Statutes, and the Commission's nuclear cost recovery clause rule, Rule 25-6.0423, F. A. C.

I. PRELIMINARY INFORMATION.

1. The Petitioner's name and address are:

Duke Energy Florida, Inc. 299 1st Avenue North St. Petersburg, Florida 33701

2. Any pleading, motion, notice, order, or other document required to be served upon DEF or filed by any party to this proceeding should be served upon the following individuals:

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II. PRIMARILY AFFECTED UTILITY.

3. DEF is the utility primarily affected by the proposed request for cost recovery. DEF is an investor-owned electric utility, regulated by the Commission pursuant to Chapter 366, Florida Statutes, and is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy"). The Company's principal place of business is located at 299 1st Ave. N., St. Petersburg, Florida 33701.

4. DEF serves approximately 1.7 million retail customers in Florida. Its service area comprises approximately 20,000 square miles in 29 of the state's 67 counties, encompassing the densely populated areas of Pinellas and western Pasco Counties and the greater Orlando area in Orange, Osceola, and Seminole Counties. DEF supplies electricity at retail to approximately 350 communities and at wholesale to Florida municipalities, utilities, and power agencies in the State of Florida.

5. This Petition represents an original pleading and is not in response to any proposed action by the Commission. Accordingly, the Petitioner is not responding to any proposed agency action.

III. DEF'S PETITION IS CONSISTENT WITH THE 2013 SETTLEMENT AGREEMENT, SECTION 366.93(6), FLORIDA STATUTES, AND RULE 25-6.0423(7), F. A. C.

6. On August 1, 2013, DEF petitioned the Commission to approve the 2013 Settlement Agreement. The Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphates ("White Springs") executed the 2013 Settlement Agreement with DEF the day before the petition was filed and supported Commission approval of the 2013 Settlement Agreement. The 2013 Settlement Agreement replaced and supplanted the January 20, 2012 Stipulation and Settlement

Agreement (the "2012 Settlement Agreement."). Both the 2012 Settlement Agreement and the 2013 Settlement Agreement addressed, among other things, cost recovery for the LNP through the NCRC under Section 366.93 and Rule 25-6.0423.

7. The rate for the LNP component of the NCRC charges was fixed at a rate (\$3.45/1,000 kWh for the residential customer) that would recover an estimated remaining LNP balance of approximately \$350 million (retail), and carrying costs on that balance, over five years as estimated in the 2012 Settlement Agreement. See ¶11, 2013 Settlement Agreement. As expressed in the 2013 Settlement Agreement, DEF and the parties to that Agreement expected that the established LNP rate would allow DEF to recover its actual LNP costs pursuant to Section 366.93 and Rule 25-6.0423 through the NCRC estimated at the \$350 million remaining LNP balance at the fixed rate over that estimated five year period.

8. At the time of the 2012 Settlement Agreement, the Engineering, Procurement, and Construction ("EPC") Agreement for the LNP between DEF and WEC had been suspended, but DEF was continuing to pursue construction of the LNP. By the time of the 2013 Settlement Agreement, DEF had elected not to complete construction of the LNP under Section 366.93(6) and Rule 25-6.0423(7), as amended, and DEF planned to terminate the EPC Agreement at the earliest reasonable and prudent time. DEF terminated the EPC Agreement in January 2014.

9. After DEF terminated the EPC Agreement, WEC presented DEF with claims for additional costs for the LNP that were never billed to DEF. DEF denied any liability to WEC for these alleged additional LNP costs and, as a result, DEF sued WEC under the EPC Agreement in March 2014 in federal court in North Carolina. DEF is entitled to recover all reasonable and prudent costs incurred as a result of the

termination of the LNP and the LNP EPC Agreement, including the potential future costs (or refunds) resulting from the litigation with WEC. In paragraph 12c, the 2013 Settlement Agreement expressly provides that DEF "shall" be permitted to recover "all" costs "associated with the termination of the LNP, including but not limited to the LNP EPC Agreement, through the NCRC" consistent with Section 366.93 and Rule 25-6.0423.¹ ¶12c, 2013 Settlement Agreement. In paragraph 10, the parties to the 2013 Settlement Agreement expressed their support for the termination of the EPC Agreement and the recovery of the costs associated with "those [termination] activities" through the NCRC as set forth in the 2013 Settlement Agreement. ¶10, 2013 Settlement Agreement. This is consistent with DEF's right to recover its prudent LNP costs under Section 366.93(6) and Rule 25-6.0423(7). §366.93(6), <u>Fla. Stats.</u>; Rule 25-6.0423(7), F.A.C.

10. In that litigation, WEC has claims against DEF for the additional costs it never billed to DEF, and DEF has claims against WEC for refunds of approximately \$54 million previously paid to WEC for LNP long lead equipment ("LLE") for which WEC never commenced manufacturing because the EPC Agreement was suspended. These LNP costs were incurred in 2008 and 2009. DEF's activities related to these payments, and these LLE payments, were previously determined to be prudent by the Commission. See p. 10, Order No. PSC-14-0617-FOF-EI, Docket No. 140009-EI. See also Order No. PSC-09-0783-FOF-EI, Docket No. 090009-EI; Order No. PSC-11-0095-FOF-EI, Docket No. 100009-EI.

¹ There is an exception for LNP costs otherwise addressed in the 2013 Settlement Agreement. This is a reference to DEF's agreement to remove certain LNP costs from recovery through the NCRC for recovery through other mechanisms. For example, DEF agreed to remove LNP COL-related costs after 2013 from recovery through the NCRC and to treat them as construction work in progress for potential future recovery in the event DEF uses the LNP COL. See ¶12b, 2013 Settlement Agreement.

11. Indeed, the Commission reaffirmed the prudence of DEF's actions with respect to these milestone LLE payments. In Order 14-0617, the Commission stated, "we observe that there is no dispute regarding the prudence of DEF's original activities when it made the scheduled milestone payment in 2008 and 2009." Order No. PSC-14-0617-FOF-EI, at p. 10. The Commission also stated that its prior decision of prudence could not and would not be revisited absent a showing of fraud, perjury, or intentional withholding of key information, and no such showing was made. Id. at pp. 10-11. The Commission, nevertheless, did find that there was a reasonable expectation that DEF will recover the amount of these prior LLE payments from WEC and, accordingly, directed DEF to make a downward adjustment of \$54 million to DEF's projected 2015 LNP expenses. Notably, the Commission recognized that its decision "must comply with the laws of this state as well as the rules established by this Commission." The Commission further indicated that "DEF will continue to account for this adjustment **consistent with Section 366.93, F.S.**" Id. at p. 12 (emphasis added).

12. Section 366.93(6), which applies to the LNP because DEF has elected not to continue construction, provides that DEF is allowed to recover its prudent costs and further provides: "The utility shall recover such costs through the capacity cost recovery clause over a period equal to the period during which the costs were incurred or 5 years, whichever is greater. The unrecovered balance during the recovery period will accrue interest at the utility's weighted average cost of capital as reported in the commission's earnings surveillance reporting requirement for the prior year." §366.93(6), <u>Fla. Stats.</u> Any balance deferred from collection, therefore, would accrue carrying costs, or interest, consistent with Section 366.93(6). There are two options to account for the carrying charges. The first is for DEF to collect the carrying charges on

an ongoing basis through the NCRC, until the WEC litigation has concluded. The second option is for DEF to accumulate carrying costs until the WEC litigation has concluded, at which time DEF would return to the PSC to collect the deferred carrying cost if DEF is unable to collect those costs in the WEC litigation. DEF is indifferent as to the two options, since both options comply with the statutory requirement that DEF be entitled to collect carrying charges on prudently incurred costs.

13. Under the circumstances, DEF has determined that if DEF continues to collect the LNP costs at the LNP fixed rate, which DEF has the right to do under the 2013 Settlement Agreement, and defers collection of the approximate \$54 million, DEF will be over-recovered commencing by the end of May 2015 or around November if the \$54 million is collected, and that over-recovery would continue to grow until the litigation between DEF and WEC is resolved. That litigation is currently scheduled for trial in the first guarter of 2016 with any final resolution at some point after that date. DEF will not know what that resolution is --- and what the final LNP costs (or refunds) for a final trueup will be --- until that litigation is resolved. To prevent this over-recovery, while still preserving DEF's right to collect all prudent LNP and LNP EPC Agreement termination costs consistent with the 2013 Settlement Agreement, Section 366.93(6), and Rule 25-6.0423(7), DEF proposes to end the fixed LNP rate effective with the first monthly billing cycle that occurs at least 10 days after the Commission approval of this request, and defer the final true-up of the LNP costs until that litigation is resolved.² This proposal shifts the recovery of the LNP costs from customers in the current period at the fixed

² Ending the fixed LNP rate component of the Company's NCRC charges authorizes DEF to increase at that point or some later point in time its retail base rate charges by the annualized projected revenue requirement for the Crystal River Unit 3 ("CR3") nuclear power plant. See ¶5e, 2013 Settlement Agreement.

rate for recovery of the estimated LNP costs to recovery from customers in the period when the final LNP costs are known after the litigation is resolved and there can be a final true-up of the LNP costs. DEF would come back to the Commission, after the conclusion of the litigation, to true up any remaining LNP costs (if needed) at that time. See Attachment C showing original and revised Capacity Cost Recovery ("CCR") Factors.

By proposing to end the LNP cost recovery charge at this time, DEF does 14. not waive its right under the 2013 Settlement Agreement, Section 366.93(6), and Rule 25-6.0423(7) to seek any additional LNP costs that may result from the pending litigation against WEC in federal court in North Carolina or, if the rate ends, to seek any unrecovered balance remaining in its May 1, 2015 filing in accordance with Section 366.93(6), and Rule 25-6.0423(7).³ OPC, FIPUG, FRF, and White Springs in fact agreed in their joint brief in the 2014 NCRC proceeding that DEF should be permitted to come back to the Commission at the conclusion of the WEC litigation and demonstrate the recovery from customers of the resulting LNP costs consistent with the requirements of Section 366.93 and Rule 25-6.0423. See Joint Intervenors' Post-Hearing Statement of Positions and Post-Hearing Brief (Duke Energy Florida), Docket No. 140009-El, p. 12, filed August 18, 2014. Said differently, no party can use DEF's proposal to end the LNP cost recovery charge, if accepted by the Commission, as an argument that DEF has waived its right to later seek any additional costs arising out of the WEC litigation. However, all parties reserve their right to later make any other arguments with respect

³ To be clear, this Petition is intended to address ending the fixed portion of the Levy rate only and the true-up of the \$54 million, including associated carrying costs, and any costs that may result from the WEC litigation until following the conclusion of the WEC litigation. This Petition is not intended to address DEF's recovery of any 2014, 2015 or 2016 actual or projected costs or unrecovered balance which DEF petitions for recovery in the 2015 NCRC docket pursuant to Section 366.93(6) and Rule 25-6.0423(7).

to whether DEF should or should not recover WEC litigation costs consistent with the 2013 Settlement Agreement, Section 366.93(6), and Rule 25-6.0423(7).

IV. DEF'S REQUESTED RELIEF.

15. For the reasons provided above, DEF's Petition is consistent with the 2013 Settlement Agreement, Section 366.93(6), and Rule 25-6.0423(7). Accordingly, DEF petitions the Commission to approve deferral of collection of the approximate \$54 million currently involved in WEC litigation until such time as the litigation is finalized, approve annual collection of or accrual until such time as the WEC litigation is finalized of the carrying costs on the deferred amount as required under Section 366.93, Florida Statutes, to end the fixed LNP rate component with the first monthly billing cycle that occurs at least 10 days after Commission approval of this Petition and set the Levy portion of the bill to zero for the remainder of 2015, conditioned upon the existing understanding that DEF can return to the Commission, and is not waiving its right to return to the Commission, at the conclusion of the litigation with WEC to recover any LNP costs resulting from that litigation subject to Section 366.93(6) and Rule 25-6.0423(7), and to approve the Revised Tariff sheet included as Attachment B to this Petition which reflects this change.

V. DISPUTED ISSUES OF MATERIAL FACT.

16. DEF is not aware at this time that there will be any disputed issues of material fact related to this Petition. DEF has demonstrated in this Petition that DEF should be authorized by the Commission to end the LNP fixed rate component of the NCRC charges until the resolution of the litigation between DEF and WEC to determine the costs, if any, associated with termination of the LNP and the LNP EPC Agreement and to recover such costs in a final true-up of LNP costs consistent with Section

366.93(6), and Rule 25-6.0423(7). If the Commission does not grant DEF's requested relief, DEF will continue to collect the LNP fixed rate component of the NCRC charges as DEF has the right to do under the 2013 Settlement Agreement until all estimated LNP costs are collected from customers and there is a final true-up of LNP costs.

VI. CONCLUSION.

17. Approval of DEF's Petition is consistent with the 2013 Settlement Agreement, Section 366.93(6), and Rule 25-6.0423(7).

WHEREFORE, for all of the reasons provided in this Petition, DEF respectfully requests that the Commission grant its Petition and enter an Order approving the relief requested.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic and U.S. Mail this 2nd day of March, 2015.

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REVISED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause	Docket No. 130009-EI
In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.	Docket No. 100437-EI
In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 130001-EI
In re: Environmental cost recovery clause	Docket No. 130007-EI
In re: Petition of Progress Energy Florida, Inc. to approve establishment of a regulatory asset and associated three-year amortization schedule for costs associated with PEF's previously approved thermal discharge compliance project.	Docket No. 130091-EI
In re: Petition of Duke Energy Florida, Inc. for limited proceeding to approve Revised and Restated Stipulation and Settlement Agreement, including certain Rate Adjustments.	Docket No

REVISED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

WHEREAS, Duke Energy Florida, Inc. ("DEF" or the "Company"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate ("White Springs"), (collectively referenced as the "Parties"), previously resolved certain issues in a Stipulation and Settlement Agreement (the "2012 Settlement Agreement"), dated January 20, 2012, that was approved by the Florida

Public Service Commission ("PSC" or the "Commission") in Order No. PSC-12-0104-FOF-EI, issued on March 8, 2012 in Docket No. 120022-EI, as amended by Order No. PSC-12-0104A-FOF-EI; and

WHEREAS, the Parties recognize that the 2012 Settlement Agreement did not resolve all issues, including, among others, issues related to the Company's Crystal River Unit 3 ("CR3") insurance claims with the Nuclear Electric Insurance Limited ("NEIL"), pending at the time of the execution and approval of the 2012 Settlement Agreement, the costs associated with repair activities subsequent to the Commission's approval of the 2012 Settlement Agreement in February 2012, the costs associated with the CR3 extended power uprate ("EPU") incurred in 2012 and beyond, and that these and other remaining issues in the above-referenced Commission dockets may have substantial consequences for DEF, consumers and investors alike, and that settlement of the various positions of the Parties on these issues is in the best interests of the Parties, the interests they represent, and the public; and

WHEREAS, in February 2013, the Company announced that it had decided to retire CR3 rather than attempt further repairs to the unit and that it had reached a settlement of all pending CR3-related insurance claims with NEIL; and

WHEREAS, on February 25, 2013, OPC and FRF filed their Petition for an Order Investigating the Prudence of Progress Energy Florida's Efforts to Obtain NEIL Insurance Proceeds, Establishing that Customers Have No Responsibility for Costs of Certain Abandoned CR3 Uprate Costs That are No Longer Subject to the Nuclear Cost Recovery Mechanism, and Delineating Parameters of CR3 "Regulatory Asset" (the "OPC/FRF Petition"); and

WHEREAS, the Parties agreed that in light of those decisions and actions that it is in the public interest to attempt to resolve all remaining rate-making issues in Docket No. 100437-EI, as well as additional matters including those that relate to or arise from the retirement of the generation capacity associated with CR3, while distinguishing and reserving the Parties' respective rights concerning DEF's future decisions, actions, and expenditures from the matters that are finally settled; and

WHEREAS, the Parties have reached a resolution as set forth in this Revised and Restated 2013 Stipulation and Settlement Agreement ("Revised and Restated Settlement Agreement"), dated July 31, 2013; and

WHEREAS, unless the context clearly indicates otherwise, the term Party or Parties means a signatory to this Revised and Restated Settlement Agreement, and Intervenor Parties means collectively OPC, FIPUG, FRF, and White Springs; and

WHEREAS, settlement of the issues in the Revised and Restated Settlement Agreement promotes administrative efficiency and avoids the time, expense, and uncertainty associated with resolving these issues in the above-referenced Commission dockets; and

WHEREAS, the Parties further recognize and agree that this Revised and Restated Settlement Agreement determines, in a comprehensive manner, the issues related to the circumstances surrounding the delaminations and repairs of CR3, the decision to retire CR3, the decision to settle the CR3 insurance claims with NEIL, issues involving the CR3 EPU project, and certain future actions regarding the Levy Nuclear Project as described herein, and resolves uncertainties related to these issues that may

adversely affect the Company and its customers including the future need for additional power generation brought about by the retirement of CR3 and other issues; and

WHEREAS, nothing in this Revised and Restated Settlement Agreement is an admission of liability, imprudence, or fault.

NOW, THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby agree and stipulate as follows:

1. This Revised and Restated Settlement Agreement incorporates, as set forth herein under the same subject headings, the surviving terms and conditions of the 2012 Settlement Agreement and its Exhibits and, as a result, this Revised and Restated Settlement Agreement replaces and supplants the 2012 Settlement Agreement. Terms and conditions of the 2012 Settlement Agreement that are not expressly included in this Revised and Restated Settlement Agreement are extinguished and are of no further effect.

2. The provisions of this Revised and Restated Settlement Agreement will become effective upon approval by final Commission vote (the "Effective Date"), and continue through the last billing cycle for December 2018 (the "Term"), unless otherwise specified in this Revised and Restated Settlement Agreement.

3. The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this Revised and Restated Settlement Agreement. No waiver or release is given orally or by implication, and the only waivers and releases agreed to by any Party to this Revised and Restated Settlement Agreement are those that are expressly stated herein. The failure to specifically set forth a reservation of right(s) clause or an affirmative reservation of right(s) in another portion of this Revised

and Restated Settlement Agreement is not, and shall not, be interpreted as a waiver of any right(s) otherwise reserved by the Intervenor Parties.

<u>CR3:</u>

It is the intent of the Parties and the Parties stipulate that this Revised 4 and Restated Settlement Agreement resolves the issues in Docket No. 100437-EI on the terms and conditions set forth herein. The Intervenor Parties fully and forever waive, release, discharge, and otherwise extinguish any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the reasonableness or prudence of any DEF action, including inaction, or decision, of any kind, type, or nature, both prior to and subsequent to the Implementation Date of the 2012 Settlement Agreement arising out of, or related or in any way connected to, directly or indirectly, the issues in Docket No. 100437-El, except for issues 11, 24, 35, 36, and 37, as set forth in Exhibit 13 to this Revised and Restated Settlement Agreement. Those issues 11, 24, 35, 36, and 37 ("Preserved Issues") will be addressed in future proceedings before the Commission as contemplated in this Revised and Restated Settlement Agreement consistent with Exhibit 10 to this Revised and Restated Settlement Agreement. Absent evidence of fraud, intentional misrepresentation, or intentional misconduct by DEF, the Intervenor Parties cannot and will not challenge in any PSC or judicial proceeding the prudence of DEF's actions in connection with the issues listed in Exhibit 13 to this Revised and Restated Settlement Agreement that are not Preserved Issues from Docket No. 100437-EI. Therefore, it is the intent of the Parties and they agree that, within five (5) days of the Effective Date of the Revised and Restated Settlement Agreement, they consent to DEF filing a motion to dismiss, with

prejudice, the OPC/FRF Petition, and to close Docket No. 100437-El, subject to the preservation of issues 11, 24, 35, 36, and 37, as set forth in Exhibit 13 to this Revised and Restated Settlement Agreement. These issues will be addressed in future proceedings before the Commission consistent with Exhibit 10 to this Revised and Restated Settlement Agreement.

5. Pursuant to the 2012 Settlement Agreement, DEF placed CR3 in а. extended cold shutdown effective January 1, 2011, at which time depreciation and other accruals were suspended and/or reversed until the unit was retired. DEF removed CR3 from rate base, and the revenue requirements for CR3 were excluded from the rates established herein effective the first billing cycle for January 2013. Effective with CR3's removal from customer rates and until DEF's decision to retire CR3, an accrual of a carrying charge equivalent to that authorized in PSC Order No. PSC-10-0604-PAA-EI (which rate is 7.44 percent ("%"), as shown in Exhibit 2 to this Revised and Restated Settlement Agreement), on CR3 investments removed from customer rates was allowed. The ratemaking treatment of placing CR3 in extended cold shutdown was based on the unprecedented and complex nature of the totality of the circumstances addressed in the 2012 Settlement Agreement and in this Revised and Restated Settlement Agreement and shall have no precedential effect in any future Commission proceeding.

b. Upon DEF's decision to retire CR3, and until inclusion of the CR3 investments and related costs in customer rates, except as provided for in paragraph 5c, DEF is authorized to implement deferral accounting through the creation of a regulatory asset or assets to address the capital cost amounts and revenue

requirements associated with all CR3-related costs (including, but not limited to, actual depreciation/amortization expense, operation and maintenance ("O&M") expense, property taxes, and cost of capital return) and regulatory liabilities to address O&M costs, which may be funded from the Nuclear Decommissioning Trust or obviated by ceasing operations, and property taxes which may no longer be assessed (for example, a type of regulatory liability would entail Retail Nuclear O&M 2010 MFR C-4 \$90 million (per year) (See Exhibit 7 to this Revised and Restated Settlement Agreement) less actual incurred O&M deferred as a regulatory asset). These amounts, together with the net plant balance of CR3 and other CR3-related investments, are recorded in various FERC accounts, and are collectively referred to herein as the "CR3 Regulatory Asset," the components of which are shown on Exhibit 10 to this Revised and Restated Settlement Agreement. The cost of capital return or carrying charge applicable to the CR3 Regulatory Asset as of February 5, 2013 will be based on the approved AFUDC rate with the cost of equity set to 70% of the then Commission authorized rate (See Exhibit 3 to this Revised and Restated Settlement Agreement); it being the intent of the Parties that whenever the Commission authorizes a change (whether an increase or a decrease) to DEF's return on equity in the future, the 70% formula in this paragraph will apply to any remaining CR3 investments, the balance of which is recorded in the CR3 Regulatory Asset. The Parties agree that the balance of the CR3 Regulatory Asset pursuant to this Revised and Restated Settlement Agreement shall not be used as the basis for interim rate relief or included for purposes of determining whether DEF's rate of return on equity ("ROE") has fallen below 9.5% so as to trigger DEF's right to seek a base rate increase pursuant to paragraph 23 of this Revised and Restated Settlement

Agreement.

c. Effective January 1, 2014, DEF will cease the deferral accounting of regulatory assets and liabilities provided for in paragraph 5b above in this Revised and Restated Settlement Agreement only for CR3 O&M expenses, CR3 property taxes, and CR3 administrative and general ("A&G") expenses. All CR3 expenses deferred prior to January 1, 2014 shall remain in the total CR3 Regulatory Asset and be recovered in base rates from customers pursuant to paragraph 5e of this Revised and Restated Settlement Agreement. DEF shall not cease but shall continue deferral accounting for any other CR3-related cost subject to deferral accounting pursuant to paragraph 5b of this Revised and Restated Settlement Agreement.

d. DEF agrees upon execution of this Revised and Restated Settlement Agreement to record a \$295 million write-down of the CR3 Regulatory Asset as a reduction to the net plant balance as shown in Exhibit 10 to this Revised and Restated Settlement Agreement.

e. <u>Recovery of the CR3 Regulatory Asset</u>. Effective the earlier of the first billing cycle for January 2017 or the expiration of the Levy Nuclear Project ("LNP") cost recovery charge established and provided for in paragraph 11 of this Revised and Restated Settlement Agreement, DEF shall be authorized to increase its retail base rate charges by the annualized projected revenue requirement for the CR3 Regulatory Asset, as illustrated by the template in Exhibit 10 to this Revised and Restated Settlement, for the first 12 months of projected costs, subject to true-up as provided in paragraph 5g, calculated based on two components shown below in paragraphs 5e(1) and 5e(2):

The projected dry cask storage ("DCS") facility costs. Prior to the (1). date set out in paragraph 5e of this Revised and Restated Settlement Agreement, DEF shall be entitled to petition the Commission for approval of the reasonable and prudent projected DCS facility capital costs. The Intervenor Parties shall be entitled to fully participate in such a proceeding and do not waive any rights related to such participation or determination. After a final decision by the Commission, DEF shall be entitled to add the Commission-determined projected total (retail jurisdictional) value of the reasonable and prudent DCS facility capital costs to the CR3 Regulatory Asset for recovery consistent with the revenue requirement calculation template in Exhibit 10 to this Revised and Restated Settlement Agreement and the base rate increase methodology in paragraphs 5g and 5h. The DCS facility capital costs shall not be recovered before the start of the recovery of the CR3 Regulatory Asset. When the DCS facility capital costs become final, DEF shall be entitled to petition the Commission for approval of the final DCS facility capital costs. The Intervenor Parties shall be entitled to fully participate in such a proceeding, for example and without limitation, to challenge the reasonableness and prudence of DEF's claimed DCS facility capital costs, and do not waive any rights related to such participation or determination. The Parties expressly agree that any proceeding to recover such costs associated with this paragraph of the Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve. After a final decision by the Commission, DEF shall adjust the CR3 Regulatory Asset to

true-up for the final Commission-determined total (retail jurisdictional) value of the DCS facility capital costs, and shall amortize the adjusted final CR3 Regulatory Asset balance over the recovery period of 240 months consistent with paragraph 5h. These base rates shall be subject to a true-up as provided in paragraph 5g; and

(2).The CR3 Regulatory Asset. The lesser of \$1.466 billion (the "Asset Cap"), or the projected or final (when final) total CR3 Regulatory Asset value (excluding DCS facility capital costs), as defined in paragraph 5b of this Revised and Restated Settlement Agreement, shall be used to calculate the annualized revenue requirements for recovery of the CR3 Regulatory Asset. This CR3 Regulatory Asset value may be increased due to an event of Force Majeure as defined in paragraph 5i of this Revised and Restated Settlement Agreement. The agreed upon Asset Cap of \$1.466 billion includes the CR3 cost of removal ("COR") regulatory asset and reflects DEF's agreement to record a \$295 million write-down of the CR3 Regulatory Asset as provided for in paragraph 5d. Once the actual CR3 Regulatory Asset value is final, if the final CR3 Regulatory Asset value is lower than the Asset Cap and different from the projected CR3 Regulatory Asset value, then the annualized revenue requirements associated with the final CR3 Regulatory Asset value shall be subject to a true-up as provided in paragraphs 5f, 5g, and 5i. With respect to the operation of the Asset Cap, for example and hypothetically, if DEF's actual CR3 Regulatory Asset value, before write-down, DCS facility capital costs, and Force Majeure, when known and totaled, is \$1.4 billion, then consistent with Exhibit 10 to this Revised and Restated Settlement Agreement, \$295 million will be deducted from the \$1.4 billion to arrive at a net CR3 Regulatory Asset value of \$1.105 billion. The \$1.105 billion will be compared to the

Asset Cap of \$1.466 billion, and the \$1.105 billion sum will be used for the final CR3 Regulatory Asset value on Exhibit 10 to this Revised and Restated Settlement Agreement because the \$1.105 billion is lower than the \$1.466 billion Asset Cap. By way of further illustration and example, if DEF's actual CR3 Regulatory Asset value, before write-down, DCS facility capital costs, and Force Majeure, when known and totaled, is \$1.8 billion, then consistent with Exhibit 10 to this Revised and Restated Settlement Agreement, \$295 million will be deducted from the \$1.8 billion to arrive at a net CR3 Regulatory Asset value of \$1.505 billion. The \$1.505 billion will be compared to the Asset Cap of \$1.466 billion, and the Asset Cap figure will be used for the final CR3 Regulatory Asset value on Exhibit 10 to this Revised and Restated Settlement Agreement billion, and the Asset Cap figure will be used for the final CR3 Regulatory Asset value on Exhibit 10 to this Revised and Restated Settlement Agreement because the Asset Cap is lower than \$1.505 billion.

If the CR3 Regulatory Asset value is increased due to an event of Force Majeure, as defined in paragraph 5i below, then the CR3 Regulatory Asset value shall be increased in accordance with paragraph 5i and the revenue requirements for recovery of the CR3 Regulatory Asset shall be increased accordingly.

f. The Parties agree that the CR3 Regulatory Asset value will be subject to Commission audit for any mathematical or accounting errors in the true-up determination of the CR3 Regulatory Asset value and resulting actual base rate annualized revenue requirements. The Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest the Asset Cap in the amount of \$1.466 billion. The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover a return of and return on the deferred and accumulated CR3 investments,

regulatory assets/liabilities, and carrying costs in the rate increase for the CR3 Regulatory Asset referenced above in paragraph 5e of this Revised and Restated Settlement Agreement, using the reduced rate of return specified in Exhibit 3 to this Revised and Restated Settlement Agreement. The Parties expressly waive, release, and do not retain the right to challenge the inclusion of the components of the CR3 Regulatory Asset that were at issue in Docket No. 100437-EI and as set forth in Exhibit 10 to this Revised and Restated Settlement Agreement. Any component not included on Exhibit 10 is not eligible for cost recovery as part of the CR3 Regulatory Asset unless caused by an event of Force Majeure as defined in paragraph 5i of this Revised and Restated Settlement Agreement. Regarding the CR3 Regulatory Asset value, the rights expressly waived, limited, or retained by the Parties are detailed in Exhibit 10 to this Revised and Restated Settlement Agreement. Furthermore, DEF shall, in accord with its obligation to do so, minimize the future costs of the CR3 Regulatory Asset and use reasonable and prudent efforts to curtail future avoidable costs or to sell or otherwise salvage assets that would otherwise be included in the CR3 Regulatory Asset as set forth in Exhibit 10 to this Revised and Restated Settlement Agreement. The Intervenor Parties retain the right to challenge whether DEF took reasonable and prudent actions to minimize the future CR3 Regulatory Asset value, as set forth in Exhibit 10 to this Revised and Restated Settlement Agreement.

g. The retail base rate change(s) described in paragraph 5e(1) and 5e(2) shall be established by the application of a uniform percentage increase to the demand and energy charges, including delivery voltage credits, power factor adjustments, and premium distribution service reflected in the Company's base rate schedules existing at

the time of the base rate increase(s) and shall be calculated using the billing determinants included in the Company's most recent projection clause filing, unless otherwise agreed to by the Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. The true-up amounts described in paragraphs 5e(1) and 5e(2) shall be calculated as the difference between the cumulative base revenues since the implementation of the initial base rate increase and the cumulative base revenues that would have resulted if the final base rate increase had been in-place during the same time period and shall be charged or credited to customers through the Capacity Cost Recovery Clause (CCR Clause) with interest at the 30-day commercial paper rate as specified in Commission Rule 25-6.109, Florida Administrative Code ("F.A.C."). On a going-forward basis, base rates shall be adjusted to reflect the updated base rate factor. To the extent that DEF has not (by July 1, 2021) filed for a general base rate case with a Test Year of 2022 or sooner, then by January 1, 2022 DEF shall petition for an update of the asset recovery factor with the most recent filed billing determinants, to be effective with the first billing cycle for July, 2022. Thereafter, DEF shall petition for an update of the asset recovery factor with the most recent filed billing determinants no less often than once every four years. For purposes of this paragraph, a general base rate case shall be considered such an update. The CR3 Regulatory Asset recovery factor shall cease no later than the last billing cycle for the 240th month from inception of the recovery of the CR3 Regulatory Asset.

h. The Parties intend that retail base rate recovery for the CR3 Regulatory Asset shall continue for 240 months from its inception. The base rate

component for recovery of the CR3 Regulatory Asset shall be set based on the billing determinants included in the Company's most recent projection clause filing unless otherwise agreed to by the Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. The initial return rate shall be fixed at the pretax weighted average cost of capital from Exhibit 3 to this Revised and Restated Settlement Agreement.

i. For the purposes of paragraph 5e(2) of this Revised and Restated Settlement Agreement, an event of Force Majeure is recognized as an event which is not reasonably capable of being controlled by the Company and means the following acts or circumstances with respect to CR3 only: (i) act(s) of God; (ii) war or wars; (iii) new requirements adopted after the Effective Date of this Revised and Restated Settlement Agreement by the United States Nuclear Regulatory Commission ("NRC"), Federal Energy Regulatory Commission ("FERC"), or North American Electric Reliability Corporation ("NERC") that are applicable industry wide or generally applicable to shut down nuclear plants; (iv) any act(s) of terror, including cyber-attacks, by groups or individuals not under the Company's control; and/or (v) natural disaster(s) (including, but not limited to, hurricane, tornado, flood, or earthquake).

(1). If a Force Majeure event occurs, DEF will provide timely written notice to the Intervenor Parties and will meet with the Intervenor Parties in good faith to determine whether there is a dispute as to whether a legitimate Force Majeure event has occurred.

(2). If, after such meeting, the Parties determine that there is not a dispute regarding an event of Force Majeure or the consequences thereof or upon a

final Commission determination that a Force Majeure event has occurred, then the total CR3 Regulatory Asset value shall be adjusted to reflect the capital cost (costs that would have otherwise been recorded in plant-in-service accounts of the FERC Uniform System of Accounts) impact of the Force Majeure event on the total CR3 Regulatory Asset value, net of insurance proceeds, and DEF will adjust customer rates accordingly. irrespective of the agreed upon Asset Cap. In calculating the impact of a Force Majeure event(s), DEF shall be responsible for up to \$5 million of Force Majeure capital cost impacts each calendar year for which the CR3 Regulatory Asset value remains unrecovered, and in any year in which Force Majeure cost impacts are incurred, those costs, in aggregate for that year, shall be reduced by up to \$5 million dollars prior to those costs being added to the CR3 Regulatory Asset value. The retail base rate increase(s) resulting from a Force Majeure event shall be established by the application of a uniform percentage increase to the demand and energy charges, including delivery voltage credits, power factor adjustments, and premium distribution service reflected in the Company's base rate schedules existing at the time of the base rate increase(s) and shall be calculated using the billing determinants included in the Company's most recent projection clause filing, unless otherwise agreed to by the Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. If the Parties determine that there is a dispute as to whether a legitimate Force Majeure event has occurred or the consequences thereof, and/or whether the cost impacts of a Force Majeure event are reasonable in amount given the circumstances, then the Parties shall submit the dispute to the Commission for resolution. However, any costs for a Force Majeure event that can be appropriately

charged to the CR3 Decommissioning Trust Fund will not be added to the total CR3 Regulatory Asset value.

j. DEF shall exclude the following amounts related to CR3 from all surveillance reports: (1) revenues associated with the recovery of the CR3 Regulatory Asset base rate increase along with expenses (including, but not limited to, amortization); (2) rate base items (including, but not limited to, all amounts that have been deferred to or recorded in regulatory assets and liabilities); and (3) cost of capital accounts with specific adjustments for items including, but not limited to, deferred income taxes, with all other CR3-related items removed from capital structure on a prorata basis.

Fuel Adjustment Clause:

6. <u>Refunds through the Fuel Adjustment Clause</u>. Pursuant to the terms of this Revised and Restated Settlement Agreement, DEF agrees to the following:

a. Pursuant to the 2012 Settlement Agreement, DEF is refunding through the Fuel Adjustment Clause ("Fuel Clause") 50% of \$258 million in 2013, and refunding the remaining 50% through the Fuel Clause in 2014. In addition, \$30 million will be refunded through the Fuel Clause solely to customers on Rate Schedules RS-1, RSL-1, RSL-2, GS-1, and GS-2 (and their time-of-use counterpart schedules, to the extent applicable) based on an allocation of 94% of such refund amounts to the Residential Service rate schedules and 6% to the General Service, Non-Demand rate schedules, at an annual rate of \$10 million per year in years 2014, 2015, and 2016.

b. DEF shall: (1) refund \$40 million towards replacement fuel and purchased power costs in 2015; and (2) refund \$60 million towards replacement fuel

and purchased power costs in 2016.

c. Except for the aforementioned refunds, DEF shall be entitled to recover its prudently incurred fuel and purchased power costs through the Fuel Clause without regard to the absence of CR3 for any reason for the period beginning October 1, 2009. DEF's right to recover its prudently incurred fuel and purchased power costs does not affect the rights of customers to receive reimbursement from NEIL proceeds for such costs as otherwise provided in this Revised and Restated Settlement Agreement. Thus, for the period beginning October 1, 2009, the unavailability of CR3 for any reason shall not be the basis for any disallowance of fuel or purchased power costs, and the Intervenor Parties waive their rights to challenge DEF's recovery of such costs, except that Intervenor Parties reserve the right to raise issues regarding the prudence and reasonableness of DEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the unavailability of CR3 for any reason.

7. Pursuant to the terms of this Revised and Restated Settlement Agreement, the Parties further agree to the following:

a. DEF shall be allowed to increase retail fuel rates as follows:

- (i) 2014 \$1.00/mWh
- (ii) 2015 \$1.00/mWh
- (iii) 2016 \$1.50/mWh

These increases shall be added to the fuel factor at secondary metering consistent with the normal fuel projection process. All other fuel factors will be developed using the adjusted fuel factor at secondary metering in a manner consistent with the normal derivation of fuel factors. An example of this is shown in Exhibit 12 to this Revised and Restated Settlement Agreement for illustrative purposes using the projected fuel costs and sales from Docket No. 120001-EI (actual costs and sales will be different when rates are set for 2014-2016). These rate increases are not cumulative but apply only for the years shown. For example, retail fuel rates will increase by \$1.00/mWh in 2014, increase by an additional \$.50/mWh in 2016 and decrease by \$1.50/mWh in 2017. Revenues collected from these retail fuel rates will be calculated by multiplying the relevant \$/mWh increase above times the jurisdictional mWh sales as reported in line 26 of Schedule A-1. These revenues will be removed from the fuel revenues for purposes of calculating the fuel true-up over/under recovery. As a result of the accelerated recovery of the carrying charge associated with the CR3 Regulatory Asset, DEF will not defer for recovery the carrying charge on the portion of the CR3 Regulatory Asset supported by these revenues. An example of this calculation is provided on Exhibit 11 to this Revised and Restated Settlement Agreement.

b. If DEF determines that additional funds are necessary in order to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3, DEF shall be allowed to petition to collect those additional funds through a surcharge in base rates. This surcharge will be the lesser of the Commission approved annual contribution amount or \$8 million. The \$8 million limitation shall expire with the last billing cycle for December 2018. After the last billing cycle for December 2018, DEF shall be authorized to recover the actual Commission approved annual contribution to the Nuclear Decommissioning Trust through a base rate surcharge, and that surcharge shall expire following the conclusion of DEF's next base rate case. If the Commission approves an annual contribution to the Nuclear Decommissioning Trust in excess of \$8 million prior to the last billing cycle for December 2018, this incremental amount of the

annual contribution in excess of what has been authorized for recovery in the base rate surcharge shall be deferred with carrying costs based on the Commission approved allowance for funds used during construction ("AFUDC"), and recovered (including carrying costs) through the CCR Clause over a 4 year period beginning with the first billing cycle for January 2019, unless otherwise agreed to by the Parties. The Intervenor Parties reserve their rights to challenge the prudence of any additional CR3 decommissioning costs in appropriate proceedings before the Commission. The Parties expressly agree that any proceeding to recover costs associated with decommissioning CR3 under this paragraph shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve.

c. DEF shall credit the retail allocation of the NEIL settlement amount of \$530 million (system), approximately \$489 million (retail), through the Fuel Adjustment Clause beginning with the first billing cycle for January 2014.

d. DEF shall collect from customers the approximately \$328 million (system), \$326 million (retail) previously credited in the Fuel Adjustment Clause beginning with the first billing cycle for January 2014. Thus, the approximate net effect of paragraphs 7c and 7d above is that DEF will credit the NEIL CR3 settlement amount of \$163 million (retail) through the Fuel Adjustment Clause beginning with the first billing cycle for January 2014.

e. Effective with the first billing cycle for January 2014, DEF shall change billing of the Retail CCR Clause for demand rate classes to be on a kilo-watt

("kW") basis rather than the current kilo-watt-hour ("kWh") method. This requires a modification to Exhibit 5 to this Revised and Restated Settlement Agreement (which was also an exhibit to the 2012 Settlement Agreement), and that modification to Exhibit 5 is presented in Exhibit 9 to this Revised and Restated Settlement Agreement.

Crystal River 1 & 2 ("CRS") Retirement:

8. If DEF retires Crystal River coal units 1 & 2 ("Crystal River South" or "CRS"), as a compliance measure to meet Mercury and Air Toxics Standards ("MATS"), the Best Available Retrofit Technology ("BART"), and/or the National Ambient Air Quality Standards ("NAAQS"), DEF shall be permitted to continue the annual depreciation expense and depreciation rate associated with CRS based on the last Commission-approved depreciation study, which assumed a 2020 CRS retirement date. DEF shall be permitted to recover in 2021, unless a different time for recovery is agreed to by the Parties, any remaining CRS net book value existing at December 31, 2020 through the CCR Clause.

CR3 Extended Power Uprate project ("EPU" or "Uprate"):

9. a. DEF shall recover all CR3 EPU revenue requirements through the Nuclear Cost Recovery Clause ("NCRC") consistent with the provisions of Section 366.93(6), Florida Statutes ("F.S."), and Commission Rule 25-6.0423(6), F.A.C. with a seven (7) year amortization recovery period established as 2013-2019. Intervenor Parties fully and forever waive, release, discharge, and otherwise extinguish any and all of their rights, claims, and interests of whatever kind or nature, whether now known or unknown, to challenge the prudence of DEF's CR3 EPU investment and activities, except that the Intervenor Parties do not waive their rights to participate in the NCRC or

other appropriate docket(s) for purposes of verification that DEF has fulfilled its obligation to minimize future costs of the abandoned uprate project. DEF shall in accord with its obligation to do so, minimize the costs of the CR3 EPU Regulatory Asset (as illustrated in Exhibit 14 to this Revised and Restated Settlement Agreement), and use reasonable and prudent efforts to curtail avoidable future costs or to sell or otherwise salvage assets that would otherwise be included in the CR3 EPU Regulatory Asset. Intervenor Parties agree that CR3 EPU assets that were placed in-service and closed to electric plant in-service FERC 101 shall be recovered as part of the CR3 Regulatory Asset and CR3 EPU assets never closed to electric plant in-service FERC 101 shall be recovered as a part of the CR3 EPU Regulatory Asset through the NCRC or other appropriate docket(s). If CR3 EPU assets are sold or salvaged before the CR3 EPU Regulatory Asset is fully recovered through the NCRC, the remaining balance of the CR3 EPU Regulatory Asset shall be reduced immediately by the retail amount of sale or salvage proceeds. If CR3 EPU assets are sold or salvaged after the CR3 EPU Regulatory Asset is fully recovered, then the retail portion of the sale or salvage proceeds shall be returned, with carrying costs at the rate prescribed in Section 366.93(6), F.S., and Commission Rule 25-6.0423(6), F.A.C., from receipt of proceeds through final refund to customers, to the customers as a refund through the NCRC or the CCR Clause if the NCRC is no longer being utilized.

b. DEF shall recover the Point of Discharge cooling tower investments not recovered in the NCRC but allocated to Environmental Cost Recovery Clause ("ECRC") through the ECRC with a return on the unrecovered investment at the authorized rate for clause recovery consistent with the April 1, 2013 petition and

testimony filed in Docket No. 130007-EI and Docket No. 130091-EI.

Levy Nuclear Project ("LNP"):

10. The Parties support DEF obtaining the LNP Combined Operating License ("COL") from the NRC, terminating the LNP Engineering, Procurement, and Construction ("EPC") contract, and recovering the costs associated with those activities through the NCRC as set forth in this Revised and Restated Settlement Agreement.

11. The LNP component of the Company's NCRC charges was, effective the first billing cycle for January 2013, set at \$3.45/1,000 kWh, for a residential customer, and a corresponding adjustment from the current LNP factors was made for commercial and industrial rates as shown on Exhibit 5 to the 2012 Settlement Agreement, as amended by Exhibit 9 to this Revised and Restated Settlement Agreement. This factor shall be fixed at the levels shown on Exhibit 5, as amended by Exhibit 9, until the estimated remaining LNP component balance of approximately \$350 million (retail) as estimated in the 2012 Settlement Agreement, and carrying costs, is recovered (estimated to be 5 years), with true up occurring in the final year of recovery, in accordance with paragraph 12 below. Concurrent with the adjustment of the LNP NCRC factor, DEF, effective with the first billing cycle for January 2013, transferred its collection of the annual retail revenue requirements associated with the carrying costs on the deferred tax asset in the amount reflected in Exhibit 6 to this Revised and Restated Settlement Agreement from the NCRC to base rates. Such base rate adjustment has been established by the application of a uniform percentage increase to the demand and energy charges of the Company's base rates, including delivery voltage credits, power factor adjustments, and premium distribution service. This

uniform percent adjustment was calculated using the billing determinants set forth in Exhibit 1, Attachment A to this Revised and Restated Settlement Agreement and presented in the format of MFRs E-12 and E-13c for the projected year of 2013. DEF shall not recover any LNP costs from customers apart from those identified in this Revised and Restated Settlement Agreement throughout its Term.

12. a. At the earliest reasonable and prudent time, DEF will be terminating the EPC contract for the Levy nuclear power plants because DEF is unable to obtain the LNP Combined Operating License ("COL") from the NRC by January 1, 2014. Regarding the LNP, DEF will exercise the provisions of Section 366.93(6), F.S., and will elect not to complete the construction of the LNP.

b. DEF agrees to exercise reasonable and prudent efforts to obtain the COL from the NRC by March 31, 2015. If DEF, at its own discretion, decides not to pursue the LNP COL prior to March 31, 2015, DEF will credit customers \$10 million (retail) as a reduction in fuel costs. DEF is not obligated to provide and shall not provide this \$10 million credit to customers as a reduction in fuel costs if: (a) the NRC unilaterally declines or stops work on the LNP Combined Operating License Application ("COLA"); (b) the NRC rejects or dismisses the LNP COLA; or (c) the NRC extends the time for final review or a decision regarding the LNP COL beyond March 31, 2015. DEF will account for the remaining COLA, environmental permitting, wetlands mitigation, conditions of certification, and other costs related or in any way connected to, directly or indirectly, obtaining or maintaining the COL that DEF incurs in 2014 and beyond as construction work in progress removed from recovery in the NCRC. Only in the event the Company uses the COL (which may be amended from time-to-time) to construct a

new nuclear facility at the Levy site, DEF shall be permitted to seek recovery of these post-2013 costs, including AFUDC, in rate base for purposes of future rate proceedings and surveillance reporting, once included in plant in service.

C. The LNP cost recovery charge component of DEF's NCRC charges, established in paragraph 11 of this Revised and Restated Settlement Agreement, shall terminate upon the earlier of full recovery of DEF's LNP costs, or the first billing cycle for January 2018, except for any final true-up. By no later than May 1. 2017. DEF shall submit a final true-up filing to the PSC setting forth the final actual LNP costs, and the amount of any true-up cost or credit to customer bills. To the extent full recovery of all LNP costs is achieved prior to 2017, DEF will file the final true-up in the applicable prior period. The final true-up amount will be recovered or refunded to customers in the following year through the NCRC. DEF shall be permitted to recover all costs associated with the termination of the LNP, including but not limited to the LNP EPC agreement, through the NCRC, consistent with the provisions of Florida statute Section 366.93(6), F.S., and Commission Rule 25-6.0423(6), F.A.C., except as otherwise provided in this Revised and Restated Settlement Agreement. DEF shall in accord with its obligation to do so, minimize the LNP costs recoverable pursuant to Section 366.93(6), F.S., and Commission Rule 25-6.0423(6), F.A.C., and shall use its reasonable and prudent efforts to curtail avoidable future LNP costs, to sell or otherwise salvage LNP assets, or otherwise refund any costs that can be recaptured for the benefit of the customers. If LNP assets are sold or salvaged before the LNP cost recovery charge component of DEF's NCRC charges is fully recovered, the remaining balance of the LNP cost shall be reduced immediately by the retail amount of sale or

salvage proceeds. If LNP assets are sold or salvaged after the LNP cost recovery charge component of DEF's NCRC charges is fully recovered, then the retail portion of the sale or salvage proceeds shall be returned, with carrying costs at the rate prescribed in Section 366.93(6), F.S., and Rule 25-6.0423(6), F.A.C., from receipt of proceeds through final refund to customers, to the customers as a refund through the NCRC or the CCR Clause if the NCRC is no longer being utilized.

Additional Base Rate Adjustments:

13. Effective with the first billing cycle for January 2013, DEF adjusted its base rates to effect a \$150 million (retail) increase in annual revenue requirements, which includes the impact of paragraph 5a above. Such base rate adjustment was established by the application of a uniform percentage increase to the demand and energy charges reflected in the Company's existing base rate schedules, including delivery voltage credits, power factor adjustments, and premium distribution service. This uniform percentage increase was calculated using the billing determinants included as Exhibit 1, Attachment A to this Revised and Restated Settlement Agreement and presented in the format of MFRs E-12 and E-13c for the projected year of 2013. All existing rate schedules shall remain in effect except as modified above and in Exhibit 8 to this Revised and Restated Settlement Agreement. Except as otherwise provided for in this paragraph and this Revised and Restated Settlement Agreement, the Company shall freeze its base rates through the last billing cycle for December 2018.

14. Effective with the first billing cycle for January 2014, the Company will be authorized to remove the capital assets installed and in-service on the Crystal River Units 4 & 5 ("CR4 & 5") power plants to comply with the Federal Clean Air Interstate

Rule ("CAIR") from the ECRC and transfer those capital assets to base rates in an amount which will equal the annual retail revenue requirements of the assets projected to be in-service as of December 31, 2013 (excluding O&M-related costs), which is reflected in the Company's filing (Form 42-4P; Project 7.4) in Docket No. 120007-EI. Such base rate adjustment shall be established by the application of a uniform percentage increase to the demand and energy charges of the Company's base rates including delivery voltage credits, power factor adjustments, and premium distribution service. This uniform percent increase will be calculated using the billing determinants for the projected year of 2014, consistent with the format shown in Exhibit 1, Attachment A to this Revised and Restated Settlement Agreement, adjusted for the increases provided herein. These adjustments are in addition to the base rate adjustments provided for in paragraphs 5e, 7b, 11, 13, 16, and 23 of this Revised and Restated Settlement Agreement.

15. DEF shall have an authorized return on equity of 10.5% with a range of reasonableness of +/-100 basis points for the purpose of addressing earnings levels, earnings surveillance and cost recovery clauses. The applicable annual AFUDC rate will be 7.44%. (See Exhibit 2 to this Revised and Restated Settlement Agreement).

16. a. Subject to the Intervenor Parties' right to challenge the need for or prudence of any costs associated with the construction, purchase, or acquisition of any such units or uprates, DEF shall have the ability to recover the full, prudently incurred revenue requirement of any: (1) combustion turbine unit(s) constructed and associated transmission required to integrate and deliver power from such unit(s) into the DEF system; (2) any power uprates to existing DEF unit(s); and/or (3) any existing

combustion turbine and/or combined cycle unit(s) acquired or purchased along with any transmission costs required to integrate and deliver power from such unit(s) into the DEF system, not to exceed a total megawatt ("MW") capacity of 1150 MWs collectively for items (1), (2) and/or (3) above (unless a higher MW amount is otherwise agreed to by the Parties), which may be placed in-service and/or acquired/purchased prior to year-end 2017, through a base rate increase at the time each unit is placed in service and/or acquired/purchased. In addition, DEF will evaluate and compare whether it is more cost effective to satisfy this MW capacity need prior to 2017 through its Integrated Resource Planning ("IRP") methodology and will provide this comparison at the time it submits these costs in (1), (2) or (3) of this paragraph for prudence review. Annualized Revenue Requirements shall be calculated using a 10.5% Return on Equity ("ROE") and DEF's capital structure reflected in DEF's most recent actual earnings surveillance DEF shall calculate and submit for Commission approval the revenue report. requirements using the billing determinants from the most recent projection clause filing, unless otherwise agreed to by the Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. Such base rate adjustment shall be established by the application of a uniform percentage increase to the demand and energy charges reflected in the Company's base rate schedules existing at the time of the adjustment, including delivery voltage credits, power factor adjustments, and premium distribution service. The uniform percentage increase shall be calculated using the billing determinants included in the Company's last filed clause projection filings. The Parties expressly agree that any proceeding to recover costs associated with this paragraph of the Revised and Restated

Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve.

b. DEF currently projects a need for additional generation in service in 2018. If DEF petitions the Commission for a need determination for additional generation, not to exceed 1800 MW, to be placed in service in 2018, and the Commission grants that determination of need, and DEF constructs and places in service that additional generation in 2018, DEF's base rates shall be increased by the annualized base revenue requirement for the first 12 months of operation (the "Annualized Base Revenue Requirement"). The Annualized Base Revenue Requirement shall reflect the costs pursuant to which the need determination was granted by the Commission. This base rate increase shall be referred to as the 2018 Generation Base Rate Adjustment ("GBRA"). The Intervenor Parties retain all rights to challenge DEF's actions in paragraphs 16b, 16c, and 16f, including, but not limited to, the right to challenge the need or prudence of any costs associated with the construction of any additional generation placed in service in 2018 as well as the initial 2018 GBRA factor and any subsequent revisions to it pursuant to Rule 25.22.082(15), F.A.C., but waive the right to argue that this Revised and Restated Settlement Agreement prevents DEF from seeking recovery for the costs described in this paragraph that the Commission determines to be reasonable and prudent.

c. The initial 2018 GBRA factor shall be established by the application of a uniform percentage increase to the demand and energy charges reflected in the

Company's base rate schedules existing at the time of the increase, including delivery voltage credits, power factor adjustments, and premium distribution service. The uniform percentage increase shall be calculated using the billing determinants included in the Company's most recent projection clause filing unless otherwise agreed to by the Parties, with the understanding that the Intervenor Parties retain the right to challenge the accuracy and validity of the billing determinants. DEF shall begin applying the 2018 GBRA to meter readings made on and after the commercial in-service date of the 2018 additional generation for which the need determination was granted by the Commission.

d. The 2018 GBRA Annualized Base Revenue Requirement shall be calculated using a 10.5% ROE and DEF's capital structure reflected in DEF's most recent actual earnings surveillance report. DEF will calculate and submit for Commission approval that amount of the 2018 GBRA using the billing determinants from the most recent projection clause filings.

e. In the event that the actual capital expenditures are less than the projected costs used to develop the initial 2018 GBRA factor, the lower figure shall be the new basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised 2018 GBRA factor shall be computed using the same data and methodology incorporated in the initial 2018 GBRA factor, with the exception that the actual capital expenditures shall be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. This credit shall be the difference between the cumulative base revenues that would have resulted if the revised 2018 GBRA factor

had been in-place during the same time period and shall be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Commission Rule 25-6.109, F.A.C. On a going-forward basis, base rates shall be adjusted to reflect the revised 2018 GBRA factor.

f. In the event that the actual capital expenditures are higher than the projection on which the Annualized Base Revenue Requirement was based, DEF at its option may initiate a limited proceeding pursuant to Section 366.076, F.S., limited to the issue of whether DEF has met the requirements of Commission Rule 25-22.082(15), If the Commission finds that DEF has met the requirements of Commission F.A.C. Rule 25-22.082(15), F.A.C., then DEF shall increase the 2018 GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, DEF's election not to seek such an increase in the 2018 GBRA shall not preclude DEF from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Any Party may participate in any such limited proceeding. The Parties expressly agree that any proceeding to recover costs associated with this paragraph of the Revised and Restated Settlement Agreement shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve.

New Economic Development and Economic Re-Development Tariffs:

17. DEF shall introduce New Economic Development and Economic Re-Development Tariffs, included as Exhibit 15 to this Revised and Restated Settlement

Agreement, on a pilot basis for a 3-year period. The attached New Economic Development and Economic Re-Development Tariffs in Exhibit 15 to this Revised and Restated Settlement Agreement shall become effective upon approval of this Revised and Restated Settlement Agreement. Commission approval of the New Economic Development and Economic Re-Development Tariffs in the limited proceeding for approval of the Revised and Restated Settlement Agreement Agreement Agreement approval of the Revised and Restated Settlement Agreement and Economic Re-Development Tariffs in the limited proceeding for approval of the Revised and Restated Settlement Agreement satisfies the requirements of Commission Rule 25-6.0426(3)-(6), F.A.C., and, accordingly, the reductions afforded in these tariffs, shall, for all ratemaking purposes and Surveillance reporting, be included as a cost in the Company's cost of service.

Other Matters:

18. DEF shall be authorized, at its discretion, to accelerate in full or in part the amortization of the regulatory assets for FAS 109 Deferred Tax Benefits Previously Flowed Through, Unamortized Loss on Reacquired Debt, 2009 Pension Regulatory Asset, and Interest on Income Tax Deficiency over the Term of this Revised and Restated Settlement Agreement. DEF will be authorized to make a new specific adjustment to its common equity balance and rate base working capital balance for the purposes of calculation of rate base and the capitalization ratios used for surveillance reporting pursuant to Commission Rule 25-6.1352, F.A.C., and pass-through clauses. The calculation of this adjustment will be based on the methodology employed by Standard and Poor's Ratings Service ("S&P") in its determination of imputed off balance sheet obligations related to future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. The amount of the adjustment to common equity and rate base will fluctuate over time with changes in the amount of

future purchase power obligations. The Parties agree that the common equity and rate base adjustment set forth in this paragraph is unique to the specific circumstances of DEF, as it relates to this Revised and Restated Settlement Agreement, and the treatment of DEF's common equity and rate base in this paragraph shall not constitute binding Commission precedent or create a presumption of correctness as to the adjustment for future ratemaking in any future proceeding involving DEF or any other utility. Moreover, this adjustment and the Parties' agreement to such adjustment in this unique proceeding shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this Revised and Restated Settlement Agreement. This adjustment shall not be taken into account for purposes of calculating interim rates or determining whether DEF can seek a base rate adjustment pursuant to paragraph 23 of this Revised and Restated Settlement Agreement.

19. All other cost of service and rate design issues will be determined in accordance with Exhibit 1 and Exhibit 8 to this Revised and Restated Settlement Agreement.

20. DEF will have the discretion to record a retail jurisdictional annual credit to depreciation expense, with any reduction in depreciation expense recorded as a cost of removal regulatory asset pursuant to a FERC accounting order received by the Company in 2011. This reduction in depreciation expense will be limited by any remaining balance of the cost of removal reserve throughout the Term. DEF shall not be permitted to use cost of removal if the use would cause the Company to exceed the high point of the ROE range established in this Revised and Restated Settlement Agreement. These credit amounts to depreciation expense are in lieu of the annual

amortization of any theoretical depreciation reserve surplus approved in DEF's previous base rate order PSC-10-0131-FOF-EI. The cost of removal regulatory asset, excluding the portion of the balance related to CR3, which is recovered as part of the CR3 Regulatory Asset described in paragraph 5(e)2, will be recovered commencing on the earlier of the Company's next filed base rate proceeding or upon completion and approval by this Commission of the Company's next depreciation study. Any recovery period of this regulatory asset will be no longer than the average remaining service life of the assets, approved in the Company's most recent depreciation study. DEF shall file a Depreciation Study, Fossil Dismantlement Study, and Nuclear Decommissioning Study on or before March 31, 2019, or accompanying the next base rate case, whichever is sooner. In any event, DEF shall file a Depreciation Study such that all issues arising from such Depreciation Study can be litigated by the Parties in the next base rate case.

21. DEF may not petition for an increase in base rates and charges that would take effect prior to the first billing cycle for January 2019, except for the increases in base rates and charges provided for or allowed by the terms of the Revised and Restated Settlement Agreement. In addition, the Parties agree that the base rate increases or charges that, pursuant to the terms of this Revised and Restated Settlement Agreement extend beyond the last billing cycle for December 2018 and survive the expiration of the term or termination of this Revised and Restated Settlement Agreement, include the recovery of the CR3 Regulatory Asset through the last billing cycle for the 240th month from inception pursuant to paragraph 5 of this Revised and Restated Settlement Agreement; the potential recovery of additional funds

to fund the CR3 Nuclear Decommissioning Trust pursuant to paragraph 7b of this Revised and Restated Settlement Agreement; the potential recovery of the CRS net book value pursuant to paragraph 8 of this Revised and Restated Settlement Agreement; and the recovery of the LNP and EPU costs through the time periods established by this Revised and Restated Settlement Agreement and Section 366.93(6), F.S., and Commission Rule 25-6.0423(6), F.A.C. Notwithstanding the rate relief mechanism described in paragraph 23, DEF is prohibited from seeking or implementing an interim rate increase pursuant to Section 366.071, F.S., until the expiration of the Term of this Revised and Restated Settlement Agreement. The Intervenor Parties likewise will neither seek nor support any reduction in DEF's base rates and charges, including limited, interim, or any other rate decreases, that would take effect prior to the first billing cycle for January 2019, except for any reduction requested by DEF or as otherwise provided for in this Revised and Restated Settlement Agreement.

22. No Party to this Revised and Restated Settlement Agreement will request, support, or seek to impose a change to any provision in this Revised and Restated Settlement Agreement. This Revised and Restated Settlement Agreement, and the attached exhibits and schedules, represent the entire and complete agreement between the Parties. The Parties consider each provision to be integral to their respective support for the Revised and Restated Settlement Agreement in its entirety, and no provision may be changed or altered without the consent of each signatory Party in a written document duly executed by all Parties to this Revised and Restated Settlement Agreement. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this Revised and Restated Settlement Agreement, the

Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution. Florida law will govern all terms, conditions, and provisions of this Revised and Restated Settlement Agreement, including, but not limited to, any disputes arising from this Revised and Restated Settlement Agreement.

23. If DEF's retail base rate earnings fall below a 9.5% ROE as reported on a Commission adjusted or pro-forma basis on a DEF monthly earnings surveillance report during the Term of this Revised and Restated Settlement Agreement, DEF may petition the Commission to amend its base rates during the Term of this Revised and Restated Settlement Agreement. Such request by the Company shall be limited to an increase that would achieve a 10.5% ROE. No Party waives its right to participate in such a proceeding, and such participation will only be limited by the terms of this Revised and Restated Settlement Agreement. If DEF's retail base rate earnings exceed an 11.5% ROE as reported on a Commission adjusted or pro-forma basis on a DEF monthly earnings surveillance report during the Term of the Revised and Restated Settlement Agreement, any Intervenor Party to this Revised and Restated Settlement Agreement shall be entitled to petition the Commission for a review of DEF's base rates and charges. Prior to requesting any such relief under this paragraph, DEF must have reflected on its referenced surveillance report any remaining credited depreciation expense (cost of removal) identified in paragraph 20. The Parties to this Revised and Restated Settlement Agreement are not precluded from participating in any such proceedings. This paragraph shall not be construed to bar or limit DEF from any recovery of costs otherwise contemplated by this Revised and Restated Settlement

Agreement, and all other provisions of this Revised and Restated Settlement Agreement shall remain in force and effect.

24. Nothing shall preclude the Company from requesting the Commission to approve the recovery of the following types of costs:

a. Costs that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or

 b. Costs which the Legislature or Commission determines are clause recoverable prior to or subsequent to the approval of this Revised and Restated Settlement Agreement.

c. With respect to storm damage costs caused by a tropical system named by the National Hurricane Center or its successor, nothing in this Revised and Restated Settlement Agreement shall preclude DEF from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or level of cost of removal reserve. The Parties agree that recovery from customers for storm damage costs will begin, subject to Commission approval on an interim basis, sixty (60) days following the filing of a cost recovery petition with the Commission, and subject to true-up pursuant to further proceedings before the Commission, and will be based on a 12-month recovery period. All storm-related costs shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, an estimate of incremental costs above the level of storm reserve prior to the storm event, and replenishment of the storm reserve to the level as of the

Implementation Date of 2012 Settlement Agreement. The Intervenor Parties to this Revised and Restated Settlement Agreement are not precluded from participating in any such proceedings. The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve.

25. The provisions of this Revised and Restated Settlement Agreement are contingent on approval of this Revised and Restated Settlement Agreement in its entirety by the Commission. The Parties further agree that they will support this Revised and Restated Settlement Agreement and will not request or support any order,

relief, outcome, or result in express conflict with the terms of this Revised and Restated Settlement Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Revised and Restated Settlement Agreement or the subject matter hereof. No Party will assert in any proceeding before the Commission that this Revised and Restated Settlement Agreement or any of the terms in the Revised and Restated Settlement Agreement shall have any precedential value. The Parties' agreement to the terms in the Revised and Restated Settlement Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving the Revised and Restated Settlement Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any party in a future proceeding nor shall any Party represent in any future forum that another Party endorses a specific

provision of this Revised and Restated Settlement Agreement because of that Party's signature herein. It is the intent of the Parties to this Revised and Restated Settlement Agreement that the Commission's approval of all the terms and provisions of this Revised and Restated Settlement Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this Revised and Restated Settlement Agreement Agreement Agreement endorses a specific provision, in isolation, of this Revised and Restated Settlement Agreement because of that Party's signature herein.

26. All dollar values, asset determinations, rate impact values, or revenue requirements in this Revised and Restated Settlement Agreement are intended by the Parties to be retail jurisdictional in amount or formulation basis, unless otherwise specified.

27. This Revised and Restated Settlement Agreement dated as of July 31, 2013 may be executed in counterpart originals, and a facsimile or PDF email of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Revised and Restated Settlement Agreement by their signatures below.

[Remainder of page left intentionally blank]

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Duke Energy Florida, Inc.

By

John T. Burnett, Esquire Post Office Box 14042 St. Petersburg, Florida 33733

Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 42 of 197

Office of Public Counsel

By

J.R. Kelly, Esquire Charles Rehwinkel, Esquire Erik Sayler, Esquire 111 W. Madison St., Room 812 Tallahassee, Florida 32399

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Florida Industrial Power Users Group

MMM Bv

Jon C. Moyle, Jr., Esquire Moyle Law Firm, PA 118 North Gadsden Street Tallahassee, FL 32301



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White Springs Agricultural Chemicals, Inc.

By NO mu

James W. Brew, Esquire Brickfield, Burchette, Ritts & Stone, P.C. 1025 Thomas Jefferson St., NW Fighth Floor, West Tower Washington, DC 20007

Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 45 of 197

Florida Retail Federation

(li)rigti By

Robert Scheffel Wright, Esquire Gardner Bist Wiener Wadsworth Bowden Bush Dee LaVia & Wright, P.A. 1300 Thomaswood Drive Tallahassee, FL 32308

REVISED AND RESTATED SETTLEMENT AGREEMENT

EXHIBITS

Exhibit 1 (Composite)

Attachment A: 2013 billing determinants in the format of MFR E-13c and E-12 including calculation of uniform percent increase of base rate demand and energy charges

Attachment B: Calculation of detailed base rate charge by rate schedule including current rates and proposed settlement rates

Attachment C: Revised Tariff Sheets in clean copy format

Attachment D: Revised Tariff Sheet in legislative format

Exhibit 2

Progress Energy Florida, Inc. Capital Structure Used for AFUDC Calculation, FPSC Order No. PSC-10-0604-PAA-EI

Exhibit 3

Progress Energy Florida, Inc. Carrying Charge Calculation Applicable Upon Retirement of CR3 to all CR3 Related Rate Base Only Common Equity Based on 70% of Authorized

Exhibit 4

Progress Energy Florida, Inc. Capital Structure & AFUDC Calculation

Exhibit 5

Levy Over 5 Years, NCRC Impact

Exhibit 6

Levy County Nuclear Units 1 & 2 Deferred Tax Asset Revenue Requirement Calculation

Exhibit 7

Jurisdictional Nuclear O&M

Exhibit 8

Cost of Service and Rate Design Issues

Exhibit 9

Impact of Billing Change to Levy – CCR rate

Exhibit 10

Template for Calculation of the CR3 Regulatory Asset Value and Revenue Requirement

Exhibit 11

Example of Recovery of CR3 Regulatory Asset Carrying Cost

Exhibit 12

Illustrative Example of Impact to Fuel Rates of Paragraph 7.a of The Revised & Restated Settlement Agreement based on 2013 Projection Filing Data

Exhibit 13

Issues List 100437-EI 6.10.13

Exhibit 14

2013 Detail – Calculation of the Revenue Requirements January 2013 Through December 2013

Exhibit 15

Economic Development and Economic Re-Development Tariffs

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> Composite Exhibit 1 Duke Energy Florida

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Duke Energy Florida

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Exhibit 1 to Stipulation and Settlement Agreement

- 1) Effective with the first billing cycle for January 2013, monthly interruptible and curtailable credits shall be as follows:
 - IS-1 \$4.99 per KW of billing demand
 - IST-1 \$4.99 per KW of on-peak demand
 - CS-1 \$3.74 per KW of billing demand
 - CST-1 \$3.74 per KW of on-peak demand
 - IS-2, IST-2 \$8.70 per KW of load factor adjusted demand
 - CS-2, CST-2 \$6.53 per KW of load factor adjusted demand
 - CS-3, CST-3 \$6.53 per KW of fixed curtailable demand
 - SS-2 the greater of:

\$0.870 per KW times the Specified Standby Capacity, or The sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times \$0.414 per KW times the appropriate monthly factor.

SS-3 – the greater of:

\$0.653 per KW times the Specified Standby Capacity, or The sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times \$0.311 per KW times the appropriate monthly factor.

2) Until such time as the Commission sets new base rates in a general rate case proceeding, for all rate making purposes including base rates, monthly actual and annual forecasted earning surveillance reporting and all cost recovery clauses including storm surcharges (if applicable) the demand related retail Jurisdictional Separation Factors will be as follows:

Production Base	92.885%
Production Intermediate	72.703%
Production Peaking	95.924%
Transmission	70.203%
Distribution Primary	99.561%

 Effective with the 1st billing cycle for January 2013, the capacity component of the GSLM-2 Monthly Credit Amount for the Standby Generation load management program shall be as follows:

> \$3.60 for fiscal year hours of <= 200 CRH (cumulative requested hours) \$4.32 for fiscal year hours of > 200 CRH (cumulative requested hours)

The capacity component of the Monthly Credit Amount is that defined to be multiplied by "*C*" in the GSLM-2 tariff where "*C*" initially represents the customer's standby generation capacity.

COM		
AFD	3	_
APA	1	-
ECO	1	
ENG	1	-
GCL	1	_
IDM		_
TEL		_
CLK		_

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Exhibit 1 Page ii of ii Duke Energy Florida

- 4) The Company will maintain the production capacity cost allocation method of 12CP and 13th AD unless such allocation is changed in the Company's next general rate case.
- 5) Special Provision number 4 of tariff sheet No. 6.2392 "Curtailable General Service Fixed Curtailable Demand" and 6.2492 "Curtailable General Service – Fixed Curtailable Demand, Optional Time of Use" shall be revised as attached hereto to clarify customer's compliance with curtailment responsibility during normal business operating conditions.

Attachment A

2013 billing determinants in the format of MFR E-13c and E-12 including calculation of uniform percent increase of base rate demand and energy charges

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SCHEDULE E-12

ADJUSTMENT TO TEST YEAR UNBILLED REVENUE

Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: PROGRESS ENERGY FLORIDA. INC DOCKET NO.; 12xxxx-El			EXPLANATION: Provide a schedule showing the calculation of the adjustment by rate class to the test year amount of unbilled revenue for the effect of the proposed rate increase.						Type of Data Shown: Historical Test Year Ended// , Projected Test Year Ended 12/31/13 Prior Year Ended// Witness:					
	DOGRET NO.,										101055.			
1		DEVEL					UMMARY OF TOTA				101	(0)	(40)	(44)
			(1)	(2)	(3) venues \$000's	(4) Billed	(5)	(6)	(7)		(8)	(9)	(10)	(11)
			Billed	Laserie	VEILOES \$000 3	Energy and		Energy and	Unbil	ed		Total Energy and		Total Class
		Rate	MWH		Customer	Demand	Unbilled	Demand Chg	Rever		Total Class	Demand Revenue	Base Rate	Revenue with
Line		Schedule	Sales	Total	Charge	Charge	MWH Sales	\$/MWH	(\$00		Revenue (\$000)	Including Unbilled	Adjustments / Shifts	Increase
No.								(4) / (1)	(5) * ((2) + (7)	(4) + (7)	,	(8) + (10)
1	I. SALES	RS-1	18,650,321	\$ 960,909			10,035	\$ 43.26	S	434 S			\$ 106,792	\$ 1,068,135
2		GS-1	1,224,785	68,364	15,813	52,551	582	42.91		25	68.389	52,576	6,955	75,344
3		G\$-2	120,842	3,715	1,733	1,982	65	16,40		1	3,716	1,983	262	3,978
4		GSD-1	14,197,009	392,101	9,285	382.816	4.495	26.96		121	392,222	382,937	50,659	442,881
5		CS-1, CS-2, CS-3	46,559	1,089	9	1,079	(218)	23.18		(5)	1.083	1,074	142	1,226
6		IS-1, IS-2, IS-3 SS-1	1.704,667 12,187	35,265 702	667 24	34,599 678	(3,111)	20 30 55.61		(63)	35,202 702	34,536 678	4,569 90	39,771
/ 8		SS-2	144,605	3,541	24	3,532	(4) (296)	24.43		(0) (7)	3,534	3,525	90 466	791 4,000
9		SS-3	16,448	673	8	665	(230)	40.44		(1)	671	664	400	759
10		LS-1	371,280	7,239	901	6,338	182	17.07		3	7,242	6,341	839	8,081
11		TOTAL	36,488,703	1,473,597	182,530	1,291,067	11,696			507 \$				
12												<u> </u>	andel at the transfer a defectation	
13	II OTHER													
14		LS-1												
15		FIXTURE		\$ 33.204						5				\$ 33,204
16		MAINTENANCE		10,361							10,361			10,361
17		POLES		24,481							24,481			24,481
16		TOTAL OTHER REVENUE		\$ 68,046							68,046	-		\$ 68,046
19				\$ 1,541,643					S	507 5	3 1,542,151	•		\$ 1,713,013
20	III. TOTAL CLAS	DO REVENUE		3 1,041,045					<u> </u>	507 3	1,042,101	:		\$ 1,713,013
21 22														
22														Concurrent
24									Components of 8	ase Rate	Adjustments/Shifts (per Settlement		Clause Decrease
25									1 2. Transfer Levy Dok			\$ 20,862	NCRC	
26									1 12 General Base Ra	ne Increase		150,000		(
27														
28									Total Bas	e Rate Ind	crease	\$ 170,862	•	
29													¶8 Fuel	
30													Total Clauses	\$ (149,862)
31														
32													Nel Base & Clause	\$ 21,000
33														
34													% Incr Total Base Rev	1.23%

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Schedule F-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 1 of 13
Florida Public Service Commission	EXPLANATION By rate rated values revealed and revealed and proposed rates for the test year. If any outlaments are to be pausferred from one schodule to enabled, show whether second king for the transfer graph. Correction Accors are used for historic lost	Type of Data Shown:
Company: Progress Energy Florida, Inc.	years briv. The belief base revenue by class must leader be believe to Scheduk E-13a. The billing lands must equal Pose engine ki Schoduke E-15, FROVIDE TOTAL NUMAER OF BILLS, MAYIFS, AND BUTUNG WAIT OR CACH RATE SCHED DER (INC. UDING	, X _ Projected Test Yoar Enced 12/31/13 Frior Year Ended Histencal Year Ended
Dockei No : 12xxxx-El	STANDARD AND TIME OF USE CUSTOWERS) AND TRANSFER GROUP	Winess

	PRESENT REVENUE (ALCULATIONS	3	
		شاہ ۵۵۰ میلی ط		
Customer Charge:				
Standard				
Secondary Standard	16,948 511	50s@ \$	876 = \$	148,458,955
Seasonal		0		
Secondary Standard Charge	517,693	Bits @ \$	8.76 - \$	4,534,593
Secondary Seasonal Charge	233,676	Bals @ \$	4.58 = \$	
Time-of-Use				
Secondary (single & three phase)	375	ga an ag	16 19 + 5	6.071
		e i Ç		
Customer CIAC Paid	155	8315 @ \$	8.76 × \$	1,367
TOTAL	17,700,411	Bills		
			_	
Energy & Demand Charge:				
Slandard				
Secondary	18,649,519			
0-1000 KWAH	12 767,451	14WH @ \$	39.82 = \$	508,400,266
over 1000 KWH	5,882,058	MWH@\$	50 73 = \$	
Time-of-Use				
Secondary	802			
On-Peak	210	14AT @ \$	122.97 = 5	25,870
Off-Puak	592	MAH Q \$	663 5	
OID DOK	252	សមាលអី ៖	0.003 2	
*07.0	10 (10 224	4.0333	43 26 3	000 501 016
TOTAL	18,650.321	MAR	4320 3	806 527,015
Adjustments				
n'a			5	•
Fotal RS-1 Base Revenue				950 938 637

EXHIBIT 1, ATTACHMENT A Page 3 of 15 Duke Energy Florida

Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 54 of 197

Schedule E-13c	BASE REVERVE BY RATE SCHEDULE - CALCULATIONS	Page 2 of 13
Flonda Public Service Commission	EXPLANATION By rate schedula, cabulate revenues under prevent and proposed rates for the test year. If any customets are to be insolitized from one schedule to another, shew revenues separately for the transfer group. Contaction factors are used for the transfer group.	Type of Data Shown:
Company, Progress Energy Florida, Inc.	years only The Carl baco reverse by class must eave that shown in Schedule E-13a. The billing units must equal hose shown in Schedules E. 15: PROVIDE TOTAL HUMBER OF BULS, MWH'S, AND BULING WHY FOR FACH RATE SCHEDULE (NO: VD NO.	XProjected Test Year Ended 12/31/13
Docket No . 12XXXX-EI	STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.	Historical Year Ended Wähass:

PH7	ESENT REVENUE (CALCULATIO	NS	
ustomer Charge!				
itandard				
Unitelend	5,464	Bills @ \$	6.64 =	\$ 35,735
Secondary	1 350 953	Brits Ag S	11.59	
Secondary Frimary	415	អាស់អ្ន B≊K@ \$	148.56 -	
Transmission	4 '0	-		
		B%s @ 5	722,90 -	\$.
lime-of-Use		011. O. C	40.04	e 13 eeo
Secondary (single & (three phase)	2,505	B.lls.(2) \$	19 01 -	\$ 47,639
Customer CIAC Paid	24	B∷is@\$	11.59 ×	\$ 276
Primary	12	B % @ \$		
Transmission	12	Bar () 1		
TOTAL	1,359,397	Bills	-	15,812,778
10112	,,,	Cind	-	10,012,110
Energy & Demand Charge:				
Standard				
Secondary	1,196,435	MWH @ \$	43 26 =	\$ 51,757,827
Primary	3,651	MWH @ \$	43.26 r	5 157,946
Transmission		MWH @ S	43 26 =	ş -
Time-of-Use		-		
Secondary				
On-Feak	3 405	15MH @ \$	122 78 =	\$ 418,007
Off-Peak	14,567	WWH @ \$		
Primary	,			
On-Pcak	607	<u>ଅ</u> ଅସ-ପୁ5	122 78 =	\$ 74,558
Off-Pcak	1,76	MWY (2) S		
Transmission	11-01			
Cri Peak	75	MWH@ \$	122.78 -	\$ 9,200
Off-Peak	4 263	MWH @ \$		
101AL	1,224,785	MAH MAH		\$ 52 554,611
IVIAL	1,224,760	99.6767		+ 32,334,011
Adjustments				
Elstabilition Pamary Meloring	1%	CF §	244,227 =	\$ (2.442)
Transmission Metering	2%			
TOTAL	17	•		\$ (3,195)
			-	10,100
Total GS-1 Base Revenue				\$ 68,364,193
			1	

EXHIBIT 1, ATTACHMENT A Page 4 of 15 Duke Energy Florida

Docket No. 150009 EL Docket 150001-El Petition - Attachment A Page 55 of 197

Schedule E-13c	BASE REVENUE BY HATE SCHEDULE - CALCULATIONS	Page 3 of 13
Flonda Public Service Commission	EXPLANATION By rate schedule, calculate revenues under present and preposed rates for the test year. If any customers are to by transferred from one schedule to another show revenues substately for the transfer group. Correction factures are used for tristeric	Type of Data Shown. X. Projected Test Year Ended 12/31/13
Company: Prograss Energy Florido, Inc.	est york only. The fold base revenue by class must optic the shown in Schedule E Tay. The boll grants must equal those shown in Scheduly E 15 - PROVIDE TOTAL RUMBER OF BASS, MWHS, AND BILLING KWI FOR SACH RATE SCHEPULE.	Price Year Ended Historica/Year Ended
Docket No : 12xxxx-El	(INCLUDING STANDARD AND THE CEUSE CUSTOMERS) AND TRANSFER GROUP	Witness:

	2013 REVENUE CALCULATION FOR RATE SCHEDULE GS-2									
	PRESENT REVENUE CALCULATIONS		PROPOSED REVENUE CALCULATIONS							
Customer Charge:										
Standard										
Unmetered	10,704 Bills @ \$	6 54 = \$ 70,004								
Secondary	143,503 Bila @ \$	11.59 . \$ 1 663,200								
TOTAL	154,207 Bilts	\$ 1,733,204								
inergy & Demand Charge:										
landard										
Secondary	120,842 MWH @ \$	18.40 - \$ 1,981,509	1							
Adjustments			l L							
			l							
n'a		\$.	ł							
fotal GS-2 Base Revenue		\$ 3,715 013								
			T							
			I							
			1							
			I							
			1							
			1							

EXHIBIT 1, ATTACHMENT A Page 5 of 15 Duke Energy Florida

Docket No. 150009 ET, Docket 150001-EI Petition - Attachment A Page 56 of 197

Schedule E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 4 of 13
Florida Fubic Service Commission	EXPLANATION. By rate polyability candidate revenues under present and proposed rakis for the test year. If any constitutions are to be particle real from one richtek to to another, show romanes separately six the transfer group. Converse, future are used for history test	Type of Data Shown
Company: Progress Energy Florida, Inc.	years only. The bala base revenue by class must equal that shown in Schedue 6, 139. The billing units must equal Proce shown in Schedules 5, 15, "PROMINE TOTAL NUMBER OF BILLS, BIVERS, AND BIZUING KWIP FOR EACH RATE SCHEDULE (INCLUDING	.X_Projected Test Year Ended 12/31/13 Frior Year Ended
Deckel No. 12xxxx-El	STANDARD AND TIME, OF USE CUSTOMERS) AND TRANSFER GROUP	Historica: Year Ended Waxess

			1	2013 REVENUE C	ALCULATION FOR RATE SCHEDULE GSD
	PRESENT REVEN	JE CALCULATIO			PROPOSEU REVENUE CALCULATIONS
Customer Charge:					1
Standard					
Secondary	535,315	DAS 😂 S	1159 × S	6,204,347	
Phmany	1,665	6415 @ \$	145 56 = 5	244,022	1
Transmission		671a @ \$	122.90 = \$		
Time-of-Use					
Secondary	128,047	Bils 🚯 💲	1901 = \$	2,434,173	
Customer CIAC Paid	132	Bails 👩 💈	11.59 × 5	1,530	
Prehary	2,499	B45 @ 5	15399 ÷ \$	354,821	
Customer CIAC Paid	48	Biscs	146 56 = \$	7,035	1
Transmission	12	B4s @ \$	73032 = \$	8,764	
TOTAL	667,722	Dils .	\$	9,284,692	1
Demand Charge:					1
Slandard					
Secondary					
Biled	17,169,704	WO C	105 0		
Primary	17,109,704	kW @ S	405 - S	69,537,301	
Bited	<i>cor a i b</i>				
Transmission	505,042	kW @ \$	373 = 5	4,883,897	
B/Fed					
Time-of-Use	•	KIV@ \$	2.85 = \$	•	
Secondary					
Ch-Pgas	16 400 110	WUG S	2.01		
Base	15,408,112	kW 🕃 S	301 + \$	46,378,417	
roase Fr≉nany	15,921,337	kW 🕼 💲	2 = 99 0	15,762,124	
Ch Poal	0.020	1111 63 8		11 003 000	
Base	3,860,572	kw@s	3.01 ÷ \$	11 620,322	
Base Transm/Pranary	4,087,546	k₩@\$	Q.67 = \$	2 738,924	
On-Peak				10.000	
	25,426	4W@ 5	3.01 · \$	76 532	
Base	26,172	kw @ S	(0,7C) - S	(5 234)	
Sec/Pn				4	ł
On Peal.	33,025	KW (CS S	3.01 × S	99,435	ł
Ease	33,539	KY (ē. S	099 = 5	33,204	
Fremain Distrib Charge	239,697	KW @ \$	0.87 S	208,710	
TOTAL SEEDED		KW .	TOTAL S	148,333 542	- -

EXHIBIT 1, ATTACHMENT A Page 6 of 15 Duke Energy Florida

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Schedule E-13c	BASE REVENUE BY RATE SCHEDULT: - CALCULATIONS	Page 5 of 13
Florida Public Service Commission	ExPLANATION - By rare solublide, excluding reserves and proposed rates for the test year. If any customers are to be transferred from one solublide to another, may texperies accurately for the basisful proce. Contracted factors are used to tackets test	Type of Data Shown:
Company Progress Energy Florida, Inc.	yours only The ball have revenue by discs must equal that shown in Schoolie F. 13a. The bring unit routil equal these stream in Schoolings F-15: FROMDE TOTAL NUMBER OF BILLS, SMM-S, AND BILLING SMM FOR EACH RATE SCHEDUSE ENVELOPMENT.	_XProjected Yest Year Ended 12/31/13 Finor Year Ended
Docket No : 12XXXX-EI	STANDARD AND TIVE OF DEL CUSTOMERS, AND TRANSFER ORGUP	——Historica: Year Ended Witness, Säisser

				2013 REVENUE CA	CULATION FOR RATE SCHEDULE GSD
	PRESENT REVEN	UE CALCULA	ATIONS		PROPOSED REVENUE CALCULATIONS
				1	
Energy Charge:				I	
Standard				l	
Secondary	4,773 044	NWH@ \$	18 06 × S	85.201,179	
Ргільку	149 849	WWH 🛱 🎗	\$8.05 ≖ \$	2,706,278	
relazimensi		ман 🛃 🖇	18.06 - \$	- 1	
Time-of-Use					
Secondary				1	
Co-Peak	2,033,759	MWH@ \$	39,32 = \$	79,967,419	
Cfl-Peak	5,134,545	MWH@S	660 5	33,887,999	
Primary				1	
Gn-Pean	558,703	1847H @ S	39.32 = \$	21,869,553	
CTI-PEZA	1.518,032	Mish @ S	660 * \$	10,019,011	
Transm/Primary				1	
On-Peak	2,824	KWH@ \$	3932 = S	111,042	
Cft-Peax	8,122	1444 G \$	8.60 ≈ S	53,604 (
Sociti				1	
On Peak	5,274	শংগদ জ্বি ১	39.32 = \$	207,371	
Base	14 857	N‰H © ?	8 CO = \$	98,059	
TOTAL	\$4,197.010	MMH	5	235 141 515]	
]	
Adjustments				1	
Distribution Primary Metening	\$\$2	0+ s	51,565,112 = \$	(\$15,651)	
Transmission Meaning	2%	0 7 5	5		
Fower Factor	(623,217)	KVar 5	0 23	Han Said - 1	
TOTAL			5	(658 991) [
Total GSD-1 Base Revenue			ŝ	392,100 755	
			pwing.	**************************************	
				1	
				1	
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				، ۲	

EXHIBIT 1, ATTACHMENT A Page 7 of 15 Duke Energy Florida

Docket No. 150009 ET, Docket 150001-EI Petition - Attachment A Page 58 of 197

Schedule E-13c	BASE REVENUE BY RATE SCHUDULE - CALCULATIONS	Page 6 of 13
Florida Public Service Commission	EXPLANATION. By rare schedule, calculate revenues under procest and proposed roles for the first year. If any custumers are to Le transferred from one schedule to accert, show revenues separating to the transfer group. Correction tactors are used for	Type of Data Shown.
Company: Progress: Energy Ficrida, Inc	historic lest years only. The total base revenue by Gass must replat that shown in Schedule E. 134. The bitting units must equal those shown in Schedules E-15. PROVICE 101AL NUMBER OF BILLS, MWARS, AND BILLING FWA FOR FACH RATE.	"X_Projected Test Year Ended 12/31/13 Prof Year Ended
Docket No. 12xxxx-El	SCHEDULE (HIGLUDING STANDARD AND TIME OF USU DISTOMERS) AND TRANSFER GROUP	L., Historical Year Ended Wimees:

				3 REVENUE C	ALCHLATION FOR RATE SCHEDULE CS
	PRESENT REVENUE	CALCULATION	S		PROPOSED REVENUE CALCULATIONS
					1
Customar Charge:					ł
Standard]
Secondary		B™ @ \$	75,96 ≈ Ş		1
Primary		පි.සිය (ථු 💲	210.93 = \$	•	1
Transmission		පිබද (මූ 💲	787.26 = \$		1
Time-of-Use					I see the second se
Secondary		04s@\$	69.61 = \$	•	1
Primary	48	Biata 🧭 💲	100.38 = 5	9,278	1
Transmission		સનક 😨 💲	72146 = 5		1
TOTAL	48	Bits	\$	9,278	
Demand Charge;					1
Standard					1
Secondary					1
B3led	,	KW G S	651 = S		
Primary					
Billad		×∀r@\$	6 19 - \$		1
Transmission		-			
Cille#	-	KW @ S	532 = \$	-	
Time-of Use					1
Secondary					1
On-Peak		kW@S	549 - S		I
Bate		kW@;S	C97 # \$		1
Prattary					
On Peak	97,600	W @ \$	549 = \$	535,824	1
Base	109,115	k¥v @ \$	0 65 = S	70,925	
Transmission					
On Pesk		kw@s	549 = S		
Base		kW 🤤 S	(6.22) = \$		I
TOTAL Bile/Dase	103,115	kW	101AL \$	606,749	•
					1
					t
					1
					1

EXHIBIT 1, ATTACHMENT A Page 8 of 15 Duke Energy Florida

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Schedule I, 13e	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 7 of 13
Florida Public Service Commission	EXPLANATION. By rate schedulo, calculate revenues uncert present and processed rates for the fost year. If any customers are to be transferred from one schoolde to another, show revenues separately for the transfer group. Covercisis are used to	Type of Data Shown:
Company: Progress Energy Flenda, Nic	Fixionaliest years aniy - The local basis revenue by class incust equal that shown in Schoolie 1.430. The biding units must equal those shows in Schedules E-15 - PRCY DE TOTAL NUMBER OF BILLS, MW-3, AND BILLING WIT PER DACH RATE.	X _Provected Test Year Ended 12/31/13 Prior Year Ended
Docket No. 12xxxx-El	SCHEDULE (INCLUDING STANDARD AND 1:ME OF USE CIRSTOMERS) AND TRANSFER GROUP	Historica: Year Ended Witness:

		20	13 REVENUE CAL	CULATION FOR RATE SCHEDULE CS
	PRESENT REVENUE CALCULATI	ONS		PROPOSED REVENUE CALCULATIONS
· · · · ·			1	
Energy Chargo:			1	
Siencard			±.	
Secondary	- МИН @ \$		- 1	
Primary	• MW1f@ \$		- 1	
Transmission	• MWH @ \$	1189 - 5	1	
Time-of Use			1	
Secondary			1	
On Feak	- WWH @ S		· 1	
Ct Peak	- WWHQES	655 - \$	L	
Premary			i	
On Feak	11.635 MWH @ \$	21.81 * \$	253,749	
Of Peak	24,924 MWH @ \$	6 55 - \$	226,755	
Transmission			1	
On Peak	- MINH @ S	21.81 👂 \$	· · · +	
Off Peak	- NMH @ \$	6 55 ÷ S	<u> </u>	
TOTAL	46,559 MWH	\$	482,504	
			1	
Adjustments			1	
Distribution Primary Melecing	1% OF \$	1.089,253 = \$	(10,893)	
Transmission Metering	2% CF S	5	1	
Power Factor	3,765 Kvar \$	0.23 \$	656	
1014		5	(10,027)	
			(10,021)	
Total CS-1, CS-2, CS-3 Base Revenue		2	1 058,504	
		1		
			1	
			1	
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Schedulu E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 8 of 13
Flanda Public Service Commasion	EXPLANATION. By rate schoolds, calculate revenues under present and prepared rates for the test year. If any customers are to be increations from one whether to a tubler show revenues separately for the transfer group. Convertion factors are used for	Type of Data Shown. X Projected Test Year Ended 12/31/13
Company Progress Energy Florida. Inc	historic test years only. The total base revenue by class must equal that shown in Schedule E. 139. The bling units must equal Buse shown in Schedules E. 15. PROVIDE 1:07AL NUZ/BER OF BILLS, MARTS, AND BILTING KWR FOR EACH RATE.	Phor Year Ended Phor Year Ended Historical Year Ended
Docket No. 12XXX-EI	SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP	Waness:

					ALCULATION FOR RATE SCREDULE IS
	PRESENT REVENUE	CALCULATION	5		PROPOSED REVENUE CALCULATIONS
Customer Charge:					
Standard					
Secondary	348	Biás @ S	276 95 🔺 \$	97,354	
Pamay	338	Bias @ S	41394 - \$	139,917	
Transmesson	-	Bals 🙆 🖇	990.26 = \$		I
Time-of Use					1
Secondary	177	B:1\$ @ \$	278 95 = \$	49 374	1
Primary	660	ይዳሄ @\$	41394 - 5	273,200	
Transmission	108	Bills 🔃 🖇	990.26 = \$	105.948	
TOTAL	1,632	B-lis	\$	656,768	
Demond Charden					
Demand Charge: Standard					1
Secondary - Baled	157,280	KW@ \$	551 <u>-</u> S	856,613	1
	461,425	kW@\$	5.19 - \$	2 394,796	
Primary - Billed	401,425	kYY @ \$	5.19 ÷ \$ 4.32 = \$	x 334/130	
Transmission - Billed	5.571	kw @ \$	432 = S 551 = S	30,65-6	
Blilled SeciPri Blilled TransmiPri	5.571	KA @ 2	432 = 5	30,020	
	-	VIA CE T	432 - 3		1
Time-ol-Use					
Secondary	101.005	1W (2) 1	4.82 = \$	586,136	
On-Pest:	121,605		€.02 = 2 087 = \$	108,095	
Base	124,247	kw@\$	001 = \$	100,000	
Primary	0.550.417		(10 - P	45 442 024	
On-Peak	2,050,117	¥₩@\$	482 = \$	10,112,924	
Base	2,285,625	kW @ \$	0.55 = \$	1,257,094	1
โกรกราณธระดุก	710 600		490 - *	3,619,348	
On-Feak	750,902	kw@s	482 = \$		
Pase	841,532	⊧₩@\$	(0.32) = \$	(259 290)	1
SeuPri	P 0.00		402 - 0	25 504	1
Cn-Peak	5,353	¥₩@ \$	482 = S	25,601	1
Base	5,507	₩© \$	087 = \$	4,791	1
Fridransm					1
On Feak	14,781	¥W @ \$	4.82 = \$	71,244	1
Base	15,792	₩W @ \$	0.55 = \$	8,685	
TransmiPh					
On Peak	678,259	kWi@ \$	4.82 = \$	3,269,205	
Base	704,531	·//:@ \$	(0.32) = \$	(225,453)	1
TCTAL Bise	d/Base 4.601,510	kW	107AL \$	21,860,692	

EXHIBIT 1, ATTACHMENT A Page 10 of 15 Duke Energy Florida

Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 61 of 197

Schadule E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 9 of 13
Florida Public Service Commission	EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any outbankers are to be transformation are schedule to another, show revenues separately to the transfor group. Correction factors are used for	Type of Data Shown: X Projected Test Year Ended 12/31/13
Company, Prograss Energy Flonda, Inc.	historic text years only. The total base revenue by class must equal it at shown in Schedule E-13a, The billing unus must equal topic straws in Schedules E-16, PROVIDE TOTAL MOVERPORTED FLIS, WHATS, AND BUILING KAINFOR FACH RATE to the straws in Walk of the TATE AND ADD ADD ADD ADD ADD ADD ADD ADD ADD	Prior Year Ended Historical Year Ended
Dockel No 12XXXX-EI	SCHEDULE (INCLUSING STANDARD AND TIME OF USE CUSTIONERS) AND TRANSFER GROUP	Witness:

			20	13 REVENUE C/	ALCULATION FOR RATE SCHEDULE IS
P	RESENT REVENUE	E CALCULATIO	NS		PROPOSED REVENUE CALCULATIONS
Energy Charge:				1	
Standard				f	
Secondary	36,701	NWH Q S	797 🤊 💲	292,511	
Рплату	116,935	WWH @ S	797 = \$	931,972 [
Transm-ssion		MAH @ 1	797 = \$	·	
Sec.Pri	1,546	ымн 🎯 1	797 = \$	12,323	
Transm/Pri		NWH@ 1	7.97 + \$	- 1	
Time-of-Use				1	
Socondary				l	
On-Peak	17,073	ମ୍ୟାଳ 😳 🏌	11.16 = \$	190,530	
Cif-Peak	44,033	MAN @ \$	6.51 = \$	286,654	
Primary				1	
Do-Peak	244,364	MMH @ \$	11 16 = \$	2,727,100	l l l l l l l l l l l l l l l l l l l
Off-Peak	725,775	MMH @ S	6.51 • \$	4,724,797	
Transmussion				1	
On-Peak	66 359	MWH & \$	11:6 = \$	740,563	
Off Peak	231,344	MWH @ \$	6 51 🗹 💲	1,506,051	
Sec/Pn					
On-Peak	791	MWH @ S	11.16 = \$	8,825	
Off-Peak	2,310	MWH @ S	651 = \$	15,039	1
Pri/Transm					
On-Peak	5,C62	HWH@\$	1116 = \$	11,852	
O'I-Peak	2,750	WWH @ \$	651 - \$	17,900	
เกิดกราชาว		•			
On-Peak	59,096	MWH @ \$	11 16 ± \$	659,661	
Off-Peak	154,508	ଏଏକ ହୁ	6.51 × S	1,006,238	
TOTAL	1,704,666	NWH		13,131,415	
					1
Adjusiments					
Distribution Primary Metering	1%	OF §	25,955,214 = \$	(269,552)	
Transmission f/elening	2%		5,706.354 = \$	(114,127)	
Power Factor	(42,425)		023 \$	(9,758)	
TOTAL	(in a)		S	(333.437)	
			1		
Total IS-1, IS-2 Base Revenue			S	35,255,458	
				*	1
					}

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Schedule E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 10 of 13
Florida Public Service Commission	EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another show revenues separately for the transferred from correction factors are used for historic test.	Type of Data Shown.
Company: Progress Energy Florida, Inc.	yona chy. The fold base revenue by class from open natisform to School e E-15a. The billing units must equal hose shown of School are E-15. PROVIDE TOTAL NUMBER OF DELIS, MMHS, AND En UNS KMT FOR EACH RATE SCHEDULE (NOLLEDNIG	_X_Projected Test Year Ended 12/31/13 Prior Year Ended Hsterica: Year Ended
Deckel No : 12XXXX-EI	STANDARD AND THE OF USE CUSTOMERSEAND TRANSFER GROUP	Witness:

			ALCULATION FOR RATE SCHEDULE LS
	PRESENT REVENUE CALCUL	ATIONS	PROPOSED REVENUE CALCULATIONS
ustomer Charge:			
anderd			
Unrasered	728,529 Bills @	\$ 1,19 = \$ 806,950	
Secondary	6,636 Bin @		
TOTAL	738,525 EFs	\$ 201,126	
IUIAL	730,020 19/5	3 301,130	
lergy & Demand Charge:			
andard			
Secondary	371,280 MWH @	\$ 17 07 = \$ 6,337,750	
,	_		
djustments			
n/a		\$	
sta: LS-1 Base Revenue		\$ 7,238,866	
		1	

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Schedule E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 11 of 13
Florida Public Service Commission	EXPLANATION. By rate sets kine, cats value control under present and proposed rates for the test year. If any distortions are to be transferred from one acheoute to another, show revenues separately for the transfer group. Connection factors are used for function test	Тура of Data Showл
Company: Progress Energy Florida, Inc.	years only. The total base revenue by class must equal that shewr in Schedule F-13a, The blong units must equal shore shown in Schedulize E 15, FROVIDE TOTAL NUMBER OF SHLES INVERS, AND BITUNG KM- FOR EACH RATE SCHEDULE (INCL, OHD	_XProjected Tast Year Ended 12/31/13
Docket No 12xxxx-El	STANDARD AND THE CYLLISE CURTOMERS) AND TRANSFER GROUP	Historical Year Endod Wilness:

						201	13 REVENUE CA	LCULATION FOR RATE SCHEDULE \$5.1
	PRESENT	T REVENUE C	ALCULATI	ONS				PROPOSED REVENUE CALCULATIONS
Customer Charge:								
Primary		26	Gels 🕲		235 59		8,485	
ารเลลเกลาหาโ		12	Bils @		812.02		5,744	
Pri/Transm (Custorrer Owned)		72	8:15 @	ş	81.21		5,847	1
	Total	120	Bits			\$	24,070	
Demand Charge:								1
Distribution Charge								1
Premary		65,160	k₩ @	\$	1.59	= \$	108,374	1
Transmission		335,032	kW @					(
Generation & Transm			-					1
(Greater of SB Cap/DD)								1
Pnmary								1
Specified SB Cap		66,900	kW @	\$	0.858	· \$	59,407	1
Cally Demand		124,633	XW @		0 423	= \$	52,720	1
Transmission			-					1
Specified SB Cap		224,850	*W @	\$	0 868	- S	199,667	1
Daily Demand		409.315	XW @	\$	0 423	= \$	173,140	1
Total Speci	fied SB Cap	453,192			lotal	\$	593,308	1
								1
Energy Charge:								1
Standard								1
Pamary			MWH @		7.85		22,132	1
Transmession		9,371	-	ţ.	7.86		73,658	I
	Teta:	12,187	MAYH			\$	95,730	1
Adjustments		63.45C			10.01-			1
Dofwery Voltage Credit		69,150	6.6	\$	(0.29)		(19,765)	
Distribution Primary Meleting		1%	Cr.	5	242,633		(2,426)	
Transmission Matering	* ·	2%	O F	\$	446,455		(8,529)	
	ែតេ					\$	(11,355)	
Total SS-1 Base Revenue						s	701,819	1
								}

EXHIBIT 1, ATTACHMENT A Page 13 of 15 Duke Energy Florida

Docket No. 150009-EI, Docket 150001-EI Petition - Attachment A Page 64 of 197

Schedule E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 12 of 13
Florida Fublic Service Commission	EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. Tany customers are to be transitived from one schedule to another, show meanwer separately for the transfer group. Connection factors are used for historic leaf	Type of Data Shown:
Company, Progress Energy Florida, Inc.	years only. The solal base rowed is by class that the qualities shown in Schedule E-13a. The bring while must equal these shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MARTS, AND BULLNG WIN FOR CACH RATE SCHEDULT (\$3CCUDING)	"X Projected Test Year Ended 12/31/13 Prior Year Ended
Docket No: 12xxxx-El	STANDARD AND THE OF USE CUSTOMERS) AND TRANSFER GROUP	Historical Year Ended Witness

					VIS REVENUE	CALCULATION FOR RATE SCHEDULE SS-2
PRESE	NT REVENUE	CALCUL	ATION	8		PROPOSED REVENUE CALCULATIONS
Customer Charge:						
Primary	12	සිංහ බූ		438.68 = \$	5,264	I
Transmission	-	Bits 🗗		1,015.02 ≈ \$		1
Transmission (Customer Owned)	12	Bills @	\$	284 20 = \$	3,410	1
Teta	24	Bills		\$	8,574	1
Demand Charge:						1
Distribution Charge						1
Photory	114,000	IW @	s	1.59 = \$	181,260	l I
Transmission	398,640	₩@		د s		t t
Generation & Transm				-		1
(Greater of S8 Cop/CO)						1
Рилагу						4
Specified SB Cap	38,003	₩@	\$	0.899 - \$	33 744	۰ ۲
Daily Demand	2,082,093	KW @		0.423 - \$	880,725	1
Transmission		0				
Specified SB Cap	25.093	kW @	s	0.888 = \$	22,287	}
Daily Demand	3,272,984	kW @		0.423 = \$	1,384,472	
Total Specified SB Cap	737,880	0		total \$	2,502,498	1
						1
Energy Charge:						•
Slandard						
Primary	11 862	мүн @	s	7.77 - \$	92,167	1
Transmission	132,743	NWH @	s	7.77 = \$	1,031,414	l
_ Tolal	:44,605	HWH		\$	1,123,581	
Adjustments						1
Delivory Voltage Credit	114,000		5	(C.29) \$	(33,060)	l
Distribution Primary Metering	1%	Ct:	\$	1,187,895 = \$	[11,879]	t i i i i i i i i i i i i i i i i i i i
Transm-salon Melenng	2%	0÷	\$	2,438,173 = \$	(48,763)	ł
Tc4a:				\$	(\$07 EQ]	ŧ
						1
Total SS-2 Base Revenue				\$	3,541,641	t
						i

EXHIBIT 1, ATTACHMENT A Page 14 of 15 Duke Energy Florida

Docket No. 150009-EI, Docket 150001-EI Petition - Attachment A Page 65 of 197

Schedule E.13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 13 cl 13
Florida Public Service Commission	EXPLANATION: By rate schedule, calculate revenues under present and prophrised ratio for the fest year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Currection factors are used for	Type of Data Shown:
Company: Progress Energy Florida, Inc.	histofic feat years only. This lotal base revenue by class must equival that shown in Schedule E. 13a . The biting units must equid Indee shown in Schedules F-15 PROVIDE TOTAL NUMBER OF BILLS, MWH75, AND BILLING KWI FOR FACIN RATE	_X_Projectod Test Year Ended 12/31/13 Pror Year Ended
Docker No 12000X-EI	SCHEDULE (NOLUDING STANDARD AND TIME OF USE OUSTOMERIS) AND TRANSFER OROUP	Histoncal Year Endro Witness:

obcecu	TREVENUE	CALCULY	TION	e		13 REVENUE CA
PRESEN	I NEVERUE	CALCULA		.a		
Customer Charge;						
-						
Primaty	24	9.55 Q	\$	235 69	\$	5,657
Formary (Customer Owned)	24	Bills 🕲	\$	81.21	≂ \$	1,949
Transmission	•	8¢s @	\$	812 02	= \$	
Toja	48	eds			s	7,600
Demand Charge:						
Primary	170,340	₩Ø	\$	1.59	- S	270,841
Transmission		¥₩ @			∴ \$	
Generation & Transm		<u>c</u> ,				
(Groater of SB Cap/DD)						
Pamary						
Specified SB Cep	58,760	kW @	s	0 688	~ \$	50,421
Daily Demand	643,721	kW 😧	\$	Ç 423	e S	272,294
Transmission						
Specified S8 Cap	-	k% @	\$	0 868	× 5	
Divy Demand		₩Ø	\$	0.423	- \$	-
Total Specified SB Cap	170,340	kly		Total	\$	593,556
Energy Charge:						
Energy Unarge: Standard						
Primary	16 //9	FRANK AR	ę	7.00		130 004
Immary Transmission	16,448	NWH @		7.80 7.60		128,294
Tensmission Igial	16,448	MWE @	ą	101	- <u>-</u>	128,291
Adjustments:	10,140	DO NT 17			4	120,291
Deivory Voitaga Credit	170,340		\$	(0.29)	s	(49,399)
Distribution Primary Motering	170,040 1%	ÓF	ə S	721,850		(48,399) (7,219)
Transmission Molenng	2%	OF OF	ŝ		* 2 : 5	(1219)
Tolar	274	Qr	÷		- - S	(50.618)
10:2'					*	(50.018)
Total SS-3 Base Revenue					\$	672,838
LOTOL TOAD THERE LIKE AT 1108						0/2,030

Attachment B

Calculation of detailed base rate charge by rate schedule including current rates and proposed settlement rates

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Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 67 of 197

PROGRESS ENERGY FLORIDA Base Rate Detailed Unit Charges by Rate Schedule 2013 Test Year - Settlement Uniform % Increase Demand & Energy Charges

Page 1 of 5

Num 21/02/10 11/02/10 Actual Relies (CS) Proposed Proposed Current/Pror Settlement Schedule Type of Charge Ref Ref Ref Current/Pror Settlement Schedule Type of Charge 10.0 91.00 91.00 91.00 91.00 91.00 70.00 Schedule Transfer of Account - No LSA Contract - \$ 22.00		2013 Test Year - Settlement Uniform % I		nts / kWh	\$/k	Wh
Base Schedule Type of Charge CurrentPhore Rate Settement Rate CurrentPhore Rate Settement Rate SC-1 Inblat Correction - 5 81.00 91.00 <t< th=""><th></th><th></th><th>2/10/2010</th><th>1/1/2013</th><th>Actual Billing</th><th>Rate (CSS)</th></t<>			2/10/2010	1/1/2013	Actual Billing	Rate (CSS)
Schedule Type of Charge Rate Rate Rate Rate Rate Rate Rate SC-1 billal Connection - \$ 61.00 62.00 28.00 28.00 28.00 28.00 28.00 28.00 28.00 28.00 60.00 50.00 50.00 50.00 75.00<				Proposed		Proposed
Schedule Type of Charge Rate Rate Rate Rate Rate Rate Rate SC-1 billal Connection - \$ 61.00 62.00 28.00 28.00 28.00 28.00 28.00 28.00 28.00 28.00 60.00 50.00 50.00 50.00 75.00<	Defe		Current/Prior	Settlement	Current/Prior	Settlement
SC-1 Ixibial Connection - 5 Plo0		Type of Charge				
Reconnection - \$ 28.00 10.00 11.00						
Construction Construct - 5 28.00 28.00 28.00 28.00 28.00 28.00 28.00 28.00 10.00 </td <td>SC-1</td> <td>Initial Connection - \$</td> <td>\$1.00</td> <td>61.00</td> <td>61.00</td> <td></td>	SC-1	Initial Connection - \$	\$1.00	61.00	61.00	
Transfer of Account - No LSA Contract - \$ 2800 28.00 28.00 28.00 28.00 28.00 10.00		Reconnection - \$	28.00	28.00	28,00	
Reconnect And Disconnect For Non Pay - 5 40.00 40.00 40.00 40.00 40.00 40.00 90.00 <td></td> <td>Transfer of Account - No LSA Contract - \$</td> <td>28.00</td> <td>28.00</td> <td>28.00</td> <td></td>		Transfer of Account - No LSA Contract - \$	28.00	28.00	28.00	
Reconnect Atter Disconnect For Non Pay - 5 40.00 40.00 40.00 40.00 50.00 Reconnect Atter Disconnect For Non Pay Atter Hours - 5 50.00 50.00 50.00 75.00 75.00 Late Payment Charge 25.07 50.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.01 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 75.00 <td< td=""><td></td><td>Transfer of Account - LSA Contract Required - \$</td><td>10.00</td><td>10.00</td><td>10.00</td><td></td></td<>		Transfer of Account - LSA Contract Required - \$	10.00	10.00	10.00	
Investigation of Loadborted Use - (RPI) 75.00		Reconnect After Disconnect For Non-Pay - \$	40.00	40.00	40,00	
Investigation of Unauthorized Use - (RPI) 75.00 <td></td> <td>Reconnect After Disconnect For Non-Pay After Hours -\$</td> <td>50,00</td> <td>50.00</td> <td>50.00</td> <td>50.00</td>		Reconnect After Disconnect For Non-Pay After Hours -\$	50,00	50.00	50.00	50.00
Late Payment Change > \$5.00 or 1.5% \$5.00 or 1.5% <td></td> <td></td> <td></td> <td>75.00</td> <td>75.00</td> <td>75.00</td>				75.00	75.00	75.00
Returned Check Charge \$25 ff <= \$20 \$30 ff <= \$30 \$30 ff <= \$30 \$40 ff <= \$30 ff <= \$30 \$40 ff <= \$30 ff		-				
Spill (+ = 500) Spill (+ =		Late 1 dynore one ge				
#40 if <= 5800 540 if <= 5800 540 if <= 5800 540 if <= 5800 540 if <= 5800 550 if > 5800 5500 if > 5800 55000 if > 5800 55000 if > 58000 55000 if > 58000000000 55000 if > 58000000000000000000		Returned Check Charge	\$25 lf <= \$50	\$25 if <= \$50	\$25 if <= \$50	\$25 # <= \$50
5% if > 5000 5% if > 50000 5% if > 50000 5% if > 500			\$30 if <= \$300	\$30 ff <= \$300	\$30 if <= \$300	\$30 lí <= \$300
TS.1 Temporary Service Extension - Mentalty S 227.00 <th< td=""><td></td><td></td><td>\$40 H <= \$800</td><td>\$40 if <= \$800</td><td>\$40 if <= \$800</td><td>\$40 if <= \$800</td></th<>			\$40 H <= \$800	\$40 if <= \$800	\$40 if <= \$800	\$40 if <= \$800
XS-1 Customer Charge - S per Line of Billing XS-1 Standard 8.76 8.75 8.76 8.75 8.76 8.75 8.75 8.75 <td></td> <td></td> <td>5% if > \$800</td> <td>5% if > \$800</td> <td>5% if > \$800</td> <td>5% if > \$800</td>			5% if > \$800			
RST-1 Standard 6.76 6.76 8.76 6.76 8.76 6.76 8.76 6.76 8.76 6.76 8.76 6.76 4.58 4.59 4.59 4.59 4.59 4.59 4.59 4.59 4.59 6.76 77 77 77 77 77 77 77 77 77 77 77	rs-1	Temporary Service Extension - Monthly \$	227.00	227.00	227,00	227.00
RST-1 Standard 6.76 6.76 8.76 6.76 8.76 6.76 8.76 6.76 8.76 6.76 8.76 6.76 4.58 4.59 4.59 4.59 4.59 4.59 4.59 4.59 4.59 6.76 77 77 77 77 77 77 77 77 77 77 77	25.4	Customer Charge Rear Line of Billing				
SS-1 Sesonal (RSS-1) 4.58 4.58 4.59 4.59 (RST-closed (RST-closed) Single Phase 16.19 16.19 16.19 16.19 16.19 2/10/2010) Single Phase 16.19 16.19 16.19 16.19 16.19 Customer CIAC Paid 8.76 8.76 8.76 8.76 8.76 TOU Metening CIAC - \$ One Time Charge 90.00 90.00 90.00 90.00 90.00 Energy and Demand Charge - cents per KWH Standard 0.1 (00 KWH 3.982 4.509 0.03982 0.04509 Over 1.000 KWH 5.073 5.744 0.05673 0.0773 0.00663 0.00773 SS1-1 Standard 11.59 11.59 11.59 11.59 11.59 SS1-1 Standard 0.9862 0.04509 0.0583 0.773 0.00683 0.0773 SS1-1 Standard 12.271 13.524 11.59 11.59 11.59 11.59 SS1-1 Standard 1.991 1.991 <td></td> <td>• • •</td> <td>0.70</td> <td>n 74</td> <td>0.70</td> <td>D 70</td>		• • •	0.70	n 74	0.70	D 70
Classed Utb/2010) Time of Use Single Phase 16.19 10.00 10.00 10.00 10.00 10.00 10.00 10.00 10.00 10.00 10.00						
Single Phase 16.19 16.19 16.19 16.19 16.19 Three Phase 16.19 16.19 16.19 16.19 16.19 Customer CIAC Paid 8.76 8.76 8.76 8.76 8.76 TOU Matering CIAC - \$ One Time Charge 90.00 90.00 90.00 90.00 90.00 Energy and Demand Charge - cents per KWH 3.862 4.509 0.03962 0.04509 Over 1,000 KWH 3.982 4.509 0.03962 0.04509 Over 1,000 KWH 5.073 5.744 0.05073 0.00683 Time of Use - Off Peak 12.297 13.824 0.1297 0.13924 Time of Use - Off Peak 0.2563 0.773 0.00683 0.00773 SS-1, Customer Charge - \$ per Line of Billing 15.59 11.59 11.59 11.59 SS-1, Customer Charge - \$ per Line of Billing 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 146.56 Ot Use	355-1	Seasonal (RSS-1)	4.58	4,58	4.58	4.58
Three Phase 16.19 16.10 10.00 <th10.00< th=""> 10.00</th10.00<>	RST closed	Time of Use				
Three Phase 16.19 16.10 10.00 <th10.01< th=""> 10.01</th10.01<>	(10/2010)	Single Phase	16,19	16.19	16,19	16.19
Customer CIAC Paid 8.76 8.76 8.76 8.76 TOU Metering CIAC - \$ One Time Charge 90.00 90.00 90.00 90.00 Energy and Demand Charge - cents per KWH 3.982 4.509 0.03982 0.04509 O - 1,000 KWH 3.982 4.509 0.03982 0.04509 Over 1,000 KWH 5.073 5.744 0.05073 0.05744 Time of Use - On Peak 12.297 13.924 0.12297 0.13924 Time of Use - On Peak 0.683 0.773 0.00683 0.00773 SS-1, Standard 0.683 0.773 0.00683 0.00773 SS-1, Standard 11.59 11.59 11.59 11.59 Ummetered 0.54 6.54 6.54 6.54 Secondary 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 Single Phase 19.01 19.01 19.01 19.01 Customer CIAC Paid 11.59 11		-	16 19	16 19	16.19	15.19
Energy and Demand Charge - cents per KWH Standard 0 - 1,000 KWH 3.862 4.509 0.03962 0.04509 Over 1,000 KWH 5.073 5.744 0.05073 0.05744 Time of Use - On Peak 12.297 13.824 0.12297 0.13924 Time of Use - On Peak 35-1, Customer Charge - \$ per Line of Billing 35-1, Standard Unmetered 6.54 6.54 6.54 6.54 6.54 Scondary 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 Transmission 722.90 722.90 722.90 722.90 Time of Use Single Phase 19.01 19.01 19.01 19.01 Three Phase 19.01 19.01 19.01 19.01 Three Phase 19.01 19.01 19.01 19.01 Three CIAC Paid 11.59 11.59 11.59 Primary 153.99 153.99 153.99 153.99 Transmission 730.32 730.32 730.32 730.32 TOU Metering CIAC - \$ One Time Charge Energy and Demand Charge - cents per KWH Standard 4.326 4.898 0.04326 0.04866 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Energy and Demand Charge - cents per KWH Standard 4.326 4.898 0.04326 0.04866 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Fremy and Demand Charge - cents per KWH Standard 4.326 4.898 0.04326 0.04866 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Premium Distribution Charge - cents per KWH Standard 4.326 4.899 0.04326 0.04686 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Premium Distribution Charge - cents per KWH 0.591 0.665 0.753 0.000655 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.000669 Meter Voltage Adjustment - % of Demand & Energy Charges Primary 1.0% 1.0% 1.0% 1.0% 1.0%						
Standard 0 -1,000 KWH 3,982 4.509 0.03982 0.04509 Over 1,000 KWH 5.073 5.744 0.05073 0.05744 Time of Use - On Peak 12.297 13.924 0.12297 0.13924 Time of Use - On Peak 0.683 0.773 0.0683 0.00773 GS-1, Customer Charge - \$ per Line of Billing 5374 0.654 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 146.56 153.99 153.99 153.99		TOU Metering CIAC - \$ One Time Charge	. 90.00	90.00	90,00	90.00
0 - 1,000 KWH 3,982 4,509 0.03982 0.04509 Over 1,000 KWH 5,073 5,744 0.05073 0.0574 Time of Use - On Peak 12,297 13,824 0.12297 0.13924 S5.1, Customer Charge - S per Line of Billing 0.0573 0.773 0.00683 0.00773 GS5.1 Standard 11.59 11.59 11.59 11.59 11.59 Customer Charge - S per Line of Billing 5574 6.54 6.54 6.54 6.54 Secondary 11.59 11.59 11.59 11.59 1159 Primary 146.56 146.56 146.56 146.56 146.56 Transmission 722.60 722.90 722.90 722.90 722.90 Three of Use 19.01 19.01 19.01 19.01 19.01 19.01 19.01 Customer CLAC Paid 11.59 11.59 11.59 11.59 11.59 Primary 153.90 153.90 153.90 153.90 153.90		Energy and Demand Charge - cents per KWH				
Over 1,000 KWH 5,073 5,744 0,05073 0,05744 Time of Use - On Peak 12,297 13,824 0,12297 0,13924 Time of Use - Off Peak 0,683 0,773 0,00683 0,00773 GS-1, Customer Charge - \$ per Line of Billing 5 6 54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 6.54 146.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 145.56 155.99 153.69 153.6		Standard				
Time of Use - On Peak 12.297 13.924 0.12297 0.13924 Time of Use - Off Peak 0.683 0.773 0.00683 0.00773 SS-1, Customer Charge - \$ per Line of Billing 537-1 Standard 0.683 0.773 0.00683 0.00773 SS-1 Standard 8.54 6.54		0 - 1,000 KWH	3.982	4.509	0.03982	0.04509
Time of Use - Off Peak 0.683 0.773 0.00683 0.00773 SS-1, Customer Charge - S per Line of Billing 537-1 Standard 537-1 Standard 6.54 146.56 14		Over 1,000 KWH	5.073	5.744	0.05073	0.05744
Time of Use - Ort Peak 0.683 0.773 0.00683 0.00773 SS-1, Customer Charge - \$ per Line of Billing 537-1 Standard 537-1 Standard 6.54 146.56 14		Time of Use - On Peak	12.297	13,924	0,12297	0.13924
Standard Standard Unmetered 6.54 6.54 6.54 6.54 Secondary 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 Transmission 722.90 722.90 722.90 722.90 Time of Use 19.01 19.01 19.01 19.01 Single Phase 19.01 19.01 19.01 19.01 Three OLAC Paid 11.59 11.59 11.59 Primary 153.99 153.99 153.99 153.99 Transmission 730.32 730.32 730.32 730.32 TCU Metering CIAC - \$ One Time Charge 132.00 132.00 132.00 132.00 Energy and Demand Charge - centa per KWH 12.278 13.902 0.12278 0.13902 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - On Peak 12.278 13.902 0.02278 0.000651 Time of Use - Off Peak 0.665						
Standard Standard Unmetered 6.54 6.54 6.54 6.54 Secondary 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 Transmission 722.90 722.90 722.90 722.90 Time of Use 11.59 11.59 11.59 11.59 Single Phase 19.01 19.01 19.01 19.01 Three OLAC Paid 11.59 11.59 11.59 Primary 153.99 153.99 153.99 153.99 Primary 153.99 153.99 153.99 153.99 Transmission 730.32 730.32 730.32 730.32 TOU Metering CIAC - \$ One Time Charge 132.00 132.00 132.00 132.00 132.00 132.00 Energy and Demand Charge - centa per KWH 12.278 13.902 0.12278 0.13902 Time of Use - On Peak 12.778 13.902 0.12278 0.13902 1.0396 0.00591						
Secondary 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 Transmission 722.90 722.90 722.90 722.90 Time of Use 19.01						
Secondary 11.59 11.59 11.59 11.59 11.59 Primary 146.56 146.56 146.56 146.56 146.56 Transmission 722.90 722.90 722.90 722.90 722.90 Time of Use		Unmetered	6.54	6.54	6,54	6.54
Primary 148.56 159.57 153.99 153.99 153.99 153.99 153.99 153.99 153.99 153.99			11.59	11.59	11.59	11.59
Transmission 722.90 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 19.01 12.00 122.00 132.00 132.00 132.00						
Time of Use 19.01 19.01 18.01 19.01 Three of Use 19.01 19.01 18.01 19.01 Three Phase 19.01 19.01 18.01 19.01 Customer CIAC Paid 11.59 11.59 11.59 11.59 Primary 153.99 153.99 153.99 153.99 153.99 TroU Metering CIAC - \$ One Time Charge 132.00 132.00 132.00 132.00 132.00 Energy and Demand Charge - centa per KWH 5tandard 4.326 4.898 0.04328 0.04898 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - Off Peak 0.665 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% <td></td> <td>-</td> <td></td> <td></td> <td></td> <td></td>		-				
Single Phase 18.01 19.01 19.01 19.01 19.01 Three Phase 19.01 19.01 19.01 19.01 19.01 19.01 Customer CIAC Paid 11.59 11.59 11.59 11.59 11.59 Primary 153.99 153.99 153.99 153.99 153.99 730.32 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00			122.00	122.90	122.80	122.00
Three Phase 19.01 153.99 153.99 153.99 153.99 153.99 153.99 153.09 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00						
Customer CIAC Paid 11.59 133.09 133.09 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00		Single Phase				
Frimary 153.99 153.99 153.99 153.99 Transmission 730.32 730.32 730.32 730.32 TCU Metering CIAC - \$ One Time Charge 132.00 132.00 132.00 132.00 Energy and Demand Charge - cents per KWH 5 5 0.04326 0.04326 0.043696 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - On Peak 0.6655 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 0.0		Three Phase	19.01	19.01	19.01	19.01
Primary 153.99 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 132.00 10.99 1.039 1.039 <td></td> <td>Customer CIAC Paid</td> <td>11,59</td> <td>11.59</td> <td>11.59</td> <td>11.59</td>		Customer CIAC Paid	11,59	11.59	11.59	11.59
Transmission 730.32 7			153.99	153,99	153,99	153.99
Energy and Demand Charge - cents per KWH Standard 4.326 4.898 0.04328 0.04898 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - Off Peak 0.665 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 0.00671 0.00669 0.00591 0.00669		-	730.32			730.32
Standard 4.326 4.898 0.04326 0.04966 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - Off Peak 0.665 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.		TCU Metering CIAC - \$ One Time Charge	132.00	132.00	132.00	132.00
Standard 4.326 4.898 0.04326 0.04966 Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - Off Peak 0.665 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.0% 1.0% 1.0% 1.0% 1.0%		Fnerov and Demand Charoe - cents per KWH				
Time of Use - On Peak 12.278 13.902 0.12278 0.13902 Time of Use - Off Peak 0.665 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 1.0% 0.0051 0.00669			A 328	4 80.9	0.04328	0.04898
Time of Use - Off Peak 0.665 0.753 0.00665 0.00753 Premium Distribution Charge - cents per KVVH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0% 1.0% 1.0% 1.0% 0.00669						
Premium Distribution Charge - cents per KWH 0.591 0.669 0.00591 0.00669 Meter Voltage Adjustment - % of Demand & Energy Charges 1.0%						
Meter Voltage Adjustment - % of Demand & Energy Charges Primary 1.0% 1.0% 1.0% 1.0% 2.00		Time of Use - Off Peak	0.665			
Primary 1.0% 1.0% 1.0% 1.0%		Premium Distribution Charge - cents per KWH	0.591	0.669	0.00591	0.00669
Primary 1.0% 1.0% 1.0% 1.0%		Meter Voltage Adjustment - % of Demand & Energy Charges				
		• •	1.0%	1.0%	1.0%	1.0%

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PROGRESS ENERGY FLORIDA Base Rate Detailed Unit Charges by Rate Schedule 2013 Test Year - Settlement Uniform % Increase Demand & Energy Charges

	2013 Test Year - Settlement Uniform % Inc	ease Demand & Energy Charges cents / kWh \$7kWh						
				Actual Billing Rate (CSS)				
		2/10/2010	1/1/2013	Actual Bling	Proposed			
			Proposed	0	Settlement			
Rate		Current/Prior	Settlement	Current/Prior	Rate			
Schedule	Type of Charge	Rate	Rate	Rate	1.67%			
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1.0776			
	O stand Oburge - Brank for of Dillog							
GS-2	Customer Charge - \$ per Line of Billing Standard							
	Unmetered	6.54	6.54	6.54	6,54			
	Metered	11.59	11.59	11.59	11.59			
	Energy and Demand Charge - cents per KWH							
	Standard	1.640	1.857	0.01640	0.01857			
	Premium Distribution Charge - cents per KWH	0.119	0.135	0.00119	0.00135			
GSD-1	Customer Charge - \$ per Line of Billing							
GSDT-1	Standard							
	Secondary	11.59	11,59	11,59	11.59			
	Primary	146.56	146.56	146.56	148,56			
	Transmission	722.90	722.90	722.90	722.90			
	Time of Use							
	Secondary	19.01	19.01	19.01	19.01			
	Secondary - Customer CIAC paid	11.59	11,59	11,59	11.50			
	Primary	153.99	153.99	153.99	153.99			
	Primary - Customer CIAC paid	146.56	146.56	146.56	148.58			
	•	730.32	730.32	730.32	730.32			
	Transmission			722.90	722.90			
	Transmission Customer CIAC paid	722.90	722.90	722,90	122.90			
	Demand Charge - \$ per KW							
	Standard	4.05	4.59	4.05	4.59			
	Time of Use							
	Base	0.99	1.12	0.99	1.12			
	On Peak	3.01	3.41	3.01	3.41			
	Delivery Voltage Credits - \$ per KW							
	Primary	0.32	0.36	0.32	0.36			
	Transmission	1,19	1,35	1.19	1.35			
	Premium Distribution Charge - \$ per KW	0.87	0.99	0.87	0.99			
	Energy Charge - cents per KWH							
	Standard	1.806	2.045	0.01808	0.02045			
	Time of Use - On Peak	3.932	4.452	0.03932	0.04452			
	Time of Use - Off Peak	0.660	0.747	0.00660	0.00747			
	Meter Voltage Adjustment - % of Demand & Energy Charges	2 001	* 0.04	1.0%	1,0%			
	Primary	1.0%	1.0%	1.0%	2.0%			
	Transmission	2.0%	2.0%		0.26			
	Power Factor - \$ per KVar	0.23	0.26	0.23				
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.87%	1.67%	1.67%			
CS-1								
CS-2	Customer Charge - \$ per Line of Billing		35.05	75 0.0	75,96			
CS-3	Secondary	75.96	75.96	75.96				
CST-1	Primary	210.93	210.93	210.93	210.93			
CST-2 CST-3	Transmission	787.28	787.26	787.26	787.26			
031-9	Demand Charge - \$ per KW							
	Standard	6.51	7.37	6.51	7.37			

Time of Use

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PROGRESS ENERGY FLORIDA Base Rate Detailed Unit Charges by Rate Schedule 2013 Test Year - Settlement Uniform % Increase Demand & Energy Charge

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	2013 Test Year - Settlement Uniform % I		gy Charges :/kWh	\$/kWb	
		2/10/2010	1/1/2013		Rate (CSS)
		1.10.2010	Proposed		Proposed
Rate		Current/Prior	Settlement	Current/Prior	Settlement
Schedule	Type of Charge	Rate	Rate	Rate	Rate
JUNCOUR	Base	0.97	1.10	0.97	1.10
	On Peak	5,49	6.22	5.49	6.22
	Curtailable Demand Credit				
	CS-1, CST-1 - \$ per KW of Curtaliable Demand	2.50	3.74	2.50	3.74
	CS-2, CST-2 - \$ per KW LF adjusted Demand	2.48 2.48	6,53 6,53	2.48 2.48	6.53 6.53
	CS-3, CST-3 - \$ per KW of Contract Demand	2.40	0.55	2.40	0.55
	Delivery Voltage Credits - \$ per KW				
	Primary	0.32	0.36	0.32	0.36
	Transmission	1.19	1.35	1.19	1.35
	Premium Distribution Charge - \$ per KW	0.87	0.99	0.87	0.99
	Energy Charge - cents per KWH				
	Standard	1.189	1.346	0.01189	0.01346
	Time of Use - On Peak	2.181	2.470	0.02181	0.02470
	Time of Use - Off Peak	0,655	0.742	0.00655	0.00742
	Meter Voltage Adjustment - % of Demand & Energy Charges				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%
	Power Factor - \$ per KVar	0.23	0.26	0.23 1.67%	0.26 1.67%
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	0,770,1	1.0770
IS-1	Customer Charge - \$ per Line of Billing		674 b.f	070.05	6 30.00
15-2	Secondary	278.95	278.95	278.95	278.95
IST-1 IST-2	Primary Transmission	413.94 990.26	413.94 990.26	413.94 990.26	413.94 990.26
10114	s ran refrime reals				
	Demand Charge - \$ per KW				
	Slandard	5.51	6.24	5,51	6.24
	Time of Use				
	Base	0.87	0.99	0.87	0.99
	On Peak	4.82	5,46	4.82	5.46
	Interruptible Demand Credit	7.50	4,99	3.62	4.99
	IS-1, IST-1 - \$ per KW of Billing Demand IS-2, IST-2 - \$ per KW LF Adjusted Demand	3.62 3.31	4.95 8.70	3.31	8,70
	(3-2, 131-2 - 3 per 144 Lr Pujusted Dertrains	5.51	0.70	0.01	0.70
	Delivery Voltage Credits - \$ per KW				
	Primary	0.32	0.36	0.32	0.36
	Transmission	1.19	1,35	1.19	1.35
	Premium Distribution Charge - \$ per KW	0.87	0.99	0.87	0.99
	Energy Charge - cents per KWH				
	Standard	0.797	0,902	0.00797	0.00902
	Time of Use - On Peak	1.116	1.264	0.01116	0.01264
	Time of Use - Off Peak	0.651	0.737	0.00651	0.00737
	Meter Vollage Adjustment - % of Demand & Energy Charges				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%
	Power Factor - \$ per KVar	0.23	0.26	0.23	0.26
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1,67%

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PROGRESS ENERGY FLORIDA Base Rate Detailed Unit Charges by Rate Schedule 2013 Test Year - Settlement Uniform % Increase Demand & Energy Charges

	2013 Test Year - Settlement Uniform % Increase				
			/ kWh	\$/k)	
		2/10/2010	1/1/2013	Actual Billing	
			Proposed		Proposed
Rate		Current/Prior	Settlement	Current/Prior	Settlement
Schedule	Type of Charge	Rate	Rate	Rate	Rate
LS-1	Customer Charge - \$ per Line of Billing				
23-1	Standard				
		1.19	1.19	1,19	1.19
	Unmetered		3.42	3.42	3.42
	Metered	3.42	3.42	3,4∠	3.42
	Energy and Demand Charge - cents per KWH				
	Standard	1.707	1.933	0.01707	0.01933
	Fixture & Maintenance Charges - \$ per future	n/a	n/a	n/a	n/a
	Pole Charges - \$ per pole	n/a	n/a	r/a	n/a
	Leic ouglies , the have				
	Other Fishers Charge Date M of leatelled Sixture Cost	1.58%	1.59%	1.59%	1.59%
	Other Fixture Charge Rate - % of Installed Fixture Cost	1.82%	1.82%	1.82%	1.82%
	Other Pole Charge Rate - % of Installed Pole Cost	1.8276	1.0270	1.02.70	1.02.70
SS-1	Customer Charge - \$ per Line of Billing				
	Secondary	100.71	100.71	100.71	100.71
	Primary	235.69	235.69	235.69	235.69
	Transmission	812.02	812.02	812,02	812.02
	Customer Owned	81.21	81.21	81.21	81.21
	Base Rate Energy Customer Charge - cents per KWH	0.786	0,890	0.00786	0,00890
	Dage (refo Eller B) opposite one (ge in the second				
	Distribution Charge - \$ per KW				
		1.50	1.80	1.59	1,80
	Applicable to Specified SB Capacity	1.00			
	Generation and Transmission Capacity Charge				
	Greater of : - \$ per KW				
	Monthly Reservation Charge				
	Applicable to Specified SB Capacity	0.888	1.005	0.888	1.005
	Peak Day Utilized SB Power Charge of:	0,423	0.479	0,423	0.479
	Delivery Voltage Credits - \$ per KW				
	Primary	0.29	0.33	0.29	0.33
		n/a	n/a	n/a	n/a
	Transmission	0.81	0.92	0.81	0.92
	Premium Distribution Charge - \$ per KW	0.07	0.52	0.01	
SS-2	Customer Charge - \$ per Line of Billing				000 74
	Secondary	303.71	303.71	303.71	303.71
	Primary	438.68	438.68	438.68	438.68
	Transmission	1,015.02	1,015.02	1,015.02	1,015.02
	Customer Owned	284.20	284.20	284.20	284.20
	Base Rate Energy Customer Charge - cents per KWH	0.777	0.880	0.00777	0.00880
	Dage (che mitorg) pagionio ottorge				
	Distribution Charge - \$ per KW				
		1.59	1.80	1.59	1.80
	Applicable to Specified SB Capacity	1.00			
	Generation and Transmission Capacity Charge				
	Greater of : - \$ per KW				
	Monthly Reservation Charge				
	Applicable to Specified SB Capacity	0.888	1.005	0,888	1.005
	Peak Day Utilized SB Power Charge of:	0.423	0.479	0.423	0.479
	Interruptible Capacity Credit - \$ par KW				
	Grandfathered Prior to 1/1/06				
	Monthly Reservation Credit	0.690	0.870	0.690	0.870
		0.329	0.414	0.329	0.414
	Daily Demand Credit	*			

Effective 1/1/06

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PROGRESS ENERGY FLORIDA Base Rate Detailed Unit Charges by Rate Schedule 2013 Test Year - Settlement Uniform % Increase Demand & Energy Charges

		cents / kWh			\$/kvvh		
		2/10/2010	1/1/2013	Actual Billing	Rate (CSS)		
			Proposed		Proposed		
Rate		Current/Prior	Settlement	Current/Prior	Settlement		
Schedule	Type of Charge	Rate	Rate	Rate	Røte		
Scriedbio	Monthly Reservation Credit	0.331	0.870	0,331	0.870		
	Daily Demand Credit	0.158	0.414	0,158	0.414		
	toony potnena areas						
	Delivery Voltage Credits - \$ per KW						
	Primary	0.29	0.33	0.29	0,33		
	Transmission	n/a	n/a	n/a	n/a		
	Premium Distribution Charge - \$ per KW	0.81	0,92	0.81	0.92		
SS-3	Customer Charge - \$ per Line of Billing						
	Secondary	100.71	100.71	100.71	100.71		
	Primary	235.69	235.69	235.69	235.69		
	Transmission	812.02	812.02	812.02	812.02		
	Customer Owned	81.21	81.21	81.21	81.21		
		0,780	0.883	0.00780	0.00883		
	Base Rate Energy Customer Charge - cents per KWH	0.780	0.003	0.00780	0.00063		
	Distribution Charge - \$ per KW						
	Applicable to Specified SB Capacity	1,59	1.80	1.59	1.80		
	Generation and Transmission Capacity Charge						
	Greater of : - \$ per KW						
	Monthly Reservation Charge						
	Applicable to Specified SB Capacity	0.888	1.005	0.888	1.005		
	Peak Day Utilized SB Power Charge of:	0.423	0.479	0.423	0.479		
	Curtailable Capacity Credit - \$ per KW						
	Grandfathered Prior to 1/1/05						
	Monthly Reservation Credit	0.345	0.653	0.345	0.653		
	Daily Demand Credit	0.164	0.311	0.164	0.311		
	Effective 1/1/06						
	Monthly Reservation Credit	0.248	0.653	0.248	0,653		
	Daily Demand Credit	0.118	0.311	0.118	0.311		
	Delivery Voltage Credits - \$ per KW						
	Primary	0.29	0.33	0.29	0.33		
	Transmission	r/a	n/a	n/a	n/a		
	Premium Distribution Charge - \$ per KW	0.81	0.92	0.81	0.92		
GSLM-2	General Service Load Management - Standby Generation						
	Monthly Credit Amount for Standby Generation Capacity						
	For fiscal year hours of <= 200 Cumulative Requested Hours	2.30	3.60	2.30	3.60		
	For fiscal year hours of >200 Cumulative Requested Hours	2.76	4.32	2.76	4.32		

S:\Rates\Krates\CSS Rate Updates\[Base Rates0113 Settlement Filing_xisx]Base Rates

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Attachment C

Revised Tariff Sheets in clean copy format

Tariff Sheet No.	Description
5 .120	RS-1
6.130	RSL-1
6.135	RSL-2
6.140	RST-1
6.150	GS-1
6.160	GST-1
6.165	GS-2
6.170	GSD-1
6.171	GSD-1
6.180	GSDT-1
6.181	GSDT-1
6.225	GSLM-2
6.230	CS-1
6.231 6.235	CS-1 CS-2
6.236	CS-2 CS-2
6.2390	CS-3
6.2391	CS-3
6.2392	CS-3
6.240	CST-1
6.241	CST-1
6.245	CST-2
6.246	CST-2
6.2490	CST-3
6.2491	CST-3
6.2492	CST-3
6.250	IS-1
6.251	IS-1
6.255	IS-2
6.256	IS-2
6.260	IST-1
6.261	IST-1
6.265	IST-2
6.266	IST-2
6.280	LS-1
6.281 6.2811	LS-1 LS-1
6.312	SS-1
6.313	SS-1
6.317	SS-2
6.318	SS-2
6.322	SS-3
6.323	SS-3



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SECTION NO. VI TWENTY-SIXTH REVISED SHEET NO. 6.120 CANCELS TWENTY-FIFTH REVISED SHEET NO. 6.120

	Page 1 of 2				
· · · · · · · · · · · · · · · · · · ·	TE SCHEDULE RS-1 SIDENTIAL SERVICE				
Availability:					
Available throughout the entire territory served by the Com	прапу.				
Applicable:					
housekeeping facilities, occupied by one family or house additional apartment with separate housekeeping facilities	nobile home, or individually metered single apartment unit or other unit having ehold as a residence. The premises of such single dwelling may include an s, as well as a garage and other separate structures where they are occupied or household. Also, for energy used in commonly-owned facilities in condominium ng criteria:				
1. 100% of the energy is used exclusively for the co-owner's benefit.					
 None of the energy is used in any endeat a fee. 					
3. Each point of delivery is separately metere	ed and billed.				
 A responsible legal entity is established a for said service. 	s the customer to whom the Company can render its bill(s)				
Character of Service:					
Continuous service, alternating current, 60 cycles per distribution voltage. Three-phase service, if available, w "Requirements for Electric Service and Meter Installations."	second, single-phase or three-phase, at the Company's standard available vill be supplied only under the conditions set forth in the Company's booklet *				
Limitation of Service:					
Standby or resale service not permitted hereunder. Ser "General Rules and Regulations for Electric Service."	vice under this rate is subject to the Company's currently effective and filed				
Rate Per Month:					
Customer Charge:	\$ 8.76				
Demand and Energy Charges:					
Non-Fuel Energy Charges:					
First 1,000 kWh All additional kWh	4.509¢ per kWh 5.744¢ per kWh				
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, <i>Billing Adjustments</i> , except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106				
Additional Charges:					
Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization Fee: Municipal Tax Sales Tax	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106				
	(Continued on Page No. 2)				



SECTION NO. VI TWENTY-EIGHTH REVISED SHEET NO. 6.130 CANCELS TWENTY-SEVENTH REVISED SHEET NO. 6.130

na na na na maraona ana ana ana ana ana ana ana ana ana					Page 1 of 3
RATE SCI RESIDENTIAL L					
Availability:					
Available only within the range of the Company's Load Managerr Available to customers whose premises have active load manager Available to customers whose premises have load management to load control of, at a minimum, central electric cooling and heat	ement (device	devices installed prices installed after Jun	or to June 30, 20 le 30, 2007 that	07. have and ar	e willing to submit
Applicable:					
To customers eligible for Residential Service under Rate Schedu (based on the most recent 12 months, or, where not available, equipment					
 Water Heater Central Electric Heating System 	3. 4.				
Character of Service:					
Continuous service, alternating current, 60 cycle, single-phase Three-phase service, if available, will be supplied only under the Service and Meter installations.*					
Limitation of Service:					
Service to the electrical equipment specified above may be int devices installed on the customer's premises.	errupte	d at the option of t	he Company by	means of lo	oad management
For new service requests after June 30, 2007 customers with a Interruption Schedule S. All other new service requests will be i the option of the customer.					
For new service requests after April 1, 1995, and before June 3 also select at least one other schedule.	0, 2007	7, customers who se	elect the swimmi	ng pool pun	np schedule must
An installation of an alternative thermal storage heating system April 1, 1995.	under S	Special Provision No	o. 7 of this rate s	chedule is r	ot available after
Standby or resale service not permitted hereunder. Service us "General Rules and Regulations for Electric Service."	nder th	ils rate is subject to	the Company's	s currently e	ffective and filed
Rate Per Month:					
Customer Charge:	\$ 8.7	76			
Energy and Demand Charges: Non-Fuel Energy Charges:					
First 1,000 kWh All additional kWh		9¢ per kWh 4¢ per kWh			
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, <i>Billing Adjustments,</i> except the Fuel Cost Recovery Factor:	See	Sheet No. 6.105 and	d 6.106		
Additional Charges:					
Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization Fee: Municipal Tax: Sales Tax:	See See See	Sheet No. 6.105 Sheet No. 6.106 Sheet No. 6.106 Sheet No. 6.106 Sheet No. 6.106			
Load Management Monthly Credit Amounts: ¹²					
Interruptible Equipment		Interruptio	on <u>Schedule</u>		
	Δ	B	<u><u>c</u></u>	D	<u>s</u>
Water Heater Central Heating System ³	\$2.00		\$3.50	-	\$8.00
Central Heating System w/Thermal Storage ³	-	-	-	\$8.00	-
Central Cooling System ⁴ Swimming Pool Pump	\$1.00	0 \$5.00	\$2.50	-	\$5.00
				(Continued	on Page No. 2)



SECTION NO. VI THIRTEENTH REVISED SHEET NO. 6.135 CANCELS TWELFTH REVISED SHEET NO. 6.135

		Page 1 of 2			
		RATE SCHEDULE RSL-2 LOAD MANAGEMENT – WINTER ONLY			
Availability:					
	Available only within the range of the Company's Load Management System.				
Applicable:					
kWh for the r	To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months) and utilizing both electric water heater and central electric heating systems.				
Character of Ser	Character of Service:				
Three-phase	Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."				
Limitation of Ser	rvice:				
	e electrical equipment specified above i led on the customer's premises.	nay be interrupted at the option of the Company by means of load management			
	esale service not permitted hereunder. as and Regulations for Electric Service."	Service under this rate is subject to the Company's currently effective and filed			
Rate Per Month:					
Customer Cl	arge:	\$ 8.76			
Energy and I	Demand Charges:				
Non-Fuel	Energy Charges:				
	First 1,000 kWh4.509¢ per kWhAll additional kWh5.744¢ per kWh				
Rate Sch	Cost Recovery Factors listed in edule BA-1, <i>Billing Adjustments</i> , a Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106			
Additional Charg	Additional Charges:				
Fuel Cost Rec		See Sheet No. 6.105			
Gross Receipt	ts Tax Factor: Utilization Fee:	See Sheet No. 6.106 See Sheet No. 6.106			
Municipal Tax		See Sheet No. 6.106			
Sales Tax;		See Sheet No. 6.106			
Load Manageme	nt Credit Amount:1				
Interruptible E	quipment	Monthly Credit ²			
Water Heater	and Central Heating System	\$11.50			
Notes: (1) Load management credit shall not ex ccess of 600 kWh/month.	ceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in			
(2) For billing months of November throug	h March only.			
Appliance Interru	Appliance Interruption Schedule:				
Heating	Heating Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.				
Water Heater	Equipment may be interrupted continu Periods.	uously, not to exceed 300 minutes, and during the Company's designated Peak			
		(Continued on Page No. 2)			
	ori I Cross Manager Utility Pegu				



SECTION NO. VI TWENTIETH REVISED SHEET NO. 6.140 CANCELS NINETEENTH REVISED SHEET NO. 6.140

	Page 1 of 2
RATE SCHEDULE RST-1 RESIDENTIAL SERVICE OPTIONAL TIME OF USE RATE (Closed to New Customers as of 02/10/10)	
Availability: Available throughout the entire territory served by the Company.	
Applicable:	
At the option of residential customers otherwise eligible for service under Rate Schedule RS-1, provided that all of the requirements on the customer's premises are metered through one point of delivery.	electric load
Character of Service:	
Continuous service, alternating current, 60 cycle, single phase, at the Company's standard distribution secondary voltag Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requi Electric Service and Meter Installations."	
Limitation of Service:	
Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effecti "General Rules and Regulations Governing Electric Service,"	ve and filed
Rate Per Month:	
Customer Charge: \$ 16.19	
Energy and Demand Charges:	
Non-Fuel Energy Charges: 13.924¢ per On-Peak kWh 0.773¢ per Off-Peak kWh	,
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, Billing Adjustments, except the Fuel Cost Recovery Factor: See Sheet No. 6.105 and 6.106	
The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all o use.	her energy
Rating Periods:	
(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:	
 For the calendar months of November through March, Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m. 	
(2) For the calendar months of April through October,	
Monday through Friday [*] : 12:00 Noon to 9:00 p.m. The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independent Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent we be excluded from the On-Peak Periods.	
(b) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Period in (a) above.	is set forth
(Continued on P	age No. 2)



SECTION NO. VI TWENTY-SEVENTH REVISED SHEET NO. 6.150 CANCELS TWENTY-SIXTH REVISED SHEET NO. 6.150

	Page 1 of 2
	ATE SCHEDULE GS-1 AL SERVICE NON-DEMAND
Availability:	1000 DOL
Available throughout the entire territory served by the C	ompany.
Applicable:	
	ower purposes for which no other rate schedule is specifically applicable.
Character of Service:	
Continuous service, alternating current, 60 cycle, single	-phase or three-phase, at the Company's standard distribution voltage available.
Limitation of Service:	
Standby or resale service not permitted hereunder, "General Rules and Regulations for Electric Service."	Service under this rate is subject to the Company's currently effective and filed
Rate Per Month:	
Customer Charge:	
Unmetered Account:	\$ 6.54
Secondary Metering Voltage: Primary Metering Voltage:	\$ 11.59 \$ 146.56
Transmission Metering Voltage:	\$ 722.90
Example and Demond Charges	
Energy and Demand Charges:	1 9094 nor With
Non-Fuel Energy Charge:	4.898¢ per kWh
Plus the Cost Recovery Factors listed in	
Rate Schedule BA-1, <i>Billing Adjustments</i> , except the Fuel Cost Recovery Factor:	See Sheet No. 6 105 and 6 106
except the rule cost netwery racion.	See Sheet No. 0.103 and 0.100
Premium Distribution Service Charge:	
Regulations Governing Electric Service, the custom this rate schedule for the costs of all additional eq	ablished after 12/15/98 in accordance with Subpart 2.05, General Rules and rer shall pay a monthly charge determined under Special Provision No. 2 of uipment, or the customer's allocated share thereof, installed to accomplish ecessary to connect to an alternate distribution circuit.
In addition, the Non-Fuel Energy Charge included 0.669¢ per kWh for the cost of reserving capacity in	in the Rate per Month section of this rate schedule shall be increased by the alternate distribution circuit.
Metering Voltage Adjustment:	
Metering voltage will be at the option of the Company. the applicable following reduction factor shall apply to the	When the Company meters at a voltage above standard distribution secondary, e Noπ-Fuel Energy Charge hereunder:
Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%
Additional Charges:	
Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor: Right-of-Way Utilization Fee:	See Sheet No. 6.106 See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106
	(Continued on Page No. 2)
ISSUED BY: Lori J. Cross, Manager, Utility Regula	atory Planning - Florida
	awy manning - mona
EFFECTIVE: January 1, 2013	





SECTION NO. VI TWENTY-THIRD REVISED SHEET NO. 6.160 CANCELS TWENTY-SECOND REVISED SHEET NO. 6.160

Page 1 of 2	1			
RATE SCHEDULE GST-1 GENERAL SERVICE – NON-DEMAND OPTIONAL TIME OF USE RATE				
Availability:				
Available throughout the entire territory served by the Company.				
Applicable:				
At the option of non-residential customers otherwise eligible for service under Rate Schedule GS-1, provided that all of the electric load requirements on the Customer's premises are metered through one point of delivery.				
Character of Service:				
Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available.				
Limitation of Service:				
Standby or Resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."				
Rate per Month:				
Customer Charge:				
Secondary Metering Voltage: \$ 19.01 Primary Metering Voltage: \$ 153.99 Transmission Metering Voltage: \$ 730.32				
Energy and Demand Charge:				
Non-Fuel Energy Charge: 13.902¢ per On-Peak kWh 0.753¢ per Off-Peak kWh				
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, Billing Adjustments, except the Fuel Cost Recovery Factor See Sheet No. 6.105 and 6.106				
The On-Peak rate shall apply to energy use during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.				
Premium Distribution Service Charge:				
Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.				
In addition, the Non-Fuel Charges included in the Rate per Month section of this rate schedule shall be increased by 0.669¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.				
Rating Periods:				
(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:				
(1) For the calendar months of November through March,				
Monday through Friday *: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.				
 (2) For the calendar months of April through October, Monday through Friday[*]: 12:00 Noon to 9:00 p.m. 				
* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.				
(Continued on Page No. 2)				
ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida				
EFFECTIVE: January 1, 2013				



SECTION NO. VI TWENTY-SIXTH REVISED SHEET NO. 6.165 CANCELS TWENTY-FIFTH REVISED SHEET NO. 6.165

	Page 1 of 2
GENERA	ATE SCHEDULE GS-2 L SERVICE – NON-DEMAND LOAD FACTOR USAGE
Availability:	
Available throughout the entire territory served by the Co	ompany.
Applicable:	
To any customer, other than residential, with fixed wat signals, cable TV amplifiers and gas transmission substa	tage loads operating continuously throughout the billing period (such as traffic ations).
Character of Service:	
Continuous service, alternating current, 60 cycle, single-	phase or three-phase, at the Company's standard distribution voltage available.
Limitation of Service:	
Standby or resale service not permitted hereunder. Se "General Rules and Regulations for Electric Service."	ervice under this rate is subject to the Company's currently effective and filed
Rate per Month:	
Customer Charge:	
Unmetered Account: Metered Account:	\$ 6.54 \$ 11.59
Energy and Demand Charges;	
Non-Fuel Energy Charge:	1.857¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, <i>Billing Adjustments</i> , except the Fuel Cost Recovery Factor	See Sheet No. 6.105 and 6.106
Premium Distribution Service Charge:	
 Regulations Governing Electric Service, the customer sh 	ished after 12/15/98 in accordance with Subpart 2.05, General Rules and all pay a monthly charge determined under Special Provision No. 2 of this rate customer's allocated share thereof, installed to accomplish automatic delivery n alternate distribution circuit.
In addition, the Non-Fuel Energy Charge included in the kWh for the cost of reserving capacity in the alternate dis	Rate per Month section of this rate schedule shall be increased by 0.135¢ per tribution circuit.
dditional Charges:	
Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization Fee: Municipal Tax: Sales Tax:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No, 6.106 See Sheet No. 6.106
	(Continued on Page No. 2)





SECTION NO. VI TWENTY-THIRD REVISED SHEET NO. 6.170 CANCELS TWENTY-SECOND REVISED SHEET NO. 6.170

	Page 1 of 3
	EDULE GSD-1 VICE - DEMAND
Availability:	
Available throughout the entire territory served by the Company.	
Applicable:	
•	coses for which no other rate schedule is specifically applicable with a ryear.
Character of Service:	
Continuous service, alternating current, 60 cycle, singe-phase or	three-phase, at the Company's standard distribution voltage available.
Limitation of Service:	
Standby or resale service not permitted hereunder. Service un "General Rules and Regulations for Electric Service."	der this rate is subject to the Company's currently effective and filed
Rate Per Month:	
Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 11.59 \$ 146.56 \$ 722.90
Demand Charge:	\$ 4.59 per kW of Billing Demand
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6,105 and 6,106
Energy Charge:	
Non-Fuel Energy Charge:	2.045¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
Premium Distribution Service Charge:	
Regulations Governing Electric Service, the customer shall pa	ter 12/15/98 in accordance with Subpart 2.05, General Rules and ay a monthly charge determined under Special Provision No. 2 of r the customer's allocated share thereof, installed to accomplish o connect to an alternate distribution circuit.
In addition, the Demand Charge included in the Rate per Mo kW for the cost of reserving capacity in the alternate distribution	nth section of this rate schedule shall be increased by \$0.99 per on circuit.
Determination of Billing Demand:	
The billing demand shall be the maximum 30-minute kW demand	established during the current billing period.
	(Continued on Page No. 2)



SECTION NO. VI SEVENTEENTH REVISED SHEET NO. 6.171 CANCELS SIXTEENTH REVISED SHEET NO. 6.171

	Page 2 of 3
GENEF	TE SCHEDULE GSD-1 RAL SERVICE - DEMAND titnued from Page No. 1)
Delivery Voltage Credit:	
When a customer takes service under this rate at a Charge hereunder shall be subject to the following credit	delivery voltage above standard distribution secondary voltage, the Demand ts:
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand
Netering Voltage Adjustment:	
	. When the Company meters at a voltage above distribution secondary, the ne Non-Fuel Energy Charge, Demand Charge and Delivery Voltage Credit
Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%
ower Factor:	
ending with the current billing period, bills computed und	more for three (3) or more months out of the twelve (12) consecutive months der the above rate per month charges will be increased 26¢ for each KVAR by nes the measured kW demand, and will be decreased 26¢ for each KVAR by times the measured kW demand.
dditional Charges:	
Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization Fee: Municipal Tax: Sales Tax:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106
inimum Monthly Bill;	
•	e. Where special equipment to serve the customer is required, the Company
erms of Payment:	
Bills rendered hereunder are payable within the time limit	specified on the bill at Company-designated locations.
erm of Service:	
	rm of twelve (12) months from commencement of service and shall continue the customer to disconnect, or upon disconnect by the Company under Florida

(Continued on Page No. 3)



SECTION NO. VI TWENTY-FOURTH REVISED SHEET NO. 6.180 CANCELS TWENTY-THIRD REVISED SHEET NO. 6.180

	Page 1 of 3
GENERAL SE	EDULE GSDT-1 RVICE - DEMAND ME OF USE RATE
Availability:	
Available throughout the entire territory served by the Company.	
Applicable:	
At the option of the customer, otherwise eligible for service requirements on the customer's premises are metered through c	under Rate Schedule GSD-1, provided that all of the electric load one point of delivery.
Character of Service:	
Continuous service, alternating current, 60 cycle, single-phase o	r three-phase, at the Company's standard distribution voltage available.
Limitation of Service:	
Standby or Resale service not permitted hereunder. Service u "General Rules and Regulations for Electric Service."	nder this rate is subject to the Company's currently effective and filed
Rate per Month:	
Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 19.01 \$ 153.99 \$ 730.32
Demand Charges:	
Base Demand Charge:	\$ 1.12 per kW of Base Demand
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	\$ 3.41 per kW of On-Peak Demand
Energy Charges:	
Non-Fuel Energy Charge:	4.452¢ per On-Peak kWh 0.747¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
The On-Peak rate shall apply to energy use during designate energy use.	ted On-Peak Periods. The Off-Peak rate shall apply to all other
Premium Distribution Service Charge:	
Regulations Governing Electric Service, the customer shall p	fter 12/15/98 in accordance with Subpart 2.05, General Rules and vay a monthly charge determined under Special Provision No. 2 of or the customer's allocated share thereof, installed to accomplish to connect to an alternate distribution circuit.
In addition, the Base Demand Charge included in the Rate p per kW for the cost of reserving capacity in the alternate distri	er Month section of this rate schedule shall be increased by \$0.99 ibution circuit.
	(Continued on Page No. 2)



SECTION NO. VI EIGHTEENTH REVISED SHEET NO. 6.181 CANCELS SEVENTEENTH REVISED SHEET NO. 6.181

		Page 2 of 3
	G	RATE SCHEDULE GSDT-1 ENERAL SERVICE DEMAND PTIONAL TIME OF USE RATE (Continued from Page No. 1)
Rating Periods		
(a) On-	Peak Periods - The designated On-Pea	ik Periods expressed in terms of prevailing clock time shall be as follows:
(For the calendar months of Novemb Monday through Friday *: 	ber through March, 6:00 a.m, to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
(For the calendar months of April thro Monday through Friday*:	ough October, 12:00 Noon to 9:00 p.m.
Labor D		d from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, n the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall
	Peak Periods - The designated Off-Pea a) above.	ak Periods shall be all periods other than the designated On-Peak Periods set forth
Determination	of Billing Demands:	
The billing d	lemands shall be the following:	
(The Base Demand shall be the ma billing period. 	aximum 30-minute kW demand established during the current
(b) The On-Peak Demand shall be designated On-Peak Periods during	the maximum 30-minute kW demand established during the current billing period.
Delivery Voltag	e Credit:	
	tomer takes service under this rate sche arge hereunder shall be subject to the fo	edule at a delivery voltage above standard distribution secondary voltage, the Base llowing credits:
	ribution Primary Delivery Voltage: Ismission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand
Note: In no	event shall the total of the Demand Char	ges hereunder, after application of the above credit, be an amount less than zero.
Metering Voltag	e Adjustment:	
Metering vol	itage will be at the option of the Comp	any. When the Company meters at a voltage above distribution secondary, the the Non-Fuel Energy Charge, Demand Charges and Delivery Voltage Credit
	<u>a Voltage</u> ion Primary ssion	Reduction Factor 1.0% 2.0%
Power Factor:		
ending with t which the re	the current billing period, bills computed	or more for three (3) or more months out of the twelve (12) consecutive months under the above rate per month charges will be increased 26¢ for each KVAR by times the measured kW demand, and will be decreased 26¢ for each KVAR by .62 times the measured kW demand.
		(Continued on Page No. 3)



SECTION NO. VI FIFTH REVISED SHEET NO. 6.225 CANCELS FOURTH REVISED SHEET NO. 6.225

Page	1	of	2

RATE SCHEDULE GSLM-2 GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GSD-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at least 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Customers cannot use the standby generation for peak shaving.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT STANDBY GENERATION

Credit		
\$3.60 x C	+	\$0.05 ¹ x kWh monthly

Cumulative Fiscal Year Hours

\$4.32 x C + \$0.05¹ x kWh monthly

0 ≤ CRH ≤ 200 200 < CRH

Immediately upon going on the rate, the customer's Capacity (C) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The C will remain at that value until the equipment is requested to run by the Company. The C for that month and subsequent months will be a calculated value based upon

C = <u>kWh annual</u> [CAH - (# of Requests x ¼ hour)]

Definitions:

the following formula:

kWh annual = Actual measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).

- CAH = Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).
- CRH = Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).
- # of Requests = The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).

kWh monthly = Actual measured kWh generated by the standby generator for the current month during Company control periods.

This \$ per kWh rate represents an incentive credit to support Customer O&M associated with run time requested by the Company. PEF will periodically review this incentive rate and request changes as deemed appropriate.

(Continued on Page No. 2)

(Continued on Page No. 2)



SECTION NO. VI TWENTY-SEVENTH REVISED SHEET NO. 6.230 CANCELS TWENTY-SIXTH REVISED SHEET NO. 6.230

	Page 1 of 4
CURTAILABLE	HEDULE CS-1 GENERAL SERVICE stomers as of 04/16/96)
Availability:	
Available throughout the entire territory served by the Company.	
Applicable:	
To any customer, other than residential, for light and power	purposes where the customer agrees during a period of requested or (b) 25% of their average monthly billing demand (based on the most or twelve (12) months).
Character of Service:	
Alternating current, 60 cycle, single-phase or three-phase, at the	Company's standard voltage available.
Limitation of Service:	
time period for economic reasons. Curtailable service under the electric power and energy delivered hereunder from the Comparisher Company's firm power customers and firm power sales company's firm power customers and firm power sales compared to the company's firm power customers and firm power sales compared to the company's firm power customers and firm power sales compared to the customers and the customers and firm power sales compared to the customers and the	service under this rate schedule is <u>not</u> subject to curtailment during any his rate schedule is subject to curtailment during any time period that ny's available generating resources is required to a) maintain service to miltments or b) supply emergency interchange service to another utility ke off-system purchases during such periods to maintain service to Provision No. 6 of this rate schedule.
Service under this rate is subject to the Company's currently effe	ective and filed "General Rules and Regulations for Electric Service."
Rate Per Month:	
Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 75.96 \$ 210.93 \$ 787.26
Demand Charge:	\$ 7.37 per kW of Billing Demand
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	\$ 3.74 per kW of Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	1.346¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
Premium Distribution Service Charge:	
Regulations Governing Electric Service, the customer shall p	after 12/15/98 in accordance with Subpart 2.05, General Rules and bay a monthly charge determined under Special Provision No. 8 of or the customer's allocated share thereof, installed to accomplish to connect to an alternate distribution circuit.
In addition, the Demand Charge included in the Rate per M kW for the cost of reserving capacity in the alternate distribut	onth section of this rate schedule shall be increased by \$0.99 per ion circuit.





SECTION NO. VI TWENTY-SECOND REVISED SHEET NO. 6.231 CANCELS TWENTY-FIRST REVISED SHEET NO. 6.231

	Page 2 of 4			
RATE SCHEDULE CS-1 CURTAILABLE GENERAL SERVICE (Closed to New Customers as of 04/16/96) (Continued from Page No. 1)				
Determination of Billing Demand:				
The billing demand shall be the maximum 30-minute kW d	emand established during the current billing period.			
Determination of Curtailable Demand:				
	etween the current Billing Demand and the contract Non-Curtailable Demand this rate. In no event shall the Curtailable Demand be less than zero.			
Delivery Voltage Credit:				
When a customer takes service under this rate at a de Charge hereunder shall be subject to the following credit:	livery voltage above standard distribution secondary voltage, the Demand			
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand			
Metering Voltage Adjustment:				
	When the Company meters at a voltage above distribution secondary, the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and			
Metering Voltage	Reduction Factor			
Distribution Primary Transmission	1.0% 2.0%			
Power Factor:				
ending with the current billing period, bills computed under	nore for three (3) or more months out of the twelve (12) consecutive months r the above rate per month charges will be increased 26¢ for each KVAR by s the measured demand, and will be decreased 26¢ for each KVAR by which e measured kW demand.			
Additional Charges:				
Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization: Municipal Tax: Sales Tax:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106			
Minimum Monthly Bill:				
The minimum monthly bill shall be the Customer Charge. may require a specified minimum charge.	Where special equipment to serve the customer is required, the Company			
Terms of Payment: Bills rendered hereunder are payable within the time limit sp	pecified on bill at Company-designated locations.			
Term of Service:				
Service under this rate schedule shall be for a minimum continue thereafter until terminated by either party by writter	initial term of two (2) years from the commencement of service and shall n notice sixty (60) days prior to termination.			
	(Continued on Page No. 3)			
ISSUED BY: Lori J. Cross, Manager, Utility Regulator	ry Planning - Florida			
EFFECTIVE: January 1, 2013				
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SECTION NO. VI TWELFTH REVISED SHEET NO. 6.235 CANCELS ELEVENTH REVISED SHEET NO. 6.235

	Page 1 of 4		
	HEDULE CS-2 GENERAL SERVICE		
Availability:			
Available throughout the entire territory served by the Company.	I,		
Applicable:			
To any customer, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where the customer agrees to curtail 25% of their average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection for twelve (12) months).			
Character of Service:			
Alternating current, 60 cycle, single-phase or three-phase, at the	e Company's standard voltage available.		
Limitation of Service:			
Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is <u>not</u> subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.			
	ective and filed "General Rules and Regulations for Electric Service."		
Rate Per Month:			
Customer Charge: Secondary Metering Voltage;	\$ 75.96		
Primary Metering Voltage: Transmission Metering Voltage:	\$ 210.93 \$ 787.26		
Demand Charge:	\$ 7.37 per kW of Billing Demand		
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106		
Curtailable Demand Credit:	\$ 6.53 per kW of Load Factor Adjusted Demand		
Energy Charge:			
Non-Fuel Energy Charge:	1.346¢ per kWh		
Plus the Cost Recovery Factors on a \notin kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106		
Premium Distribution Service Charge:			
Where Premium Distribution Service has been established a Regulations Governing Electric Service, the customer shall p	after 12/15/98 in accordance with Subpart 2.05, General Rules and pay a monthly charge determined under Special Provision No. 8 of or the customer's allocated share thereof, installed to accomplish to connect to an alternate distribution circuit.		
In addition, the Demand Charge included in the Rate per Mo kW for the cost of reserving capacity in the alternate distributi	fonth section of this rate schedule shall be increased by \$0.99 per tion circuit.		
	(Continued on Page No. 2)		



SECTION NO. VI EIGHTH REVISED SHEET NO. 6.236 CANCELS SEVENTH REVISED SHEET NO. 6.236

	Page 2 of 4		
RATE SCHEDULE CS-2 CURTAILABLE GENERAL SERVICE (Continued from Page No. 1)			
Determination of Billing Demand:			
The billing demand shall be the maximum 30-minute kW kW.	demand established during the current billing period, but not less than 500		
Determination of Load Factor Adjusted Demand:			
The Load Factor Adjusted Demand shall be the difference, if any, between the maximum 30-minute kW demand established during the current billing period and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of this rate, multiplied by the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand, multiplied by the number of hours in the billing period). In no event shall the Curtailable Demand be less than zero.			
Delivery Voltage Credit:			
When a customer takes service under this rate at a del Charge hereunder shall be subject to the following credit:	livery voltage above standard distribution secondary voltage, the Demand		
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand		
Metering Voltage Adjustment:			
	When the Company meters at a voltage above distribution secondary, the Jon-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and		
Metering Voltage	Reduction Factor		
Distribution Primary Transmission	1.0% 2.0%		
Power Factor:			
Bills computed under the above rate per month charges wi numerically, .62 times the measured demand, and will be numerically, .62 times the measured kW demand.	ill be increased 26¢ for each KVAR by which the reactive demand exceeds, decreased 26¢ for each KVAR by which the reactive demand is less than,		
Additional Charges:			
Fuel Cost Recovery Factor:	See Sheet No. 6.105		
Gross Receipts Tax Factor: Right-of-Way Utilization:	See Sheet No. 6.106 See Sheet No. 6.106		
Municipal Tax:	See Sheet No. 6.106		
Sales Tax:	See Sheet No. 6.106		
Minimum Monthly Bill:			
The minimum monthly bill shall be the Customer Charge equipment to serve the customer is required, the Company is	e and the Demand Charge for the current billing period. Where special may require a specified minimum charge.		
Terms of Payment:			
Bills rendered hereunder are payable within the time limit sp	ecified on bill at Company-designated locations.		
Term of Service:			
	n of two (2) years from the commencement of service, and shall continue		
thereafter until terminated by either party by written notice si	xty (60) days prior to termination.		
	(Continued on Page No. 3)		



SECTION NO. VI NINTH REVISED SHEET NO. 6.2390 CANCELS EIGHTH REVISED SHEET NO. 6.2390

	Page 1 of 3			
RATE SCHEDULE CS-3				
CURTAILABLE GENERAL SERV	ICE - FIXED CURTAILABLE DEMAND			
Availability:				
Available throughout the entire territory served by the Company				
Applicable:				
recent twelve (12) months or, where not available, projected bil	irposes where the billing demand is 2,000 kW or more (based on most ling demand for twelve (12) months), and where the customer agrees to than 2,000 kW upon request of the Company in accordance with the			
Character of Service:				
Alternating current, 60 cycle, single-phase or three-phase, at the	e Company's standard voltage available.			
Limitation of Service:				
Standby or resale service is not permitted hereunder. Service	under this rate schedule is subject to curtailment during any time period			
that electric power and energy delivered hereunder from the service to the Company's firm power customers and firm pow another utility for its firm load obligations only. Service under	Company's available generating resources is required to a) maintain er sales commitments or b) supply emergency interchange service to this rate schedule is not subject to curtailment for economic reasons, curtailment periods to maintain service hereunder except as set forth in			
Service under this rate is subject to the "General Rules and F Company's currently effective and filed retail tariff.	Regulations Governing Electric Service" contained in Section IV of the			
Rate Per Month:				
Customer Charge:				
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 75.96 \$ 210.93 \$ 787.26			
Demand Charge:	\$ 7.37 per kW of Billing Demand			
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106			
Curtailable Demand Credit:	\$ 6.53 per kW of Fixed Curtailable Demand			
Energy Charge:				
Non-Fuel Energy Charge:	1.346¢ per kW			
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106			
Premium Distribution Service Charge:				
Provision No. 8 of this rate schedule for the costs of all additic accomplish automatic delivery transfer, including, all line costs n	the customer shall pay a monthly charge determined under Special anal equipment, or the customer's allocated share thereof, installed to ecessary to connect to an alternate distribution circuit. section of this rate schedule shall be increased by \$0.99 per kW for the			
Determination of Billing Demand:	ed established during the surrout billing period, but pat loss than 2,000			
kW. Delivery Voltage Credit:	nd established during the current billing period, but not less than 2,000			
	e delivery voltage above standard distribution secondary voltage, the it			
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand			
	(Continued on Page No. 2)			



SECTION NO. VI FIFTH REVISED SHEET NO. 6.2391 CANCELS FOURTH SHEET NO. 6.2391

			Page 2 ATE SCHEDULE CS-3 _ SERVICE – FIXED CURTAILABLE DEMAND	2 of 3
		(Con	ntinued from Page No. 1)	
Meteri	ng Voltag	e Adjustment:		
app	propriate f	age will be at the option of the Company ollowing reduction factor shall apply to the age Credit hereunder:	y. When the Company meters at a voltage above distribution secondary e Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credi	/, the t and
	Metering	Voltage	Reduction Factor	
	Distributio Transmis	on Primary ision	1.0% 2.0%	
Power	Factor Ac	ljustment:		
nun	nerically, .		s will be increased 26¢ for each KVAR by which the reactive demand exce be decreased 26¢ for each KVAR by which the reactive demand is less	
Additio	nal Charç	jes:		
Gro	ss Receip	covery Factor: ts Tax Factor: Utilization:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106	
	nicipal Tax es Tax:	c	See Sheet No. 6.106 See Sheet No. 6.106	
Minimu	ım Monthi	ly Bill:		
			arge and the Demand Charge for the current billing period. Where sp ny may require a specified minimum charge.	ecial
Terms	of Paymer	nt:		
Bills	rendered	hereunder are payable within the time limit	t specified on bill at Company-designated locations.	
Term of	Service:			
			im initial term of two (2) years from the commencement of service and a termination.	shall
Special	Provision	19:		
curt: avai	ailment an Iable. If s	d for which energy purchased from source	ested curtailment" shall mean a period for which the Company has reque es outside the Company's system, pursuant to Special Provision No. 6, is of Special Provision No. 6 will apply and a period of requested curtailment ble.	s not
filed	standard		stomer is required to enter into a contract with the Company on the Comp ilable Demand of at least 2,000 kW shall be specified in the contract, which	
		· · · · · · · · · · · · · · · · · · ·	quirements occurs, the Company and the customer may	
	(b)	If the customer fails to reduce load by the	e Fixed Curtailable Demand for the duration of any period	
			easured load reduction achieved during such period shall effective with the next billing period following the period of ial Provision No. 5 is applicable.	
	(c)	duration of each period of requested curt	eduction larger than the Fixed Curtailable Demand for the tailment occurring within a billing period, upon request by reductions achieved during each such period shall become ith the next billing period.	
resp Suct	onsible for requests	the curtailment of its load by at least the l	Demand Credit provided under this rate schedule, a customer shall be str Fixed Curtailable Demand upon each curtailment request from the Compa d under Limitation of Service above. The Company shall also have the righ year irrespective of such limitations.	any.
			(Continued on Page No). 3)
ISSUED	BY: Lo	ri J. Cross, Manager, Utility Regulate	tory Planning - Florida	
		nuary 1, 2013	ory reaning - rionea	
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SECTION NO. VI TWENTY-SIXTH REVISED SHEET NO. 6.240 CANCELS TWENTY-FIFTH REVISED SHEET NO. 6.240

		Page 1 of 5			
CURTAILABLE OPTIONAL T	GEN ME C	JLE CST-1 ERAL SERVICE DF USE RATE ers as of 04/16/96)			
Availability:					
Available throughout the entire territory served by the Company	<i>ı</i> .				
Applicable:					
• •		Schedule CS-1, provided that all of the electric load requirements ry.			
Character of Service:					
Alternating current, 60 cycle, single-phase or three-phase, at th	Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.				
Limitation of Service:					
time period for economic reasons. Curtailable Service under electric power and energy delivered hereunder from the Compa the Company's firm power customers and firm power sales cor	this n any's a mmitn ike of	ice under this rate schedule is <u>not</u> subject to curtailment during any rate schedule is subject to curtailment during any time period that available generating resources is required to a) maintain service to nents or b) supply emergency interchange service to another utility ff-system purchases during such periods to maintain service to vision No. 6 of this rate schedule.			
Service under this rate is subject to the Company's currently eff	ective	e and filed "General Rules and Regulations for Electric Service."			
Rate per Month:					
Customer Charge:					
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 2	75.96 210.93 787.26			
Demand Charges:					
Base Demand Charge:	\$	1.10 per kW of Base Demand			
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	Se	ee Sheet No. 6.105 and 6.106			
On-Peak Demand Charge:	\$	6.22 per kW of On-Peak Demand			
Curtailable Demand Credit:	\$	3.74 per kW of Curtailable Demand			
Energy Charge:					
Non-Fuel Energy Charge:		470¢ per On-Peak kWh 742¢ per Off-Peak kWh			
Plus the Cost Recovery Factors on a #/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor; See Sheet No. 6.105 and 6.106					
The On-Peak rate shall apply to energy use during On-Peak	Peric	ds. The Off-Peak rate shall apply to all other energy use.			
Premium Distribution Service Charge:					
Regulations Governing Electric Service, the customer shall	pay a or th	12/15/98 in accordance with Subpart 2.05, General Rules and a monthly charge determined under Special Provision No. 8 of he customer's allocated share thereof, installed to accomplish innect to an alternate distribution circuit.			
In addition, the Base Demand Charge included in the Rate p per kW for the cost of reserving capacity in the alternate dist		lonth section of this rate schedule shall be increased by \$0.99 on circuit.			
		(Continued on Page No. 2)			



SECTION NO. VI TWENTIETH REVISED SHEET NO. 6.241 CANCELS NINETEENTH REVISED SHEET NO. 6.241

		RATE SCHEDULE CST-1
	(CURTAILABLE GENERAL SERVICE
	(0)	OPTIONAL TIME OF USE RATE losed to New Customers as of 04/16/96)
	(0)	(Continued from Page No. 1)
	Periods:	-Peak Periods expressed in terms of prevailing clock time shall be as follows:
(a)		
	 For the calendar months of Nov Monday through Friday *: 	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
	(2) For the calendar months of Apri Monday through Friday*:	il through October, 12:00 Noon to 9:00 p.m.
Ĺ		suded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Da is. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday sha
(b)	Off-Peak Periods - The designated Off in (a) above.	f-Peak Periods shall be all periods other than the designated On-Peak Periods set for
Determi	nation of Billing Demands:	
The I	billing demands shall be the following:	
	 (a) The Base Demand shall be the billing period. 	e maximum 30-minute kW demand established during the current
	(b) The On-Peak Demand shall designated On-Peak Periods du	be the maximum 30-minute kW demand established during ring the current billing period.
Determir	nation of Curtailable Demand:	
The	Curtailable Demand shall be the differen	ce, if any, between the current On-Peak Demand and the contract Non-Curtailab
Dema zero.	and determined in accordance with Specia	al Provision No. 2 of this rate. In no event shall the Curtailable Demand be less that
Delivery	Voltage Credit:	
	n a customer takes service under this rate ge hereunder shall be subject to the followir	at a delivery voltage above standard distribution secondary voltage, the Base Deman ng credit:
	or Distribution Primary Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand
	or Transmission Delivery Voltage:	1.35 per ker of Dring Demand
F		
F Note:	In no event shall the total of the Demand (
F Note: Metering Meter appro	In no event shall the total of the Demand (Voltage Adjustment: ring voltage will be at the option of the Ca	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th
F Note: Metering Meter appro Delive	In no event shall the total of the Demand d Voltage Adjustment: ring voltage will be at the option of the Co priate following reduction factor shall appl ary Voltage Credit hereunder:	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th
F Note: Metering Meter appro Delive M D	In no event shall the total of the Demand of Voltage Adjustment: ring voltage will be at the option of the Co priate following reduction factor shall apple any Voltage Credit hereunder: <u>Intering Voltage</u> istribution Primary	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th ly to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit an <u>Reduction Factor</u> 1.0%
F Note: Metering Meter appro Delive M D	In no event shall the total of the Demand of Voltage Adjustment: ring voltage will be at the option of the Co priate following reduction factor shall appl ery Voltage Credit hereunder: letering Voltage	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th ly to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit an <u>Reduction Factor</u>
F Note: Metering Meter appro Delive D	In no event shall the total of the Demand G Voltage Adjustment: ing voltage will be at the option of the Ca priate following reduction factor shall appl ery Voltage Credit hereunder: Intering Voltage istribution Primary ransmission	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th ly to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit an <u>Reduction Factor</u> 1.0%
F Note: Metering Meter appro Delive Delive M D Delive Delive Sower Fa Bills c nume	In no event shall the total of the Demand d Voltage Adjustment: ring voltage will be at the option of the Co priate following reduction factor shall appl ary Voltage Credit hereunder: <u>letering Voltage</u> istribution Primary ransmission actor: computed under the above rate per month	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th ly to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit an <u>Reduction Factor</u> 1.0% 2.0% charges will be increased 26¢ for each KVAR by which the reactive demand exceeds nd, and will be decreased 26¢ for each KVAR by which the reactive demand is les.
F Note: Metering Delive Delive M D D Ti Power Fa Bills o nume: than,	In no event shall the total of the Demand d Voltage Adjustment: ring voltage will be at the option of the Co priate following reduction factor shall appl ary Voltage Credit hereunder: letering Voltage istribution Primary ransmission actor: computed under the above rate per month rically, .62 times the measured kW deman	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, th ly to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit an <u>Reduction Factor</u> 1.0% 2.0% charges will be increased 26¢ for each KVAR by which the reactive demand exceeds nd, and will be decreased 26 ¢ for each KVAR by which the reactive demand is les.
F Note: Metering Meter appro Delive D D Ti Power Fa Bills c nume than, i Additiona	In no event shall the total of the Demand d Voltage Adjustment: ring voltage will be at the option of the Co opriate following reduction factor shall apple any Voltage Credit hereunder: <u>letering Voltage</u> istribution Primary ransmission actor: computed under the above rate per month rically, .62 times the measured kW demar numerically, .62 times the measured kW demar	Charges hereunder, after application of the above credit, be an amount less than zero. ompany. When the Company meters at a voltage above distribution secondary, the ly to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and <u>Reduction Factor</u> 1.0% 2.0% charges will be increased 26¢ for each KVAR by which the reactive demand exceeds nd, and will be decreased 26¢ for each KVAR by which the reactive demand is less



SECTION NO. VI ELEVENTH REVISED SHEET NO. 6.245 CANCELS TENTH REVISED SHEET NO. 6.245

Page	1	of	đ

RATE SCHEDULE CST-2 CURTAILABLE GENERAL SERVICE OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-2, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is <u>not</u> subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	
Secondary Metering Voltage:	\$ 75.96
Primary Metering Voltage:	\$ 210.93
Transmission Metering Voltage:	\$ 787.26
Demand Charges:	
Base Demand Charge:	\$ 1.10 per kW of Base Demand
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
in Nate Schedule DA-1, bining Aujustments.	See Sheet No. 0. 105 and 0. 106
On-Peak Demand Charge:	\$ 6.22 per kW of On-Peak Demand
-	
Curtailable Demand Credit:	C 52 and Web and Franks Adjusted Demand
Contailable Demaild Credit;	\$ 6.53 per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	2.470¢ per On-Peak kWh
	0.742¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis	
in Rate Schedule BA-1, Billing Adjustments,	
except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.99 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)



SECTION NO. VI EIGHTH REVISED SHEET NO. 6.246 CANCELS SEVENTH REVISED SHEET NO. 6.246

	Page 2 of 4
	RATE SCHEDULE CST-2
	CURTAILABLE GENERAL SERVICE OPTIONAL TIME OF USE RATE
	(Continued from Page No. 1)
Rating Periods:	
(a) On-Peak Periods - The designated C	In-Peak Periods expressed in terms of prevailing clock time shall be as follows:
(1) For the calendar months of N	ovember through March,
Monday through Friday *:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of A Monday through Friday*:	pril through October, 12:00 Noon to 9:00 p.m.
	xcluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, nas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall
(b) Off-Peak Periods - The designated (in (a) above.	Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth
Determination of Billing Demands:	
The billing demands shall be the following:	
The binning bernands shall be the following.	
 (a) The Base Demand shall be billing period, but not less that 	the maximum 30-minute kW demand established during the current n 500 kW.
	II be the maximum 30-minute kW demand established during during the current billing period.
Determination of Load Factor Adjusted Deman	d:
The Load Factor Adjusted Demand shall be th current billing period and the contract Non-C	e difference, if any, between the maximum 30-minute kW demand established during the urtailable Demand determined in accordance with Special Provision No. 2 of this rate, r (ratio of billing kWh to maximum 30-minute kW demand, multiplied by the number of
Delivery Voltage Credit:	
	e at a delivery voltage above standard distribution secondary voltage, the Base Demand
Charge hereunder shall be subject to the follow	ving credit:
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0,36 per kW of Billing Demand \$1.35 per kW of Billing Demand
Note: In no event shall the total of the Demand	d Charges hereunder, after application of the above credit, be an amount less than zero.
Metering Voltage Adjustment:	
	Company. When the Company meters at a voltage above distribution secondary, the ply to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and
Metering Voltage	Reduction Factor
Distribution Primary Transmission	1.0% 2.0%
Power Factor:	
	h charges will be increased 26¢ for each KVAR by which the reactive demand exceeds, nd, and will be decreased 26¢ for each KVAR by which the reactive demand is less than, nd.
Additional Charges:	
Fuel Cost Recovery Factor: Gross Receipts Tax Factor:	See Sheet No. 6.105 See Sheet No. 6.106
	(Continued on Page No. 3)



SECTION NO. VI NINTH REVISED SHEET NO. 6.2490 CANCELS EIGHTH REVISED SHEET NO. 6.2490

	Page 1 of 5
CURTAILABLE GENERAL SER	CHEDULE CST-3 RVICE – FIXED CURTAILABLE DEMAND
Availability:	TIME OF USE RATE
Available throughout the entire territory served by the Compar	iny.
Applicable:	
To any customer otherwise eligible for service under Rate S customer's premises are metered through one point of deliver	Schedule CS-3, provided that all of the electric load requirements on the ry.
Character of Service:	
Alternating current, 60 cycle, single-phase or three-phase, at t	the Company's standard voltage available.
Limitation of Service:	
that electric power and energy delivered hereunder from the service to the Company's firm power customers and firm po- another utility for its firm load obligations only. Service under	be under this rate schedule is subject to curtailment during any time period the Company's available generating resources is required to a) maintain ower sales commitments, or b) supply emergency interchange service to ther this rate schedule is not subject to curtailment for economic reasons. ch curtailment periods to maintain service hereunder except as set forth in
Service under this rate is subject to the "General Rules and Company's currently effective and filed retail tariff.	d Regulations Governing Electric Service" contained in Section IV of the
Rate Per Month:	
Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 75.96 \$ 210.93 \$ 787.26
Demand Charges:	
Base Demand Charge: Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments:</i> On-Peak Demand Charge:	 \$ 1.10 per kW of Base Demand See Sheet No. 6.105 and 6.106 \$ 6.22 per kW of On-Peak Demand
Curtailable Demand Credit:	 6.53 per kW of Fixed Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	2.470¢ per On-Peak kWh
Hole de Lhegy onlige.	0.742¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a <i>\$</i> / kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
The On-Peak rate shall apply to energy use during On-Pea	ak Periods. The Off-Peak rate shall apply to all other energy use.
Premlum Distribution Service Charge:	
Provision No. 8 of this rate schedule for the costs of all addit accomptish automatic delivery transfer including, all line costs r In addition, the Base Demand Charge included in the Rate per	ar Month section of this rate schedule shall be increased by \$0.99 per kW
for the cost of reserving capacity in the alternate distribution circ Rating Periods:	rcuit.
On-Peak Periods - The designated On-Peak Periods expresse	ed in terms of prevailing clock time shall be as follows:
For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.
* The following general holidays shall be excluded from the C Labor Day, Thanksglving Day, and Christmas. In the event shall be excluded from the On-Peak Periods.	On-Peak Periods: New Year's Day, Memorial Day, Independence Day, It the holiday occurs on a Saturday or Sunday, the following Monday

Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

(Continued on Page No. 2)





SECTION NO. VI SIXTH REVISED SHEET NO. 6.2491 CANCELS FIFTH REVISED SHEET NO. 6.2491

	Page 2 of 4
CURTAILABLE	RATE SCHEDULE CST-3 GENERAL SERVICE – FIXED CURTAILABLE DEMAND OPTIONAL TIME OF USE RATE (Continued from Page No. 1)
Determination of Billing Demand:	
The Base Demand for billing purposes shall not less than 2,000 kW.	I be the maximum 30-minute kW demand established during the current billing period, bu
The On-Peak Demand for billing purposes Periods during the current billing period.	shall be the maximum 30-minute kW demand established during designated On-Peak
Delivery Voltage Credit:	
When a customer takes service under this random because the subject to be a su	ate schedule at a delivery voltage above standard distribution secondary voltage, the Base to the following credit:
For Distribution Primary Delivery Voltage For Transmission Delivery Voltage:	: \$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand
Note: In no event shall the total of the Demai	nd Charges hereunder, after application of the above credit, be an amount less than zero.
Metering Voltage Adjustment:	
	e Company. When the Company meters at a voltage above distribution secondary, the apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit, and
Metering Voltage	Reduction Factor
Distribution Primary Transmission	1.0% 2.0%
Power Factor Adjustment:	
	nth charges will be increased 26¢ for each KVAR by which the reactive demand exceeds, d, and will be decreased 26¢ for each KVAR by which the reactive demand is less than, and.
Additional Charges:	
Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor: Right-of-Way Utilization:	See Sheet No. 6.106 See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax	See Sheet No. 6.106
Minimum Monthly Bill:	
	stomer Charge and the Demand Charge for the current billing period. Where special the Company may require a specified minimum charge.
Terms of Payment:	
Bills rendered hereunder are payable within th	e time limit specified on bill at Company-designated locations.
Term of Service:	
	r a minimum initial term of two (2) years from the commencement of service, and shall party by written notice sixty (60) days prior to termination.
Special Provisions:	
	od of requested curtailment" shall mean a period for which the Company has requested from sources outside the Company's system, pursuant to Special Provision No. 6, is not the terms of Special Provision No. 6 will apply and a period of requested curtailment will
available. If such energy can be purchased, not be deemed to exist while such energy rem	ains available.
available. If such energy can be purchased,	ains available.



SECTION NO. VI FIRST REVISED SHEET NO. 6.2492 CANCELS ORIGINAL SHEET NO. 6.2492

		Page 3 of 4
6	i-t Dravision	RATE SCHEDULE CST-3 CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND OPTIONAL TIME OF USE RATE (Continued from Page No. 2)
	filed standard o	for service under this rate schedule, a customer is required to enter into a contract with the Company on the Company bontract Form No. 2. An initial Fixed Curtailable Demand of at least 2,000 kW shall be specified in the contract, which ma ed under the following conditions:
	(a)	If a change in the customer's power requirements occurs, the Company and the customer may establish a new Fixed Curtallable Demand of at least 2,000 kW.
	(b)	If the customer fails to reduce load by the Fixed Curtailable Demand for the duration of any period of requested curtailment, the lowest measured load reduction achieved during such period, but not less than 2,000 kW, shall become the Fixed Curtailable Demand effective with the next billing period following the period of requested curtailment. In addition, Special Provision No. 5 is applicable.
	(c)	If the customer establishes a demand reduction larger than the Fixed Curiallable Demand for the duration of each period of requested curtailment occurring within a billing period, upon request by the customer, the lowest of the demand reductions achieved during each such period shall become the Fixed Curtailable Demand effective with the next billing period.
3.	responsible for Such requests	I requirement for receiving the Curtailable Demand Credit provided under this rate schedule, a customer shall be strictly the curtailment of its load by at least the Fixed Curtailable Demand upon each curtailment request from the Company. will be made during those periods specified under Limitation of Service above. The Company shall also have the right to one additional curtailment each catendar year irrespective of such limitations.
4.	during each per been during the	I be deemed to have complied with its curtailment responsibility if the maximum 30-minute kW demand established riod of requested curtailment is lower than what the customer's maximum 30-minute kW demand would otherwise have a period of requested curtailment by at least the Fixed Curtailable Demand defined in Special Provision No. 2. This will by the Company using customer's load data of similar day, time and weather conditions where a curtailment was not
5.	following addition	as not complied with its curtailment responsibility during a period of requested curtailment, the customer will be billed the anal charge for all billing periods following the previous period of requested curtailment through the billing period in which liance occurred, not to exceed a total of twelve (12) billing periods:
		125% of the difference in Demand and Energy Charges which would have resulted under Rate Schedule GSDT-1 and those Demand and Energy Charges calculated under this rate schedule, plus the difference between ECCR, CCR and ECRC of this rate schedule and GSDT-1. This calculation shall be exclusive of any additional charges rendered under Special Provision No. 6 of this rate schedule.
6.	additional energ requested. The imminent or as of such purchas forth in the sec	e frequency and duration of curtailments requested under this rate schedule, the Company will attempt to purchase gy, if available, from sources outside the Company's system during periods for which curtailment would otherwise be a Company will also attempt to notify any customer, desirous of such notice, in advance when such purchases are soon as practical thereafter where advance notice is not feasible. Similar notification will be provided upon termination es. Any energy associated with curtailable loads used during these periods will be subject to the additional charges set and paragraph of this provision. Customers may avoid these higher charges by curtailing their usage during such ist their Fixed Curtailable Demand pursuant to the third paragraph of these provisions.
	applicable energy hereunder, base consumption ab requested. The this rate schedu SS-3 during the purchased from	customer elects not to curtail, the customer will be required to pay an additional charge, in lieu of the otherwise gy charges (Non-Fuel Energy Charge, Capacity Cost Recovery Factor and Fuel Cost Recovery Factor), provided ad on the customer's proportionate share of the higher cost of such purchased energy, plus 3.0 mills per kWh, for all bove the customer's Non-Curtailable Demand during the period for which curtailment would have otherwise been cost of such purchased energy shall be based on the average cost of all purchased power and energy provided under le and under similar provisions in Rate Schedules IS-1, IS-1, CS-1, IS-2, IS-2, CS-2, CS-3, SS-2 and e corresponding calendar month. If, for any reason during such period, the customer is notified that the energy outside sources is no longer available, the terms of this Special Provision will cease to apply and curtailments to at the's Fixed Curtailable Demand will be required for the remainder of such period.
	least its Fixed C	ustomer elects to curtail irrespective of the availability of additional energy purchased by the Company and curtails by at urtailable Demand during the period for which curtailment would have otherwise been requested, the customer will incur for the payment of the additional cost of such energy.
7.		increases its power requirements in any manner which requires the Company to install additional facilities for the ne customer, a new Term of Service may be required at the Company's option.
	-perme 600 of 6	(Continued on Page No. 4)

EFFECTIVE: January 1, 2013



SECTION NO. VI TWENTY-SEVENTH REVISED SHEET NO. 6.250 CANCELS TWENTY-SIXTH REVISED SHEET NO. 6.250

	Page 1 of 3			
RATE SCHEDULE IS-1 INTERRUPTIBLE GENERAL SERVICE (Closed to New Customers as of 04/16/96)				
Availability: Available throughout the entire territory served by the Company.				
Applicable:				
To any customer, other than residential, for light and power purpo	ses where service may be interrupted by the Company.			
Character of Service;				
Alternating current, 60 cycle, single-phase or three-phase, at the	Company's standard voltage available.			
Limitation of Service:				
time period for economic reasons. Interruptible service under electric power and energy delivered hereunder from the Compa the Company's firm power customers and firm power sales comm	service under this rate schedule is <u>not</u> subject to interruption during any this rate schedule is subject to interruption during any time period that ny's available generating resources is required to a) maintain service to nitments or b) supply emergency interchange service to another utility for stem purchases during such periods to maintain service to interruptible b. 4 of this rate schedule.			
Service under this rate is subject to the Company's currently effect	tive and filed "General Rules and Regulations for Electric Service."			
Rate Per Month:				
Customer Charge:				
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 278.95 \$ 413.94 \$ 990.26			
Demand Charge:	\$ 6.24 per kW of Billing Demand			
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6,105 and 6,106			
Interruptible Demand Credit:	\$ 4.99 per kW of Billing Demand			
Energy Charge:				
Non-Fuel Energy Charge:	0.902¢ per kWh			
Plus the Cost Recovery Factors on a #/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106			
Premium Distribution Service Charge:				
Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.				
In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.99 per kW for the cost of reserving capacity in the alternate distribution circuit.				
Determination of Billing Demand:				
The Billing Demand shall be the maximum 30-minute kW demand	established during the billing period.			
Delivery Voltage Credit:				
When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:				
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand			
	(Continued on Page No. 2)			



SECTION NO. VI NINETEENTH REVISED SHEET NO. 6.251 **CANCELS EIGHTEENTH REVISED SHEET NO. 6.251**

	Page 2 of 3			
RATE SCHEDULE IS-1 INTERRUPTIBLE GENERAL SERVICE (Closed to New Customers as of 04/16/96) (Continued from Page No. 1)				
Metering Voltage Adjustment:				
Metering voltage will be at the option of the Company.	When the Company meters at a voltage above distribution secondary, the lon-Fuel Energy Charge, Demand Charge, Interruptible Demand Credit and			
Metering Voltage	Reduction Factor			
Distribution Primary Transmission	1.0% 2.0%			
Power Factor:				
ending with the current billing period, bills computed under	ore for three (3) of more months out of the twelve (12) consecutive months the above rate per month charges will be increased 26¢ for each KVAR by s the measured kW demand, and will be decreased 26¢ for each KVAR by es the measured kW demand.			
Additional Charges:				
Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization Fee: Municipal Tax: Sales Tax:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106			
Minimum Monthly Bill:				
The minimum monthly bill shall be the Customer Charge and to serve the customer is required, the Company may require	the Demand Charge for the current billing period. Where special equipment a specified minimum charge.			
Terms of Payment: Bills rendered hereunder are payable within the time limit spe	ecified on bill at Company-designated locations.			
Term of Service:				
	I term of five (5) years from the commencement of service, and shall continue ty (60) days prior to termination.			
Special Provisions:				
 When the customer increases the electrical load, which increases the electrical load, which increases the customer, a new Term of Service may be required und 	ease requires the Company to increase facilities installed for the specific use er this rate at the option of the Company.			
first-come, first-served basis. Required equipment (meter	edule who elect to transfer to this rate will be accepted by the Company on a ering, under-frequency relay, etc.) will be installed accordingly, subject to a with the first full billing period following the date of equipment installation.			
The Company may, under the provisions of this rate, at its o contract form.	ption, require a special contract with the customer upon the Company's filed			
The Company will attempt to minimize interruption hereunder by purchasing power and energy from other sources during periods of normal interruption. The Company will also attempt to notify any customer, desirous of such notice, in advance when such purchases are imminent or as soon as practical thereafter where advance notice is not feasible. Similar notification will be provided upon termination of such purchases. When the Company is successful in making such purchases, the customer will be required to pay an additional charge, in lieu of the otherwise applicable energy charges (Non-Fuel Energy Charge, Capacity Cost Recovery Factor and Fuel Cost Recovery Factor), provided hereunder based on the customer's proportionate share of the higher cost of such purchased energy, plus 3.0 mills per kWh. The cost of such purchased energy provided under this rate schedule and under similar provisions in Rate Schedules IST-1, CS-1, CST-1, IS-2, IST-2, CS-2, CST-2, CS-3, CST-3, SS-2 and SS-3 during the corresponding calendar month.				
	(Continued on Page No. 3)			
ISSUED BY: Lori J. Cross, Manager, Utility Regulator	y Planning - Florida			

EFFECTIVE: January 1, 2013



SECTION NO. VI THIRTEENTH REVISED SHEET NO. 6.255 **CANCELS TWELFTH REVISED SHEET NO. 6.255**

Page 1 of 3

RATE SCHEDULE IS-2 INTERRUPTIBLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

Applicable to customers, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where service may be interrupted by the Company. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service,"

Rate Per Month:

Pr

Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmisston Metering Voltage:	\$ 278.95 \$ 413.94 \$ 990.26
Demand Charge: Plus the Cost Recovery Factors on a S/ kW basis in Pate Schedule D.1.4. Different demonstration	\$ 6.24 per kW of Billing Demand
in Rate Schedule BA-1, Billing Adjustments:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	\$ 8.70 per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	0.902¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor.	See Sheet No. 6.105 and 6.106
remium Distribution Service Charge:	
Regulations Governing Electric Service, the customer shall pay a	ter 12/15/98 in accordance with Subpart 2.05, General Rules and monthly charge determined under Special Provision No. 5 of this rate er's allocated share thereof, installed to accomplish automatic delivery te distribution circuit.
In addition, the Demand Charge included in the Rate per Month s	ection of this rate schedule shall be increased by \$0.99 per kW for the

or the cost of reserving capacity in the alternate distribution circuit. Determination of Billing Demand:

The Billing Demand shall be the maximum 30-minute kW demand established during the billing period, but not less than 500 kW. Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:

\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand

(Continued on Page No. 2)



SECTION NO. VI SEVENTH REVISED SHEET NO. 6.256 CANCELS SIXTH REVISED SHEET NO. 6.256

		Page 2 of 3 RATE SCHEDULE IS-2
		INTERRUPTIBLE GENERAL SERVICE (Continued from Page No. 1)
м	letering Voltage Adjustment:	
		the Company. When the Company meters at a voltage above distribution secondary, the Il apply to the Non-Fuel Energy Charge, Demand Charge, Interruptible Demand Credit, and
	Metering Voltage	Reduction Factor
	Distribution Primary Transmission	1.0% 2.0%
P	ower Factor:	
		nonth charges will be increased 26¢ for each KVAR by which the reactive demand exceeds, emand, and will be decreased 26¢ for each KVAR by which the reactive demand is less than, mand.
A	dditional Charges:	
	Fuel Cost Recovery Factor: Gross Receipts Tax Factor: Right-of-Way Utilization Fee: Municipal Tax:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106
	Sales Tax:	See Sheet No. 6.106
м	inimum Monthly Bill:	
Lat 1	The minimum monthly bill shall be the Cust	omer Charge and the Demand Charge for the current billing period. Where special equipment any may require a specified minimum charge.
Те	ems of Payment:	
	Bills rendered hereunder are payable within	the time limit specified on bill at Company-designated locations.
Те	rm of Service:	
		r a minimum initial term of five (5) years from the commencement of service, and shall continue written notice sixty (60) days prior to termination.
Sp	ecial Provisions:	
1.		load, which increase requires the Company to increase facilities installed for the specific use y be required under this rate at the option of the Company.
2.	first-come, first-served basis. Required e availability. Service under this rate schedu Before commencement of service under thi	Impany rate schedule who elect to transfer to this rate will be accepted by the Company on a aquipment (metering, under-frequency relay, etc.) will be installed accordingly, subject to be shall commence with the first full billing period following the date of equipment installation. Is rate, the Company shall exercise an interruption for purposes of testing its equipment. The se at least one additional interruption each calendar year irrespective of capacity availability or e the customer notice of the test.
3.	The Company may, under the provisions of contract form.	this rate, at its option, require a special contract with the customer upon the Company's filed
4.	normal interruption. The Company will also imminent or as soon as practical thereafter such purchases. When the Company is sur in lieu of the otherwise applicable energy of Factor), provided hereunder based on the c kWh. The cost of such purchased energy si	emption hereunder by purchasing power and energy from other sources during periods of attempt to notify any customer, desirous of such notice, in advance when such purchases are where advance notice is not feasible. Similar notification will be provided upon termination of ccessful in making such purchases, the customer will be required to pay an additional charge, harges (Non-Fuel Energy Charge, Capacity Cost Recovery Factor, and Fuel Cost Recovery ustomer's proportionate share of the higher cost of such purchased energy, plus 3.0 mills per hall be based on the average cost of all purchased power and energy provided under this rate ate Schedules IS-1, IST-1, CS-1, CST-1, IST-2, CS-2, CST-2, CS-3, CST-3, SS-2 and SS-3
		(Continued on Page No. 3)
ISS	SUED BY: Lori J. Cross, Manager, Ut	llity Regulatory Planning - Florida
	FECTIVE: January 1, 2013	

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SECTION NO. VI **TWENTY-SEVENTH REVISED SHEET NO. 6.260** CANCELS TWENTY-SIXTH REVISED SHEET NO. 6.260

INTERRUPTIBLE OPTIONAL TI	HEDULE IST-1 GENERAL SERVICE ME OF USE RATE stomers as of 04/16/96)		
Availability:			
Available throughout the entire territory served by the Company.			
Applicable:			
At the option of customers otherwise eligible for service under each point of delivery are measured through one meter.	Rate Schedule IS-1, provided that the total electric load requirements at		
Character of Service:			
Alternating current, 60 cycle, single-phase or three-phase, at the	Company's standard voltage available.		
Limitation of Service:			
Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.			
Service under this rate is subject to the Company's currently effer	tive and filed "General Rules and Regulations for Electric Service."		
Rate Per Month:			
Customer Charge:			
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 278.95 \$ 413.94 \$ 990.26		
Demand Charge:			
Base Demand Charge: Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	 0.99 per kW of Base Demand See Sheet No. 6.105 and 6.106 		
On-Peak Demand Charge:	\$ 5.46 per kW of On-Peak Demand		
Interruptible Demand Credit:	\$ 4.99 per kW of On-Peak Demand		
Energy Charge:			
	1 2614 por On Book WM/b		
Non-Fuel Energy Charge:	1.264¢ per On-Peak kWh 0.737¢ per Off-Peak kWh		
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> ,			
except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106		
The On-Peak rate shall apply to energy used during designa use,	ted On-Peak Periods. The Off-Peak rate shall apply to all other energy		
Premium Distribution Service Charge:			
Where Premium Distribution Service has been established a Regulations Governing Electric Service, the customer shall pay a schedule for the costs of all additional equipment, or the custom transfer including all line costs necessary to connect to an alterna			
In addition, the Base Demand Charge included in the Rate per M for the cost of reserving capacity in the alternate distribution circu Rating Periods:	Nonth section of this rate schedule shall be increased by \$0.99 per kW it.		
(a) On-Peak Periods - The designated On-Peak Periods express	ed in terms of prevailing clock time shall be as follows:		
(1) For the calendar months of November through March, Monday through Friday ⁺ :	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.		
(2) For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.		
	n-Peak Periods: New Year's Day, Memorial Day, Independence Day,		

The following Day. Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Period.

(Continued on Page No. 2)





SECTION NO. VI TWENTY-FIRST REVISED SHEET NO. 6,261 CANCELS TWENTIETH REVISED SHEET NO. 6,261

	Page 2 of 3
OP (Closed	RATE SCHEDULE IST-1 RUPTIBLE GENERAL SERVICE TIONAL TIME OF USE RATE to New Customers as of 04/16/96) Continued from Page No. 1)
Rating Periods: (Continued)	
(b) Off-Peak Periods - The designated Off-Peak Per above.	riods shall be all periods other than the designated On-Peak Periods set forth in (a)
Determination of Billing Demands:	
The billing demands shall be the following:	
(a) The Base Demand shall be the maximum 30-minu	te kW demand established during the current billing period.
(b) The On-Peak Demand shall be the maximum 3 current billing period.	0-minute kW demand established during designated On-Peak Periods during the
Delivery Voltage Credit:	
When a customer takes service under this rate at a charge hereunder shall be subject to the following cred	delivery voltage above standard distribution secondary voltage, the Base Demand dit;
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$0.36 per kW of Billing Demand \$1.35 per kW of Billing Demand
Note: In no event shall the total of the Demand Charge	es hereunder, after application of the above credit, be an amount less than zero.
Metering Voltage Adjustment:	
Metering voltage will be at the option of the Compa appropriate following reduction factor shall apply to Delivery Voltage Credit hereunder:	any. When the Company meters at a voltage above distribution secondary, the the Non-Fuel Energy Charge, Demand Charge, Interruptible Demand Credit and
Metering Voltage	Reduction Factor
Distribution Primary Transmission	1.0% 2.0%
Power Factor:	
ending with the current billing period, bills computed a	or more for three (3) or more months out of the twelve (12) consecutive months under the above rate per month charges will be increased 26¢ for each KVAR by mes the measured kW demand, and will be decreased 26¢ for each KVAR by which s the measured kW demand.
Additional Charges:	
Fuel Cost Recovery Factor:	See Sheet No. 6.105 See Sheet No. 6.106
Gross Receipts Tax Factor: Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax: Sales Tax:	See Sheet No. 6.106 See Sheet No. 6.106
Minimum Monthly Bill:	
The minimum monthly bill shall be the Customer Charg	je.
Terms of Payment:	
Bills rendered hereunder are payable within the time lin	nit specified on bill at Company-designated locations.
	(Continued on Page No. 3)



SECTION NO. VI TWELFTH REVISED SHEET NO. 6.265 CANCELS ELEVENTH REVISED SHEET NO. 6.265

Page 1 of 3

RATE SCHEDULE IST-2 INTERRUPTIBLE GENERAL SERVICE OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

At the option of the customer, applicable to customers otherwise eligible for service under Rate Schedule IS-2, where the billing demand is 500 kW or more, provided that the total electric requirements at each point of delivery are measured through one meter. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants, or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generalion is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, shortes, tores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is <u>not</u> subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service,"

Rate Per Month:

C	Customer Charge:		
	Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$	278.95 413.94 990.26
D	emand Charge:		
	Base Demand Charge: Plus the Cost Recovery Factors on a \$/ kW basis	\$	0,99 per kW of Base Demand
	in Rate Schedule BA-1, Billing Adjustments:	S	ee Sheet No. 6,105 and 6,106
	On-Peak Demand Charge:	\$	5.46 per kW of On-Peak Demand
lr	iterruptible Demand Credit:	\$	8.70 per kW of Load Factor Adjusted Demand
E	nergy Charge:		
	Non-Fuel Energy Charge:	1.	264¢ per On-Peak kWh
			737¢ per Off-Peak kWh
	Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> ,		
	except for the Fuel Cost Recovery Factor.	50	ee Sheet No. 6,105 and 6,106
	The On-Peak rate shall apply to energy used during design	ated (On-Peak Periods. The Off-Peak rate shall apply to all other ene

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit. In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.99 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

- (a) On-Peak Periods The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:
 (1) For the calendar months of November through March,
 - Monday through Friday*:
 - 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

12:00 Noon to 9:00 p.m.

(2) For the calendar months of April through October, Monday through Friday*:

The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

Continued on Page No. 2)



SECTION NO. VI **SEVENTH REVISED SHEET NO. 6.266** CANCELS SIXTH REVISED SHEET NO. 6.266

Page	2	of	ŝ
1 490	-	U I	~

RATE SCHEDULE IST-2 INTERRUPTIBLE GENERAL SERVICE OPTIONAL TIME OF USE RATE (Continued from Page No. 1)

Rating Periods: (Continued)

(b) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

Determination of Billing Demands:

The billing demands shall be the following:

- (a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW
- (b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Penods during the current billing period.

Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand charge hereunder shall be subject to the following credit:

 For Distribution Primary Delivery Voltage: 	
For Transmission Delivery Voltage:	

\$0.36 per kW of Billing Demand \$1,35 per kW of Billing Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Interruptible Demand Credit and Delivery Voltage Credit hereunder.

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with measured demands of 1,000 kW or more for three (3) or more months out of the twelve (12) consecutive months ending with the current billing period, bills computed under the above rate per month charges will be increased 26¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 26¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6,106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.



(Continued on Page No. 3)



SECTION NO. VI TWENTY-FOURTH REVISED SHEET NO. 6.280 CANCELS TWENTY-THIRD REVISED SHEET NO. 6.280

						Page 1 of 6	
RATE SCHEDULE LS-1 LIGHTING SERVICE							
ity:							
able throughout the entire territory	served by the C	ompany.					
le'							
ny customer for the sole purpose d fixtures of the type available u	inder this rate so	chedule. Servi	ce hereunde	r is provided for	the sole and exclu	sive benefit of the	
r of Service:							
		ng service (i.e.	photoelectric	cell); alternating	current, 60 cycle, s	ingle phase, at the	
n of Service:							
bility of certain fixture or pole type	es at a location n	nay be restricte	d due to acc	essibility.			
			this rate is s	subject to the Co	mpany's currently	effective and filed	
Month:							
omer Charge:							
nmetered: etered:							
y and Demand Charge:							
on-Fuel Energy Charge:	1.933¢ per kWh						
ate Schedule BA-1, <i>Billing Adjusti</i> cept the Fuel Cost Recovery Fac nit Charges:	ments,	Se	e Sheet No.	5.105 and 6,106			
					121600.00 ⁻⁰⁰⁰		
		AMP SIZE ²			CHARGES PER	UNIT	
DESCRIPTION	LUMENS	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY ³	
Incandescent; ¹ Roadway Roadway Post Top	1,000 2,500 2,500	105 205 205	32 66 72	\$1.03 1.61 20.39	\$4.07 3.67 3.67	\$0.62 1.28 1.39	
Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway Open Bottom Roadway Roadway Flood Flood	4,000 4,000 8,000 21,000 62,000 62,000 62,000	100 100 175 175 400 1,000 1,000	44 44 71 71 158 386 158 386	\$2.55 2.95 3.47 3.34 2.50 4.04 5.29 5.29 6.20	\$1.80 1.80 1.77 1.77 1.81 1.78 1.81 1.78	\$0.85 0.85 1.37 1.37 3.05 7.46 3.05 7.46	
	Able throughout the entire territory fe: hy customer for the sole purposed d fixtures of the type available u- mer, and nothing herein or in the ompany to any such third party. r of Service: huous dusk to dawn automatically any's standard voltage available. n of Service: hubility of certain fixture or pole type by or resale, service not permitted terral Rules and Regulations Gover Month: orner Charge: numetered: etered: hy and Demand Charge: us the Cost Recovery Factors list the Schedule BA-1, <i>Billing Adjusti</i> (cept the Fuel Cost Recovery Factors nit Charges: xtures: DESCRIPTION Incandescent: ¹ Roadway Roadway Post Top Roadway Post Top Roadway Open Bottorn Roadway Roadway Flood	ity: able throughout the entire territory served by the C fe: hy customer for the sole purpose of lighting road d fixtures of the type available under this rate so mer, and nothing herein or in the contract execut ompany to any such third party. r of Service: huous dusk to dawn automatically controlled lighting hany's standard voltage available. n of Service: ability of certain fixture or pole types at a location m by or resale, service not permitted hereunder. Service and Regulations Governing Electric Service and Regulations Governing Electric Service and Regulations Governing Electric Service at a location m by or resale, service not permitted hereunder. Service: hor resale, service not permitted hereunder. Service at a location m by or resale, service not permitted hereunder. Service: metered: etered: hy and Demand Charge: on-Fuel Energy Charge: us the Cost Recovery Factors listed in ate Schedule BA-1, <i>Billing Adjustments</i> , iccept the Fuel Cost Recovery Factor: mit Charges: xtures:	LIGHTING SE thy: able throughout the entire territory served by the Company. fe: ny customer for the sole purpose of lighting roadways or other of fixtures of the type available under this rate schedule. Servi mer, and nothing herein or in the contract executed hereunder i ompany to any such third party. r of Service: nuous dusk to dawn automatically controlled lighting service (i.e. any's standard voltage available. n of Service: biblity of certain fixture or pole types at a location may be restricte by or resale service not permitted hereunder. Service under ral Rules and Regulations Governing Electric Service.* Month: mer Charge: nmetered:	LIGHTING SERVICE ity: able throughout the entire territory served by the Company. le: y customer for the sole purpose of lighting roadways or other outdoor land d fixtures of the type available under this rate schedule. Service hereunder mer, and nothing herein or in the contract executed hereunder is intended to ompany to any such third party. r of Service: nuous dusk to dawn automatically controlled lighting service (i.e. photoelectric any's standard voltage available. n of Service: Not of Service: Service under this rate is service and Regulations Governing Electric Service." Month: Service Under this rate is service lenerd: \$ 1.19 per line of \$ 3.42 per line of \$ 1.933¢ per kWr LAMP SiZE ² LAMP SiZE ² Intillat Lumers LAMP SiZE ² Intillat Lumers <td colsp<="" td=""><td>LIGHTING SERVICE ity: bit throughout the entire territory served by the Company. let: y customer for the sole purpose of lighting roadways or other outdoor land use areas; server of nere, and nothing herein or in the contract executed hereunder is intended to benefit any third ormer, and nothing herein or in the contract executed hereunder is intended to benefit any third ormany to any such third party. r of Service: nouse dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating wany's standard voltage available. n of Service: nouse dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating wany's standard voltage available. n of Service: Not for sesale service not permitted hereunder. Service under this rate is subject to the Corrat Rules and Regulations Governing Electric Service." Month: metered: \$1.19 per line of billing three for brane of billing three for Service: Nortfuel Energy Charge: LAMP SIZE ² Intitrat. LAMP SIZE ² INTITL LAMP SIZE ²</td><td>LIGHTING SERVICE ity: isile incurption in the entire lemitory served by the Company. le: y customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Com d fotures of the type available under this rate schedule. Service hereunder is provided for the sole and exclu- mer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose ompany to any such third party. r of Service: nuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, s any's standard voltage available. n of Service: billity of certain fixture or pole types at a location may be restricted due to accessibility. by or reasile service and permitted hereunder. Service under this rate is subject to the Company's currently rral Rules and Regulations Governing Electric Service." Month: mere Charge: meterad: s 3.42 per line of billing y and Demand Charge: notelerengy Charge: to the Cost Recovery Factors listed in tat Schedule BA-1, Billing Adjustments, cept the Fuel Cost Recovery Factor: set the Set Recovery Factors: set the Cost Recovery Factors: set the Set Recovery Factors: set the Set Recovery Factors: set the Set Recovery Factors: set the Cost Recovery Factors: tures: tur</td></td>	<td>LIGHTING SERVICE ity: bit throughout the entire territory served by the Company. let: y customer for the sole purpose of lighting roadways or other outdoor land use areas; server of nere, and nothing herein or in the contract executed hereunder is intended to benefit any third ormer, and nothing herein or in the contract executed hereunder is intended to benefit any third ormany to any such third party. r of Service: nouse dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating wany's standard voltage available. n of Service: nouse dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating wany's standard voltage available. n of Service: Not for sesale service not permitted hereunder. Service under this rate is subject to the Corrat Rules and Regulations Governing Electric Service." Month: metered: \$1.19 per line of billing three for brane of billing three for Service: Nortfuel Energy Charge: LAMP SIZE ² Intitrat. LAMP SIZE ² INTITL LAMP SIZE ²</td> <td>LIGHTING SERVICE ity: isile incurption in the entire lemitory served by the Company. le: y customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Com d fotures of the type available under this rate schedule. Service hereunder is provided for the sole and exclu- mer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose ompany to any such third party. r of Service: nuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, s any's standard voltage available. n of Service: billity of certain fixture or pole types at a location may be restricted due to accessibility. by or reasile service and permitted hereunder. Service under this rate is subject to the Company's currently rral Rules and Regulations Governing Electric Service." Month: mere Charge: meterad: s 3.42 per line of billing y and Demand Charge: notelerengy Charge: to the Cost Recovery Factors listed in tat Schedule BA-1, Billing Adjustments, cept the Fuel Cost Recovery Factor: set the Set Recovery Factors: set the Cost Recovery Factors: set the Set Recovery Factors: set the Set Recovery Factors: set the Set Recovery Factors: set the Cost Recovery Factors: tures: tur</td>	LIGHTING SERVICE ity: bit throughout the entire territory served by the Company. let: y customer for the sole purpose of lighting roadways or other outdoor land use areas; server of nere, and nothing herein or in the contract executed hereunder is intended to benefit any third ormer, and nothing herein or in the contract executed hereunder is intended to benefit any third ormany to any such third party. r of Service: nouse dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating wany's standard voltage available. n of Service: nouse dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating wany's standard voltage available. n of Service: Not for sesale service not permitted hereunder. Service under this rate is subject to the Corrat Rules and Regulations Governing Electric Service." Month: metered: \$1.19 per line of billing three for brane of billing three for Service: Nortfuel Energy Charge: LAMP SIZE ² Intitrat. LAMP SIZE ² INTITL LAMP SIZE ²	LIGHTING SERVICE ity: isile incurption in the entire lemitory served by the Company. le: y customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Com d fotures of the type available under this rate schedule. Service hereunder is provided for the sole and exclu- mer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose ompany to any such third party. r of Service: nuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, s any's standard voltage available. n of Service: billity of certain fixture or pole types at a location may be restricted due to accessibility. by or reasile service and permitted hereunder. Service under this rate is subject to the Company's currently rral Rules and Regulations Governing Electric Service." Month: mere Charge: meterad: s 3.42 per line of billing y and Demand Charge: notelerengy Charge: to the Cost Recovery Factors listed in tat Schedule BA-1, Billing Adjustments, cept the Fuel Cost Recovery Factor: set the Set Recovery Factors: set the Cost Recovery Factors: set the Set Recovery Factors: set the Set Recovery Factors: set the Set Recovery Factors: set the Cost Recovery Factors: tures: tur

(Continued on Page No. 2)



SECTION NO. VI TWENTY-SECOND REVISED SHEET NO. 6.281 CANCELS TWENTY-FIRST REVISED SHEET NO. 6.281

							Page 2 of 6
			ATE SCHEDU				
			LIGHTING SEI				
		(Coi	ntinued from Pa	age No. 1)			
<u> </u>	tures: (Continued)						
			AMP SIZE 2			CHARGES PER	UNIT
BILLING		INITIAL	LAMP				NON-FUEL
TYPE	DESCRIPTION	LUMENS	WATTAGE	kWh	FIXTURE	MAINTENANCE	
1115		OULLOI	TATTAGE	NUTII	PIATURE	MANTENANCE	ENERGI
	Sodium Vapor:						
300	HPS Deco Rdwy White	50,000	400	168	\$14.73	\$1.61	\$3.25
301	Sandpiper HPS Deco Roadway	27,500	250	104	13.81	1.72	2.01
302	Sandpiper HPS Deco Rdwy Blk	9,500	100	42	14.73	1.58	0.81
305	Open Bottom '	4,000	50	21	2.54	2.04	0.41
310	Roadway 1	4,000	50	21	3.12	2.04	0.41
313	Open Bottom '	6,500	70	29	4.19	2.05	0.56
314	Hometown II	9,500	100	42	4.08	1.72	0.81
315	Post Top - Colonial/Contemp	4,000	50	21	5.04	2.04	0.41
316	Colonial Post Top	4,000	50	34	4.05	2.04	0.66
318	Post Top 1	9,500	100	42	2.50	1.72	0.81
320	Roadway-Overhead Only	9,500	100	42	3.64	1.72	0.81
321	Deco Post Top - Monticello	9,500	100	49	12.17	1.72	0.95
322	Deco Post Top - Flagler	9,500	100	49	16.48	1.72	0.95
323	Roadway-Turtle OH Only	9,500	100	42	4.32	1.72	0.81
325	Roadway-Overhead Only	16,000	150	65	3.78	1.75	1.26
326	Deco Post Top – Sanibel	9,500	100	49	18.16	1.72	0.95
330	Roadway-Overhead Only	22,000	200	87	3.64	1.83	1.68
335	Roadway-Overhead Only	27,500	250	104	4.16	1.72	2.01
336	Roadway-Bridge 1	27,500	250	104	6.74	1.72	2.01
337	Roadway-DOT 1	27,500	250	104	5.87	1.72	2.01
338	Deco Roadway-Maitland	27,500	250	104	9.62	1.72	2.01
340	Roadway-Overhead Only	50,000	400	169	5.03	1.76	3.27
341	HPS Flood-City of Sebring only 1	16,000	150	65	4.06	1.75	1.26
342	Roadway-Tumpike 1	50,000	400	168	8,95	1.76	3.25
343	Roadway-Tumpike 1	27,500	250	108	9.12	1.72	2.09
345	Flood-Overhead Only	27,500	250	103	5.21	1.72	1.99
347	Clermont	9,500	100	49	20,65	1.72	0.95
348	Clermont	27,500	250	104	22.65	1.72	2.01
350	Flood-Overhead Only	50,000	400	170	5.19	1.76	3.29
351	Underground Roadway	9,500	100	42	6.22	1.72	0.81
352	Underground Roadway	16,000	150	65	7.58	1.75	1.26
354	Underground Roadway	27,500	250	108	8.10	1.72	2.09
356	Underground Roadway	50,000	400	168	8.69	1.76	3.25
357	Underground Flood	27,500	250	108	9.36	1.72	2.09
358	Underground Flood 1	50,000	400	168	9.49	1.76	3.25
359	Underground Turtle Roadway	9,500	100	42	6.09	1.72	0.81
360	Deco Roadway Rectangular ¹	9,500	100	47	12.53	1.72	0.91
365	Deco Roadway Rectangular	27,500	250	108	11.89	1.72	2.09
366	Deco Roadway Rectangular	50,000	400	168	12.00	1.76	3.25
370	Deco Roadway Round	27,500	250	108	15.41	1.72	2.09
375	Deco Roadway Round ¹	50,000	400	168	15.42	1.76	3.25
380	Deco Post Top - Ocala	9,500	100	49	8.78	1.72	0.95
381	Deco Post Top 1	9,500	100	49	4.05	1.72	0.95
383	Deco Post Top-Biscayne	9,500	100	49	14.17	1.72	0.95
385	Deco Post Top - Sebring	9,500	100	49	6.75	1.72	0.95
393	Deco Post Top ¹	4,000	50	21	8.72	2.04	0.33
394	Deco Post Top 1	9,500	100	49	18.16	1.72	0.95
	2000 t 00t t 0p	0,000	100	-10	10.50	1.12	0.00

(Continued on Page No. 3)





SECTION NO. VI FIRST REVISED SHEET NO. 6.2811 CANCELS ORIGINAL SHEET NO. 6.2811

Page 3 of 6 RATE SCHEDULE LS-1 LIGHTING SERVICE (Continued from Page No. 2)							Page 3 of 6
I. Fiz	ctures: (Continued)			.			
			AMP SIZE 2			CHARGES PER	UNIT
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	k₩h	FIXTURE	MAINTENANCE	NON-FUEL ENERGY ³
	Metal Halide:						
307	Deco Post Top-MH Sanibel P	11,600	150	65	\$16.85	\$2.68	\$1.26
308	Clermont Tear Drop P	11,600	150	65	19.91	2.68	1.26
309	MH Deco Rectangular P	36,000	320	126	13.07	2.74	2.44
311	MH Deco Cube P	36,000	320	126	15.98	2.74	2.44
312	MH Flood P	36,000	320	126	10.55	2.74	2.44
319	MH Post Top Biscayne P	11,600	150	65	15.24	2.68	1,26
327	Deco Post Top-MH Sanibel 1	12,000	175	74	18.39	2.72	1.43
349	Clermont Tear Drop 1	12,000	175	74	21.73	2.72	1.43
371	MH Deco Rectangular 1	38,000	400	159	14.26	2.84	3.07
372	MH Deco Circular	38,000	400	159	16.70	2.84	3.07
373	MH Deco Rectangular	110,000	1,000	378	15.30	2.96	7.31
386	MH Flood	110,000	1,000	378	13.17	2.96	7.31
389	MH Flood-Sportslighter *	110,000	1,000	378	13.01	2.96	7.31
390	MH Deco Cube 1	38,000	400	159	17.44	2.84	3.07
396	Deco PT MH Sanibel Dual	24,000	350	148	33.73	5.43	2.86
397	MH Post Top-Biscayne	12,000	175	74	14.98	2.72	1.43
398	MH Deco Cube 5	110,000	1,000	378	20.34	2.96	7.31
399	MH Flood	38,000	400	159	11.51	2.84	3.07
	LED:						
325	LED Roadway	6,000	95	33	\$16.93	\$2.43	\$0.64
326	LED Roadway	9,600	157	55	20.07	2.43	1.06
330	LED Shoebox Type 3	20,664	309	108	41.08	2.84	2.09
335	LED Shoebox Type 4	14,421	206	72	32.59	2.84	1.39
336	LED Shoebox Type 5	14,421	206	72	31.65	2.84	1.39
	•						

(Continued on Page No. 4)



SECTION NO. VI SIXTEENTH REVISED SHEET NO. 6.312 CANCELS FIFTEENTH REVISED SHEET NO. 6.312

			Page 3 of 5
		FIRM ST	SCHEDULE SS-1 ANDBY SERVICE ad from Page No. 2)
De	etermin	ation of Specified Standby Capacity:	
1.		ly, the customer and the Company shall mutually agree bany. This shall be termed for billing purposes as the "Sp	upon a maximum amount of standby capacity in kW to be supplied by the becified Standby Capacity".
2.		e a bona fide change in the customer's standby capacity fied Standby Capacity.	requirement occurs, the Company and the customer shall establish a new
3.	Capa		shall be the greater of: (1) the mutually agreed upon Specified Standby irement established in the current billing month, or (3) the maximum 30- ie twenty-three (23) preceding billing months.
Ra	ite Per	Month:	
1.	Custo	omer Charge:	
	P	econdary Metering Voltage: rimary Metering Voltage: ransmission Metering Voltage:	\$ 100.71 \$ 235.69 \$ 812.02
	Note:	Where the Customer has paid the costs of metering equipe \$81.21.	ipment pursuant to a Cogeneration Agreement, the Customer Charge shall
2.	Suppl	lemental Service Charges:	
	All sup sched	pplemental power requirements shall be billed in accordation.	ance with the demand and energy charges of the otherwise applicable rate
3.	Stand	by Service Charges:	
	A.	Distribution Capacity:	
		\$1.80 per kW times the Specified Standby Capacity.	
		Note: No charge is applicable to a customer who has system.	provided all the facilities for interconnection to the Company's transmission
	в.	Generation & Transmission Capacity:	
		The charge shall be the greater of: 1. \$1.005 per kW times the Specified Standby Capaci	ity or
		 The sum of the daily maximum 30-minute kW o \$0.479/kW times the appropriate following monthly 	demand of actual standby use occurring during On-Peak Periods times factor.
		Billing Month	_Factor_
		March, April, May, October	0.80
		June, September, November, December January, February, July, August	1.00 1.20
		Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments:</i>	See Sheet No. 6.105 and 6,106
	C.	Energy Charges	
		Non-Fuel Energy Charge;	0.890¢ per kWh
		Plus the Cost Recovery Factors on a <i>¢</i> / kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> ,	See Sheet No. 6.105 and 6.106
		except for the Fuel Cost Recovery Factor:	
			(Continued on Page No. 4)



SECTION NO. VI FIFTEENTH REVISED SHEET NO. 6.313 CANCELS FOURTEENTH REVISED SHEET NO. 6.313

			Page 4 of 5			
		FIRM ST	CHEDULE \$S-1 ANDBY SERVICE d from Page No. 3)			
R	Rate Per	Month: (Continued)				
1		dby Service Charges: (Continued)				
	D.	Delivery Voltage Credit:				
			tribution primary delivery voltage, the Distribution Capacity Charge			
	E.	Metering Voltage Adjustment:				
			When the Company meters at a voltage above distribution secondary, the the Distribution Capacity Charge, Generation & Transmission Capacity e Credit hereunder.			
1		Metering Voltage	Reduction Factor			
		Distribution Primary Transmission	1.0% 2.0%			
[F.	Fuel Cost Recovery Factor:				
		Time of Use Fuel Charges of applicable metering voltage	ge provided on Tariff Sheet No. 6.105.			
	G.	Gross Receipts Tax Factor:	See Sheet No. 6.106			
	H.	Right-of-Way Utilization Fee:	See Sheet No. 6.106			
	1.	Municipal Tax:	See Sheet No. 6.106			
	J.	Sales Tax:	See Sheet No. 6.106			
	transf	er including all line costs necessary to connect to an alter	mer's allocated share thereof, installed to accomplish automatic delivery nate distribution circuit.			
		r the cost of reserving capacity in the alternate distribution				
R	ating Pe	eriods:				
1.	On-Pe	eak Periods - The designated On-Peak Periods expressed	d in terms of prevailing clock time shall be as follows:			
	Α.	For the calendar months of November through March, Monday through Friday*:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.			
	8.	For the calendar months of April through October, Monday through Friday*:	12:00 Noon to 9:00 p.m.			
*	* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Mernorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.					
2.	2. Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above.					
Mi	Minimum Monthly Bill:					
	The m	-	he Capacity Charges for Standby Service. Where Special Equipment to ecified minimum charge.			
			(Continued on Page No. 5)			
IS	SUED	BY: Lori J. Cross, Manager, Utility Regulatory f	Planning - Florida			

EFFECTIVE: January 1, 2013



SECTION NO. VI NINETEENTH REVISED SHEET NO. 6.317 CANCELS EIGHTEENTH REVISED SHEET NO. 6.317

			Page 3 of 5
		INTERRUPTIBL	CHEDULE SS-2 E STANDBY SERVICE I from Page No. 2)
De	termi	nation of Specified Standby Capacity:	
1.		lly, the customer and the Company shall mutually agree t pany. This shall be termed for billing purposes as the "Spe	upon a maximum amount of standby capacity in kW to be supplied by the actived Standby Capacity".
2.		re a bona fide change in the customer's standby capacity ified Standby Capacity.	requirement occurs, the Company and the customer shall establish a new
3.	Capa	Specified Standby Capacity for the current billing period sl ccity, (2) the maximum 30-minute kW standby power requir te kW standby power requirement established in any of the	hall be the greater of: (1) the mutually agreed upon Specified Standby rement established in the current billing month, or (3) the maximum 30- twenty-three (23) preceding billing months.
		Month:	
1.		omer Charge:	¢ 202 74
		Secondary Metering Voltage: Primary Metering Voltage:	\$ 303.71 \$ 438.68
		ransmission Metering Voltage:	\$ 1,015.02
	Note:	Where the customer has paid the costs of metering equi be \$284.20.	pment pursuant to a Cogeneration Agreement, the Customer Charge shall
2,			nce with the demand and energy charges of the otherwise applicable rate
3.	Stand A.	 dby Service Charges: Distribution Capacity: \$1.80 per kW times the Specified Standby Capacity. Note: No charge is applicable to a Customer who has p system. 	provided all the facilities for interconnection to the Company's transmission
	B.	 Generation & Transmission Capacity: The charge shall be the greater of: \$1.005 per kW times the Specified Standby Capacit The sum of the daily maximum 30-minute kW dema kW times the appropriate following monthly factor: 	y or and of actual standby use occurring during On-Peak Periods times \$0.479
		Billing Month	Factor
		March, April, May, October	0.80
		June, September, November, December January, February, July, August	1.00 1.20
		Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> .	See Sheet No. 6.105 and 6.106
	C.	Interruptible Capacity Credit; The credit shall be the greater of: 1. \$0.870 per kW times the Specified Standby Capacity 2. The sum of the daily maximum 30-minute kW di \$0.414/kW times the appropriate Billing Month Factor	emand of actual standby use occurring during On-peak periods times
	D.	Energy Charges: Non-Fuel Energy Charge:	0.880¢ per kWh
		Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, Billing Adjustments,	
		except for the Fuel Cost Recovery Factor	See Sheet No. 6.105 and 6.106
	E.	Delivery Voltage Credit: When a customer takes service under this rate at a distri hereunder will be reduced by 33¢ per kW.	bution primary delivery voltage, the Distribution Capacity Charge
			(Continued on Page No. 4)
100		RV: Losi I Croco Meneror Ilélike Beruleton B	



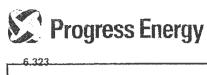
SECTION NO. VI FOURTEENTH REVISED SHEET NO. 6.318 CANCELS THIRTEENTH REVISED SHEET NO. 6.318

	Page 4 of 5				
	RATE SCHEDULE SS-2 INTERRUPTIBLE STANDBY SERVICE (Continued from Page No. 3)				
	r Month: (Continued) Idby Service Charges: (Continued)				
F.	Metering Voltage Adjustment: Metering voltage will be at the option of the Company, When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity Charge, Interruptible Capacity Credit, Non-Fuel Energy Charge and Delivery Voltage Credit hereunder:				
	Metering Voltage Reduction Factor Distribution Primary 1.0% Transmission 2.0%				
G.	Fuel Cost Recovery Factor: Time of Use Fuel Charges of applicable metering voltage provided on Tariff Sheet No. 6.105.				
H. I. J. K.	Gross Receipts Tax Factor;See Sheet No. 6.106Right-of-Way Utilization Fee:See Sheet No. 6.106Municipal Tax;See Sheet No. 6.106Sales Tax:See Sheet No. 6.106				
Whe Reg sche	n Distribution Service Charge: re Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and ilations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 4 of this rate dule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery fer including all line costs necessary to connect to an alternate distribution circuit.				
	dition the Distribution Capacity Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.92 per or the cost of reserving capacity in the alternate distribution circuit.				
Rating P 1. On-F	eriods: eak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:				
A.	For the calendar months of November through March, Monday through Friday*: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.				
В.	For the calendar months of April through October, Monday through Friday*: 12:00 Noon to 9:00 p.m.				
Day,	ollowing general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded the On-Peak Periods.				
2. Off-P	eak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above.				
Minimum Monthly Bill: The minimum monthly bill shall be the Customer Charge and the Capacity Charges for Standby Service. Where Special Equipment to service the customer is required, the Company may require a specified minimum charge.					
	Payment: endered hereunder are payable within the time limit specified on bill at company-designated locations.				
Term of Servi	ervice: the under this rate schedule shall be under the same terms as that specified in the otherwise applicable rate schedule.				
Special F	rovisions:				
	the customer increases the electrical load, which increase requires the Company to increase facilities installed for the specific the customer, a new Term of Service may be required under this rate at the option of the Company.				
a first	 Customer, a new Term of Service may be required under this rate at the option of the Company. Customers taking service under another Company rate schedule who elect to transfer to this rate will be accepted by the Company on a first-come, first-served basis. Required interruptible equipment will be installed accordingly, subject to availability. Service under this rate schedule shall commence with the first full billing period following the date of equipment installation. 				
	(Continued on Page No. 5)				
	DV: Losi L Crace Menaner Hillity Devulatory Olennian Flavide	-			



SECTION NO. VI FIFTEENTH REVISED SHEET NO. 6.322 CANCELS FOURTEENTH REVISED SHEET NO. 6.322

RATE SCHEDULE SS-3	f 6
CURTAILALBE STANDBY SERVICE (Continued from Page No. 2)	
Determination of Specified Standby Capacity:	
 Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by Company. This shall be termed for billing purposes as the "Specified Standby Capacity". 	the
 Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a n Specified Standby Capacity. 	ew
3. The Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby Capacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month or (3) the maximum 30-minute kW standby power requirement established in any of the twenty-three (23) preceding billing months.	
Rate Per Month: 1, Customer Charge:	
Secondary Metering Voltage: \$ 100.71 Primary Metering Voltage: \$ 235.69 Transmission Metering Voltage: \$ 812.02	
Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge sh be \$81.21.	all
 Supplemental Service Charges: All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable raschedule. 	ite
 Standby Service Charges: A. Distribution Capacity: \$1.80 per kW times the Specified Standby Capacity. \$1.80 per kW times the Specified Standby Capacity. Note: No charge is applicable to a customer who has provided all the facilities for interconnection to the Company's transmission system. 	วท
B. Generation & Transmission Capacity: The charge shall be the greater of: 1. \$1.005 per kW times the Specified Standby Capacity or 2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods time \$0.479/kW times the appropriate following monthly factor: Billing Month Factor March, April, May, October June, September, November, December 1.00 January, February, July, August 1.20 Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, Billing Adjustments: See Sheet No. 6.105 and 6.106	æs
 C. Curtailable Capacity Credit: The credit shall be the greater of: 1. \$0.653 per kW times the Specified Standby Capacity, or 2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods time \$0.311/kW times the appropriate Billing Month Factor shown in part 3.B. above. 	×s
D. Energy Charges: Non-Fuel Energy Charge: 0.883¢ per kWh	
Plus the Cost Recovery Factors on a ¢ kWh basis listed in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor: See Sheet No. 6.105 and 6.106	
E. Delivery Voltage Credit: When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 33¢ per kW.	
(Continued on Page No. 4	\$)



SECTION NO. VI TWELFTH REVISED SHEET NO. 6.323 CANCELS ELEVENTH REVISED SHEET NO.

			Page 4 of 6			
	RATE SCHEDULE SS-3 CURTAILABLE STANDBY SERVICE (Continued from Page No. 3)					
Ra	te Per I	Month: (Continued)				
3.	Stand	by Service Charges: (Continued)				
	F.	Metering Voltage Adjustment:				
			y. When the Company meters at a voltage above distribution secondary, the to the Distribution Capacity Charge, Generation & Transmission Capacity gy Charge and Delivery Voltage Credit hereunder:			
		Metering Voltage	Reduction Factor			
		Distribution Primary Transmission	1.0% 2.0%			
	G.	Fuel Cost Recovery Factor: Time of Use Fuel Charges of applicable metering voll	tage provided on Tariff Sheet No. 6.105.			
	Н.	Gross Receipts Tax Factor:	See Sheet No. 6.106			
	l. J.	Right-of-Way Utilization Fee: Municipal Tax:	See Sheet No. 6.106 See Sheet No. 6.106			
	к.	Sales Tax:	See Sheet No. 6.106			
Pre	mium l	Distribution Service Charge:				
	Regula schedu transfe	tions Governing Electric Service, the customer shall p le for the costs of all additional equipment, or the cus r including all line costs necessary to connect to an alt				
		tion the Distribution Capacity Charge included in the R the cost of reserving capacity in the alternate distribution	Rate per Month section of this rate schedule shall be increased by \$0.92 per ion circuit.			
Rati	ing Per	iods:				
1.	On-Pea	ak Periods - The designated On-Peak Periods express	ed in terms of prevailing clock time shall be as follows:			
	Α.	For the calendar months of November through March, Monday through Friday*:	, 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.			
	В.	For the calendar months of April through October, Monday through Friday*:				
l	Day, Th	lowing general holidays shall be excluded from the On	12:00 Noon to 9:00 p.m. -Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor ay occurs on a Saturday or Sunday, the adjacent weekday shall be excluded			
2.	Off-Pea	ak Periods - The designated Off-Peak Periods shall be	all periods other than the designated On-Peak Periods set forth above.			
Mini	mum N	fonthly Bill:				
		nimum monthly bill shall be the Customer Charge and the customer is required, the Company may require as	I the Capacity Charges for Standby Service. Where Special Equipment to specified minimum charge.			
Tem	ns of P	ayment:				
ł	Bills rer	dered hereunder are payable within the time limit spec	ified on bill at Company-designated locations.			
Tem	n of Se	rvice:				
5	Service	under this rate schedule shall be under the same term	s as that specified in the otherwise applicable rate schedule.			
			(Continued on Page No. 5)			

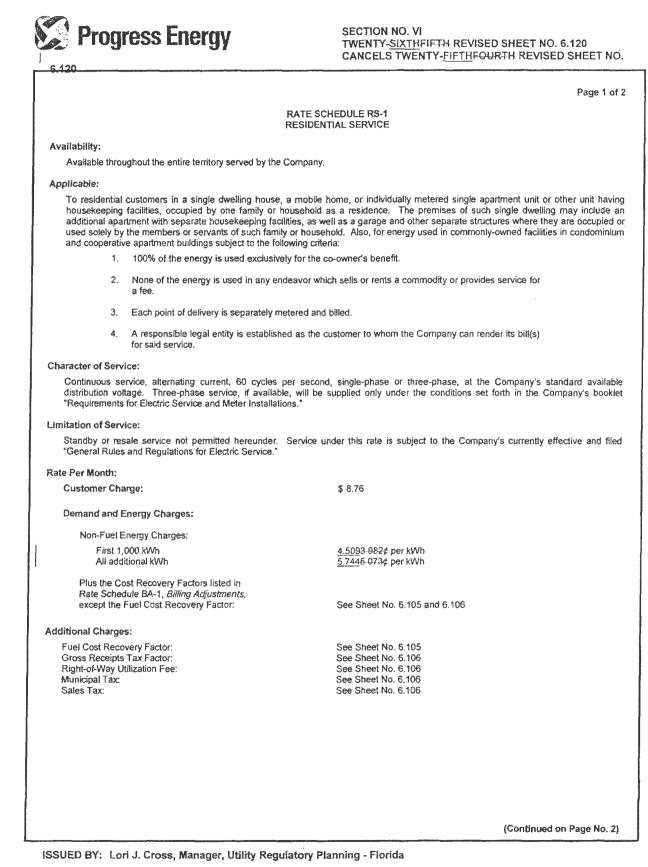
Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 115 of 197

Attachment D

Revised Tariff Sheet in legislative format

Tariff Sheet No.	Description
6.120	RS-1
6.130	RSL-1
6.135	RSL-2
6.140	RST-1
6.150	GS-1
6.160	GST-1
6.165	GS-2
6,170	GSD-1
6.171	GSD-1
6.180	GSDT-1
6.181	GSDT-1
6.225	GSLM-2
6.230	CS-1
6.231	CS-1
6.235	CS-2
6.236	CS-2
6.2390	CS-3
6.2391	CS-3
6.2392	CS-3
6.240	CST-1 CST-1
6.241 6.245	CST-2
6.245	CST-2
6.2490	CST-3
6.2491	CST-3
6.2492	CST-3
6.250	IS-1
6.251	IS-1
6.255	IS-2
6.256	IS-2
6.260	IST-1
6.261	IST-1
6.265	IST-2
6.265	IST-2
6.280	LS-1
6.281	LS-1
6.2811	LS-1
6.312	SS-1
6.313	SS-1
6.317	SS-2
6.318	SS-2
6.322	SS-3
6.323	SS-3





EFFECTIVE: January 1, February 10, 20130

Progress Energy SECTION NO. VI TWENTY-SEVENTH-EIGHTH REVISED SHEET NO. 6.130 CANCELS TWENTY-SIXTH-SEVENTH REVISED SHEET NO. 6.130 Page 1 of 3 RATE SCHEDULE RSL-1 **RESIDENTIAL LOAD MANAGEMENT** Availability: Available only within the range of the Company's Load Management System. Available to customers whose premises have active load management devices installed prior to June 30, 2007. Available to customers whose premises have load management devices installed after June 30, 2007 that have and are willing to submit to load control of, at a minimum, central electric cooling and heating systems. Applicable: To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months, or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment: Water Heater Central Electric Heating System 3. Central Electric Cooling System 1 2. Swimming Pool Pump 4 Character of Service: Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations." Limitation of Service: Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises. For new service requests after June 30, 2007 customers with a central electric heating system that is a heat pump will be installed on Interruption Schedule S. All other new service requests will be installed on Interruption Schedule B. Interruption Schedule C shall be at the option of the customer. For new service requests after April 1, 1995, and before June 30, 2007, customers who select the swimming pool pump schedule must also select at least one other schedule. An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after April 1, 1995 Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Rate Per Month: **Customer Charge:** \$ 8.76 Energy and Demand Charges: Non-Fuel Energy Charges: First 1 000 kWh 3.9824.509¢ per kWh All additional kWh 5.0735.704¢ per kWh Plus the Cost Recovery Factors listed in Rate Schedule BA-1, Billing Adjustments, See Sheet No. 6.105 and 6.106 except the Fuel Cost Recovery Factor.

Additional Charges: Fuel Cost Recovery Factor: See Sheet No. 6.105 Gross Receipts Tax Factor: See Sheet No. 6.106 Right-of-Way Utilization Fee: See Sheet No. 6.106 Municipal Tax: See Sheet No. 6.106 See Sheet No. 6.106 Sales Tax: Load Management Monthly Credit Amounts:12 Interruptible Equipment Interruption Schedule D <u>s</u> A в С \$3.50 Water Heater -\$8.00 \$2.00 \$8.00 Central Heating System³ Central Heating System w/Thermal Storage³ . \$8.00 Central Cooling System⁴ \$1.00 \$5.00 \$5.00 Swimming Pool Pump \$2.50

(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: February 10, 2010January 1, 2013





SECTION NO. VI TWELFTH THIRTEENTH REVISED SHEET NO. 6.135 CANCELS ELEVENTH TWELFTH REVISED SHEET NO.

	RATE S	Page 1 of 2 CHEDULE RSL-2
		IANAGEMENT – WINTER ONLY
Availability:		
Available only	y within the range of the Company's Load Manag	ement System.
Applicable:		
kWh for the r		hedule RS-1 or RSS-1 having a minimum average monthly usage of 600 ne most recent billings, where not available, a projection for those months) ating systems.
Character of Ser	vice:	
Three-phase		ise, at the Company's standard distribution secondary voltage available. the conditions set forth in the Company's booklet "Requirements for Electric
Limitation of Ser	vice:	
	e electrical equipment specified above may be led on the customer's premises.	interrupted at the option of the Company by means of load management
	esale service not permitted hereunder. Service and Regulations for Electric Service.*	under this rate is subject to the Company's currently effective and filed
Rate Per Month:		
Customer Ch	large:	\$ 8.76
Energy and I	Demand Charges:	
Non-Fuel	Energy Charges:	
	l,000 kWh ditional kWh	<u>3-9824,509</u> ¢ per kWh <u>6-0735,744</u> ¢ per kWh
Rate Sche	Cost Recovery Factors listed in edule BA-1, <i>Billing Adjustments,</i> a Fuel Cost Recovery Factor;	See Sheet No. 6.105 and 6.106
Additional Charg	es:	
Fuel Cost Rec Gross Receipt Right-of-Way Municipal Tax Sales Tax:	s Tax Factor: Jtilization Fee:	See Sheet No. 6.105 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106 See Sheet No. 6.106
Load Managemer	nt Credit Amount:1	
Interruptible E	quipment	Monthly Credit ²
Water Heater	and Central Heating System	\$11.50
) Load management credit shall not exceed 40 cess of 600 kWh/month.	% of the Non-Fuel Energy Charge associated with kWh consumption in
(2) For billing months of November through March	only.
Appliance Interru	ption Schedule:	
Heating	Company's designated Peak Periods. Heat j	cumulated total of 16.5 minutes during any 30 minute interval within the pump back-up strip may be interrupted continuously, not to exceed 300 k. When the heat pump back-up strip is being interrupted, the heat pump
Water Heater	Equipment may be interrupted continuously, r Periods.	ot to exceed 300 minutes, and during the Company's designated Peak
		(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

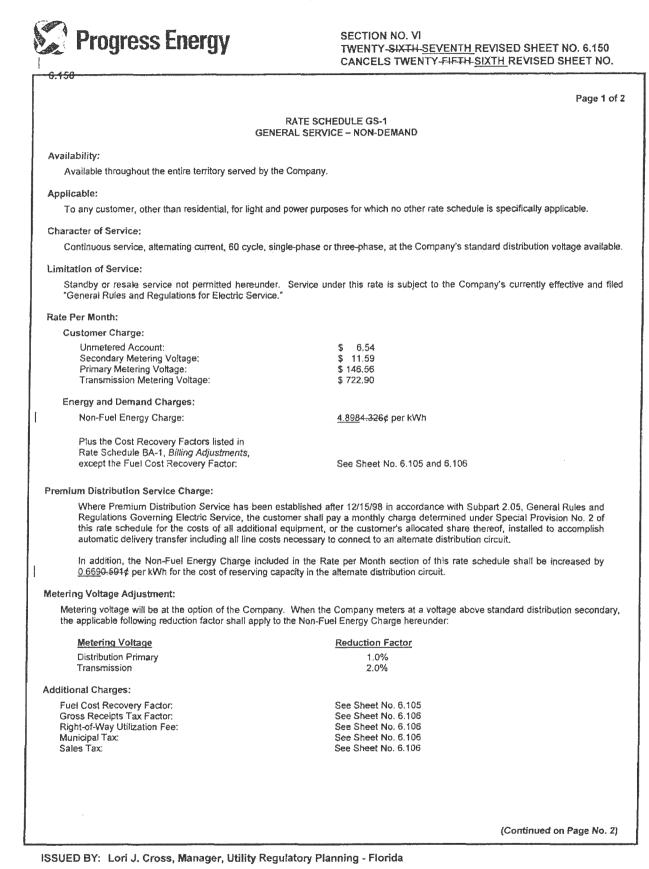
EFFECTIVE: February 10, 2010January 01, 2013



SECTION NO. VI <u>TWENTIETHEIGHTEENTH</u> REVISED SHEET NO. 6.140 CANCELS NINE<u>T</u>EENTH REVISED SHEET NO. 6.140

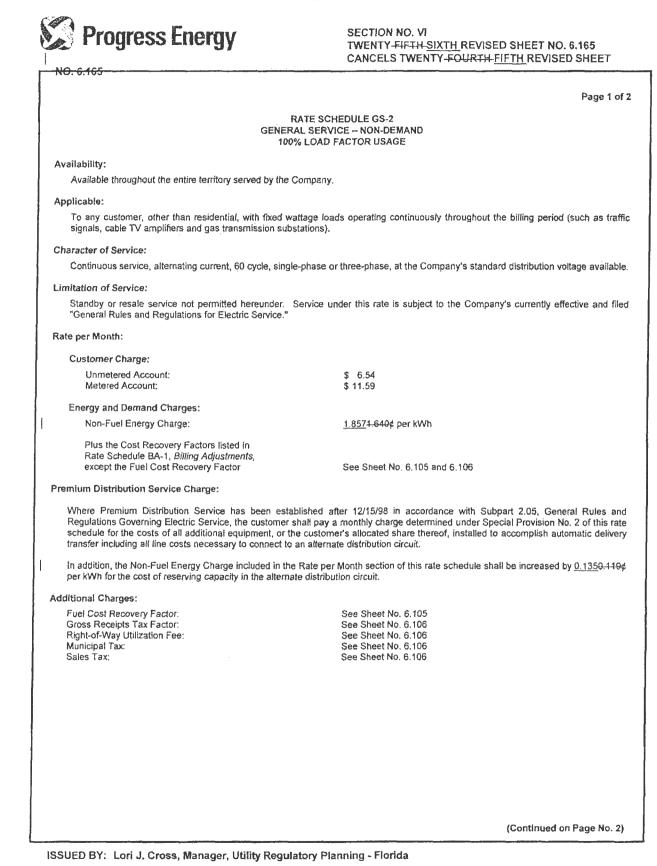
	Page 1 of 2
RESIDEN OPTIONAL TH	IEDULE RST-1 TAL SERVICE ME OF USE RATE stomers as of 02/10/10)
Availability:	
Available throughout the entire territory served by the Company.	
Applicable:	
At the option of residential customers otherwise eligible for se requirements on the customer's premises are metered through o	rvice under Rate Schedule RS-1, provided that all of the electric load one point of delivery.
Character of Service:	
	at the Company's standard distribution secondary voltage available, the conditions set forth in the Company's booklet "Requirements for
Limitation of Service:	
Standby or resale service not permitted hereunder. Service un "General Rules and Regulations Governing Electric Service."	nder this rate is subject to the Company's currently effective and filed
Rate Per Month:	
Customer Charge:	\$ 16.19
Energy and Demand Charges:	
Non-Fuel Energy Charges:	<u>13.92412.297</u> ¢ per On-Peak kWh <u>0.773</u> 0.683¢ per Off-Peak kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, <i>Billing Adjustments,</i> except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
The On-Peak rate shall apply to energy used during designate use,	d On-Peak Periods. The Off-Peak rate shall apply to all other energy
Rating Periods:	
	pressed in terms of prevailing clock time shall be as follows:
(1) For the calendar months of November through N Monday through Friday *:	6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through Octobe Monday through Friday*:	r, 12:00 Noon to 9:00 p.m.
	n-Peak Periods: New Year's Day, Memorial Day, Independence Day, ne holiday occurs on a Saturday or Sunday, the adjacent weekday shall
(b) Off-Peak Periods - The designated Off-Peak Periods sl in (a) above.	nall be all periods other than the designated On-Peak Periods set forth
	(Continued on Page No. 2)
ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Pla	anning - Florida

EFFECTIVE: February 10, 2010 January 1, 2013



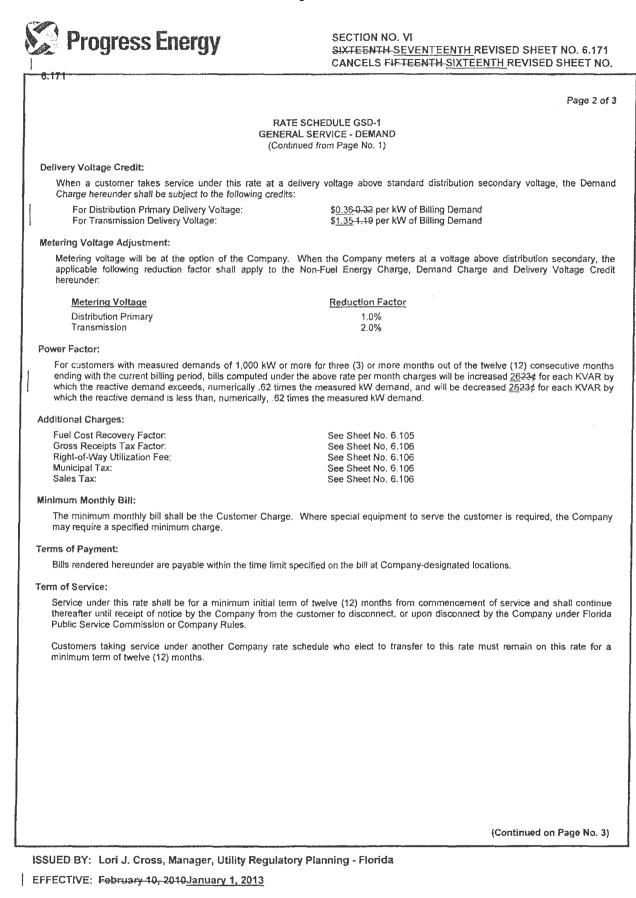
EFFECTIVE: Fobruary 10, 2010 January 1, 2013

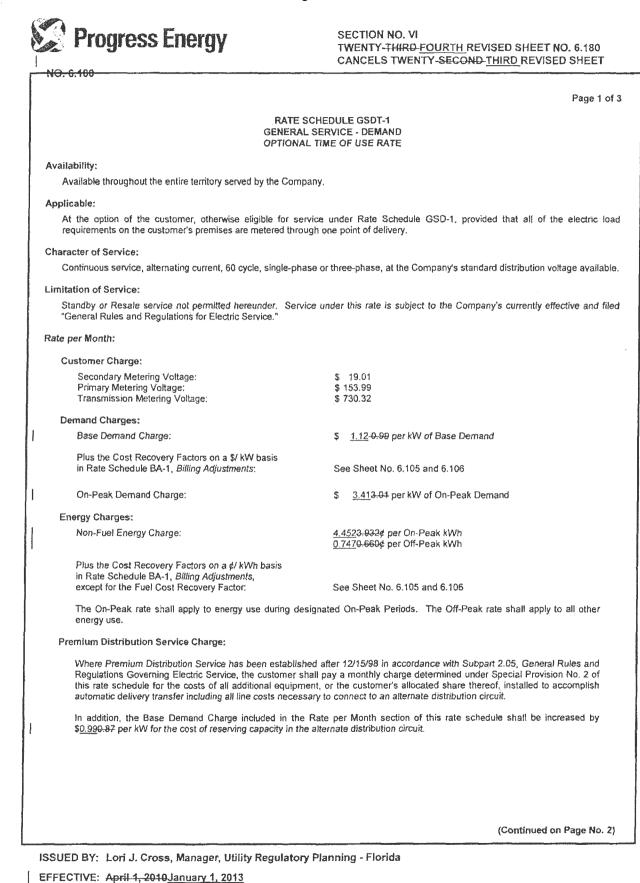
Progress Energy SECTION NO. VI TWENTY-SECOND-THIRD REVISED SHEET NO. 6.160 CANCELS TWENTY-FIRST_SECOND REVISED SHEET 0 6 160 Page 1 of 2 **RATE SCHEDULE GST-1** GENERAL SERVICE - NON-DEMAND **OPTIONAL TIME OF USE RATE** Availability: Available throughout the entire territory served by the Company. Applicable: At the option of non-residential customers otherwise eligible for service under Rate Schedule GS-1, provided that all of the electric load requirements on the Customer's premises are metered through one point of delivery. Character of Service: Continuous service, alternating current, 60 cycle, single-phase or three-phase, at the Company's standard distribution voltage available. Limitation of Service: Standby or Resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Rate per Month: **Customer Charge:** Secondary Metering Voltage: \$ 19.01 Primary Metering Voltage: \$ 153.99 Transmission Metering Voltage: \$ 730.32 Energy and Demand Charge: Non-Fuel Energy Charge: 13.90212.278¢ per On-Peak KWh 0.7530.665¢ per Off-Peak kWh Plus the Cost Recovery Factors listed in Rate Schedule BA-1, Billing Adjustments, except the Fuel Cost Recovery Factor See Sheet No. 6.105 and 6.106 The On-Peak rate shall apply to energy use during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use. Premium Distribution Service Charge: Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 2 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit. In addition, the Non-Fuel Charges included in the Rate per Month section of this rate schedule shall be increased by 0.6690.591¢ per kWh for the cost of reserving capacity in the alternate distribution circuit. Rating Periods: (a)On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows: (1) For the calendar months of November through March, 6:00 a.m. to 10:00 a.m. and Monday through Friday *: 6:00 p.m. to 10:00 p.m. (2) For the calendar months of April through October, 12:00 Noon to 9:00 p.m. Monday through Friday*; The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods. (Continued on Page No. 2) ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida EFFECTIVE: February 10, 2010 January 1, 2013

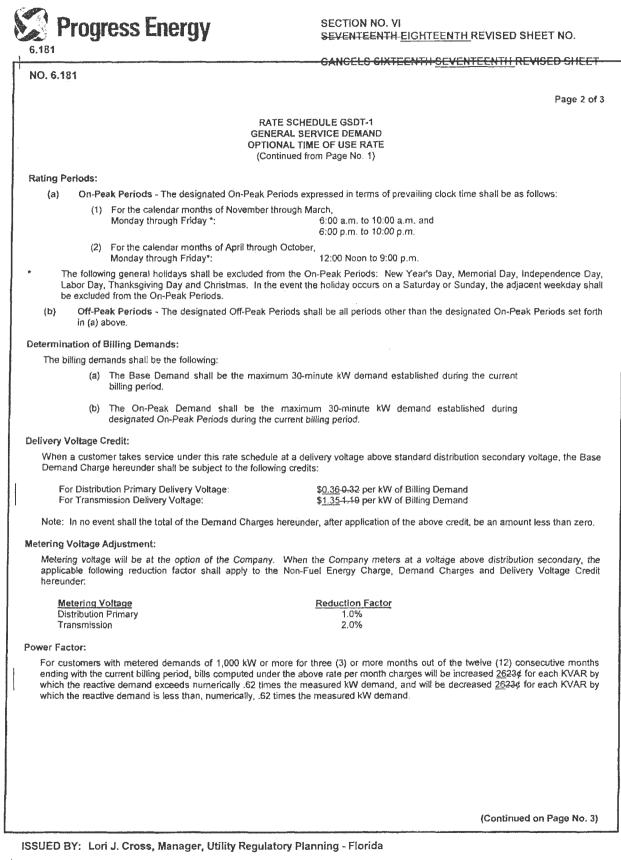


EFFECTIVE: February 10, 2010 January 1, 2013

	Progress Energy	SECTION NO. VI TWENTY- SECOND THIRD REVISED SHEET NO. 6.170 CANCELS TWENTY-FIRST- <u>SECOND</u> REVISED SHEET
		Page 1 of
		SCHEDULE GSD-1
		SERVICE - DEMAND
A	valiability: Available throughout the entire territory served by the Comp	
		airy.
А	pplicable: To any customer, other than residential, for light and powe measured annual kWh consumption of 24,000 kWh or great	r purposes for which no other rate schedule is specifically applicable with er per year.
C	haracter of Service:	
Ŭ		se or three-phase, at the Company's standard distribution voltage available
	imitation of Service:	
L		ce under this rate is subject to the Company's currently effective and file
	"General Rules and Regulations for Electric Service."	
R	ate Per Month:	
	Customer Charge:	
	Secondary Metering Voltage:	\$ 11.59
	Primary Metering Voltage: Transmission Metering Voltage:	\$ 146.56 \$ 722.90
1		
	Demand Charge:	\$ <u>4.594.05</u> per kW of Billing Demand
	Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
	Energy Charge:	
	Non-Fuel Energy Charge:	<u>2.045</u> 1.806 ¢ per kWh
	Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
Pr	remium Distribution Service Charge:	
	Where Premium Distribution Service has been establish Regulations Governing Electric Service, the customer sh	ed after 12/15/98 in accordance with Subpart 2.05, General Rules and hall pay a monthly charge determined under Special Provision No. 2 of ent, or the customer's allocated share thereof, installed to accomplish eary to connect to an alternate distribution circuit.
	In addition, the Demand Charge included in the Rate per per kW for the cost of reserving capacity in the alternate	er Month section of this rate schedule shall be increased by $0.990.87$ distribution circuit.
De	termination of Billing Demand:	
	The billing demand shall be the maximum 30-minute kW dem	hand established during the current billing period.
		(Continued on Page No. 2







EFFECTIVE: February 10, 2010 January 1, 2013



SECTION NO. VI FOURTH FIFTH REVISED SHEET NO. 6.225 CANCELS THIRD FOURTH REVISED SHEET NO. 6.225

Page 1 of 2

RATE SCHEDULE GSLM-2 GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at lease-least 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Customers cannot use the standby generation for peak shaving.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT STANDBY GENERATION

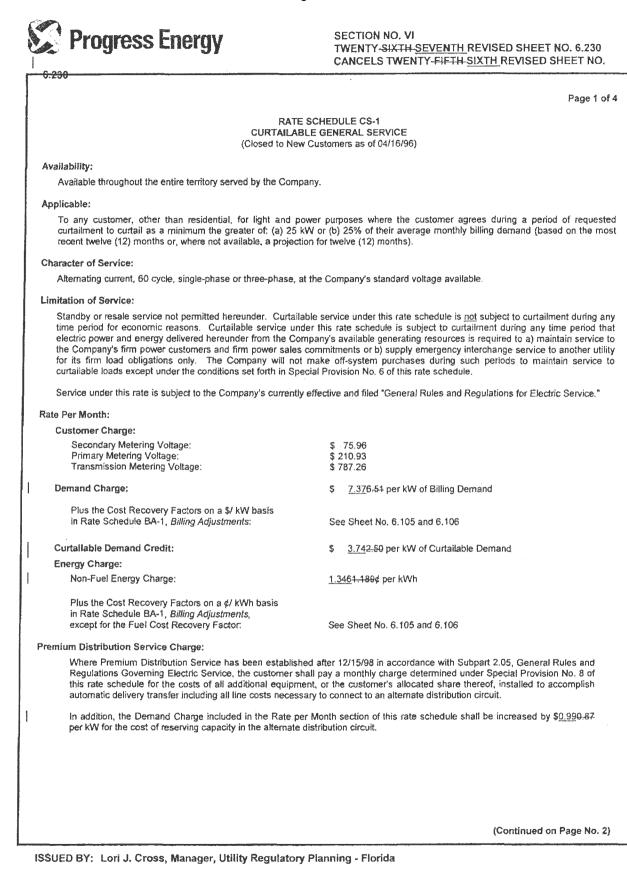
Credit	Cumulative Fiscal Year Hours	
\$ <u>3.60</u> 2.30 x C + \$0.05 ¹ x kWh monthly	$0 \leq CRH \leq 200$	
\$ <u>4.32</u> 2.76 x C + \$0.05 ¹ x kWh monthly	200 < CRH	

Immediately upon going on the rate, the customer's Capacity (C) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The C will remain at that value until the equipment is requested to run by the Company. The C for that month and subsequent months will be a calculated value based upon the following formula:

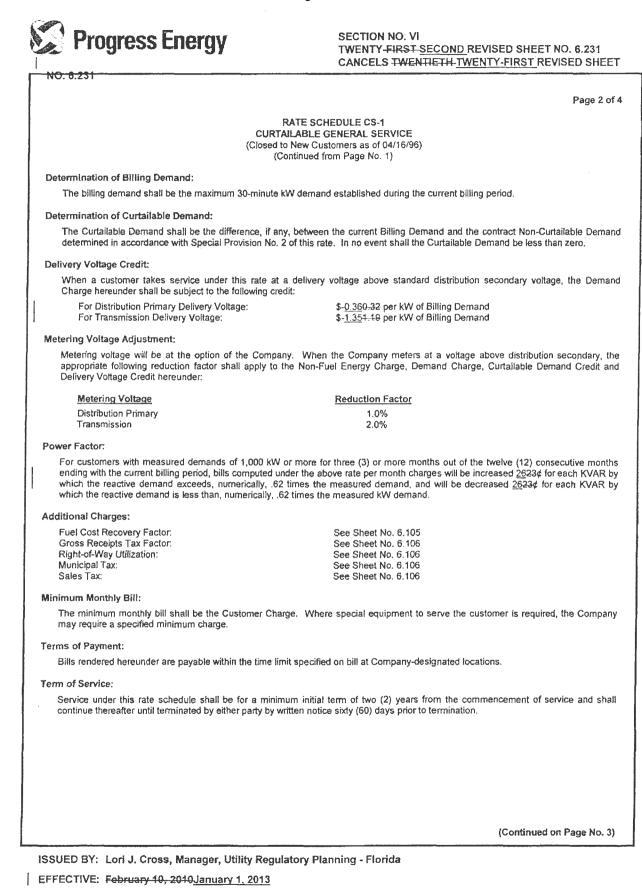
Definitions:	C = <u>KWh annual</u> [CAH - (# of Requests x ¼ hour)]
kWh annual =	Actual measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).
CAH =	Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).
CRH =	Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).
# of Requests ≃	The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).
kWh monthly =	Actual measured kWh generated by the standby generator for the current month during Company control periods.
	h rate represents an incentive credit to support Customer O&M associated with run time requested by the Company. ically review this incentive rate and request changes as deemed appropriate.
	(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: August 31, 2007 January 1, 2013

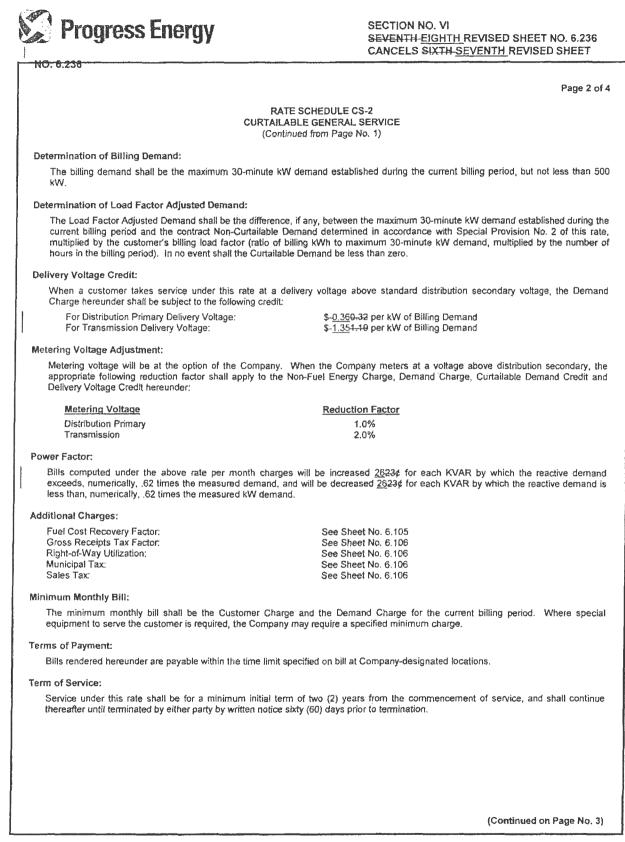


EFFECTIVE: April 10, 2010 January 1, 2013



	Progress Energy	ELEVENTH TWELFTH REVISED SHEET NO.
-		CANCELS TENTILELEVENTIL REVISED SHEET
	NO. 6.235	
		Page 1 o
		TE SCHEDULE CS-2 ABLE GENERAL SERVICE
	Availability:	
	Available throughout the entire territory served by the Cor	mpany.
	Applicable:	
		ower purposes where the billing demand is 500 kW or more, and where to y billing demand (based on the most recent twelve (12) months or, where n
,	Character of Service:	
	Alternating current, 60 cycle, single-phase or three-phase	, at the Company's standard voltage available.
1	Limitation of Service:	
	any time period for economic reasons. Curtailable servic electric power and energy delivered hereunder from the C the Company's firm power customers and firm power sal	surtailable service under this rate schedule is <u>not</u> subject to curtailment duri we under this rate schedule is subject to curtailment during any time period the Company's available generating resources is required to a) maintain service es commitments or b) supply emergency interchange service to another util not make off-system purchases during such periods to maintain service Special Provision No. 6 of this rate schedule,
	Service under this rate is subject to the Company's curren	tly effective and filed "General Rules and Regulations for Electric Service."
i	Rate Per Month:	
	Customer Charge:	
	Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 75.96 \$ 210.93 \$ 787.26
	Demand Charge:	\$ 7.376-54 per kW of Billing Demand
	Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
	Curtailable Demand Credit:	\$ 6.532.48 per kW of Load Factor Adjusted Demand
	Energy Charge:	
	Non-Fuel Energy Charge:	<u>1,346</u> 1-189¢ per kWh
	Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor;	See Sheet No. 6.105 and 6.106
F	Premium Distribution Service Charge:	
	Where Premium Distribution Service has been establing Regulations Governing Electric Service, the customer	ished after 12/15/98 in accordance with Subpart 2.05, General Rules and shall pay a monthly charge determined under Special Provision No. 8 of orment, or the customer's allocated share thereof, installed to accomplish essary to connect to an alternate distribution circuit.
	In addition, the Demand Charge included in the Rate per kW for the cost of reserving capacity in the alterna	per Month section of this rate schedule shall be increased by $\frac{0.990.87}{0.990.87}$ te distribution circuit.

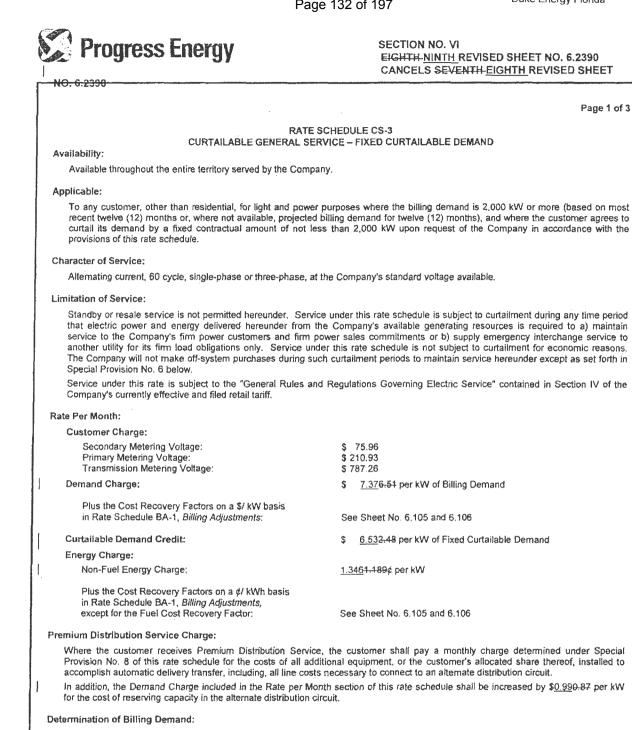
EFFECTIVE: April 1, 2010 January 1, 2013



ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: February 10, 2010 January 1, 2013

Page 1 of 3



The billing demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 2,000 kW.

Delivery Voltage Credit:

When a customer takes service under this rate schedule at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:

\$-0.360.32 per kW of Billing Demand \$-1.351.19 per kW of Billing Demand

(Continued on Page No. 2)

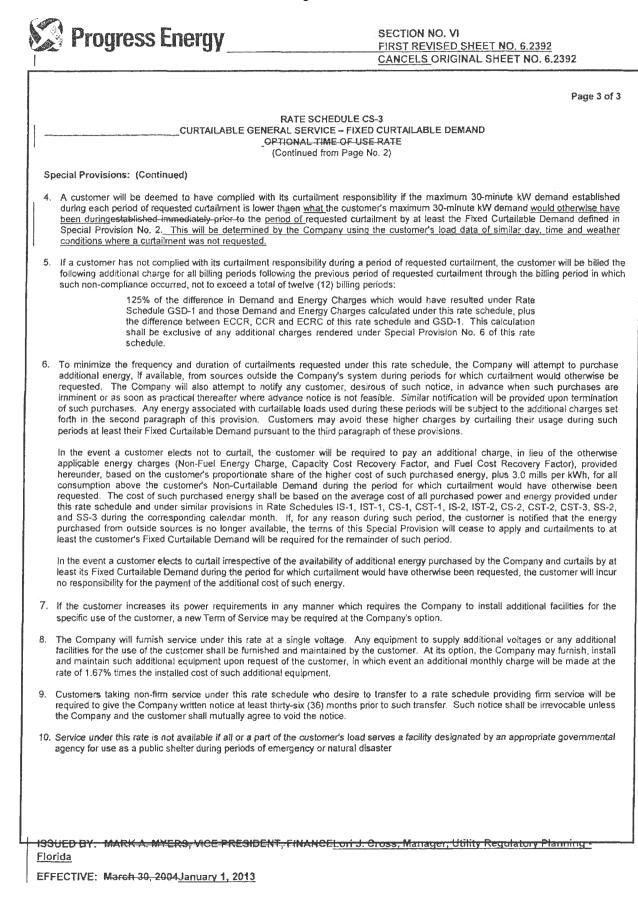
ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: April 1, 2010 January 1, 2013

EXHIBIT 1, ATTACHMENT D Page 19 of 45 Duke Energy Florida

Progress Energy SECTION NO. VI FOURTH-FIFTH REVISED SHEET NO. 6.2391 CANCELS THIRD FOURTH SHEET NO. 6.2391 Page 2 of 3 **RATE SCHEDULE CS-3** CURTAILABLE GENERAL SERVICE - FIXED CURTAILABLE DEMAND (Continued from Page No. 1) Metering Voltage Adjustment: Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and Delivery Voltage Credit hereunder: Metering Voltage **Reduction Factor Distribution Primary** 1.0% Transmission 2.0% Power Factor Adjustment: Bills computed under the above rate per month charges will be increased 2623¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 2623¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand, Additional Charges: Fuel Cost Recovery Factor: See Sheet No. 6.105 Gross Receipts Tax Factor: See Sheet No. 6.106 Right-of-Way Utilization; See Sheet No. 6.106 Municipal Tax: See Sheet No. 6.106 Sales Tax: See Sheet No. 6.106 Minimum Monthly Bill: The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge. Terms of Payment: Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations. Term of Service: Service under this rate schedule shall be for a minimum initial term of two (2) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination. Special Provisions: 1. As used in this rate schedule, the term "period of requested curtailment" shall mean a period for which the Company has requested curtailment and for which energy purchased from sources outside the Company's system, pursuant to Special Provision No. 6, is not available. If such energy can be purchased, the terms of Special Provision No. 6 will apply and a period of requested curtailment will not be deemed to exist while such energy remains available. 2. As a condition for service under this rate schedule, a customer is required to enter into a contract with the Company on the Company's filed standard contract Form No. 2. An initial Fixed Curtailable Demand of at least 2,000 kW shall be specified in the contract, which may be re-established under the following conditions: (a) If a change in the customer's power requirements occurs, the Company and the customer may establish a new Fixed Curtailable Demand. If the customer fails to reduce load by the Fixed Curtailable Demand for the duration of any period (b) of requested curtailment, the lowest measured load reduction achieved during such period shall become the Fixed Curtailable Demand effective with the next billing period following the period of requested curtailment. In addition, Special Provision No. 5 is applicable. If the customer establishes a demand reduction larger than the Fixed Curtailable Demand for the duration of each period of requested curtailment occurring within a billing period, upon request by the customer, the lowest of the demand reductions achieved during each such period shall become the Fixed Curtailable Demand effective with the next billing period. 3. As an essential requirement for receiving the Curtailable Demand Credit provided under this rate schedule, a customer shall be strictly responsible for the curtailment of its load by at least the Fixed Curtailable Demand upon each curtailment request from the Company. Such requests will be made during those periods specified under Limitation of Service above. The Company shall also have the right to request at least one additional curtailment each calendar year irrespective of such limitations. (Continued on Page No. 3)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida





SECTION NO. VI TWENTY-FIFTH-SIXTH REVISED SHEET NO. 6.240 CANCELS TWENTY-FOURTH-FIFTH REVISED SHEET

Page 1 of 5

RATE SCHEDULE CST-1 CURTAILABLE GENERAL SERVICE OPTIONAL TIME OF USE RATE (Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-1, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable Service under this rate schedule is <u>not</u> subject to curtailment during any time period for economic reasons. Curtailable Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to curtailable loads except under the conditions set forth in Special Provision No. 6 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

Customer Chamer

Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 75.96 \$ 210.93 \$ 787.26
Demand Charges:	
Base Demand Charge:	\$ 1.100.97 per kW of Base Demand
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	\$ 6.225.49 per kW of On-Peak Demand
Curtailable Demand Credit:	\$ 3.742.50 per kW of Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	<u>2.470</u> 2.181¢ per On-Peak kWh <u>0.742</u> 0.655¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, Billing Adjustments, except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

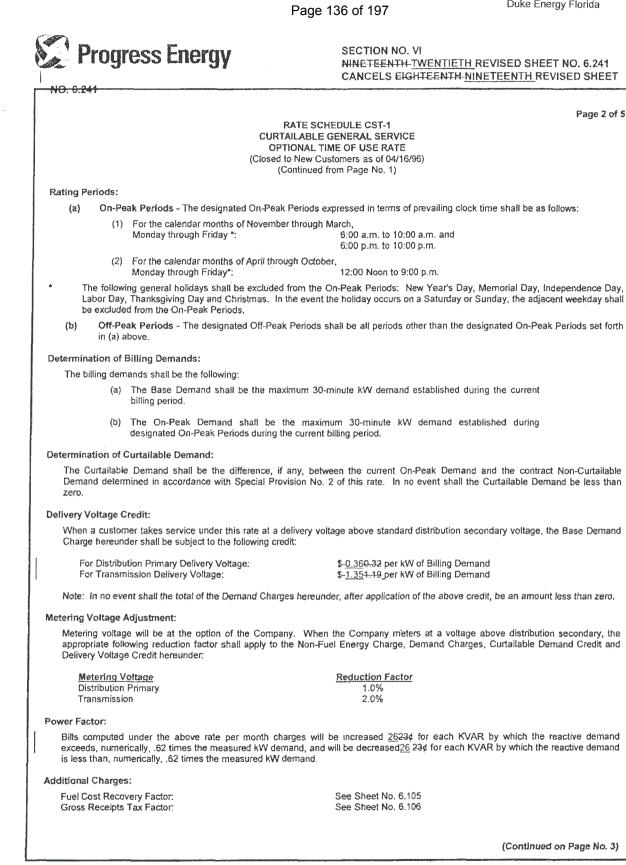
Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.990.87 per kW for the cost of reserving capacity in the alternate distribution circuit.

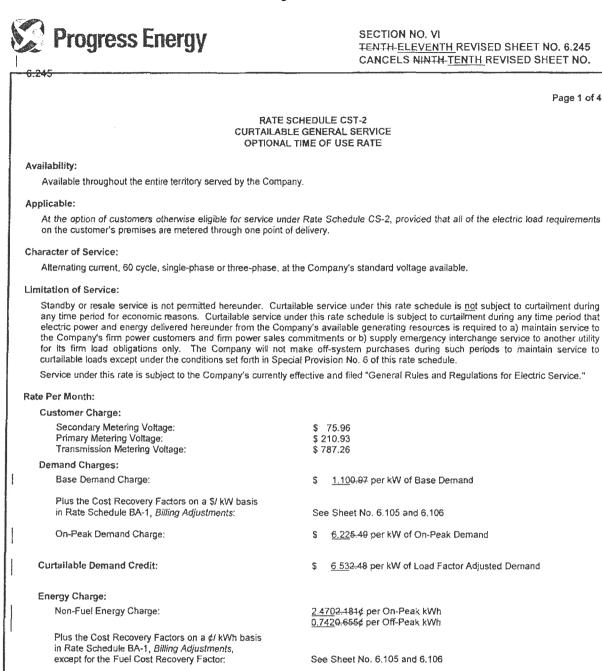
(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida



ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

Page 1 of 4



The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

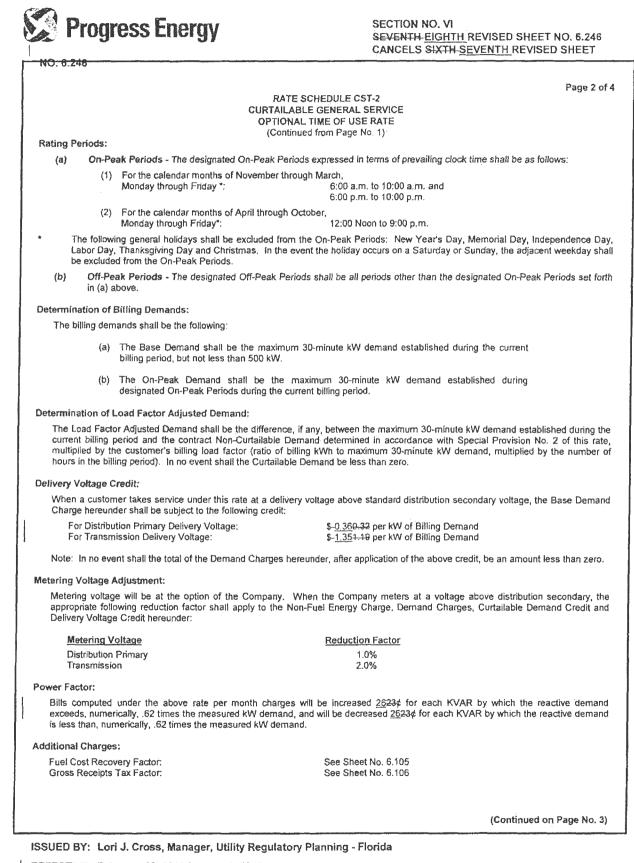
Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05. General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.990-87 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida





Page 1 of 5



SECTION NO. VI EIGHTH-<u>NINTH</u> REVISED SHEET NO. 6.2490 CANCELS SEVENTH <u>EIGHTH</u> REVISED SHEET NO. 6.2490

RATE SCHEDULE CST-3 CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer otherwise eligible for service under Rate Schedule CS-3, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. Service under this rate schedule is not subject to curtailment for economic reasons. The Company will not make off-system purchases during such curtailment periods to maintain service hereunder except as set forth in Special Provision No. 6 below.

Service under this rate is subject to the "General Rules and Regulations Governing Electric Service" contained in Section IV of the Company's currently effective and filed retail tariff.

Rate Per Month:

Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 75.96 \$ 210.93 \$ 787.26
Demand Charges:	
Base Demand Charge: Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> : On-Peak Demand Charae:	 <u>1,10</u>0.97 per kW of Base Demand See Sheet No. 6.105 and 6.106 <u>6,225.49 per kW of On-Peak Demand</u>
Curtailable Demand Credit:	\$ 6.532.48 per kW of Fixed Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	<u>2.470</u> 2-181¢ per On-Peak kWh <u>0.742</u> 0-666¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor,	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where the customer receives Premium Distribution Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including, all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.990.87 per kW for the cost of reserving capacity in the alternate distribution circuit. Rating Periods:

On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

- For the calendar months of November through March,
- Monday through Friday*: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m. For the calendar months of April through October,
- Monday through Friday*:
- The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. In the event the holiday occurs on a Saturday or Sunday, the following Monday shall be excluded from the On-Peak Periods.

12:00 Noon to 9:00 p.m.

Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth in (a) above.

(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

Progress Energy	SECTION NO. VI FIFTH <u>SIXTH</u> REVISED SHEET NO. 6.2491 CANCELS FOURTH <u>FIFTH</u> REVISED SHEET NO.
	Page 2 of
CURTAILABLE GENER	RATE SCHEDULE CST-3 RAL SERVICE – FIXED CURTAILABLE DEMAND TIONAL TIME OF USE RATE Continued from Page No. 1)
Determination of Billing Demand:	
-	maximum 30-minute kW demand established during the current billing period, bu
The On-Peak Demand for billing purposes shall be Periods during the current billing period.	e the maximum 30-minute kW demand established during designated On-Pea
Delivery Voltage Credit:	
When a customer takes service under this rate sche Demand Charge hereunder shall be subject to the fol	dule at a delivery voltage above standard distribution secondary voltage, the Bas lowing credit:
For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage:	\$- <u>0.36</u> 0-32 per kW of Billing Demand \$- <u>1.35</u> 1-19 per kW of Billing Demand
Note: In no event shall the total of the Demand Charg	ges hereunder, after application of the above credit, be an amount less than zero.
Metering Voltage Adjustment:	
	any. When the Company meters at a voltage above distribution secondary, th the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit, an
Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%
Power Factor Adjustment:	
	narges will be increased <u>26</u> 23¢ for each KVAR by which the reactive demand nd, and will be decreased <u>26</u> 23¢ for each KVAR by which the reactive demand is emand.
Additional Charges:	
Fuel Cost Recovery Factor: Gross Receipts Tax Factor:	See Sheet No. 6.105 See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106
Minimum Monthly Bill:	
The minimum monthly bill shall be the Customer C equipment to serve the customer is required, the Com	Charge and the Demand Charge for the current billing period. Where special pany may require a specified minimum charge.
Terms of Payment:	
Bills rendered hereunder are payable within the time li	mit specified on bill at Company-designated locations.
Term of Service:	
Service under this rate schedule shall be for a minin continue thereafter until terminated by either party by v	num initial term of two (2) years from the commencement of service, and shal written notice sixty (60) days prior to termination.
Special Provisions:	
curtailment and for which energy purchased from sou	quested curtailment" shall mean a period for which the Company has requested inces outside the Company's system, pursuant to Special Provision No. 6, is not is of Special Provision No. 6 will apply and a period of requested curtailment wil itable.

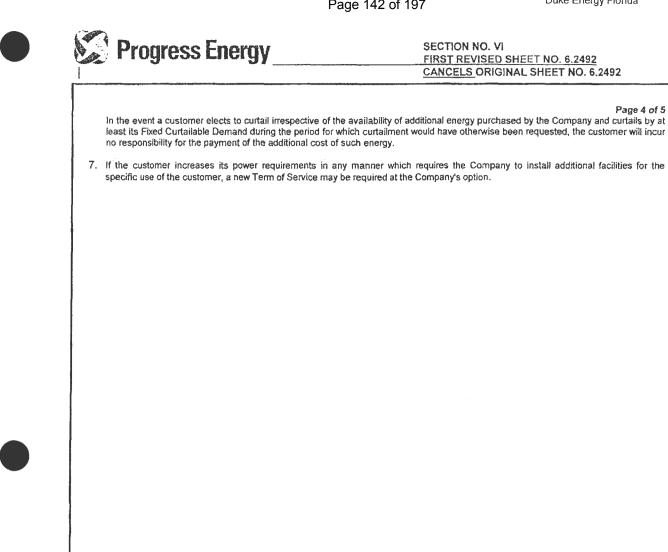
ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

		lingi	ess Energy	FIRST REVISED SHEET NO. 6.2492 CANCELS ORIGINAL SHEET NO. 6.2492
				Page 3 of
			CURTAILABLE GENERAL OPTIO	TE SCHEDULE CST-3 SERVICE – FIXED CURTAILABLE DEMAND NAL TIME OF USE RATE Itinued from Page No. 2)
	Sp	ecial Provision	s: (Continued)	
	2.	filed standard (ustomer is required to enter into a contract with the Company on the Compan ailable Demand of at least 2,000 kW shall be specified in the contract, which m
		(a)	If a change in the customer's power n establish a new Fixed Curtailable Dema	equirements occurs, the Company and the customer may nd of at least 2,000 kW.
		(b)	of requested curtailment, the lowest me less than 2,000 kW, shall become the	he Fixed Curtailable Demand for the duration of any period asured load reduction achieved during such period, but not Fixed Curtailable Demand effective with the next billing red curtailment. In addition, Special Provision No. 5 is
		(C)	duration of each period of requested cu	reduction larger than the Fixed Curtailable Demand for the intailment occurring within a billing period, upon request by reductions achieved during each such period shall become with the next billing period.
	3.	responsible for Such requests	the curtailment of its load by at least the	Demand Credit provided under this rate schedule, a customer shall be strictly Fixed Curtailable Demand upon each curtailment request from the Company ed under Limitation of Service above. The Company shall also have the right to year irrespective of such limitations.
	4.	during each per been duringest Special Provisi	tod of requested curtailment is lower that ablished immodiately prior to the period	curtailment responsibility if the maximum 30-minute kW demand established on <u>what</u> the customer's maximum 30-minute kW demand <u>would otherwise have</u> of requested curtailment by at least the Fixed Curtailable Demand defined in the Company using customer's load data of similar day, time and weathe
	5.	following addition		onsibility during a period of requested curtailment, the customer will be billed th the previous period of requested curtailment through the billing period in whice welve (12) billing periods:
			Schedule GSDT-1 and those Demand a plus the difference between ECCR, CC	Energy Charges which would have resulted under Rate and Energy Charges calculated under this rate schedule, CR and ECRC of this rate schedule and GSDT-1. This litional charges rendered under Special Provision No. 6 of
1	6.	additional energy requested. The imminent or as of such purchase forth in the sec	if available, from sources outside the e Company will also attempt to notify a soon as practical thereafter where advan es. Any energy associated with curtailab ond paragraph of this provision. Custo	s requested under this rate schedule, the Company will attempt to purchase Company's system during periods for which curtailment would otherwise be ny customer, desirous of such notice, in advance when such purchases are ce notice is not feasible. Similar notification will be provided upon termination le loads used during these periods will be subject to the additional charges set mers may avoid these higher charges by curtailing their usage during such nt to the third paragraph of these provisions.
		applicable ener hereunder, base consumption at requested. The this rate schedu SS-3 during the purchased from	gy charges (Non-Fuel Energy Charge, ed on the customer's proportionate share over the customer's Non-Curtailable De cost of such purchased energy shall be le and under similar provisions in Rate St e corresponding calendar month. If, for	comer will be required to pay an additional charge, in lieu of the otherwise Capacity Cost Recovery Factor and Fuel Cost Recovery Factor), provided of the higher cost of such purchased energy, plus 3.0 mills per kWh, for all mand during the period for which curtailment would have otherwise been based on the average cost of all purchased power and energy provided under chedules IS-1, IST-1, CS-1, CST-1, IS-2, IST-2, CS-2, CST-2, CS-3, SS-2 and or any reason during such period, the customer is notified that the energy the terms of this Special Provision will cease to apply and curtailments to at juired for the remainder of such period.
				(Continued on Page No. 4)
				-FINANGELori J. Cross, Manager, Utility Regulatory Planning -

SECTION NO. VI

FIRST REVISED SHEET NO. 6.2492 **CANCELS ORIGINAL SHEET NO. 6.2492**

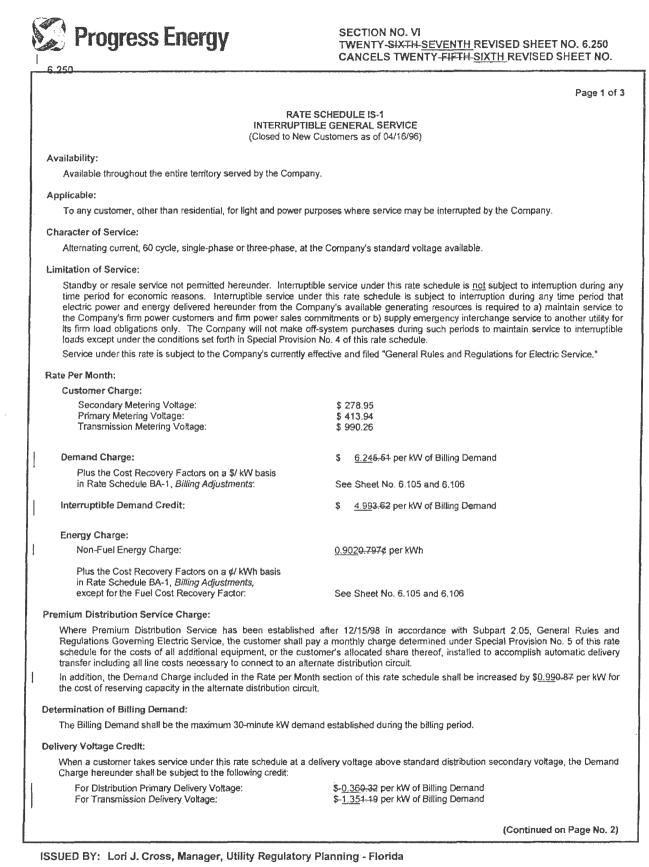
Page 4 of 5

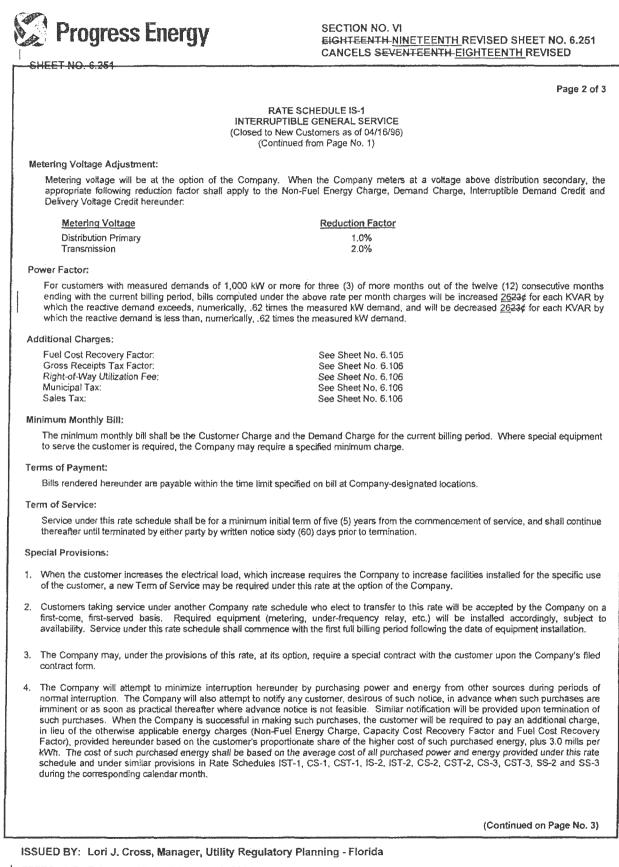


(Continued on Page No. 4)

ISSUED BY. MARK A. MYERS, VICE PRESIDENT, FINANCELori J. Cross, Manager, Utility Regulatory Planning Florida

EFFECTIVE: March 30, 2004 January 1, 2013







SECTION NO. VI TWELFTH_THIRTEENTH REVISED SHEET NO. 6.255 CANCELS ELEVENTH_TWELFTH REVISED SHEET NO.

Page 1 of 3

RATE SCHEDULE IS-2 INTERRUPTIBLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

Applicable to customers, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where service may be interrupted by the Company. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is <u>not</u> subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency Interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during such periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	
Secondary Metering Voltage:	\$ 278.95
Primary Metering Voltage:	\$ 413.94
Transmission Metering Voltage:	\$ 990.26
Demand Charge: Plus the Cost Recovery Factors on a \$/ kW basis	\$ <u>6.24</u> 5-54 per kW of Billing Demand
in Rate Schedule BA-1, Billing Adjustments:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	\$ 8.703-31 per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	0.9020.797¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> ,	
except for the Fuel Cost Recovery Factor.	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.990-87 per kW for the cost of reserving capacity in the alternate distribution circuit.

Determination of Billing Demand:

The Billing Demand shall be the maximum 30-minute kW demand established during the billing period, but not less than 500 kW. Determination of Load Factor Adjusted Demand:

The Load Factor Adjusted Demand shall be the product of the maximum 30-minute kW demand established during the current billing period and the customer's billing load factor (ratio of billing kWh to maximum 30-minute kW demand times the number of hours in the billing period).

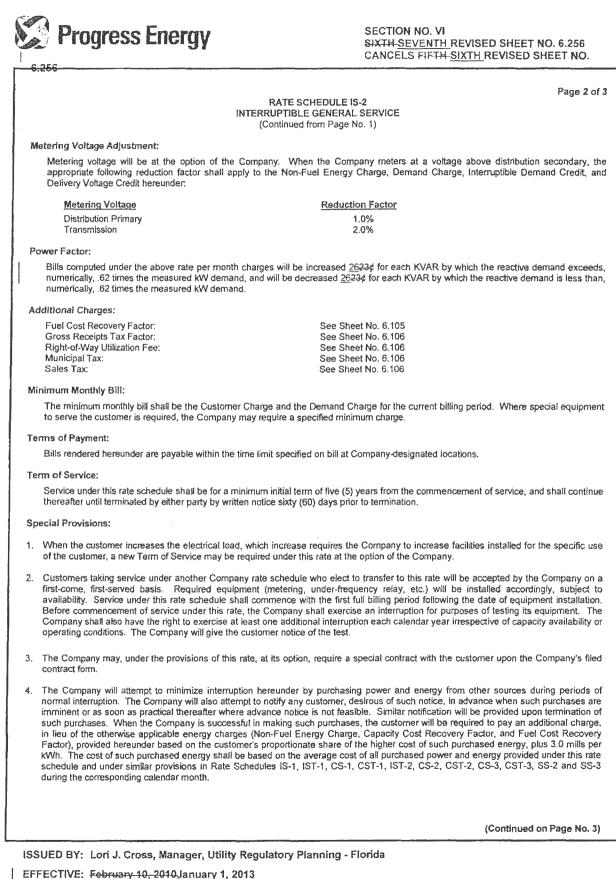
Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage: For Transmission Delivery Voltage: \$-0.360.32 per kW of Billing Demand \$-1.351.19 per kW of Billing Demand

(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida





SECTION NO. VI TWENTY-SIXTH <u>SEVENTH REVISED</u> SHEET NO. 6.260 CANCELS TWENTY FIFTH-<u>SIXTH</u> REVISED SHEET NO. 6.260

Page 1 of 3

RATE SCHEDULE IST-1 INTERRUPTIBLE GENERAL SERVICE OPTIONAL TIME OF USE RATE (Closed to New Customers as of 04/16/96)

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule IS-1, provided that the total electric load requirements at each point of delivery are measured through one meter.

Character of Service: Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is <u>not</u> subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible loads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

	Customer Charge:		
	Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$	278.95 413.94 990.26
	Demand Charge:		
I	Base Demand Charge: Plus the Cost Recovery Factors on a \$/ kW basis	\$	0.990.87 per kW of Base Demand
	in Rate Schedule BA-1, Billing Adjustments:	Se	e Sheet No. 6.105 and 6.106
	 On-Peak Demand Charge; 	\$	5.464-82 per KW of On-Peak Demand
	Interruptible Demand Credit:	\$	4.993.62 per kW of On-Peak Demand
	Energy Charge:		
	Non-Fuel Energy Charge:		<u>2641.11</u> 6¢ per On-Peak kWh <u>′370.65</u> 1¢ per Off-Peak kWh
	Plus the Cost Recovery Factors on a <i>¢I</i> kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	Se	e Sheet No. 6,105 and 6,106
	The On-Peak rate shall apply to energy used during designat use.	ed C	n-Peak Periods. The Off-Peak rate shall apply to all other energy
Pre	mium Distribution Service Charge:		
	Where Premium Distribution Service has been established of	tor 1	2/15/08 in accordance with Subpart 2.05. General Pulse and

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.990.87 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

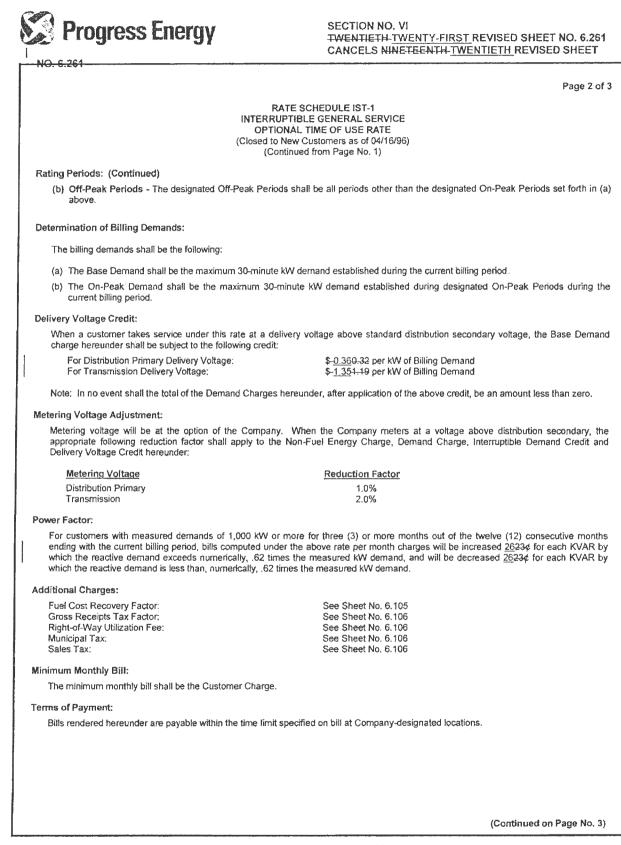
(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

- For the calendar months of November through March, Monday through Friday*;
 - 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.
- (2) For the calendar months of April through October, Monday through Friday*:
- 12:00 Noon to 9:00 p.m.
- The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Period.

(Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida





ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida



SECTION NO. VI ELEVENTH TWELFTH REVISED SHEET NO. 6,265 CANCELS TENTH ELEVENTH REVISED SHEET NO. 6,265

Page 1 of 3

RATE SCHEDULE IST-2 INTERRUPTIBLE GENERAL SERVICE OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

At the option of the customer, applicable to customers otherwise eligible for service under Rate Schedule IS-2, where the billing demand is 500 kW or more, provided that the total electric requirements at each point of delivery are measured through one meter. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants, or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is <u>not</u> subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only. The Company will not make off-system purchases during periods to maintain service to interruptible leads except under the conditions set forth in Special Provision No. 4 of this rate schedule.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	
Secondary Metering Voltage: Primary Metering Voltage; Transmission Metering Voltage;	\$ 278.95 \$ 413.94 \$ 990.26
Demand Charge:	
Base Demand Charge; Plus the Cost Recovery Factors on a \$/ kW basis	\$ 0.990.87 per kW of Base Demand
in Rate Schedule BA-1, Billing Adjustments:	See Sheet No. 6,105 and 6,106
On-Peak Demand Charge:	\$ 5.464.82 per kW of On-Peak Demand
Interruptible Demand Credit:	\$ 8.703-31 per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	<u>1.2641.116</u> ¢ per On-Peak kWh 0.7370-651¢ per Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments,</i> except for the Fuel Cost Recovery Factor.	See Sheet No. 6.105 and 6.106
The On-Peak rate shall apply to energy used during des use.	signated On-Peak Periods. The Off-Peak rate shall apply to all other energy
Premium Distribution Service Charge:	
Governing Electric Service, the customer shall pay a monthl costs of all additional equipment, or the customer's allocate line costs necessary to connect to an alternate distribution	after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations ly charge determined under Special Provision No. 5 of this rate schadule for the ed share thereof, installed to accomplish automatic delivery transfer including all o circuit. In addition, the Base Demand Charge included in the Rate per Month & per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

P

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

 For the calendar months of November through March, Monday through Friday*:

6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.

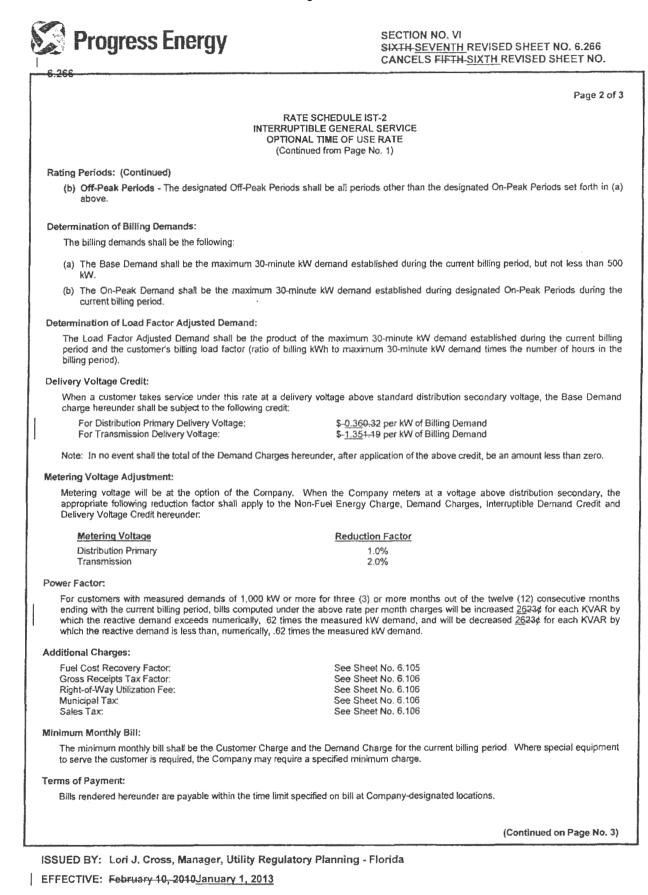
(2) For the calendar months of April through October, Monday through Friday*:

12:00 Noon to 9:00 p.m.

The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

Continued on Page No. 2)

ISSUED BY: Lori J. Cross, Manager, Utility Regulaory Planning - Florida



NO 6 28	rogress Energ	7				ND THIRD REVI	T NO. 6.280 SED SHEET
							Page 1 o
		F	LIGHTING SI				
Availabili	ity:						
Availa	able throughout the entire territor	y served by the Co	ompany.				
Applicabl	le:						
owner custor	ny customer for the sole purposed fixtures of the type available of mer, and nothing herein or in the ompany to any such third party.	under this rate so	hedule. Servi	ice hereunde	r is provided for	the sole and exclu	sive benefit of t
Characte	r of Service:						
	nuous dusk to dawn automaticall any's standard voltage available		ng service (i.e.	photoelectric	cell); alternating	current, 60 cycle, s	ingle phase, at t
Limitation	n of Service:						
	bility of certain fixture or pole typ	es at a location m	ay be restricte	d due to acce	essibility.		
	• • •				-	manufa	offorting and P
	by or resale service not permit ral Rules and Regulations Gove			uns rate is s	iobject to the Co	mpanys cufrendy	elective and th
Rate Per I	Month:						
	mer Charge:						
	nmetered:		\$	1.19 per line o	of billing		
M	etered:		\$ 3	3.42 per line o	of billing		
Energ	y and Demand Charge:						
No	on-Fuel Energy Charge:		4.7	² 07 <u>1,933</u> ¢ pe	r kWh		
Pi	us the Cost Recovery Factors lis	ted in					
	ate Schedule BA-1, <i>Billing Adjust</i> cept the Fuel Cost Recovery Fa		5.	o Chaot No. (6.105 and 6.106		
			36	e Sheet NO. (5, 105 and 0, 100		
Per Ur	nit Charges:						
<u> </u>	xtures:	······					
		E.	AMP SIZE ²			CHARGES PER	UNIT
			intere grande			011110000101	
		INITIAL			······		
BILLING TYPE	DESCRIPTION		LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL
		INITIAL LUMENS		kWh	FIXTURE	MAINTENANCE	NON-FUEL
TYPE	Incandescent: ¹	INITIAL LUMENS OUTPUT	WATTAGE				NON-FUEL ENERGY ³
		INITIAL LUMENS OUTPUT		32	\$1.03	\$4;07	NON-FUEL ENERGY ³ \$0.55 <u>0.62</u>
110	Incandescent: ¹ Roadway	INITIAL LUMENS OUTPUT	WATTAGE 105				NON-FUEL ENERGY ³
110 115	Incandescent: ¹ Roadway Roadway Post Top	INITIAL LUMENS OUTPUT 1,000 2,500	WATTAGE 105 205	32 66	\$1.03 1.61	\$4.07 3.67	NON-FUEL ENERGY 3 \$0-550.62 1.131.28
110 115 170	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹	INITIAL LUMENS OUTPUT 1,000 2,500 2,500	105 205 205	32 66 72	\$1.03 1.61 20.39	\$4.07 3.67 3.67	NON-FUEL ENERGY ³ \$0.660.62 1.131.28 1.231.39
110 115	Incandescent: ¹ Roadway Roadway Post Top	INITIAL LUMENS OUTPUT 1,000 2,500	WATTAGE 105 205	32 66	\$1.03 1.61	\$4.07 3.67	NON-FUEL ENERGY 3 \$0-550.62 1.131.28
110 115 170 205 210 215	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000	WATTAGE 105 205 205 100 100 100	32 66 72 44 44 44	\$1.03 1.61 20.39 \$2.55 2.95 3.47	\$4,07 3.67 3.67 \$1.80 1.80 1.80	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 4.231.39 \$0.750.85 0.750.85 0.750.85
110 115 170 205 210 215 220	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 8,000	WATTAGE 105 205 205 100 100 100 175	32 66 72 44 44 44 71	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34	\$4.07 3.67 3.67 \$1.80 1.80 1.80 1.80 1.77	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 1.231.39 \$0.750.85 0.750.85 0.750.85 1.241.37
110 115 170 205 210 215 220 225	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway Open Bottom	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 8,000 8,000	WATTAGE 105 205 205 100 100 100 175 175	32 66 72 44 44 44 71 71	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34 2.50	\$4.07 3.67 3.67 \$1.80 1.80 1.80 1.77 1.77	NON-FUEL ENERGY 3 \$0.550.62 1.431.26 1.231.39 \$0.750.85 0.750.85 0.750.85 1.241.37 1.241.37
110 115 170 205 210 215 220	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 8,000 8,000 8,000 21,000 62,000	WATTAGE 105 205 205 100 100 100 175	32 66 72 44 44 44 71	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34 2.50 4.04 5.29	\$4.07 3.67 3.67 \$1.80 1.80 1.80 1.77 1.77 1.81 1.78	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 4.231.39 \$0.750.85 0.750.85 1.241.37 2.703.05 6.597.46
110 115 170 205 210 215 220 225 235 240 245	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway Open Bottom Roadway Roadway Flood	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 4,000 8,000 8,000 8,000 21,000 62,000 21,000	WATTAGE 105 205 205 100 100 100 175 175 400 1,000 400	32 66 72 44 44 44 71 71 158 386 158	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34 2.50 4.04 5.29 5.29	\$4.07 3.67 3.67 51.80 1.80 1.80 1.80 1.77 1.77 1.77 1.81 1.78 1.81	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 1.231.39 \$0.750.85 0.750.85 1.241.37 1.241.37 1.241.37 1.241.37 1.241.37 2.703.05 6.597.46 2.703.05
110 115 170 205 210 215 220 225 235 240	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway Open Bottom Roadway Roadway Roadway	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 8,000 8,000 8,000 21,000 62,000	WATTAGE 105 205 205 100 100 100 100 175 175 400 1,000	32 66 72 44 44 44 71 71 158 386	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34 2.50 4.04 5.29	\$4.07 3.67 3.67 \$1.80 1.80 1.80 1.77 1.77 1.81 1.78	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 4.231.39 \$0.750.85 0.750.85 1.241.37 2.703.05 6.597.46
110 115 170 205 210 215 220 225 235 240 245	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway Open Bottom Roadway Roadway Flood	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 4,000 8,000 8,000 8,000 21,000 62,000 21,000	WATTAGE 105 205 205 100 100 100 175 175 400 1,000 400	32 66 72 44 44 44 71 71 158 386 158	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34 2.50 4.04 5.29 5.29	\$4.07 3.67 3.67 51.80 1.80 1.80 1.80 1.77 1.77 1.77 1.81 1.78 1.81	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 1.231.39 \$0.750.85 0.750.85 1.241.37 1.241.37 1.241.37 1.241.37 1.241.37 2.703.05 6.597.46 2.703.05
110 115 170 205 210 215 220 225 235 240 245	Incandescent: ¹ Roadway Roadway Post Top Mercury Vapor: ¹ Open Bottom Roadway Post Top Roadway Open Bottom Roadway Roadway Flood	INITIAL LUMENS OUTPUT 1,000 2,500 2,500 2,500 4,000 4,000 4,000 4,000 8,000 8,000 8,000 21,000 62,000 21,000	WATTAGE 105 205 205 100 100 100 175 175 400 1,000 400	32 66 72 44 44 44 71 71 158 386 158	\$1.03 1.61 20.39 \$2.55 2.95 3.47 3.34 2.50 4.04 5.29 5.29	\$4.07 3.67 3.67 51.80 1.80 1.80 1.77 1.77 1.81 1.78 1.81 1.78	NON-FUEL ENERGY ³ \$0.550.62 1.131.28 1.231.39 \$0.750.85 0.750.85 1.241.37 1.241.37 1.241.37 1.241.37 2.703.05 8.597.46 2.703.05

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: March 8, 2011 January 1, 2013

Progress Energy

SECTION NO. VI TWENTY-FIRST SECOND REVISED SHEET NO. 6.281 CANCELS TWENTIETH-TWENTY-FIRST REVISED SHEET

NO. 6.281

I Eij	Page 2 of 6 RATE SCHEDULE LS-1 LIGHTING SERVICE (Continued from Page No. 1) I. Fixtures: (Continued)							
I. CIA	(Ures: (Conunued)		LAMP SIZE 2			CHARGES PER UNIT		
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY 3	
	Sodium Vapor:			<u>_</u>			<u> </u>	
300	HPS Deco Rdwy White	50,000	400	168	\$14.73	\$1.61	\$2-87 <u>3.25</u>	
301	Sandpiper HPS Deco Roadway	27,500	250	104	13.81	1.72	1.78<u>2.01</u>	
302	Sandpiper HPS Deco Rdwy Blk	9,500	100	42	14.73	1.58	0.72 <u>0.81</u>	
305	Open Bottom *	4,000	50	21	2.54	2.04	0.360.41	
310	Roadway 1	4,000	50	21	3.12	2.04	0.360.41	
313	Open Bottom	6,500	70	29 42	4.19	2.05	0.500.56	
314 315	Hometown II	9,500	100		4.08	1.72	0.720.81	
315	Post Top - Colonial/Contemp ¹ Colonial Post Top ¹	4,000 4,000	50 50	21 34	5.04 4.05	2.04 2.04	0.360.41	
318	Post Top 1	4,000 9,500	100	42	2.50	1.72	0.58 <u>0.66</u> 0.720.81	
320	Roadway-Overhead Only	9,500	100	42	3.64	1.72	0.720.81	
321	Deco Post Top - Monticello	9,500	100	49	12.17	1.72	0.840.95	
322	Deco Post Top - Flagler	9,500	100	49	16.48	1.72	0.840.95	
323	Roadway-Turtle OH Only	9,500	100	42	4.32	1.72	0.720.81	
325	Roadway-Overhead Only	16,000	150	65	3.78	1.75	1.111.26	
326	Deco Post Top - Sanibel	9,500	100	49	18.16	1.72	0.840.95	
330	Roadway-Overhead Only	22,000	200	87	3.64	1.83	1.491.66	
335	Roadway-Overhead Only	27,500	250	104	4.16	1.72	1.782.01	
336	Roadway-Bridge 1	27,500	250	104	6.74	1.72	1.782.01	
337	Roadway-DOT 1	27,500	250	104	5.87	1.72	1.782.01	
338	Deco Roadway–Maitland	27,500	250	104	9.62	1.72	1.782.01	
340	Roadway-Overhead Only	50,000	400	169	5.03	1.76	2.883.27	
341	HPS Flood-City of Sebring only	16,000	150	65	4.06	1.75	1,11<u>1,26</u>	
342	Roadway-Tumpike 1	50,000	400	168	8.95	1.76	2.873.25	
343	Roadway-Tumpike 1	27,500	250	108	9.12	1.72	1.842.09	
345 347	Flood-Overhead Only Clermont	27,500	250	103	5.21	1.72	4.761.99	
347	Clemont	9,500 27,500	100 250	49 104	20.65 22.65	1.72 1.72	0.84<u>0.95</u> 1.78 2.01	
350	Flood-Overhead Only	50,000	400	170	5.19	1.72	2,903,29	
351	Underground Roadway	9,500	100	42	6.22	1.72	0.720.81	
352	Underground Roadway	16,000	150	65	7.58	1.75	1,11 1,26	
354	Underground Roadway	27,500	250	108	8.10	1.72	1.842.09	
356	Underground Roadway	50,000	400	168	8.69	1.76	2.873.25	
357	Underground Flood	27,500	250	108	9.36	1.72	1,842.09	
358	Underground Flood 1	50,000	400	168	9.49	1.76	2.873.25	
359	Underground Turtle Roadway	9,500	100	42	6.09	1.72	0.720.81	
360	Deco Roadway Rectangular	9,500	100	47	12.53	1.72	0.800.91	
365	Deco Roadway Rectangular	27,500	250	108	11.89	1.72	1.842.09	
366	Deco Roadway Rectangular	50,000	400	168	12.00	1.76	2.873.25	
370	Deco Roadway Round	27,500	250	108	15.41	1.72	1,84 <u>2.09</u>	
375	Deco Roadway Round 1	50,000	400	168	15.42	1,76	2.973.25	
380	Deco Post Top - Ocala	9,500	100	49	8.78	1.72	0.840.95	
381	Deco Post Top 1	9,500	100	49	4.05	1.72	0.840.95	
383	Deco Post Top-Biscayne	9,500	100	49	14.17	1.72	0.84 <u>0.95</u>	
385	Deco Post Top – Sebring	9,500	100	49	6.75	1.72	0.840.95	
393	Deco Post Top 1	4,000	50	21	8.72	2.04	0.36 <u>0.41</u>	
394	Deco Post Top 1	9,500	100	49	18.16	1.72	0.8 4 <u>0.95</u>	

(Continued on Page No. 3)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: March 8, 2011 January 1, 2013





Progress Energy

SECTION NO. VI ORIGINAL FIRST REVISED SHEET NO. 6.2811 CANCELS ORIGINAL SHEET NO. 6.2811

Page RATE SCHEDULE LS-1 LIGHTING SERVICE (Continued from Page No. 2)							Page 3 of 6
	anna an an Arrange ann an Arraigh	L	AMP SIZE 2			CHARGES PER	UNIT
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY 3
	Metal Halide:						
307	Deco Post Top-MH Sanibel P	11,600	150	65	\$16.85	\$2.68	\$ 1.11<u>1.26</u>
308	Clemont Tear Drop P	11,600	150	65	19.91	2.68	1.111.26
309	MH Deco Rectangular P	36,000	320	126	13.07	2.74	2,152.44
311	MH Deco Cube P	36,000	320	126	15.98	2.74	2.152.44
312	MH Flood P	36,000	320	126	10.55	2.74	2.452.44
319	MH Post Top Biscayne P	11,600	150	65	15.24	2.68	1.111.26
327	Deco Post Top-MH Sanibel 1	12,000	175	74	18.39	2.72	4-26 <u>1.43</u>
349	Clermont Tear Drop	12,000	175	74	21.73	2.72	1.261.43
371	MH Deco Rectangular '	38,000	400	159	14.26	2.84	2.71 <u>3.07</u>
372	MH Deco Circular 1	38,000	400	159	16.70	2.84	2.743.07
373	MH Deco Rectangular *	110,000	1,000	378	15.30	2.96	6.457.31
386	MH Flood	110,000	1,000	378	13.17	2.96	6.457.31
389	MH Flood-Sportslighter ^{\$}	110,000	1,000	378	13.01	2.96	6.457.31
390	MH Deco Cube ¹	38,000	400	159	17.44	2.84	2.743.07
396	Deco PT MH Sanibel Dual 5	24,000	350	148	33.73	5.43	2.532.86
397	MH Post Top-Biscayne	12,000	175	74	14.98	2.72	4.261.43
398	MH Deco Cube 5	110,000	1,000	378	20.34	2.96	6.457.31
399	MH Flood	38,000	400	159	11.51	2.84	2.713.07
	LED:						
325	LED Roadway	6,000	95	33	\$16.93	\$2.43	\$ 0.56 0.64
326	LED Roadway	9,600	157	55	20.07	2.43	0.941.06
330	LED Shoebox Type 3	20,664	309	108	41.08	2.84	1.842.09
335	LED Shoebox Type 4	14,421	206	72	32.59	2.84	1.231.39
336	LED Shoebox Type 5	14,421	206	72	31.65	2.84	4.231.39
							a

(Continued on Page No. 4)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida EFFECTIVE: March 8, 2011January 1, 2013

	Progress Energy	SECTION NO. VI FIFTEENTH <u>SIXTEENTH</u> REVISED SHEET NO. 6.312 CANCELS FOURTEENTH FIFTEENTH REVISED SHEE
		Page 3 of
	FIRM ST	SCHEDULE SS-1 FANDBY SERVICE ad from Page No. 2)
Deten	mination of Specified Standby Capacity:	
	itially, the customer and the Company shall mutually agree ompany. This shall be termed for billing purposes as the "Sp	upon a maximum amount of standby capacity in kW to be supplied by the becified Standby Capacity".
	here a bona fide change in the customer's standby capacity becified Standby Capacity.	y requirement occurs, the Company and the customer shall establish a ne
Ca		shall be the greater of: (1) the mutually agreed upon Specified Standby irrement established in the current billing month, or (3) the maximum 30- ne twenty-three (23) preceding billing months.
Rate F	Per Month:	
1. C	ustomer Charge:	
	Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage:	\$ 100.71 \$ 235.69 \$ 812.02
No	te: Where the Customer has paid the costs of metering equipe \$81.21.	uipment pursuant to a Cogeneration Agreement, the Customer Charge sh
2. St.	pplemental Service Charges:	
	supplemental power requirements shall be billed in accord hedule.	ance with the demand and energy charges of the otherwise applicable ra
3. St	andby Service Charges:	
Α,	Distribution Capacity:	
	\$1.801.59 per kW times the Specified Standby Capaci	ty.
	Note: No charge is applicable to a customer who has system.	provided all the facilities for interconnection to the Company's transmission
В.	Generation & Transmission Capacity:	
	The charge shall be the greater of: 1. \$ <u>1.005</u> 0.888 per kW times the Specified Standby (Capacity or
	 The sum of the daily maximum 30-minute kW \$0.4790.423/kW times the appropriate following m 	demand of actual standby use occurring during On-Peak Periods time ionthly factor.
	Billing Month	Factor
	March, April, May, October June, September, November, December	0.80 1.00
	January, February, July, August	1.20
	Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments</i> :	See Sheet No. 6.105 and 6.106
	Energy Charges	
C,	Non-Fuel Energy Charge:	0.8900.786¢ per kWh
C,	tion f det miorg) ofte got	
C,	Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106
c.	Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> ,	See Sheet No. 6.105 and 6.106

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

	Progress Energy	SECTION NO. VI FOURTEENTH <u>FIFTEENTH</u> REVISED SHEET NO. 6.313 CANCELS THIRTEENTH FOURTEENTH REVISED
		Page 4 of 5
		RATE SCHEDULE SS-1 FIRM STANDBY SERVICE (Continued from Page No. 3)
Data		(continued non rage hat o)
	Per Month: (Continued) andby Service Charges: (Continued)	
D.	Delivery Voltage Credit:	
		r this rate at a distribution primary delivery voltage, the Distribution Capacity Charge ver kW.
E.	Metering Voltage Adjustment:	
	Metering voltage will be at the option of	of the Company. When the Company meters at a voltage above distribution secondary, the or shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity d Delivery Voltage Credit hereunder:
	Metering Voltage	Reduction Factor
	Distribution Primary Transmission	1.0% 2.0%
F.	Fuel Cost Recovery Factor:	Rector FW
	•	le metering voltage provided on Tariff Sheet No. 6.105.
G.	Gross Receipts Tax Factor:	See Sheet No. 6.106
Н.	Right-of-Way Utilization Fee:	See Sheet No. 6.106
I.	Municipal Tax:	See Sheet No. 6.106
J.	Sales Tax:	See Sheet No. 6.106
Promis	Im Distribution Service Charge:	
Wh Re sch	ere Premium Distribution Service has be gulations Governing Electric Service, the ci	een established after 12/15/98 in accordance with Subpart 2.05, General Rules and ustomer shall pay a monthly charge determined under Special Provision No. 3 of this rate nent, or the customer's allocated share thereof, installed to accomplish automatic delivery onnect to an alternate distribution circuit.
	addition the Distribution Capacity Charge in kW for the cost of reserving capacity in the	cluded in the Rate per Month section of this rate schedule shall be increased by \$0.920.84 e alternate distribution circuit.
Rating	Periods:	
1. On	-Peak Periods - The designated On-Peak P	Periods expressed in terms of prevailing clock time shall be as follows:
A.	For the calendar months of November Monday through Friday*:	through March, 6:00 a.m. to 10:00 a.m. and
		6:00 p.m. to 10:00 p.m.
В.	For the calendar months of April throug Monday through Friday*:	gh October, 12:00 Noon to 9:00 p.m.
Day	following general holidays shall be exclude	ed from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be
2. Off	Peak Periods - The designated Off-Peak P	Periods shall be all periods other than the designated On-Peak Periods set forth above.
Vilnimu	m Monthly Bill:	
	minimum monthly bill shall be the Custom vice the customer is required, the Company	ner Charge and the Capacity Charges for Standby Service, Where Special Equipment to may require a specified minimum charge.
		(Continued on Page No. 5)



SHEET NO. 6.317

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SECTION NO. VI EIGHTEENTH NINETEENTH REVISED SHEET NO. 6.317 CANCELS SEVENTEENTH EIGHTEENTH REVISED

			Page 3 of 5						
		INTERRUPTIB	SCHEDULE SS-2 LE STANDBY SERVICE ed from Page No. 2)						
1	Determir	nation of Specified Standby Capacity;							
	 Initially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the Company. This shall be termed for billing purposes as the "Specified Standby Capacity". 								
2	Where a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new Specified Standby Capacity.								
3	Capa		shall be the greater of: (1) the mutually agreed upon Specified Standby irement established in the current billing month, or (3) the maximum 30- e twenty-three (23) preceding billing months.						
	Rate Per								
r		omer Charge: econdary Metering Voltage:	\$ 303.71						
	Р	nmary Metering Voltage:	\$ 438.68						
		ransmission Metering Voltage:	\$ 1,015.02						
		be \$284.20.	ipment pursuant to a Cogeneration Agreement, the Customer Charge shall						
2			ance with the demand and energy charges of the otherwise applicable rate						
3	Stand	by Service Charges:							
1	A.	Distribution Capacity: \$1.801,59 per kW times the Specified Standby Capacit							
1			provided all the facilities for interconnection to the Company's transmission						
	В.	Generation & Transmission Capacity:							
1		The charge shall be the greater of: 1. \$ <u>1.0050-888</u> per kW times the Specified Standby C	Capacity or						
-		 The sum of the daily maximum 30-minute kW (\$0.4790.423 kW times the appropriate following methods) 	demand of actual standby use occurring during On-Peak Periods times						
		Billing Month	Factor						
		March, April, May, October June, September, November, December	0.80 1.00						
		January, February, July, August	1.20						
		Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, <i>Billing Adjustments:</i>	See Sheet No. 6.105 and 6.106						
1	C‡.	Interruptible Capacity Credit-for-customer-accounts	established prior to 01/01/2006:						
1		The credit shall be the greater of: 1. \$0.8700 690 per kW times the Specified Standby C	anarity or						
		2. The sum of the daily maximum 30-minute kW (demand of actual standby use occurring during On-peak periods times						
	C2	\$ <u>0.414</u> 0.329/kW times the appropriate Billing Mont Interruptible Capacity Credit for customer accounts							
		The credit shall be the greater of:							
		 S0.331 cer-kW times the Specified Standby Capacity The sum of the daily maximum 30 minute kW (ty, or temand of actual standby use occurring-during. On peak periods times						
		\$0.158/kW times the appropriate Billing Month Fact	tor shown in part 3.B. abovo.						
-	D.	Energy Charges: Non-Fuel Energy Charge:	<u>0.8800.777</u> ¢ per kWh						
-		Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, <i>Billing Adjustments</i> ,							
		except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106						
	E.	Delivery Voltage Credit:							
1			ribution primary delivery voltage, the Distribution Capacity Charge						
I			(Continued on Page No. 4)						

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

Progress Energy SECTION NO. VI THIRTEENTH FOURTEENTH REVISED SHEET NO. CANCELS TWELFTH THIRTEENTH REVISED **SHEET NO. 6.318** Page 4 of 5 **RATE SCHEDULE SS-2** INTERRUPTIBLE STANDBY SERVICE (Continued from Page No. 3) Rate Per Month: (Continued) 3. Standby Service Charges; (Continued) F. Metering Voltage Adjustment: Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Distribution Capacity Charge, Generation & Transmission Capacity Charge, Interruptible Capacity Credit, Non-Fuel Energy Charge and Delivery Voltage Credit hereunder. **Reduction Factor** Metering Voltage Distribution Primary 1.0% Transmission 2.0% G. Fuel Cost Recovery Factor: Time of Use Fuel Charges of applicable metering voltage provided on Tariff Sheet No. 6.105. Gross Receipts Tax Factor: See Sheet No. 6.106 H. Right-of-Way Utilization Fee: See Sheet No. 6 106 Ł **Municipal Tax:** See Sheet No. 6,106 J. К. Sales Tax: See Sheet No. 6 106 Premium Distribution Service Charge: Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 4 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit. In addition the Distribution Capacity Charge included in the Rate per Month section of this rate schedule shall be increased by \$0.920.81 per kW for the cost of reserving capacity in the alternate distribution circuit. Rating Periods: 1. On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows: For the calendar months of November through March, A. Monday through Friday*: 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m. For the calendar months of April through October, 8 Monday through Friday*: 12:00 Noon to 9:00 p.m. The following general holidays shall be excluded from the On-Peak Penods; New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods. 2. Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak Periods set forth above. Minimum Monthly Bill: The minimum monthly bill shall be the Customer Charge and the Capacity Charges for Standby Service. Where Special Equipment to service the customer is required, the Company may require a specified minimum charge. Terms of Payment: Bills rendered hereunder are payable within the time limit specified on bill at company-designated locations. Term of Service: Service under this rate schedule shall be under the same terms as that specified in the otherwise applicable rate schedule. Special Provisions: 1. When the customer increases the electrical load, which increase requires the Company to increase facilities installed for the specific use of the customer, a new Term of Service may be required under this rate at the option of the Company. Customers taking service under another Company rate schedule who elect to transfer to this rate will be accepted by the Company on a first-come, first-served basis. Required interruptible equipment will be installed accordingly, subject to availability. Service under this rate schedule shall commence with the first full billing period following the date of equipment installation. (Continued on Page No. 5)

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida



SECTION NO. VI FOURTEENTH_FIFTEENTH_REVISED SHEET NO. 6.322 CANCELS THIRTEENTH_FOURTEENTH_REVISED

		Page 3 of	6
		RATE SCHEDULE SS-3 CURTAILALBE STANDBY SERVICE (Continued from Page No. 2)	
	Dete	mination of Specified Standby Capacity:	
		itially, the customer and the Company shall mutually agree upon a maximum amount of standby capacity in kW to be supplied by the ompany. This shall be termed for billing purposes as the "Specified Standby Capacity".)
		there a bona fide change in the customer's standby capacity requirement occurs, the Company and the customer shall establish a new pecified Standby Capacity.	1
	(ne Specified Standby Capacity for the current billing period shall be the greater of: (1) the mutually agreed upon Specified Standby apacity, (2) the maximum 30-minute kW standby power requirement established in the current billing month or (3) the maximum 30- inute kW standby power requirement established in any of the twenty-three (23) preceding billing months.	
		Per Month:	
	1. (ustomer Charge: Secondary Metering Voltage: Primary Metering Voltage: Transmission Metering Voltage: \$ 812.02	
	1	te: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be \$81,21.	I
	A	applemental Service Charges: supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate hedule.	ł
	3. S A	andby Service Charges: Distribution Capacity: \$ <u>1.80</u> 4.69 per kW times the Specified Standby Capacity. Note: No charge is applicable to a customer who has provided all the facilities for interconnection to the Company's transmission system.	
50000h	B	Generation & Transmission Capacity: The charge shall be the greater of: 1. \$1.0050-888 per kW times the Specified Standby Capacity or 2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-Peak Periods times \$0.4790-423/kW times the appropriate following monthly factor: Billing Month Factor. March, April, May, October 0.80 June, September, November, December 1.00 January, February, July, August 1.20 Plus the Cost Recovery Factors on a \$/ kW basis See Sheet No. 6.105 and 6.106	
ļ	с		
		 The credit shall be the greater of: \$<u>0.653</u>0.345 per kW times the Specified Standby Capacity, or The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods times \$<u>0.311</u>0.164/kW times the appropriate Billing Month Factor shown in part 3.B. above. 	
	c	 Curtailable Capacity Gredit for customer accounts established on or after 01/01/2006: The credit shall be the greater of: 1\$0.248 per kW times the Specified Standby Capacity, or 2The sum of the daily maximum 30 minute kW demand of actual standby use occurring during On peak periods times \$0.118/kW times the appropriate Billing Month Factor shown in part 3.8. above. 	
1	D	Energy Charges: Non-Fuel Energy Charge: <u>0.8830-780</u> ¢ per kWh	
		Plus the Cost Recovery Factors on a #/ kWh basis listed in Rate Schedule BA-1, <i>Billing Adjustments</i> , except for the Fuel Cost Recovery Factor. See Sheet No. 6.105 and 6.106	
1	E.	Delivery Voltage Credit: When a customer takes service under this rate at a distribution primary delivery voltage, the Distribution Capacity Charge bereurder will be reduced by 33296 per KW	
1		hereunder will be reduced by 3329¢ per kW. (Continued on Page No. 4)	

ISSUED BY: Lori J. Cross, Manager, Utility Regulatory Planning - Florida

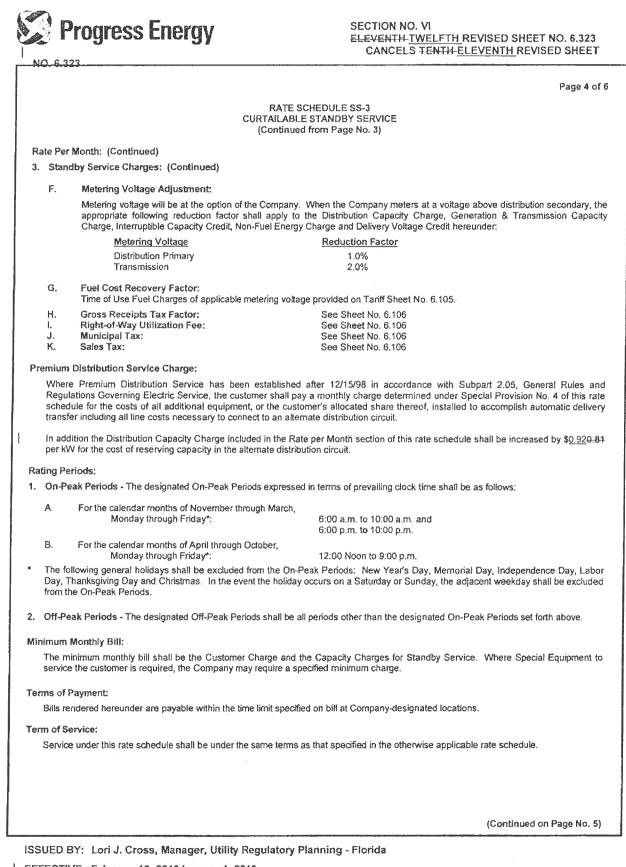


Exhibit 2 Page 1 of 1 Duke Energy Florida

PROGRESS ENERGY FLORIDA, INC. Capital Structure Used for AFUDC Calculation FPSC Order No. PSC-10-0604-PAA-EI

AFUDC

	Capital Ratio	Cost Rates	Weighted Average Cost of Capital
Long Term Debt	45.2906%	5.42%	2.46%
Short Term Debt	0.0000%	0.65%	0.00%
Customer Deposits	2.5835%	6.25%	0.16%
Preferred Stock	0.3661%	4.51%	0.02%
Common Equity	45.7446%	10.5%	4.80%
Deferred Income Taxes	7.8269%	-	0.00%
Deferred Taxes - FAS 109	-1.9014%	-	0.00%
Tax Credits - Weighted Cost	0.0897%	-	0.00%
Total	100.00%		7.44%



Exhibit 3 Page 1 of 1 Duke Energy Florida

PROGRESS ENERGY FLORIDA, INC. Carrying Charge Calculation Applicable Upon Retirement of CR3 <u>to all CR3 Related Rate Base Only</u> Common Equity Based on 70% of Authorized

AFUDC Weighted

Capital RatioCost RatesAverage Cost of CapitalLong Term Debt45.2906%5.42%2.46%Short Term Debt0.0000%0.65%0.00%Customer Deposits2.5835%6.25%0.16%Preferred Stock0.3661%4.51%0.02%Common Equity45.7446%7.35%3.36%Deferred Income Taxes7.8269%-0.00%Tax Credits - Weighted Cost0.0897%-0.00%				weighted
Long Term Debt 45.2906% 5.42% 2.46% Short Term Debt 0.0000% 0.65% 0.00% Customer Deposits 2.5835% 6.25% 0.16% Preferred Stock 0.3661% 4.51% 0.02% Common Equity 45.7446% 7.35% 3.36% Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%		Capital	Cost	Average
Short Term Debt 0.0000% 0.65% 0.00% Customer Deposits 2.5835% 6.25% 0.16% Preferred Stock 0.3661% 4.51% 0.02% Common Equity 45.7446% 7.35% 3.36% Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%		Ratio	Rates	Cost of Capital
Short Term Debt 0.0000% 0.65% 0.00% Customer Deposits 2.5835% 6.25% 0.16% Preferred Stock 0.3661% 4.51% 0.02% Common Equity 45.7446% 7.35% 3.36% Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%				
Customer Deposits 2.5835% 6.25% 0.16% Preferred Stock 0.3661% 4.51% 0.02% Common Equity 45.7446% 7.35% 3.36% Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%	Long Term Debt	45.2906%	5.42%	2.46%
Preferred Stock 0.3661% 4.51% 0.02% Common Equity 45.7446% 7.35% 3.36% Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%	Short Term Debt	0.0000%	0.65%	0.00%
Common Equity 45.7446% 7.35% 3.36% Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%	Customer Deposits	2.5835%	6.25%	0.16%
Deferred Income Taxes 7.8269% - 0.00% Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%	Preferred Stock	0.3661%	4.51%	0.02%
Deferred Taxes - FAS 109 -1.9014% - 0.00% Tax Credits - Weighted Cost 0.0897% - 0.00%	Common Equity	45.7446%	7.35%	3.36%
Tax Credits - Weighted Cost 0.0897% - 0.00%	Deferred Income Taxes	7.8269%	-	0.00%
	Deferred Taxes - FAS 109	-1.9014%	-	0.00%
Total 100.00% 6.00%	Tax Credits - Weighted Cost	0.0897%	-	0.00%
	Total	100.00%		6.00%



Exhibit 4 Page 1 of 1 Duke Energy Florida

PROGRESS ENERGY FLORIDA, INC. Capital Structure & AFUDC Calculation

			AFUDC
			Weighted
			Average
	Capital	Cost	Cost of
	Ratio	Rates	Capital
Long Term Debt	45.2906%	5.42%	2.46%
Short Term Debt	0.0000%	0.65%	0.00%
Customer Deposits	2.5835%	6.25%	0.16%
Preferred Stock	0.3661%	4.51%	0.02%
Common Equity	45.7446%	10.70%	4.90%
Deferred Income Taxes	7.8269%	-	0.00%
Deferred Taxes - FAS 109	-1.9014%	-	0.00%
Tax Credits - Weighted Cost	0.0897%	-	0.00%
Total	100.00%		7.53%

1

Exhibit 5 Page 1 of 1 Duke Energy Florida

RS	3.45 \$/1000 KWH
RS	0.345 cents/KWH
	NCRC Impact
	Levy over 5 years

GS - 1	0.252 cents/KWH
GS - 2	0.182 cents/KWH
GSD	0.224 cents/KWH
CS	0.207 cents/KWH
IS	0.180 cents/KWH
LS	0.052 cents/KWH

Retail Avg 0.282 cents/KWH

All rates at Secondary - for primary and transmission use 99% and 98% adjustment

Note: Above rates assume the transfer of land investments previously included in NCRC to base rate FERC Account 105 "Plant Held For Future Use" effective 1/1/2013 and that such investments will be included as rate base for Cost of Service and Surveillance Reporting. In accordance with the Stipulation and Settlement Agreement PEF will transfer these land investments back to NCRC as part of such filing contemplated under the provisions of paragraph 4.

Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 164 of 197

chedule P-1 - (Ravised 6/2/2011) P EXPLANATION: Provide summary calculation of the month In the event that no costs were approved fr	rojection Filling: Summa y Projected Amount for ea	ach cost catego	ry: 1. Site Select	tion, 2. Preconst	ruction, and 3. Co	unstruction.	(25-6.0423(5)(c)1.c.,F.A (25-6.0423 (8)(e),F.A.C.
OMPANY: Interest Energy - FL projection and Projected amounts for the re	ting schedule and line. In	clude in the Pro	pjected calculatio	on applicable Co	mmission approv	ed	Witness: Thomas G For
OCKET NO.: 110009-EI							For Year Ended 12/31/2
ine	(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(N) 12 Month Total
o. Description	JORY	August	Jurisdictional D		November	Decanoer	Forda
 Projected Site Selection Costs for the Period (25-6.0423(2)(1), F.A., C.) a. Additions (Schedule P-2, 1, line 1) b. Carrying Costs on Additions (Schedule P-2, 1, line 7) 	\$0 0	\$0 0	\$0 0	0 20	\$0 0	\$0 0	\$0 0
 c. Carrying Costs on Additions (Schedule P-21, inter) c. Carrying Costs on Deferred Tax Asset (Schedule P-3A.1, line 11) 	0	0	0	0	0	0	
 d. Total Sie Selection Amount (Lines 1.a through 1.c) 	\$0	\$0	50	\$0	\$0	\$0	\$0
Projected Preconstruction Costs for the Period [25-6.0423(2)(3),F.AC.] a. Additions (Schedule P-2,2, line 1) Carrying Costs on Additions (Schedule P-2,2, line 9) C. Carrying Costs on Deferred Tax (Schedule P-3A,2, line 11) Total Preconstruction Amount	\$1,651,403 918,468 <u>1,746,948</u> \$4,316,819	\$1,658,254 872,274 1,766,560 \$4,297,088	\$2,561,754 830,797 1,788,019 \$5,180,570	\$2,677,348 785,176 1,811,546 \$5,274,069	\$2,552,414 738,288 1,835,053 \$5,125,756	\$2,562,189 692,110 <u>1,858,328</u> \$5,112,627	
 (Lines 2.a through 2c) Projected Construction Costs for the Period [25-6.0423(2)(i),F.AC.] Avg. Net Additions Balance (Schedule P-2.3, line 7) a. Carrying Costs on Additions (Schedule P-2.3, line 9) b. Carrying Costs on Deferred Tax (Schedule P-3A.3, line 11) 	\$130,997,420 1,378,276	\$131,983,243 1,388,649 0	\$132,998,419 1,399,330 0	\$133,194,134 1,401,389 0	\$133,571,543 1,405,360 0	\$134,086,267 1,410,775 0	
 b. Carrying Costs on Deterred fax (Schedule Provid, line 11) c. Total Construction Amount (Lines 3.a through 3.b) 	\$1,378,276	\$1,388,649	\$1,399,330	\$1,401,389	\$1,405,360	\$1,410,775	\$16,275,073
 Allocated or Assigned O&M Amounts (Schedule P-4, line 43) 	\$112,500	\$208,274	\$129,061	\$85,560	\$83,800	\$79,807	\$1,405,073
5. Total Projected Period Amount (Lines 1.d + 2.d + 3.c + 4)	\$5,807,596	\$5,894,011	\$6,708,961	\$6,761,017	\$6,614,916	\$6,603,209	\$75,324,920
). Prior Period (Over) / Under Recovery		,					(54,968,206)
7. Period Collection of Deferred Regulatory Asset							114,968,361
 Total Amount for the Projected Period Revenue Requirement (Line 5 + Line 6 + Line 7) 							135,325,074
), Revenue Tax Multiplier							1.00072
							\$135,422,508

11NC-FPSCPOD3-7-162

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Exhibit 6 Page 1 of 1 Duke Energy Florida

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Exhibit 7 Page 1 of 4 Duke Energy Florida

Jurisdictional Nuclear O&M

FERC Acct	System	Retail
517	\$2,253	\$1,964
519	4,724	4,121
520	13,682	11,949
521	-	_
523	9	8
524	43,189	37,660
528	13,327	11,718
529	2,672	2,330
530	13,055	11,258
531	6,783	5,899
532	2,172	1,906
Subtotal	101,866	88,813
Add Fuel Handling - 518	1,691	1,652
	\$103,557	\$90,465

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JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME

1,964

4,121

-

11,949

11,949

4,121

0.87177

0.88462

0.87237

0.88462

0.87335

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Exhibit 7

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Duke Energy Florida

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FLORIDA PUBLIC SERVICE COMMISSION Company: PROGRESS ENERGY FLORIDA INC. Docket No. 090079-EI		RESS ENERGY FLORIDA INC. test year and the most recent historical year if the lest year is projected.			Type of data shown: X Projected Test Year Ended 12/31/201 Prior Year Ended 12/31/200 Historical Test Year Ended 12/31/200 Witness: Toomey / Slusser		
JUCKE	(140. 090079-EI		r	housands)		Wittess. Toomey robsser	
			(A)	(B)	(C)		
Line	A A	Account Title	Total	FPSC	Jurisdictional		
No.	Account	OPERATION & MAINTENANCE EXPENSES	Сотралу	Jurisdictional	Sep Factor		
	1	OPERATION & MAINTENANCE EXPENSES					
	2	PRODUCTION EXPENSES					
	3	PRODUCTION EXPENSES					
	5 5012000	Fuel - Non Recoverable					
	6	Non-Recoverable Energy	5,080	4,816	0.94789		
	7	Total Fuel - Non Recoverable	5,080	4,816	0.94789		
	8 500-507	Steam Generation-Operation	0,000		0.01100		
	9	Base - Demand	23,200	20,523	0.88462		
	10	Intermediate - Demand	12,204	. 7,091	0.58105		
	11	Peaking - Demand	-,-	-	0.91520		
	12	Total Steam Generation - Operation	35,404	27,614	0.77998		
	13 510-514	Steam Generation - Maintenance					
	14	Base - Energy	42,659	40,436	0.94789		
	15	Intermediate - Energy	4,000	3,792	0.94789		
	16	Peaking - Energy	-	~	0.94789		
	17	Direct Assign - Tallahassee Buyback			-		
	18	Direct Assign Wholesale	12,160		-		
	19	Total Steam Generation - Maintenance	58,818	44,228	0.75193		
	20 5182300	Nuclear Fuel - Non-Recoverable					
	21	Non-Recoverable Energy	582	552	0.94789		
	22	Non-Recoverable Energy - Tallahassee Buyback	9	-	-	•	
	23	Direct Assign Retail - Energy	1,100	1,100	1.00000		
	24	Total Nuclear Fuel - Non-Recoverable	1,691	1,652	0.97699		
	25 517	Operations Supervision Engineering					
	26	Base - Demand	2,221	1,964	0.88462		
	27	<u> Base - Demand - Tallahassee Buyback</u>	33				

2,253

4,659

4,724

13,508

13,682

174

65

Supporting Schedules: C-19, C-20, C-21, C-22

28

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31

32

34

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36

37

29 **519**

33 520

Base - Demand - Tallahassee Buyback

Base - Demand - Tallahassee Buyback

Coolant & Water

Steam Expenses

Base - Demand

Total Coolant & Water

Total Steam Expenses

Base - Demand

Total Operations Supervision Engineering

Recap Schedules: C-1

SCHEDULE C-4

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Exhibit 7

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Duke Energy Florida

	HEDULE C-4			Duke Energy Florida			
SCHE	DULE C-4		JURISDICTIC	NAL SEPARATION FACTORS - NET	OPERATING INCOME		Page 3 of 48
FLORI	DA PUBLIC SE	RVICE COMMISSION	Explanation:	Provide jurisdictional factors for net of	operating income for the	Type of data shown:	
				test year and the most recent historic	cal year if the test year	X Projected Test Year Ended	12/31/2010
Compa	iny: PROGRES	SS ENERGY FLORIDA INC.		is projected.		Prior Year Ended	12/31/2009
Dockel	No. 090079-E					Historical Test Year Ended Witness; Toomey / Slusse	12/31/2008
DUCKE	110. 0300/ 3·C	1		(Thousands)		Wittess, Toomey rousse	I
						·····	
Line		Account	(A) Total	(B) FPSC	(C) Jurisdictional		
No.	Account	Title	Company	Jurisdictional	Sep Factor		
140.	1 521	Nuclear Steam Other Sources	Company	Junscictional	Sep Factor		
	2	Base - Energy	-		0.88462		
	3	Base - Energy - Tallahassee Buyback	-		-		
	4	Total Nuclear Steam Other Sources			<u> </u>		
	5 5210001	Steam Other Sources					
	6	Base - Energy	_	-	0.88462		
	7	Base - Energy - Tallahassee Buyback	-	-	-		
	8	Total Steam Other Sources			-		
	9 522	Steam Transfer Credit					
	10	Total Steam Transfer Credit	-	-	-		
	11 523	Nuclear - Electric Expenses					
	12	<u>Base - Demand</u>	9	8	0.88462		
	13	Base - Demand - Tallahassee Buyback	-				
	14	Total Nuclear - Electric Expenses	9	8	0.88462		
	15 524	Nuclear - Misc Power Expenses					
	16	<u>Base - Demand</u>	42,572	37,660	0.88462		
	17	<u> Base - Demand - Tallahassee Buyback</u>	617				
	18	Total Nuclear - Misc Power Expenses	43,189	37,660	0.87198		
	19 525	Nuclear - Rents					
	20	<u>Base - Demand</u>	-	-	0.88462		
	21	Base - Demand - Tallahassee Buyback			-		
	22	Total Nuclear - Rents	-	-	-		
	23 528	Nuclear - Maintenance Supervisor & Engineering					
	24	<u>Base - Energy</u>	10,779	10,218	0.94789		
	25 26	<u>Direct Assign Retail - Energy</u>	1,500	1,500	1.00000		
	20 27	Direct Assign Wholesale	915		-		
	28	Base - Energy - Tallahassee Buyback	132	44.740	-		
	29 529	Total Nuclear - Maintenance Supervisor & Engineering Nuclear - Maintenance Structures	13,327	11,718	0.87923		
	30	Base - Demand	0.004	0.000	0.00.100		
	31	Base - Demand - Tallahassee Buyback	2,634 39	2,330	0.88462		
	32	Total Nuclear - Maintenance Structures	2,672		0.07430		
	33 530	Nuclear - Maintenance Structures	2,0/2	2,330	0.87179		
	34	Base - Energy	11,877	11 760	0.04790		
	35	Direct Assign Wholesale	1,009	11,258	0.94789		
	36	Base - Energy - Tallahassee Buyback	169	-	-		
	37	Total Nuclear - Maintenance Reactor Plant Equipment	13,055	11,258	0.86239		
	• 7	i oran ranoloan - maniferiance reactor Frant Equipment	12,025	11,200	0.00239		

Supporting Schedules: C-19, C-20, C-21, C-22

Recap Schedules: C-1

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Exhibit 7

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Duke Energy Florida

SCHEDULE C-4			JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME				
ORID	ORIDA PUBLIC SERVICE COMMISSION		Explanation: Provide jurisdictional factors for net operating income for the Type of data shown: test year and the most recent historical year if the test year X Projected Test Year Ended				12/31/2010
ompan	y: PROGRES	S ENERGY FLORIDA INC.	is projected.			Prior Year Ended Historical Test Year Ended	12/31/2009
ocket N	lo. 090079-El			(Thousands)		Witness: Toomey / Slusser	
				(mousanos)			
ne		Account	(A) Total	(B) FPSC	(C) Jurisdictional		
0	Account	Title	Company	Jurisdictional	Sep Factor		
	1 531 2	Nuclear - Maintenance Electric Plant Base - Energy	6,223	5,899	0.94789		
	2	Direct Assign Wholesale	528	5,699	0.94789		
	4	Base - Energy - Tallahassee Buyback	32	-	÷		
	4 5	Total Nuclear - Maintenance Electric Plant	6,783	5,899	0.86960		
	6 532	Nuclear - Maintenance Misc Nuclear Plant	0,705	2,033	0.80900		
	7	Base - Demand	2,155	1,906	0.88462		
	8	Base - Demand - Tallahassee Buyback	17	1000	-		
	9	Total Nuclear - Maintenance Misc Nuclear Plant	2,172	1,906	0.87777		
	10 5472000	Fuel - Other Prod Base	-1	110.00			
	11	Non-Recoverable Energy	1,748	1,657	0,94789		
	12	Total Fuel - Other Prod Base	1,748	1,657	0.94789		
	13 546-550	Other Power Gen - Operation					
	14	Base - Demand	12,895	11,407	0.88462		
	15	Peaking - Demand	9,178	8,400	0.91520		
	16	Total Other Power Gen - Operation	22,073	19,807	0.89734		
	17 551-554	Other Power Gen - Maintenance					
	18	Peaking - Demand	16,757	15,336	0.91520		
	19	Base - Energy	32,771	31,063	0.94789		
	20	Direct Assign Wholesale	2,783		-		
	21	Total Other Power Gen - Maintenance	52,311	46,399	0.88699		
	22 5550709	PP CAP - Base - Nonrecoverable - WH					
	23	Direct Assign Wholesale	51,676	·	-		
	24	Total PP CAP - Base - Nonrecoverable - WH	51,676	-	-		
	25 5550710	PP CAP - Base - Nonrecoverable - Retail					
	26 27	Non-Recoverable Demand	*	ai	1.00000		
		Total PP CAP - Base - Nonrecoverable - Retail	-	-	~		
	28 5560000 29	Sys Control & Dispatch Base - Demand	4 30 4	4 474	0.00400		
	29 30	<u>Base - Demano</u> Intormediate - Demand	1,324 251	1,171	0,88462		
	30	Peaking - Demand	577	146	0.58105		
	32	Total Sys Control & Dispatch	2,152	<u>528</u> 1,845	0.91520		
	32 33 5570001	Other Pwr Supply Expenses	2,152	1,645	0.85745		
	34	Total Other Pwr Supply Expenses			······································		
	35	iotal other FWI output Expenses	-	-	-		
	36	TOTAL PRODUCTION O&M EXPENSES	332,822	236,832	0.71450		
	37	TO THE ENDOUTION ORINE APENDED	332,022	230,032	0.71159		

Supporting Schedules: C-19, C-20, C-21, C-22

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Exhibit 8 Page 1 of 2

Duke Energy Florida

All cost of service and rate design issues will continue to be determined in accordance with Exhibit 1 to this Revised and Restated Settlement Agreement, except as amended by this Exhibit 8 to this Revised and Restated Settlement Agreement. The tariff sheet changes provided herein effective with the first billing cycle for January 2014 will be provided to the Commission staff for administrative approval along with the changes in base rates for the Federal Clean Air Interstate Rule ("CAIR") assets effective with the first billing cycle for January 2014 pursuant to paragraph 14 of this Revised and Restated Settlement Agreement. The tariff sheet changes provided herein effective with the first billing cycle for January 2015 will be provided to the Commission staff for administrative approval prior to the effective date of these credits.

1) Effective with the first billing cycle for January 2014, monthly interruptible and curtailable credits shall be as follows:

IS-1	\$5.61 per KW of billing demand
IST-1	\$5.61 per KW of on-peak demand
CS-1	\$4.21 per KW of billing demand
CST-1	\$4.21 per KW of on-peak demand
IS-2, IST-2	\$9.79 per KW of load factor adjusted demand
CS-2, CST-2	\$7.35 per KW of load factor adjusted demand
CS-3, CST-3	\$7.35 per KW of fixed curtailable demand
SS-2 – the great	er of:
\$0.979	per KW times the Specified Standby Capacity, or
the sun	n of the daily maximum 30 minute KW demand of actual standby use
occurri	ng during on-peak periods times \$0.466 per KW times the appropriate

- monthly factor.
- SS-3 the greater of:

\$0.734 per KW times the Specified Standby Capacity, or

the sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times \$0.350 per KW times the appropriate monthly factor.

Exhibit 8 Page 2 of 2

- 2) Effective with the first billing cycle for January 2015, monthly interruptible and curtailable credits shall be as follows:
 - IS-1 \$6.24 per KW of billing demand
 - IST-1 \$6.24 per KW of on-peak demand
 - CS-1 \$4.68 per KW of billing demand
 - CST-1 \$4.68 per KW of on-peak demand
 - IS-2, IST-2 \$10.88 per KW of load factor adjusted demand
 - CS-2, CST-2 \$8.16 per KW of load factor adjusted demand
 - CS-3, CST-3 \$8.16 per KW of fixed curtailable demand
 - SS-2 the greater of:

\$1.088 per KW times the Specified Standby Capacity, or the sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times \$0.518 per KW times the appropriate monthly factor.

SS-3 – the greater of:

\$0.816 per KW times the Specified Standby Capacity, or

the sum of the daily maximum 30 minute KW demand of actual standby use occurring during on-peak periods times \$0.389 per KW times the appropriate monthly factor.

3) Effective with the 1st billing cycle for January 2014, the capacity component of the GSLM-2 Monthly Credit Amount for the Standby Generation load management program shall be as follows:

> \$4.50 for fiscal year hours of <= 200 CRH (cumulative requested hours) \$5.40 for fiscal year hours of > 200 CRH (cumulative requested hours)

The capacity component of the Monthly Credit Amount is that defined to be multiplied by "C" in the GSLM-2 tariff where "C" initially represents the customer's standby generation capacity.

- 4) The Company will maintain the production capacity cost allocation method of 12CP and 13th AD unless such allocation is changed in the Company's next general rate case.
- 5) In addition to the provisions of this Revised and Restated Settlement Agreement allowing for or permitting base rate or charges, subject to Commission approval DEF may implement any new or revised tariff provision or rate schedule provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the term of the Revised and Restated Settlement Agreement unless the application of such new or revised tariff or rate schedule is optional to DEF's customers, is required in order to implement a legislative requirement or is required to implement Commission order/rulemaking, of statewide applicability.

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Exhibit 9 Page 1 of 1 Duke Energy Florida

Duke Energy Florida

Impact of Billing change to Levy - CCR rate for demand based rate classes to be on a kW basis rather than on current kWh basis

	<u>2013</u>		<u>201</u>	4 and Bey	ond_
	NCRC Impact		1_	ICRC Impa	<u>ct</u>
RS	0.345	cents/KWH	RS	0.345	cents/KWH
RS	3.45	\$ /1 000 KWH	RS	3.45	\$/1000 KWH
GS - 1	0.252	cents/KWH	GS - 1	0.252	cents/KWH
GS - 2	0.182	cents/KWH	GS - 2	0.182	cents/KWH
GSD	0.224	cents/KWH	GSD	0.84	\$/kW-Mo
CS	0.207	cents/KWH	CS	0.91	\$/kW-Mo
IS	0.180	cents/KWH	IS	0.69	\$/kW-Mo
LS	0.052	cents/KWH	LS	0.052	cents/KWH
Retail Avg	0.282	cents/KWH	Retail Avg	0.282	cents/KWH

All rates at Secondary - for primary and transmission use 99% and 98% adjustment

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Exhibit 10 Page 1 of 1 Duke Energy Florida

Template for Calculation of the CR3 Regulatory Asset Value and Revenue Requirement

Interference Interferenc	Line No.	Pre or Post Retirement Component Classification	categóry	Subject to Cap	Dry Cask Storage
2Electric Plant In Servicea\$			curogory		storuge
4Net plant balancefallout\$		Electric Plant In Service	а	\$	
5Write-Downb(\$295m)6Construction Work In Progress (CWIP)a\$	3	Less Accumulated Depreciation	b	\$	
6Construction Work In Progress (CWIP)7Steam Generator Replacement (SGR) Projecta\$	4	Net plant balance	fallout	\$	
7Steam Generator Replacement (SGR) Projecta\$8Delam Repair Projectb\$9License Amendment Request (LAR)b\$10Dry Cask Storaged\$11Fukushimad\$12Building Stabilization Projectc\$13Other - CWIPd\$14Nuclear Fuel Inventoriesa\$15Nuclear Materials and Supplies Inventoriesa\$16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$	5	Write-Down	b	(\$295m)	
8Delam Repair Projectb\$	6	Construction Work In Progress (CWIP)			
9 License Amendment Request (LAR) b \$	7	Steam Generator Replacement (SGR) Project	а	\$	
10Dry Cask Storaged\$	8	Delam Repair Project	b	\$	
11Fukushimad\$12Building Stabilization Projectc\$13Other - CWIPd\$14Nuclear Fuel Inventoriesa\$15Nuclear Materials and Supplies Inventoriesa\$16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$19Total CR3 Regulatory Assetfallout\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b\$.12%\$.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	9	License Amendment Request (LAR)	Ь	\$	
12Building Stabilization Projectc\$13Other - CWIPd\$14Nuclear Fuel Inventoriesa\$15Nuclear Materials and Supplies Inventoriesa\$16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$19Total CR3 Regulatory Assetfallout\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b\$.12%21Returnb\$22Amortization expense (20 years)b\$	10	Dry Cask Storage	d		\$
13Other - CWIPd\$14Nuclear Fuel Inventoriesa\$15Nuclear Materials and Supplies Inventoriesa\$16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$19Total CR3 Regulatory Assetfallout\$\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b\$.12%\$.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	11	Fukushima	d	\$	
14Nuclear Fuel Inventoriesa\$15Nuclear Materials and Supplies Inventoriesa\$16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$19Total CR3 Regulatory Assetfallout\$\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b8.12%8.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	12	Building Stabilization Project	с	.\$	
15Nuclear Materials and Supplies Inventoriesa\$16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$\$19Total CR3 Regulatory Assetfallout\$\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b8.12%8.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	13	Other - CWIP	d	\$	
16Deferred expensese\$17Cumulative AFUDC (6.00%)fallout\$\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$19Total CR3 Regulatory Assetfallout\$\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b8.12%8.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	14	Nuclear Fuel Inventories	а	\$	
17Cumulative AFUDC (6.00%)fallout\$18Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)b\$19Total CR3 Regulatory Assetfallout\$\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b8.12%8.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	15	Nuclear Materials and Supplies Inventories	а	\$	
18 Cost of Removal Reg Asset - CR3 Portion {Order No. PSC 10-0398-S-EI} b \$ 19 Total CR3 Regulatory Asset fallout \$ \$ 20 Rate of Return {Settlement Agreement Exhibit 3: 6% grossed up for taxes} b 8.12% 8.12% 21 Return b \$ \$ 22 Amortization expense (20 years) b \$ \$	16	Deferred expenses	е	\$	
19Total CR3 Regulatory Assetfallout\$20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b8.12%21Returnb\$22Amortization expense (20 years)b\$	17	Cumulative AFUDC (6.00%)	fallout	\$	\$
20Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)b8.12%8.12%21Returnb\$\$22Amortization expense (20 years)b\$\$	18	Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)	b	<u>\$</u>	
21 Return b \$\$ 22 Amortization expense (20 years) b \$\$	19	Total CR3 Regulatory Asset	fallout	\$	\$
22 Amortization expense (20 years) b <u>\$</u>	20	Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)	Ь	8.12%	8.12%
	21	Return	Ь	\$	\$
23 Total revenue requirement fallout <u>\$</u> \$	22	Amortization expense (20 years)	Ь	\$	\$
	23	Total revenue requirement	fallout	\$	\$

category

- a The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs except that the Intervenor Parties retain the right to challenge whether DEF took reasonable and prudent actions to minimize the future CR3 Regulatory Asset value after February 5, 2013 and to sell or otherwise salvage assets after February 5, 2013 that would otherwise be included in the CR3 Regulatory Asset.
- b The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs.
- c The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover costs incurred by the Company before February 5, 2013. The Intervenor Parties retain the right to challenge the prudence of any costs incurred after and applicable to the period after February 5, 2013 that are submitted for recovery by the Company.
- d The Intervenor Parties retain the right to challenge the prudence of any costs submitted for recovery by the Company.
- e The Intervenor Parties retain the right to verify that the Company has complied with paragraph 5b of the Revised and Restated Settlement Agreement.

Note: Line 17 of this exhibit reflects the impact of the calculation presented on line 5 of exhibit 11.

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Exhibit 11 Page 1 of 1 Duke Energy Florida

Example of Recovery of CR3 Regulatory Asset Carrying Cost

Line		2014	2015	2016
1	Fuel Rate Increase (\$/mWh)	\$1.00	\$1.00	\$1.50
2	Multiply by Retail mWhs	X	x	x
3	Equals Total Revenue Recovered in Rates	\$x	\$x	\$x
4	Less Income Tax Expense	-\$x	-\$x	-\$x
5	Equals Avoided Increase in CR3 Regulatory Asset	\$x	\$x	\$x

Note: The effects of the calculation on line 5 of this exhibit are incorporated in the final calculation of line 17 of exhibit 10.

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Illustrative Example of Impact to Fuel Rates of Paragraph 7.a of Revised & Restated Settlement Agreement Based on 2013 Projection Filing Data ⁽¹⁾

		cents/Kwh									
			2013		2014		2015		2016		2017
	Level and Evel Contents	(No	Change)	(\$1 Adj.)	(\$1 Adj.)	(\$1	50 Adj.)	(No	Change)
А	Levelized Fuel Factors: Fuel Factor at Secondary Metering {Sch E1-D, line 8}	\$	3.703	ć	3.703	Ś	3.703	Ś	3.703	ć	3.703
В	Fuel Adjustment per proposed Settlement	\$	- 3.705	ŝ	0.100	\$	0.100		0.150	,	5.705
B C ≍ A+B	Adjusted Fuel Factor at Secondary Metering	\$	3.703		3.803	\$	3.803		3.853	<u> </u>	3.703
$D = C^* 0.99$	Fuel Factor at Primary Metering	\$	3.666	+	3.765	ŝ	3.765		3.814	*	3.666
E = C*0.98	Fuel Factor at Transmission Metering	\$	3.629		3.727	\$	3.727	'	3.776		3.629
	Time of Use - On-Peak ⁽²⁾ .										
F =C*1.413	Distribution Secondary	\$	5.232	\$	5.374	\$	5.374	\$	5.444	\$	5.232
G = D*1.413	Distribution Primary	\$	5.180	\$	5.320	\$	5.320	\$	5.389	\$	5.180
H = E*1.413	Transmission	\$	5.128	\$	5.266	\$	5.266	\$	5.335	\$	5.128
	Time of Use - <u>Off</u> -Peak ⁽³⁾ :										
F =C*0.803	Distribution Secondary	\$	2.974	\$	3.054	\$	3.054	\$	3.094	\$	2.974
G = D*0.803	Distribution Primary	\$	2.944	\$	3.023	\$	3.023	\$	3.063	\$	2.944
H = E*0.803	Transmission	\$	2.914	\$	2.993	\$	2.993	\$	3.032	\$	2.914
	Time of Use - Lighting Service ⁽⁴⁾ .										
See ⁽⁴⁾ below	Lighting Service	\$	3.396	\$	3.488	\$	3.488	\$	3.533	\$	3.396
	Tiered Fuel Factors:										
	Fuel Factor - First Tier (0-1000 KWH)	\$	3.393	\$	3.493	\$	3.493	\$	3.543	\$	3.393
	Fuel Factor - Second Tier (Over 1000 KWH)	\$	4.393	\$	4.493	\$	4.493	\$	4.543	\$	4.393

Notes:

⁽¹⁾ This exhibit is presented for Informational purposes only. Data assumes 2014-2016 fuel costs and sales are the same as those used in the 2013 projection filing. Actual rates will be different based on projected costs and sales at that time. This is intended to show the impact of the fuel adjustment in paragraph 7.a to the various fuel rates. The adjustment will be made to the fuel factor at Secondary Metering. The other rates will be developed using the adjusted fuel factor at Secondary Metering in a manner consistent with the normal derivation of fuel factors.

⁽²⁾ Assumed On-Peak Multiplier is 1.413

(3) Assumed Off-Peak Multiplier is 0.803

⁽⁴⁾ Lighting Service calculation formula is consistent with schedule E1-E included in DEF's 2013 Projected Filing: Secondary Metering rate (line C) * (18.7% * On-Peak Multiplier 1.413 + 81.3% * Off-Peak Multiplier 0.803).

Exhibit 13 Page 1 of 5 Duke Energy Florida

<u>ISSUES LIST</u>¹ 100437-EI 6.10.13

Issue 1: What is the total amount of repair costs incurred between October 2, 2009 and March 14, 2011, and what portion of those costs, if any, has been recovered from ratepayers?

Issue 2: What refunds under the Settlement Agreement approved in Commission Order No. PSC-12-0104-FOF-EI has Duke Energy Florida (DEF) made and what refunds under that Agreement are still due and owing?

<u>Issue</u> <u>3</u>: Have the terms and conditions of the Settlement Agreement approved in Commission Order No. PSC-12-0104-FOF-EI, associated with Crystal River 3 (CR3) been followed?

<u>Issue 4</u>: What is the total amount of repair costs incurred from March 14, 2011, to date, and what portion of those costs, if any, has been recovered from ratepayers?

<u>Issue 5</u>: What was the total amount of Nuclear Electric Insurance Limited (NEIL) insurance coverage available to DEF related to the CR 3 outage?

Issue 6: How much did DEF claim was due and owing from NEIL?

Issue 7: What monies, if any, were received for each insurance claim filed with NEIL for each accident that occurred at the CR 3 nuclear plant since 2009? (Formerly FIPUG Issue 3)

• DEF proposed the following modification: What monies, if any, were received for each insurance claim filed with NEIL for the CR3 nuclear power plant since 2009.

Issue 8: Was interest applied to the NEIL settlement sums, and if so, at what rate?

Issue 9: Did DEF make an accidental outage insurance claim with NEIL associated with the second delamination event that occurred on or about March 14, 2011? If not, why not?

Issue 10: Did DEF ever file a "Proof of Loss" under the NEIL policies, and if so, in what amounts by policy category?

Issue 11: What is the current booked amount of the deferred regulatory asset associated with the retirement of the CR 3 nuclear unit, based on Section 11(b) of the Settlement Agreement approved in Commission Order No. PSC-12-0104-FOF-EI?

Issue 12: What are the replacement fuel costs from December 31, 2012 to February 5, 2013?

¹ Please note that issues previously identified as factual in nature have been moved to the beginning of the Issues List. The substantive issues follow in sequential order immediately thereafter.

Issue 13: What was the replacement cost estimate to repair CR3 at the time the Duke Energy Corporation's Board of Directors made its decision to retire CR3?

<u>Issue 14</u>: How much did DEF receive from NEIL to repair CR3 at the time the Duke Energy Corporation's Board of Directors made its decision to retire CR3?

Issue 15: How much did DEF receive from NEIL attributable to Accidental Outage or replacement power at the time the Duke Energy Corporation's Board of Directors made its decision to retire CR3?

<u>Issue 16</u>: How many accidents significantly affecting operations at the CR3 nuclear plant occurred since 2009? (FIPUG Issue 1)

• Objection raised by DEF.

Issue 17: When did each accident occur, what were the facts and circumstances involved with each accident, and was an insurance claim filed with NEIL for each accident? (FIPUG Issue 2)

- Objection raised by DEF.
- FIPUG has offered to replace Issue Nos. 16 and 17 above, with the following: modification to former Issue 4(b): Did DEF preserve the issue whether Was the second delamination event that occurred on or about March 14, 2011 was a separate and distinct event an accident for which NEIL replacement insurance coverage was in place?

Issue 18: If the Commission awards a rate reduction to Duke Energy's customers at the conclusion of this case, should ratepayers receive interest on the monies the Commission determines Duke Energy owes its customers, and if so, at what interest rate? (FIPUG Issue 4)

- At the 5/20/13 Issue Identification Meeting this issue was raised by FIPUG and will remain subject to discussion/revision among FIPUG and DEF.
- DEF believes this issue is not necessary because they do not dispute that the Commission in the past has included interest at the commercial paper rate on the amount of additional costs that the Commission actually determined resulted from a utility's acts found to be imprudent.

Issue 19: Did Progress Energy Florida (now Duke Energy, the regulated Florida utility company) decide to accept the NEIL settlement offer, and if so, did it exercise independent judgment in making this decision? (FIPUG Issue 5)

• At the 5/20/13 Issue Identification Meeting this issue was raised by FIPUG and identified for further discussion /revision among FIPUG and DEF. DEF suggest that this proposed issue aside until all the parties understand the facts surrounding the decision made by the Company to accept the NEIL settlement offer.

Issue 20: Did DEF maintain adequate and appropriate accidental outage and property damage insurance coverage for CR3?

<u>Issue 21</u>: Did DEF maintain a prudent arm's length relationship with NEIL in all dealings, including negotiation of the scope of policy coverage, endorsement provisions and other amendatory and/or change activities related to the terms and conditions of the NEIL Policies?

<u>Issue 22</u>: Was DEF's decision-making prudent with respect to the pursuit (or lack thereof) of claims, if any, against any vendor on the SGR Project or CR3 delamination repair project?

Issue 23: Did Duke Energy have a conflict of interest when negotiating with NEIL for insurance proceeds? If so, was that conflict of interest made known to the Commission and intervening parties? (formerly DEF's Issue 9; replacing OPC's Issue 13)

Issue 24: What is the salvage value, if any, for any CR3-related asset(s)?

Issue 25: Were DEF's actions taken during the period from the SGR project inception through the Implementation Date in connection with the SGR project or the repair activities associated with the delaminations from the first delamination in the containment structure at CR 3 in October, 2009 until the "Implementation Date" of DEF's Stipulation and Settlement Agreement in FPSC Docket 120022-EI (February 22, 2012) reasonable and prudent? If not, what action, if any, should the Commission take?

Staff offers the following issue to replace Issue No. 25: Was DEF's decision to pursue the repair of the CR3 nuclear unit immediately after the October 2, 2009 delamination event the most cost-effective alternative available, given the information available at that time?

• Objection raised by DEF.

Issue 26: Were DEF's actions taken during the period from the SGR project inception through the Implementation Date in connection with the SGR project or the repair activities associated with the delaminations from the "Implementation Date" of DEF's Stipulation and Settlement Agreement in FPSC Docket 120022-EI (February 22, 2012) until the date DEF made the decision to retire CR3 (January 31, 2013) reasonable and prudent? If not, what action, if any, should the Commission take?

Staff offers the following issue to replace Issue No. 26: Did DEF's repair activities performed on the CR3 nuclear unit between the initial October 2, 2009 delamination event and the discovery of the second delamination on March 14, 2011 reduce or eliminate any of DEF's coverage under its NEIL insurance policies?

• Objection raised by DEF.

Issue 27: Was DEF's decision to retire CR3 reasonable and prudent? If not, what action, if any, should the Commission take?

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Issue 28: Did DEF prudently pursue its CR3-related insurance claims with NEIL?

• (DEF's former Issue 3, replacing former Issue 4(a))

Issue 29: Did DEF preserve the issue whether the second delamination event that occurred on or about March 14, 2011 was a separate and distinct event for which NEIL replacement insurance coverage was in place?

- Proposed FIPUG Modification to Former Issue 4(b): Did DEF preserve the issue whether Was the second delamination event that occurred on or about March 14, 2011 was a separate and distinct event an accident for which NEIL replacement insurance coverage was in place?
- Proposed OPC Modification to Former Issue 4(b): Did DEF preserve <u>all of its rights</u> relative to the issue (for purposes of pursuing its CR3-related insurance claims with <u>NEIL</u>) whether the second delamination event that occurred on or about March 14, 2011 was a separate and distinct event for which NEIL replacement insurance coverage was in place?

• Staff believes that Issue 29 may be dropped as it is subsumed within Issue Nos. 28 and 30.

Issue 30: Was Duke's decision to settle DEF's claims with NEIL regarding the CR3 outage on the terms set forth in the Settlement agreement between DEF and NEIL reasonable and prudent? If not, what action, if any, should the Commission take?

- Staff's proposed revision to former Issue 4: Was <u>DEF's</u> decision to settle<u>it's</u> claims with NEIL regarding the CR3 outage on the terms set forth in the Settlement agreement between DEF and NEIL reasonable and prudent? If not, what action, if any, should the Commission take?
- FIPUG's proposed revision to former Issue 4: Was <u>Duke Energy Corporation's</u> decision to settle PEF's claims with Nuclear Electric Insurance Limited regarding the CR3 outage on the terms set forth in the Settlement agreement between DEF and NEIL reasonable and prudent? If not, what action, if any, should the Commission take?
- PCS's proposed revision to former Issue 4: <u>Did DEF reasonably address all insurance</u> questions associated with the second delamination event that occurred on or about March 14, 2011, including whether it was a separate and distinct event for which NEIL replacement insurance coverage was in place?

Issue 31: Was it prudent for DEF not to submit to binding arbitration with NEIL?

Issue 32: What is the amount of payments that DEF received from NEIL?

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Issue 33: What action, if any, should the Commission take as a result of the DEF decision to retire the CR3 unit with respect to the Balance of Plant Uprate of CR3 associated with the December 7, 2009 base rate tariff filing by DEF?

Issue 34: What are the appropriate components or types of cost of the CR3 Asset for purposes of establishing customer rates after December 31, 2016?

Issue 35: What are the appropriate amounts of the individual components of the CR3 Asset for purposes of establishing customer rates after December 31, 2016?

Issue 36: What criteria, methodologies or procedures, if any, should the Commission establish for determining the components and amounts of the CR3 Asset for purposes of establishing customer rates after December 31, 2016?

Issue 37: What monitoring or auditing measures, if any, should the Commission establish or undertake in order to determine the CR3 Asset for purposes of establishing customer rates after December 31, 2016?

Issue 38: Have the NEIL insurance proceeds been allocated consistent with the Settlement Agreement approved in Commission Order No. PSC-12-0104-FOF-EI?

Issues Previously Identified by the Parties as Possible DROPPED Issues:

Issue _____: Is PEF/Duke obligated to refund any additional replacement fuel costs pursuant to Section 9 of the Settlement Agreement approved in Commission Order No. PSC-12-0104-FOF-EI? If so, what is the amount to be refunded and through which clause(s) should the amount be refunded, and when?

• Staff believes that this issue should be dropped as it may be subsumed under existing Issue Nos. 26 and 38 above.

Issue _____: Were DEF's actions with respect to, and course of action toward, NEIL, reasonable and prudent with respect to the events related to the CR3 Outage and DEF's claims for payment under the NEIL Policies?

• The parties agreed to drop this issue as it may be argued under Issue Nos. 28, 29, and 30.

Docket No. 150009-EI; Docket 150001-EI DUKE ENERGY FLORIDA Nuclear Cost Recovery Clause (NCRC)Petition - Attachment A 2013 Detail - Calculation of the Revenue Requirem सिक्कge 180 of 197 January 2013 through December 2013

EXHIBIT 14

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				January 2	2013 through Dec	ember 2013	-								
Line	Description	Beginning of Period Amount	Actual January 13	Actual February 13	Estimated March 13	Estimated April 13	Estimated May 13	Estimated June 13	Estimated July 13	Estimated August 13	Estimated September 13	Estimated October 13	Estimated November 13	Estimated December 13	Period Total
1	Construction Additions:														
-	a License Application & Permitting	29,886,920	\$369,604	\$35,261	\$9,161	\$125,000	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$539,026
	b Project Management	43,672,300	160,177	156,905	97,603	10,633	9,310	0	o	0	o	0	0	0	\$434,628
	c On-Site Construction Facilities	1,441,680	4,926	12,986	11,911	0	0	0	0	0	0	0	0	0	\$29,823
	d Power Block Engineering, Procurement, etc.	279,706,493	987,107	1,461,060	164,055	1,795,397	8,500,965	36,973	32,973	32,973	20,340	20,340	20,340	20,340	\$13,092,863
	e Non-Power Block Engineering, Procurement, etc. f Total	<u> </u>	(5,885) 1,515,929	916 1,667,128	<u>5,893</u> 288,623	0 1,931,030	36,832 8,547,107	0 36,973	0 32,973	0 32,973	0 20,340	20,340	20,340	20,340	\$37,756 \$14,134,096
		303,014,001	1,515,525	1,007,120	200,025	1,551,050	0,547,107	50,575	32,373	52,975	20,340	20,340	20,340	20,540	\$14,134,050
2	Adjustments														
	a Non-Cash Accruals	(370,130)	1,579,731	174,715	(259,761)	(2,963,843)	(7,432,636)	1,704,651	7,662,721	3,600	11,370	11,370	0	0	\$491,918
	b Joint Owner Credit	(28,792,221)	(125,084)	(136,953)	(23,815)	(402,016)	(705,248)	(3,051)	(2,721)	(2,721)	(1,678)	(1,678)	(1,678)	(1,678)	(\$1,408,321)
	c Other (a)	(28,549,393)	(62,748)	39,395	0	(477,513)	0	0	0	0	0	0	0	0	(\$500,866)
	d Adjusted System Generation Construction Cost Additions Retail Jurisdictional Factor : Generation 92.885:	305,303,116 %	2,907,827	1,744,286	5,047	(1,912,342)	409,223	1,738,573	7,692,973	33,852	30,031	30,031	18,662	18,662	\$12,716,827
	e Construction Cost: Plant Additions for the Period	283,580,800	2,700,935	1,620,181	4,688	(1,776,279)	380,107	1,614,874	7,145,618	31,444	27,895	27,895	17,334	17,334	\$11,812,025
	Carrying Cost on Construction Balance														
3	Construction Cost: Plant Additions for the Period (Beg Balance: Line 2.e Above)	283,580,800	2,700,935	1,620,181	4,688	(1,776,279)	380,107	1,614,874	7,145,618	31,444	27,895	27,895	17,334	17,334	295,392,824
4	Transferred to Plant-in-Service (Beg Balance: Appendix A Line 23)	30,378,678	0	5,076	0	0	0	0	0	0	0	0	0	0	30,383,754
5	Amortization (Not used for 2013 Revenue Requirement Calculations)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Prior Period Carrying Charge Unrecovered Balance (b) Prior Period Carrying Charge Recovered (b)	11,624,453 9,372,769	10,843,389 781,064	10,062,325 781,064	9,281,260 781,064	8,500,196 781,064	7,719,132 781,064	6,938,068 781,064	6,157,004 781,064	5,375,940	4,594,876	3,813,812	3,032,748	2,251,683	2,251,683
8	Prior Period Under/(Over) Recovery (Prior Month)	3,372,703	781,004	244,075	(326,485)	(324,782)	(337,153)	(348,067)	(344,985)	781,064 (313,771)	781,064 (288,877)	781,064 (293,344)	781,064 (297,862)	781,064 (302,463)	
9	Net Investment	\$264,826,574	\$266,746,446	\$267,824,561		\$263,839,575	\$263,101,465	\$263,587,208	\$269,606,777	\$268,543,385	\$267,501,339	\$266,454,825	\$265,393,233	\$264,327,040	\$264,019,895
10	Average Net Investment		\$265,786,510	\$267,407,541	\$267,109,888	\$265,118,246	\$263,301,943	\$263,170,303	\$266,424,500	\$268,918,195	\$267,877,923	\$266,831,410	\$265,775,098	\$264,708,905	
11	Return on Average Net Investment (January 2013 Rate Only)	(New Rates)													
11	a Equity Component 0.00546		1,452,257	1,053,586	1,052,413	1,044,566	1,037,410	1,036,891	1,049,713	1,059,538	1,055,439	1,051,316	1,047,154	1,042,953	12,983,236
	b Equity Component Grossed Up For Taxes 1.62800		2,364,277	1,715,240	1,713,330	1,700,555	1,688,905	1,688,060	1,708,934	1,724,930	1,718,256	1,711,544	1,704,768	1,697,929	12,505,250
	c Debt Component 0.00163	0.00189	432,169	506,470	505,906	502,134	498,694	498,445	504,608	509,331	507,361	505,379	503,378	501,359	5,975,234
	d Total Return		2,796,446	2,221,710	2,219,236	2,202,689	2,187,599	2,186,505	2,213,542	2,234,261	2,225,617	2,216,923	2,208,146	2,199,288	27,111,962
12	Projected Carrying Cost Plant for the Period (Order No. PSC 12-0650-FOF-EI)		\$2,552,371	\$2,548,195	\$2,544,018	\$2,539,842	\$2,535,666	\$2,531,490	\$2,527,314	\$2,523,138	\$2,518,961	\$2,514,785	\$2,510,609	\$2,506,433	\$30,352,822
13	Over/Under Recovery For the Period		244,075	(326,485)	(324,782)	(337,153)	(348,067)	(344,985)	(313,771)	(288,877)	(293,344)	(297,862)	(302,463)	(307,145)	(3,240,858)
14	0&M														
	a Accounting		9,291	9,133	6,765	9,737	9,737	9,737	9,737	9,737	9,737	9,737	9,737	9,737	\$112,821
	b Corporate Planning		6,152	9,776	14,266	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	\$191,563
	c Legal		(10,091)	13,080	22,201	22,201	22,201	22,201	22,201	22,201	22,201	22,201	22,201	22,201	\$225,000
	d Joint Owner Credit	-	(440)	(2,629)	(3,553)	(4,099)	(4,099)	(4,099)	(4,099)	(4,099)	(4,099)	(4,099)	(4,099)	(4,099)	(\$43,512)
	e Total O&M		4,912	29,359	39,679	45,769	45,769	45,769	45,769	45,769	45,769	45,769	45,769	45,769	\$485,872
15	Jurisdictional Factor (A&G)		0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	
16	Jurisdictional O&M Amount		4,579	27,369	36,989	42,666	42,666	42,666	42,666	42,666	42,666	42,666	42,666	42,666	452,935
17	Prior Period (Over)/Under Recovery (See Appendix A lines 7-9)	894,073	855,563	817,053	778,544	740,034	701,525	663,015	624,505	585,996	547,486	508,977	470,467	431,957	
18	Prior Period Costs Recovered (Appendix D)	462,115	38,510	38,510	38,510	38,510	38,510	38,510	38,510	38,510	38,510	38,510	38,510	38,510	38,510
19	Prior Month Period (Over)/Under Recovery		0	4,602	27,411	37,033	42,713	42,716	42,719	42,721	42,724	42,727	42,730	42,732	
20	Unamortized Balance	894,073	855,563	821,656	810,558	809,081	42,713 813,285	817,491	42,719 821,700	42,721 825,912	42,724 830,127	42,727 834,344	42,730 838,564	42,732 842,787	804,278
		,	,	,000		222,001	510,200	01,701	022,700	520,012	000,127	00-,0	000,004	0.2,707	507,270
21	Projected Construction Carrying Cost Plant Additions for the Period														
	a Balance Eligible for Interest		877,107	854,595	848,307	849,669	853,873	858,079	862,288	866,500	870,715	874,932	879,152	883,375	
	b Monthly Commercial Paper Rate c Interest Provision		0.01% S1	0.01% 68	0.01% 67	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	803
	d Total O&M Costs and Interest (Line 16 + Line 21c)	-	4,630	27,437	37,056	42,734	42,734	<u>68</u>	<u> </u>	<u>69</u> 42,735	69 42,735	69 42,736	70 42,736		<u> </u>
24	Recovered (Order No. PSC 12-0650-FOF-EI)	-	28	25	····			· · · · · · · · · · · · · · · · · · ·							
	Over/Under Recovery For the Period	_			23	20	18	16	13	11	8	6	4	1	173
25		-	4,602	27,411	37,033	42,713	42,716	42,719	42,721	42,724	42,727	42,730	42,732	42,735	453,565
26	Other - Adjustments (Prior Period Carrying Cost Refund on In-Service Assets)	(57,190)	(613)	(499)	(513)	(527)	(542)	(557)	(573)	(590)	(606)	(624)	(642)	(661)	(6,946)
27	Recovered (Order No. PSC 12-0650-FOF-EI)	-	(552)	(507)	(462)	(417)	(371)	(325)	(278)	(231)	(184)	(135)	(87)	(37)	(3,587)
28	Over/Under Recovery For the Period	_	(62)	9	(50)	(110)	(170)	(232)	(295)	(358)	(423)	(489)	(555)	(623)	(3,358)
29	Total Period Revenue Requirements for 2013	=	2,800,463	2,248,648	2,255,780	2,244,896	2,229,791	2,228,682	2,255,704	2,276,406	2,267,746	2,259,035	2,250,240	2,241,364	27,558,755

(a) Other line reflects cost of removal of previously existing assets. In the future it will also include any credits due to salvage or sale of equipment being recovered through NCRC. (b) Please see appendix A lines 1-6 for detail on line 6 above. Please see Appendix D for detail on line 7 above. Due to retirement DTA impacts go away in 2013. Rows 6 and 7 above include the prior period over(under) recoveries associated with the DTA carrying costs.

	Witness: Thomas G. Foster / Garry Miller
а	Docket No. 130009-EI
	Duke Energy Florida

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Exhibit 15 Page 1 of 17 Duke Energy Florida

Economic Development and Economic Re-Development Tariffs

Legislative & Clean Copy Formats

Tariff Sheet No.	Description
6.100	Index of Rate Schedules
6.380	ED-1 Economic Development Rider
6.385	EDR-1 Economic Re-Development Rider
7.000	Index of Standard Contract and Other Agreement Forms
7.500	Economic Development Rider Service Agreement
7.510	Economic Re-Development Rider Service Agreement



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 182 of 197 NO. VI TWENTY-SECOND REVISED SHEET NO. 6.100 CANCELS TWENTY-FIRST REVISED SHEET NO. 6.100

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ENERGY.				
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SC-1	Service Charges	6.110		
RS-1	Residential Service	6.120		
RSL-1	Residential - Load Management (Optional)	6.130		
RSL-2	Residential - Load Management - Winter Only - (Optional)	6.135		
RST-1	Residential Service (Optional Time of Use) (Closed to New Customers as of 02/10/10)	6.140		
GS-1	General Service - Non-Demand	6.150		
GST-1	General Service - Non-Demand (Optional Time of Use)	6.160		
GS-2	General Service - Non-Demand (100% Load Factor Usage)	6.165		
GSD-1	General Service - Demand	6.170		
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GSLM-1	General Service - Load Management (Optional)	6.220		
GSLM-2	General Service - Load Management - Standby Generation	6.225		
CS-1	Curtailable General Service (Closed to New Customers as of 04/16/96)	6.230		
CS-2	Curtailable General Service	6.235		
CS-3	Curtailable General Service Fixed Curtailable Demand	6.2390		
CST-1	Curtailable General Service (Optional Time of Use) (Closed to New Customers as of 04/16/96)	6.240		
CST-2	Curtailable General Service (Optional Time of Use)	6.245		
CST-3	Curtailable General Service (Optional Time of Use) Fixed Curtailable Demand	6.2490		
IS-1	Interruptible General Service (Closed to New Customers as of 04/16/96)	6.250		
IS-2	Interruptible General Service	6.255		
IST-1	Interruptible General Service (Optional Time of Use) (Closed to New Customers as of 04/16/96)	6.260		
IST-2	Interruptible General Service (Optional Time of Use)	6.265		
LS-1	Lighting Service	6.280		
SS-1	Firm Standby Service	6.310		
SS-2	Interruptible Standby Service	6.315		
SS-3	Curtailable Standby Service	6.320		
TS-1	Temporary Service	6.330		
RSS-1	Residential Seasonal Service Rider	6.350		
CISR-1	Commercial/Industrial Service Rider	6.360		
PPS-1	General Service – Premier Power Service Rider	6.370		
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Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 183 of 197 NO. VI **ORIGINAL SHEET NO. 6.380**

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Page 1 of 2

RATE SCHEDULE ED-1 ECONOMIC DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service. Application for service under this tariff is available to qualifying customers for 3 years after its original issue date.

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

- The minimum qualifying new load must be at least 500 kW with a minimum load factor of 50% at a single point of delivery. The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic b) development policy.
- The new or expanding business must also meet at least one of the following two requirements at the project location: 1) The addition of 25 net new full time equivalent (FTE) jobs in the Company's Florida service area; or 2) Capital investment of \$500,000 or greater and a net increase in FTE jobs in the Company's Florida service area. C)
- Customer must provide written documentation attesting that the availability of this rider is a significant factor in the d) Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the EDR-1 tariff of 300 megawatts or a total of 25 customers served under both this tariff and the EDR-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the EDR-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Development Rate Reduction Factor.

Economic Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charges
Year 1	50%
Year 2	40%
Year 3	30%
Year 4	20%
Year 5	10%

(Continued on Page No. 2)



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 184 of 197 SECTION NO. VI ORIGINAL SHEET NO. 6.381

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Page 2 of 2

RATE SCHEDULE ED-1 ECONOMIC DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM (Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest.



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 185 of 197 SECTION NO. VI **ORIGINAL SHEET NO. 6.385**

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Page 1 of 2

RATE SCHEDULE EDR-1 ECONOMIC RE-DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service. Application for service under this tariff is available to qualifying customers for 3 years after its original issue date

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Re-Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Re-Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

- New load must be at an existing Company premise location previously served by the Company which has been unoccupied or otherwise essentially dormant (evidenced by minimal to no electric usage) for a minimum period of 90 days. a)
- Customer must not have a relationship with the previous occupant of the unoccupied premise location. b)
- The minimum qualifying new load must be at least 350 kW with a minimum load factor of 50% at a single point of delivery. C) d) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
- The new or expanding business must also meet at least one of the following two requirements at the project location: e)
- The addition of 15 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
 Capital investment of \$200,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
 Customer must provide written documentation attesting that the availability of this rider is a significant factor in the f) Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the ED-1 tariff of 300 megawatts or a total of 25 customers served under both this tariff and the ED-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the ED-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Re-Development Rate Reduction Factor.

Economic Re-Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charge	Reduction of the Non-Fuel BA-1 Tariff Charges
Year 1	50%	50%
Year 2	35%	35%
Year 3	15%	15%
Year 4	0%	0%
Year 5	0%	0%

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Director, Rates & Regulatory Strategy - FL EFFECTIVE:



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 186 of 197 SECTION NO. VI ORIGINAL SHEET NO. 6.386

Exhibit 15 Page 6 of 17 Duke Energy Florida

Page 2 of 2

RATE SCHEDULE EDR-1 ECONOMIC RE-DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM (Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest. Repayments will be appropriately treated and apportioned by the Company in direct proportion to the base rate or clause revenues as discounts were achieved and repaid.

Other Charges:

Customers requiring installation of additional new facilities at an existing premise location may be subject to contribution in aid to construction, construction advances or equipment rental charges as may be applicable in accordance with the Company's Rules and Regulations.



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 187 of 197 SECTION NO. VII

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SECTION NO. VII Duke Energy Florida FOURTEENTH REVISED SHEET NO. 7.000 CANCELS THIRTEENTH REVISED SHEET NO. 7.000

INDEX OF STANDARD CONTRACT AND OTHER AGREEMENT FORMS

FORM NO	DESCRIPTION	SHEET NO.
Form No. 1	Contract, Form No. 1 (after 11/21/98, applicable only to a Customer who requires this type form be executed for service under Rate Schedule LS-1, Lighting Service. Form No. LS-1HPS shall normally be used for application for service under LS-1).	7.010 - 7.011
Form No. 2	Contract Form No. 2 (applicable when service is provided under Company General Service Rate Schedules and special contract terms or investments in special facilities are required and furnished by the Company to provide service to the Customer).	7.020 - 7.021
IS-2 DISC	Interruptible General Service Rate Schedules IS-2 and IST-2 Risk Disclosure	7.025
CS-2 DISC	Curtailable General Service Rate Schedule CS-2 and CST-2 Risk Disclosure	7.027
Form No. 5	Contract, Form No. 5 (applicable when a contract is made between the Company and the Customer to cover advances by the Customer for construction).	7.030
DVLP DIST	Agreement for Electric Service Between Duke Energy Florida, Inc. (the "Utility") and (the "Applicant") (applicable when a developer requests the Company to install a distribution system for a new development).	7.050
PEFI LSA	Leave Service Active Agreement (applicable to Customers who wish service to be left active on rental units, regardless if they are occupied or not).	7.070 - 7.071
3RD PRT	Request for Third Party Notification (applicable to Customers who request the Company to notify another person that their bill is overdue).	7.090
LS-1	Lighting Service Contract.	7.110 - 7.113
PEFI TOU	Application for TOU Rate (applicable to Customers requesting time of use rates).	7.120
PEFI GSLM	Rate Schedule GSLM-1 Customer Agreement (applicable to Customers requesting General Service Load Management).	7.150
MSTR MTR	Standard Letter Agreement (applicable to master metered Customers indicating understanding of rules and regulations affecting resale of electricity).	7.160
EQP RNTL	Standard Letter Agreement (applicable to Customers who request additional facilities at their service location).	7.170
GUAR CNTR	Guarantee Contract (applicable when a third party guarantees payment for another individual's billing).	7.180
STRT LTS	Agreement to Purchase and Sell Street Lighting System and to Furnish and Receive Electric Service	7.190 - 7.192
RES DEP	Residential Deposit Release - Releases current customer's deposit to new customer who then assumes responsibility for all payments of account.	7.220 - 7.221
PWR PAY	Power Pay - Customers bill is automatically paid from their checking account.	7.230
CISR	Contract Service Arrangement for service under the Commercial/Industrial Service Rider.	7.250 - 7.253
PPS	Premier Power Service - Contract signed by the customer requesting backup service through the Premier Power Service rate schedule.	7.270 - 7.273
NMRG - Tier 1	Standard Interconnection Agreement for Tier 1 Customer Owned Renewable Generation	7.310 - 7.313
IC APP - Tier 1	Application for Interconnection for Tier 1 Customer Owned Renewable Generation	7.317-7.317
NMRG - Tier 2	Standard Interconnection Agreement for Tier 2 Customer Owned Renewable Generation	7.320 - 7.323
NMRG – Tier 3	Standard Interconnection Agreement for Tier 3 Customer Owned Renewable Generation	7.330 - 7.333
IC APP -Tier 2,3	Application for Interconnection for Tier 2 and 3 Customer Owned Renewable Generation	7.337-7.337
ECON DEV .	Economic Development Rider Service Agreement	7.500
ECON RE-DEV	Economic Re-Development Rider Service Agreement	7.510



Exhibit 15 Page 8 of 17 Duke Energy Florida

			Page 1 of 1
	DUKE ENERGY FLORIDA, ECONOMIC DEVELOPMENT		
	Service Agreement		
For a Ne	w Establishment or an Existing Establishment with Expanding Lo	bad	
	CUSTOMER NAME		
	ADDRESS	TYPE OF BUSINESS	
The Cust	omer hereto agrees as follows:		
1.	To create full - time jobs or new capital investme and a net increase of full - time jobs.	ent of \$	-
2.	That the quantity of new or expanded load shall be% load factor.	KW of demand with a	
З.	The nature of this new or expanded load is		
4.	To initiate service under this rider on,, under this rider on, This s		
5.	In case of early termination by the Customer, or an early disco violation of the terms and conditions of this rider, the Custome Energy Florida, Inc. the cumulative discounts received to date	r shall be required to repay Duke	
6.	If a change in ownership occurs after the Customer contracts f successor Customer may be allowed to fulfill the balance of the continue the schedule of rate reductions.		
7.	All terms of Rate Schedule ED-1, Economic Development Ride incorporated by reference herein.	er, apply to this agreement and an	e
	g below, I hereby attest that the availability of this rider is a signifer expansion decision.	ficant factor in this Customer's	
Signed: _	Accepted by:		
	Customer	Duke Energy Florida, Inc.	
Title:	Title:		

Date:

Date:



	DUKE ENERGY FLORIDA, INC. ECONOMIC RE-DEVELOPMENT RIDER Service Agreement	Page 1 of 1
For new lo	ad established at existing Company premise location that has been vacant for at least 90 days	
	CUSTOMER NAME	
	ADDRESS TYPE OF BUSINESS	
The Custo	mer hereto agrees as follows:	
1.	To establish service at a currently vacant Company premise location and createfutime jobs or new capital investment of \$ and a net increase of full - tin jobs.	ill - ne
2.	That the quantity of new or expanded load shall be KW of demand with a % load factor.	
3.	The nature of this new or expanded load is	
4.	The Company premise location for the new or expanded load has been vacant for at least 90 day	/S.
5.	The Customer load will be served with existing facilities or the Customer may be subject to contribution in aid to construction, construction advances or equipment rental charges as may be applicable in accordance with the Company's Rules and Regulations.	
6.	To initiate service under this rider on,, and terminate service under this rider on, This shall constitute a period of 5 years.	
7.	In case of early termination by the Customer, or an early discontinuation by the Company for a violation of the terms and conditions of this rider, the Customer shall be required to repay Duke Energy Florida, Inc the cumulative discounts received to date under this rider plus interest.	
8.	If a change in ownership occurs after the Customer contracts for service under this rider, the successor Customer may be allowed to fulfill the balance of the contract under Rider EDR-1 and continue the schedule of rate reductions.	
9.	All terms of Rate Schedule EDR-1, Economic Re-Development Rider, apply to this agreement ar are incorporated by reference herein.	d
	below, I hereby attest that the availability of this rider is a significant factor in this Customer's expansion decision and Customer has no affiliation with the previous occupant of the premise.	
Signed:	Accepted by:	
	Customer Duke Energy Florida, Inc.	
Title:	Title:	
Date:	Date:	



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 190 of 197 SECTION NO. VI TWENTY-SECONDFIRST REVISED SHEET NO. 6.100 CANCELS TWENTY-FIRSTIETH REVISED SHEET NO.

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1	INDEX OF RATE SCHEDULES	Page 1 of 1
FPSC UNIFORM RATE SCHEDULE DESIGNATION		BEGINS ON SHEET NO.
BA-1	Billing Adjustments	6.105
SC-1	Service Charges	6.110
RS-1	Residential Service	6.120
RSL-1	Residential - Load Management (Optional)	6.130
RSL-2	Residential - Load Management - Winter Only - (Optional)	6.135
RST-1	Residential Service (Optional Time of Use) (Closed to New Customers as of 02/10/10)	6.140
GS-1	General Service - Non-Demand	6.150
GST-1	General Service - Non-Demand (Optional Time of Use)	6.160
GS-2	General Service - Non-Demand (100% Load Factor Usage)	6.165
GSD-1	General Service - Demand	6.170
GSDT-1	General Service - Demand (Optional Time of Use)	6.180
GSLM-1	General Service - Load Management (Optional)	6.220
GSLM-2	General Service - Load Management - Standby Generation	6.225
CS-1	Curtailable General Service (Closed to New Customers as of 04/16/96)	6.230
CS-2	Curtailable General Service	6.235
CS-3	Curtailable General Service Fixed Curtailable Demand	6.2390
CST-1	Curtailable General Service (Optional Time of Use) (Closed to New Customers as of 04/16/96)	6.240
CST-2	Curtailable General Service (Optional Time of Use)	6.245
CST-3	Curtailable General Service (Optional Time of Use) Fixed Curtailable Demand	6.2490
IS-1	Interruptible General Service (Closed to New Customers as of 04/16/96)	6.250
IS-2	Interruptible General Service	6.255
IST-1	Interruptible General Service (Optional Time of Use) (Closed to New Customers as of 04/16/96)	6.260
IST-2	Interruptible General Service (Optional Time of Use)	6.265
LS-1	Lighting Service	6.280
SS-1	Firm Standby Service	6.310
SS-2	Interruptible Standby Service	6.315
SS-3	Curtailable Standby Service	6.320
TS-1	Temporary Service	6.330
RSS-1	Residential Seasonal Service Rider	6.350
CISR-1	Commercial/Industrial Service Rider	6.360
PPS-1	General Service – Premier Power Service Rider	6.370
ED-1	Economic Development Rider	6.380
EDR-1	Economic Re-Development Rider	6.385

ISSUED BY: Javier J. Portuondo, Director, Rates & Regulatory Strategy - FL



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 191 of 197 <u>SECTION NO. VI</u> ORIGINAL SHEET NO. 6.380

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Page 1 of 2

RATE SCHEDULE ED-1 ECONOMIC DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM

Availability:

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service. Application for service under this tariff is available to gualifying customers for 3 years after its original issue date.

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for renewal of a previously existing service. Customers must execute an Economic Development Service Agreement and such agreement must specify all qualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

- a) The minimum qualifying new load must be at least 500 kW with a minimum load factor of 50% at a single point of delivery.
 b) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
- c) <u>The new or expanding business must also meet at least one of the following two requirements at the project location:</u>

 The addition of 25 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
 2) Capital investment of \$500,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
- 2) <u>Capital investment of \$500,000 or greater and a net increase in FTE jobs in the Company's Florida service area.</u>
 d) <u>Customer must provide written documentation attesting that the availability of this rider is a significant factor in the Customer's location/expansion decision.</u>

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the EDR-1 tariff of 300 megawatts or a total of 25 customers served under both this tariff and the EDR-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the EDR-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Development Rate Reduction Factor.

Economic Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charges
Year 1	<u>50%</u>
<u>Year 2</u>	<u>40%</u>
<u>Year 3</u>	<u>30%</u>
<u>Year 4</u>	<u>20%</u>
Year 5	<u>10%</u>

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Director, Rates & Regulatory Strategy - FL EFFECTIVE:_



Page 2 of 2

RATE SCHEDULE ED-1 ECONOMIC DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM (Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the terms of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest.

Page 1 of 2

RATE SCHEDULE EDR-1 ECONOMIC RE-DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM

Availability:

🔍 DUKE

Available throughout the entire territory served by the Company. Customers desiring to take service under this tariff must make a written request for service. Application for service under this tariff is available to qualifying customers for 3 years after its original issue date.

Applicable:

To any customer taking firm service, other than residential, for light and power purposes who meet the Qualifying Criteria set forth in this tariff. This tariff provides for an Economic Re-Development Rate Reduction Factor as described herein for new load which is defined as load being established after the date of the original issue of this tariff sheet by a new business or the expansion of an existing business. This rider is not available for retention of existing load or for relocation of existing load within the Company's service territory. Relocating businesses that provide expansion of existing business may qualify for the expanded load only. This rider is not available for short-term, construction, temporary service, or renewal of a previously existing service. Customers must execute an Economic Re-Development Service Agreement and such agreement must specify all gualifying criteria customer expects to meet for this rider to be applicable.

Qualifying Criteria:

- New load must be at an existing Company premise location previously served by the Company which has been unoccupied a)
- h)
- The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic c) d)
- <u>development policy.</u>
 <u>The new or expanding business must also meet at least one of the following two requirements at the project location:</u>

 <u>The addition of 15 net new full time equivalent (FTE) jobs in the Company's Florida service area; or</u>
 <u>Capital investment of \$200,000 or greater and a net increase in FTE jobs in the Company's Florida service area.</u>

 e)
- Customer must provide written documentation attesting that the availability of this rider is a significant factor in the Ð Customer's location/expansion decision.

Limitation of Service:

Service under this tariff is limited to a total load served under both this tariff and the ED-1 tariff of 300 megawatts or a total of 25 customers served under both this tariff and the ED-1 tariff. Standby or resale service not permitted hereunder. Service under this tariff is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service." Service under this tariff may not be combined with service under the ED-1 tariff. Service under this tariff is available on a first come, first served basis.

Otherwise Applicable General Service Tariff:

Service under this rider shall be provided under any of the Company's currently available general service tariffs to be initially determined by mutual agreement of the Company and customer based on the usage characteristics provided by the customer for new load. All provisions, terms and conditions of the Otherwise Applicable General Service Tariff shall apply.

Rate Per Month:

All charges shall be those set forth in the Otherwise Applicable General Service Tariff adjusted by the Economic Re-Development Rate Reduction Factor.

Economic Re-Development Rate Reduction Factor:

The following rate reduction factors shall apply:

Year of Agreement	Reduction of Base Rate Demand and Energy Charge	Reduction of the Non-Fuel BA-1 Tariff Charges
Year 1	<u>50%</u>	<u>50%</u>
Year 2	35%	35%
Year 3	<u>15%</u>	<u>15%</u>
Year 4	<u>0%</u>	<u>0%</u>
Year 5	<u>0%</u>	<u>0%</u>

(Continued on Page No. 2)

ISSUED BY: Javier J. Portuondo, Director, Rates & Regulatory Strategy - FL EFFECTIVE:



Page 2 of 2

RATE SCHEDULE EDR-1 ECONOMIC RE-DEVELOPMENT RIDER EXPERIMENTAL PILOT PROGRAM (Continued from Page No. 1)

Term of Service:

Service under this rider shall be for a term of five (5) years from the commencement of service of new load. Service under this rider will terminate at the end of the 5 year period.

Penalty for Non-Compliance with Qualifying Criteria or Term of Service:

If at any time during the term of the rider agreement the customer violates the terms and conditions of the rider or agreement, the Company may discontinue the discount provided for under this rider, and bill the customer based on the Otherwise Applicable General Service Tariff. If the customer terminates service prior to the end of the agreement period, or fails to meet the qualifying criteria agreed to for the term of the agreement, this will constitute a violation of the terms and conditions of the rider and agreement.

Should service under this rider be discontinued by the Company or the customer for said violation the customer shall be required to repay to the Company the amount of the cumulative discounts received under this rider with interest. Repayments will be appropriately treated and apportioned by the Company in direct proportion to the base rate or clause revenues as discounts were achieved and repaid.

Other Charges:

Customers requiring installation of additional new facilities at an existing premise location may be subject to contribution in aid to construction, construction advances or equipment rental charges as may be applicable in accordance with the Company's Rules and Regulations.



Docket No. 150009-EI; Docket 150001-EI Petition - Attachment A Page 195 of 197 SECTION NO

Exhibit 15 Page 15 of 17

Page 195 of 197 SECTION NO. VII Duke Energy Florida <u>FOURTHIR</u>TEENTH REVISED SHEET NO. 7.000 CANCELS <u>THIRTEENTH</u> REVISED SHEET NO. 7.000

INDEX OF STANDARD CONTRACT AND OTHER AGREEMENT FORMS

FORM NO	DESCRIPTION	SHEET NO.
Form No. 1	Contract, Form No. 1 (after 11/21/98, applicable only to a Customer who requires this type form be executed for service under Rate Schedule LS-1, Lighting Service. Form No. LS-1HPS shall normally be used for application for service under LS-1).	7.010 - 7.011
Form No. 2	Contract Form No. 2 (applicable when service is provided under Company General Service Rate Schedules and special contract terms or investments in special facilities are required and furnished by the Company to provide service to the Customer).	7.020 - 7.021
IS-2 DISC	Interruptible General Service Rate Schedules IS-2 and IST-2 Risk Disclosure	7.025
CS-2 DISC	Curtailable General Service Rate Schedule CS-2 and CST-2 Risk Disclosure	7.027
Form No. 5	Contract, Form No. 5 (applicable when a contract is made between the Company and the Customer to cover advances by the Customer for construction).	7.030
DVLP DIST	Agreement for Electric Service Between Duke Energy Florida, Inc. (the "Utility") and (the "Applicant") (applicable when a developer requests the Company to install a distribution system for a new development).	7.050
PEFI LSA	Leave Service Active Agreement (applicable to Customers who wish service to be left active on rental units, regardless if they are occupied or not).	7.070 - 7.071
3RD PRT	Request for Third Party Notification (applicable to Customers who request the Company to notify another person that their bill is overdue).	7.090
LS-1	Lighting Service Contract.	7.110 - 7.113
PEFI TOU	Application for TOU Rate (applicable to Customers requesting time of use rates).	7.120
PEFI GSLM	Rate Schedule GSLM-1 Customer Agreement (applicable to Customers requesting General Service Load Management).	7.150
MSTR MTR	Standard Letter Agreement (applicable to master metered Customers indicating understanding of rules and regulations affecting resale of electricity).	7.160
EQP RNTL	Standard Letter Agreement (applicable to Customers who request additional facilities at their service location).	7.170
GUAR CNTR	Guarantee Contract (applicable when a third party guarantees payment for another individual's billing).	7.180
STRT LTS	Agreement to Purchase and Sell Street Lighting System and to Furnish and Receive Electric Service	7.190 - 7.192
RES DEP	Residential Deposit Release - Releases current customer's deposit to new customer who then assumes responsibility for all payments of account.	7.220 - 7.221
PWR PAY	Power Pay - Customers bill is automatically paid from their checking account.	7.230
CISR	Contract Service Arrangement for service under the Commercial/Industrial Service Rider.	7.250 - 7.253
PPS	Premier Power Service - Contract signed by the customer requesting backup service through the Premier Power Service rate schedule.	7.270 - 7.273
NMRG - Tier 1	Standard Interconnection Agreement for Tier 1 Customer Owned Renewable Generation	7.310 - 7.313
IC APP –Tier 1	Application for Interconnection for Tier 1 Customer Owned Renewable Generation	7.317-7.317
NMRG - Tier 2	Standard Interconnection Agreement for Tier 2 Customer Owned Renewable Generation	7.320 - 7.323
NMRG - Tier 3	Standard Interconnection Agreement for Tier 3 Customer Owned Renewable Generation	7.330 - 7.333
IC APP – Tier 2,3	Application for Interconnection for Tier 2 and 3 Customer Owned Renewable Generation	7.337-7.337
ECON DEV	Economic Development Rider Service Agreement	7.500
ECON RE-DEV	Economic Re-Development Rider Service Agreement	7.510



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		Page 1 of 1
	DUKE ENERGY FLORIDA, INC. ECONOMIC DEVELOPMENT RIDER	
	Service Agreement	
For a Nev	v Establishment or an Existing Establishment with Expanding Load	
	CUSTOMER NAME	
		-
- <u></u> .	ADDRESS TYPE OF BUSINESS	
The Custo	omer hereto agrees as follows:	
1.	To create full - time jobs or new capital investment of \$	-
	and a net increase of full - time jobs.	
2.	That the quantity of new or expanded load shall be KW of demand with a % load factor.	
3.	The nature of this new or expanded load is	
4.	To initiate service under this rider on , and terminate service under this rider on . This shall constitute a period of 5 years	
5.	In case of early termination by the Customer, or an early discontinuation by the Company for a violation of the terms and conditions of this rider, the Customer shall be required to repay Duke Energy Florida, Inc. the cumulative discounts received to date under this rider plus interest.	
6.	If a change in ownership occurs after the Customer contracts for service under this rider, the successor Customer may be allowed to fulfill the balance of the contract under rider ED-1 and continue the schedule of rate reductions.	
7.	All terms of Rate Schedule ED-1, Economic Development Rider, apply to this agreement and ar incorporated by reference herein.	<u>e</u>
	a below, I hereby attest that the availability of this rider is a significant factor in this Customer's expansion decision.	
Signed:	Accepted by: Customer Duke Energy Florida, Inc.	
Title:	Title:	
Date:	Date:	

ISSUED BY: EFFECTIVE: Javier J. Portuondo, Director, Rates & Regulatory Strategy - FL



		Page 1 of 1
	DUKE ENERGY FLORIDA, INC. ECONOMIC RE-DEVELOPMENT RIDER	
	Service Agreement	
For new	load established at existing Company premise location that has been vacant for at least 90 days	
<u>1 01 11017</u>		
	CUSTOMER NAME	
		-
<u></u>	ADDRESS TYPE OF BUSINESS	
The Cus	tomer hereto agrees as follows:	
1.	To establish service at a currently vacant Company premise location and create time jobs or new capital investment of \$ and a net increase of full - ti jobs.	full <u>-</u> me
2.	That the quantity of new or expanded load shall be KW of demand with a % load factor. %	
3.	The nature of this new or expanded load is	1
4.	The Company premise location for the new or expanded load has been vacant for at least 90 da	ays.
5.	The Customer load will be served with existing facilities or the Customer may be subject to contribution in aid to construction, construction advances or equipment rental charges as may be applicable in accordance with the Company's Rules and Regulations.	e
6.	To initiate service under this rider on, and terminate service, and terminate service, under this rider on This shall constitute a period of 5 years	<u>-</u>
7.	In case of early termination by the Customer, or an early discontinuation by the Company for a violation of the terms and conditions of this rider, the Customer shall be required to repay Duke Energy Florida, Inc. the cumulative discounts received to date under this rider plus interest.	
8.	If a change in ownership occurs after the Customer contracts for service under this rider, the successor Customer may be allowed to fulfill the balance of the contract under Rider EDR-1 and continue the schedule of rate reductions.	Ē
9.	All terms of Rate Schedule EDR-1, Economic Re-Development Rider, apply to this agreement a are incorporated by reference herein.	Ind
By signin	g below, I hereby attest that the availability of this rider is a significant factor in this Customer's	
location /	expansion decision and Customer has no affiliation with the previous occupant of the premise.	
Signed:	Accepted by:	
	Customer Duke Energy Florida, Inc.	
<u>Title:</u>	Title:	
Date	Data	
Date:	Date:	



RATE SCHEDULE BA-1 BILLING ADJUSTMENTS

Page 1 of 2

Applicable:

To the Rate Per Month provision in each of the Company's filed rate schedules which reference the billing adjustments set forth below.

COST RECOVERY FACTORS									
	Fue	ECO	CR ⁽²⁾	CC	ECRC ⁽⁴⁾				
Rate Schedule/Metering Level	Levelized								
	¢/ kWh	¢/ kWh	¢/ kWh	¢/ kWh	\$/ kW	¢/ kWh	\$/ kW	¢/ kWh	
RS-1, RST-1, RSL-1, RSL-2,		6.189	3.849	0.270	-	1.274	-	0.138	
RSS-1 (Sec.) < 1000	4.323								
> 1000	5.323								
GS-1, GST-1	5.525								
Secondary	4.605	6.198	3.854	0.231	_	1.030	_	0.133	
Primary	4.559	6.136	3.816	0.231	-	1.030	-	0.133	
Transmission	4.513	6.074	3.777	0.225	_	1.020	_	0.132	
GS-2 (Sec.)	4.605	-	-	0.179	-	0.701	-	0.130	
GS-2 (Sec.) GSD-1, GSDT-1, SS-1*	4.000			0.179		0.701	-	0.120	
Secondary	4.647	6.255	3.890		0.79	_	3.35	0.129	
Primary	4.601	6.193	3.890	-	0.79	-	3.35	0.129	
Transmission	4.554	6.130	3.812	-	0.78	-	3.28	0.128	
CS-1, CST-1, CS-2, CST-2,	4.004	0.150	5.012	-	0.11	-	5.20	0.120	
CS-3, CST-3, SS-3*									
Secondary	4.647	6.255	3.890	_	0.60	_	2.22	0.123	
Primary	4.601	6.193	3.851	_	0.59	_	2.20	0.120	
Transmission	4.554	6.130	3.812	-	0.59	_	2.18	0.121	
IS-1, IST-1, IS-2, IST-2, SS- 2*									
Secondary	4.647	6.255	3.890	-	0.71	-	2.83	0.122	
Primary	4.601	6.193	3.851	-	0.70	-	2.80	0.121	
Transmission	4.554	6.130	3.812	-	0.70	-	2.77	0.120	
LS-1 (Sec.)	4.332	-	-	0.097	-	0.183	-	0.114	
*SS-1, SS-2, SS-3									
Monthly									
Secondary	-	-	-	-	0.078	-	0.328	-	
Primary	-	-	-	-	0.077	-	0.325	-	
Transmission	-	-	-	-	0.076	-	0.321	-	
Daily									
Secondary	-	-	-	-	0.037	-	0.156	-	
Primary	-	-	-	-	0.037	-	0.154	-	
Transmission	-	-	-	-	0.036	-	0.153	-	
GSLM-1, GSLM-2		See appropr	iate General S	Service rate	schedule				

(1) Fuel Cost Recovery Factor:

The Fuel Cost Recovery Factors applicable to the Fuel Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. These factors are designed to recover the costs of fuel and purchased power (other than capacity payments) incurred by the Company to provide electric service to its customers and are adjusted to reflect changes in these costs from one period to the next. Revisions to the Fuel Cost Recovery Factors within the described period may be determined in the event of a significant change in costs.

(2) Energy Conservation Cost Recovery Factor:

The Energy Conservation Cost Recovery (ECCR) Factor applicable to the Energy Charge under the Company's various rate schedules is normally determined annually by the Florida Public Service Commission for twelve-month periods beginning with the billing month of January. This factor is designed to recover the costs incurred by the Company under its approved Energy Conservation Programs and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the ECCR charge will be included in the base demand only.



Page 1 of 2

RATE SCHEDULE BA-1 BILLING ADJUSTMENTS

Applicable:

To the Rate Per Month provision in each of the Company's filed rate schedules which reference the billing adjustments set forth below.

		COST RI	ECOVERY FA					
	Fue	Cost Recove	e ry ⁽¹⁾	ECO	CR ⁽²⁾	CC	ECRC ⁽⁴	
Rate Schedule/Metering Level	Levelized	On-Peak	Off-Peak		\$/ kW	¢/ kWh	¢/ 1.34/	
RS-1, RST-1, RSL-1, RSL-2,	¢/ kWh	¢/ kWh	¢/ kWh	¢/ kWh	Φ/ Κνν	<u>¢/ KWII</u> <u>1.6191.</u>	\$/ kW	¢/ kWh
RSS-1 (Sec.)		6.189	3.849	0.270	-	<u>274</u>	-	0.138
< 1000	4.323							
> 1000	5.323							
GS-1, GST-1						1.282 1.		
Secondary	4.605	6.198	3.854	0.231	-	030	-	0.133
Primary	4.559	6.136	3.816	0.229	-	<u>1.2691.</u> <u>020</u>	-	0.132
Transmission	4.513	6.074	3.777	0.226	-	1.256 <u>1.</u> 009	-	0.130
GS-2 (Sec.)	4.605	-	-	0.179	-	0.883<u>0.</u> 701	-	0.125
GSD-1, GSDT-1, SS-1*								
Secondary	4.647	6.255	3.890	-	0.79	-	4 .19<u>3.3</u> 5	0.129
Primary	4.601	6.193	3.851	-	0.78	-	4 <u>.15</u> 3.3 2	0.128
Transmission	4.554	6.130	3.812	-	0.77	-	4.11 <u>3.2</u> <u>8</u>	0.126
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3*								
Secondary	4.647	6.255	3.890	-	0.60	-	3.13<u>2.2</u> 2	0.123
Primary	4.601	6.193	3.851	-	0.59	-	3.10<u>2.2</u> 0	0.122
Transmission	4.554	6.130	3.812	-	0.59	-	3.07<u>2.1</u> <u>8</u>	0.121
IS-1, IST-1, IS-2, IST-2, SS- 2*								
Secondary	4.647	6.255	3.890	-	0.71	-	3.52<u>2.8</u> <u>3</u>	0.122
Primary	4.601	6.193	3.851	-	0.70	-	3.48<u>2.8</u> 0	0.121
Transmission	4.554	6.130	3.812	-	0.70	-	3.45<u>2.7</u> <u>7</u>	0.120
LS-1 (Sec.)	4.332	-	-	0.097	-	<u>0.2350.</u> <u>183</u>	-	0.114
*SS-1, SS-2, SS-3 Monthly								
Secondary	-	-	-	-	0.078	-	<u>0.4100.</u> <u>328</u>	-
Primary	-	-	-	-	0.077	-	0. <u>406</u> 0. <u>325</u>	-
Transmission	-	-	-	-	0.076	-	0. <u>402</u> 0. <u>321</u>	-
Daily								
Secondary	-	-	-	-	0.037	-	0.195<u>0.</u> <u>156</u>	-
Primary	-	-	-	-	0.037	-	0.193<u>0.</u> 154	-
Transmission	-	-	-	-	0.036	-	<u>0.1910.</u> <u>153</u>	-
GSLM-1, GSLM-2	l	See appropr	riate General S	Service rate	schedule			

ISSUED BY: Javier J. Portuondo, Director Rates & Regulatory Strategy – FL



(1) Fuel Cost Recovery Factor:

The Fuel Cost Recovery Factors applicable to the Fuel Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. These factors are designed to recover the costs of fuel and purchased power (other than capacity payments) incurred by the Company to provide electric service to its customers and are adjusted to reflect changes in these costs from one period to the next. Revisions to the Fuel Cost Recovery Factors within the described period may be determined in the event of a significant change in costs.

(2) Energy Conservation Cost Recovery Factor:

The Energy Conservation Cost Recovery (ECCR) Factor applicable to the Energy Charge under the Company's various rate schedules is normally determined annually by the Florida Public Service Commission for twelve-month periods beginning with the billing month of January. This factor is designed to recover the costs incurred by the Company under its approved Energy Conservation Programs and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the ECCR charge will be included in the base demand only.

(Continued on Page No. 2)

Page 2 of 2

Duke Energy Florida Calculation of Capacity Cost Recovery Factors by Rate Class as approved in Order No. PSC-14-0701-FOF-EI For the Year 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Rate Class	12CP 1/13 AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	Capacity Production Demand Costs (\$)	Levy Production Demand Costs (\$)	CR3 Production Demand Costs (\$)	Capacity + Nuclear Production Demand Costs (\$)	Capacity CCR Factor (c/kWh)	Levy CCR Factor (c/kWh)	CR3 CCR Factor (c/kWh)	Capacity & Nuclear CCR
<u>Residential</u> RS-1, RST-1, RSL-1, RSL-2, RSS-1 Secondary	61.248%	19,390,958	\$208,177,843	\$66,898,805	\$38,739,021	\$313,815,669	1.074	0.345	0.200	(c/kWh)
General Service Non-Demand GS-1, GST-1 Secondary Primary Transmission		1,264,199 4,384 3,741					0.868 0.859 0.851	0.252 0.249 0.247	0.162 0.160 0.159	1.619
TOTAL GS	3.251%	1,272,323	11,049,420	3,205,956	2,056,144	16,311,521				1.269 1.256
General Service GS-2 Secondary	0.257%	147,708	872,374	268,829	162,337	1,303,539	0.591	0.182	0.110	
General Service Demand GSD-1, GSDT-1, SS-1 Secondary Primary Transmission TOTAL GSD	31.449%	12,149,615 2,311,921 5,729 14,467,265	106.891.929	31,830,333	19,891,111	158.613.373				0.883
Curtailable CS-1, CST-1, CS-2, CST-2, CS-3, CS Secondary Primary Transmission		- 35,746 -								
TOTAL CS Interruptible IS-1, IST-1, IS-2, IST-2, SS-2 Secondary Primary Transmission TOTAL IS	0.052%	35,746 89,325 1,621,463 324,813 2,035,601	178,297	86,524 3,511,060	33,179 2,256,121	297,999				
Lighting LS-1 Secondary	0.177%	389,030	600,567	202,296	111,757	914,620	0.154	0.052	0.029	
Total	100.000%	37,738,631	\$339,894,492	\$106,003,803	\$63,249,670 0.000%	\$509,147,965	0.901	0.202	0.100	0.200
Notes: () () () () () () () () () () ()	0.000% (9) (((10) C (11) C (12) C (13) C (14) C (14) C (15) C (16) C			-	1.351					

ATTACHMENT C (Page 2 of 4)

Duke Energy Florida Calculation of Capacity Cost Recovery Factors by Rate Class as approved in Order No. PSC-14-0701-FOF-EI For the Year 2015

	(1)	(2)	(3)	(4)	(5)	(6)	(11)	(12)	(13)	(14)	(15)	(16)
Rate Class	12CP 1/13 AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	Capacity Production Demand Costs (\$)	Levy Production Demand Costs (\$)	CR3 Production Demand Costs (\$)	Capacity + Nuclear Production Demand Costs (\$)	Billing KW Load Factor (%)	Projected Effective KW at Meter Level (kW)	Capacity CCR Factor (\$/kW-mo)	Levy CCR Factor (\$/kW-mo)	CR3 CCR Factor (\$/kW-mo)	Capacity & Nuclear CCR Factor (\$/kW-mo)
Residential RS-1, RST-1, RSL-1, RSL-2, RSS-1 Secondary	61.248%	19,390,958	\$208,177,843	\$66,898,805	\$38,739,021	\$313,815,669						
General Service Non-Demand GS-1, GST-1 Secondary	01.24070	1,264,199	φ200,177,040	φ00,000,000	φ00,700,021	ψο το, ο το, ο ο ο						
Primary Transmission		4,384 3,741										
TOTAL GS	3.251%	1,272,323	11,049,420	3,205,956	2,056,144	16,311,521						
General Service GS-2 Secondary	0.257%	147,708	872,374	268,829	162,337	1,303,539						
General Service Demand GSD-1, GSDT-1, SS-1												
Secondary Primary Transmission		12,149,615 2,311,921 5,729							2.82 2.79 2.76	0.84 0.83 0.82	0.52 0.51 0.51	4.19 4.15 4.11
TOTAL GSD	31.449%	14,467,265	106,891,929	31,830,333	19,891,111	158,613,373	52.30%	37,893,254		0.02	0.01	
<u>Curtailable</u> CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3	1											
Secondary Primary		- 35,746							1.88 1.86	0.91 0.90	0.35 0.35	3.13 3.10
Transmission TOTAL CS	0.052%	35,746	178,297	86,524	33,179	297,999	51.50%	95,082	1.84	0.89	0.34	3.07
Interruptible IS-1, IST-1, IS-2, IST-2, SS-2												
Secondary Primary		89,325 1,621,463							2.38 2.36	0.69 0.68	0.44 0.44	3.52 3.48
Transmission	3.567%	324,813 2,035,601	12,124,063	3,511,060	2,256,121	17,891,244	54.80%	5,088,493	2.33	0.68	0.43	3.45
- Lighting												
LS-1 Secondary	0.177%	389,030	600,567	202,296	111,757	914,620						
Total	100.000%	37,738,631	\$339,894,492	\$106,003,803 0.000%	\$63,249,670 0.000%	\$509,147,965						
	chedule E12-D, Col ed mWh sales at eff		for Jan-Dec		Column 5 / Column 2 olumn 7 + Column 8							

(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) (Column 8 x Column 2) x 10
(5) Column 1 x Total Recoverable Payments (Schedule E12-A)
(6) Column 3 + Column 4 + Column 5
(7) (Column 3 / Column 2) / 10
(8) (Column 4 / Column 2) / 10

 (10) Column 7 + Column 8 + Column 9
 (11) Class Billing kW Load Factor
 (12) Column 2 x 1000 / 8760 / Column 11 x 12
 (13) Column 3 / Column 12 (14) Column 4 / Column 12 (15) Column 5 / Column 12 (16) Column 6 / Column 12

	Capacity + Nuclear Cost		
	Cost	Effective kW	\$/kW
Total GSD, CS, IS	\$176,802,616	43,076,828	4.10
SS-1, 2, 3 - \$/kW-mo	Secondary	Primary	Trans
Monthly - \$4.10/kW * 10%	0.410	0.406	0.402
Daily - \$4.10/kW / 21	0.195	0.193	0.191

Duke Energy Florida Calculation of Capacity Cost Recovery Factors by Rate Class reflecting termination of Levy Fixed Rate For the remainder of the Year 2015 - effective with the first monthly billing cycle that occurs at least 10 days after Commission approval

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Rate Class	12CP 1/13 AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	Capacity Production Demand Costs (\$)	Levy Production Demand Costs (\$)	CR3 Production Demand Costs (\$)	Capacity + Nuclear Production Demand Costs (\$)	Capacity CCR Factor (c/kWh)	Levy CCR Factor (c/kWh)	CR3 CCR Factor (c/kWh)	Capacity & Nuclear CCR Factor (c/kWh)
Residential										
RS-1, RST-1, RSL-1, RSL-2, RSS- Secondary	1 61.248%	19,390,958	\$208,177,843	\$0	\$38,739,021	\$246,916,864	1.074	0.000	0.200	1.274
<u>General Service Non-Demand</u> GS-1, GST-1										
Secondary Primary Transmission		1,264,199 4,384 3,741					0.868 0.859 0.851	0.000 0.000 0.000	0.162 0.160 0.159	1.030 1.020 1.009
TOTAL GS	3.251%	1,272,323	11,049,420	0	2,056,144	13,105,565				
General Service GS-2 Secondary	0.257%	147,708	872,374	0	162,337	1,034,711	0.591	0.000	0.110	0.701
General Service Demand GSD-1, GSDT-1, SS-1										
Secondary Primary Transmission		12,149,615 2,311,921 5,729								
TOTAL GSD	31.449%	14,467,265	106,891,929	0	19,891,111	126,783,040				
Curtailable CS-1, CST-1, CS-2, CST-2, CS-3, (Secondary	CST-3, SS-3	-								
Primary Transmission		35,746								
TOTAL CS	0.052%	35,746	178,297	0	33,179	211,475				
Interruptible IS-1, IST-1, IS-2, IST-2, SS-2 Secondary Primary Transmission		89,325 1,621,463 324,813								
TOTAL IS	3.567%	2,035,601	12,124,063	0	2,256,121	14,380,184				
<u>Lighting</u> L S-1 Secondary	0.177%	389,030	600,567	0	111,757	712,324	0.154	0.000	0.029	0.183
Total	100.000%	37,738,631	\$339,894,492	\$0	\$63,249,670	\$403,144,163	0.901	0.000	0.168	1.069
	100.000 /8	07,700,001	\$000,00 1 ,402	0.000%	0.000%	φ-00, 1++, 100	0.001	0.000	0.100	1.000
Notes:	 From Schedule E12-D, Colu Projected mWh sales at effic Column 1 x Total Recoveral (4) (Column 8 x Column 2) x 10 Column 1 x Total Recoveral (6) Column 3 + Column 4 + Col (7) (Column 3 / Column 2) / 10 (8) (Column 4 / Column 2) / 10 	ective voltage leve ble Payments (Sch) ble Payments (Sch	edule E12-A)	(10) C (11) C (12) C (13) C (14) C (15) C	Column 5 / Column 2 column 7 + Column 8 class Billing kW Load column 2 x 1000 / 87 column 3 / Column 1 column 4 / Column 1 column 5 / Column 1	9 + Column 9 1 Factor 60 / Column 11 x 12 2 2 2				

Duke Energy Florida Calculation of Capacity Cost Recover For the remainder of the Year 2015				s after Commission	approval						AT	ACHMENT C (Page 4 of 4)
	(1)	(2)	(3)	(4)	(5)	(6)	(11)	(12)	(13)	(14)	(15)	(16)
Rate Class	12CP 1/13 AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	Capacity Production Demand Costs (\$)	Levy Production Demand Costs (\$)	CR3 Production Demand Costs (\$)	Capacity + Nuclear Production Demand Costs (\$)	Billing KW Load Factor (%)	Projected Effective KW at Meter Level (kW)	Capacity CCR Factor (\$/kW-mo)	Levy CCR Factor (\$/kW-mo)	CR3 CCR Factor (\$/kW-mo)	Capacity & Nuclear CCR Factor (\$/kW-mo)
Residential RS-1, RST-1, RSL-1, RSL-2, RSS- Secondary	1 61.248%	19,390,958	\$208,177,843	\$0	\$38,739,021	\$246,916,864						
General Service Non-Demand GS-1, GST-1 Secondary Primary Transmission		1,264,199 4,384 3,741										
TOTAL GS	3.251%	1,272,323	11,049,420	0	2,056,144	13,105,565						
General Service GS-2 Secondary	0.257%	147,708	872,374	0	162,337	1,034,711						
General Service Demand GSD-1, GSDT-1, SS-1 Secondary Primary Transmission		12,149,615 2,311,921 5,729							2.82 2.79 2.76	0.00 0.00 0.00	0.52 0.51 0.51	3.35 3.32 3.28
TOTAL GSD	31.449%	14,467,265	106,891,929	0	19,891,111	126,783,040	52.30%	37,893,254				
Curtailable CS-1, CST-1, CS-2, CST-2, CS-3, C Secondary Primary Transmission	_	35,746							1.88 1.86 1.84	0.00 0.00 0.00	0.35 0.35 0.34	2.22 2.20 2.18
TOTAL CS	0.052%	35,746	178,297	0	33,179	211,475	51.50%	95,082				
Interruptible IS-1, IST-1, IS-2, IST-2, SS-2 Secondary Primary		89,325 1,621,463							2.38 2.36	0.00 0.00	0.44 0.44	2.83 2.80
Transmission		324,813							2.30	0.00	0.44	2.00
TOTAL IS	3.567%	2,035,601	12,124,063	0	2,256,121	14,380,184	54.80%	5,088,493				
Lighting LS-1 Secondary	0.177%	389,030	600,567	0	111,757	712,324						
<u>Total</u>	100.000%	37,738,631	\$339,894,492	\$0	\$63,249,670	\$403,144,163						
				0.000%	0.000%							
Notes:	 (1) From Schedule E12-D, Colu (2) Projected mWh sales at efference (3) Column 1 x Total Recoveral (4) (Column 8 x Column 2) x 10 	ective voltage leve ble Payments (Sch		(10) ((11) (Column 5 / Column 2 Column 7 + Column 8 Class Billing kW Load	+ Column 9 I Factor						

(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) (Column 8 x Column 2) x 10
(5) Column 1 x Total Recoverable Payments (Schedule E12-A)
(6) Column 3 + Column 4 + Column 5
(7) (Column 3 / Column 2) / 10
(8) (Column 4 / Column 2) / 10

(11) Class Billing kW Load Factor
 (12) Column 2 x 1000 / 8760 / Column 11 x 12
 (13) Column 3 / Column 12
 (14) Column 4 / Column 12
 (15) Column 5 / Column 12
 (16) Column 6 / Column 12

*Calculation of Standby Se		jes:	
	Capacity +		
	Nuclear Cost		
	Cost	Effective kW	\$/kW
Total GSD, CS, IS	\$141,374,699	43,076,828	3.28
SS-1, 2, 3 - \$/kW-mo	Secondary	Primary	Trans
Monthly - \$3.28/kW * 10%	0.328	0.325	0.321
Daily - \$3.28/kW / 21	0.156	0.154	0.153