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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), Fla. Stats.; 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.

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[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), Fla. Stats. 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 quarter 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 true-up 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.

14. By proposing to end the LNP cost recovery charge at this time, DEF does 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-EI, 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,

/s/ *Blaise N. Gamba*

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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

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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>

4. It is the intent of the Parties and the Parties stipulate that this Revised 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-EI, 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-EI, 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. a. Pursuant to the 2012 Settlement Agreement, DEF placed CR3 in 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 Agreement, 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):

(1). <u>The projected dry cask storage ("DCS") facility costs</u>. Prior to the 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 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 pro-rata basis.

Fuel Adjustment Clause:

6. Refunds through the Fuel Adjustment Clause. 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 report. DEF shall calculate and submit for Commission approval the revenue 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 since the implementation of the initial 2018 GBRA factor and 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), F.A.C. If the Commission finds that DEF has met the requirements of Commission 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.

<u>New Economic Development and Economic Re-Development Tariffs:</u>

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 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.

<u>Other Matters:</u>

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 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.

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Duke Energy Florida, Inc.

By______________________

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

Office of Public Counsel

By______________________

J.R. Kelly, Esquire
Charles Rehwinkel, Esquire
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Florida Industrial Power Users Group

By____________________________

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

White Springs Agricultural Chemicals, Inc.

By ______________________

James W. Brew, Esquire
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1025 Thomas Jefferson St., NW
Eighth Floor, West Tower
Washington, DC 20007

Florida Retail Federation

By Robert Scheffel Wright

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

Composite Exhibit 1
Duke Energy Florida

FILED AUG 14, 2013
DOCUMENT NO. 04749-13
FPSC - COMMISSION CLERK

13 AUG 14 PM 12: 12
COMMISSION CLERK
RECEIVED -FPSC

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%

3) 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

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

SCHEDULE E-12

ADJUSTMENT TO TEST YEAR UNBILLED REVENUE

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: PROGRESS ENERGY FLORIDA, INC

DOCKET NO.: 12xxxx-EI

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 ___/__/___
_X__Projected Test Year Ended 12/31/13
____Prior Year Ended __/__/__
Witness:

DEVELOPMENT OF UNBILLED REVENUE @ PRESENT RATES AND SUMMARY OF TOTAL CLASS REVENUES

Line No.		Rate Schedule	(1) Billed MWH Sales	(2) Base Revenues $000's - Billed: Total	(3) Base Revenues $000's - Billed: Customer Charge	(4) Base Revenues $000's - Billed: Energy and Demand Charge	(5) Unbilled MWH Sales	(6) Energy and Demand Chg $/MWH (4) / (1)	(7) Unbilled Revenue ($000) (5) * (6)	(8) Total Class Revenue ($000) (2) + (7)	(9) Total Energy and Demand Revenue Including Unbilled (4) + (7)	(10) Base Rate Adjustments / Shifts	(11) Total Class Revenue with Increase (8) + (10)
1	I. SALES	RS-1	18,650,321	$ 960,909	$ 154,082	$ 806,827	10,035	$ 43.26	$ 434	$ 961,343	$ 807,261	$ 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		GS-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	1,704,667	35,265	667	34,599	(3,111)	20.30	(63)	35,202	34,536	4,569	39,771
7		SS-1	12,187	702	24	678	(4)	55.61	(0)	702	678	90	791
8		SS-2	144,605	3,541	9	3,532	(296)	24.43	(7)	3,534	3,525	466	4,000
9		SS-3	16,448	673	8	665	(34)	40.44	(1)	671	664	88	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	$ 1,474,105	$ 1,291,575	$ 170,862	$ 1,644,967
12													
13	II OTHER												
14		LS-1											
15		FIXTURE		$ 33,204						$ 33,204			$ 33,204
16		MAINTENANCE		10,361						10,361			10,361
17		POLES		24,481						24,481			24,481
18		TOTAL OTHER REVENUE		$ 68,046						$ 68,046			$ 68,046
19													
20	III. TOTAL CLASS REVENUE			$ 1,541,643					$ 507	$ 1,542,151			$ 1,713,013

Line No.	Components of Base Rate Adjustments/Shifts per Settlement			Concurrent Clause Decrease
21				
22				
23				
24				
25	¶2. Transfer Levy Deferred Tax Asset from NCRC	$ 20,862	NCRC	$ (20,862)
26	¶12 General Base Rate Increase	150,000		
27				
28	Total Base Rate Increase	$ 170,862		
29			¶8 Fuel	(129,000)
30			Total Clauses	$ (149,862)
31				
32			Net Base & Clause	$ 21,000
33				
34			% Incr Total Base Rev	1.23%

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING MW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
X Projected Test Year Ended 12/31/13
__ Prior Year Ended
__ Historical Year Ended
Witness

2013 REVENUE CALCULATION FOR RATE SCHEDULE RS-1

PRESENT REVENUE CALCULATIONS							PROPOSED REVENUE CALCULATIONS
Customer Charge:							
Standard							
Secondary Standard	16,948,511	Bills @ $	8.76	=	$	148,468,956	
Seasonal							
Secondary Standard Charge	517,693	Bills @ $	8.76	=	$	4,534,993	
Secondary Seasonal Charge	233,676	Bills @ $	4.58	=	$	1,070,235	
Time-of-Use							
Secondary (single & three phase)	375	Bills @	16.19	=	$	6,071	
Customer CIAC Paid	156	Bills @ $	8.76	=	$	1,367	
TOTAL	17,700,411	Bills			$	154,081,622	
Energy & Demand Charge:							
Standard							
Secondary	18,649,519						
0-1000 KWH	12,767,461	MWH @ $	39.82	=	$	508,400,266	
over 1000 KWH	5,882,058	MWH @ $	50.73	=	$	298,396,818	
Time-of-Use							
Secondary	802						
On-Peak	210	MWH @ $	122.97	=	$	25,870	
Off-Peak	592	MWH @ $	6.83	=	$	4,041	
TOTAL	18,650,321	MWH	43.26		$	806,827,015	
Adjustments							
n/a					$		
Total RS-1 Base Revenue					$	960,908,637	

Schedule E-13c | BASE REVENUE BY RATE SCHEDULE - CALCULATIONS |

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
X Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE GS-1

PRESENT REVENUE CALCULATIONS								PROPOSED REVENUE CALCULATIONS
Customer Charge:								
Standard								
Unmetered	5,464	Bills @	$	6.54	=	$	35,735	
Secondary	1,350,953	Bills @	$	11.59	=	$	15,657,545	
Primary	416	Bills @	$	146.56	=	$	60,959	
Transmission		Bills @	$	722.90	=	$	-	
Time-of-Use								
Secondary (single & three phase)	2,506	Bills @	$	19.01	=	$	47,639	
Customer CIAC Paid	24	Bills @	$	11.59	=	$	278	
Primary	12	Bills @	$	153.99	=	$	1,848	
Transmission	12	Bills @	$	730.32	=	$	8,764	
TOTAL	1,359,397	Bills				$	15,812,778	
Energy & Demand Charge:								
Standard								
Secondary	1,196,436	MWH @	$	43.26	=	$	51,757,827	
Primary	3,651	MWH @	$	43.26	=	$	157,946	
Transmission		MWH @	$	43.26	=	$	-	
Time-of-Use								
Secondary								
On-Peak	3,405	MWH @	$	122.78	=	$	418,007	
Off-Peak	14,567	MWH @	$	6.65	=	$	96,869	
Primary								
On-Peak	607	MWH @	$	122.78	=	$	74,568	
Off-Peak	1,761	MWH @	$	6.65	=	$	11,713	
Transmission								
On Peak	75	MWH @	$	122.78	=	$	9,200	
Off-Peak	4,283	MWH @	$	6.65	=	$	28,481	
TOTAL	1,224,785	MWH				$	52,554,611	
Adjustments								
Distribution Primary Metering	1%	OF	$	244,227	=	$	(2,442)	
Transmission Metering	2%	OF	$	37,601	=	$	(754)	
TOTAL						$	(3,196)	
Total GS-1 Base Revenue						$	68,364,193	

EXHIBIT 1, ATTACHMENT A
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Duke Energy Florida

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE GS-2

PRESENT REVENUE CALCULATIONS

Customer Charge:					
Standard					
Unmetered	10,704	Bills @ $	6.54	= $	70,004
Secondary	143,503	Bills @ $	11.59	= $	1,663,200
TOTAL	154,207	Bills		$	1,733,204
Energy & Demand Charge:					
Standard					
Secondary	120,842	MWH @ $	16.40	= $	1,981,809
Adjustments					
n/a				$	-
Total GS-2 Base Revenue				$	3,715,013

PROPOSED REVENUE CALCULATIONS

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No. 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KW'S FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown
X Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE GSD

PRESENT REVENUE CALCULATIONS						PROPOSED REVENUE CALCULATIONS
Customer Charge:						
Standard						
Secondary	535,319	Bills @ $	11.59	= $	6,204,347	
Primary	1,665	Bills @ $	146.56	= $	244,022	
Transmission	-	Bills @ $	722.90	= $	-	
Time-of-Use						
Secondary	128,047	Bills @ $	19.01	= $	2,434,173	
Customer CIAC Paid	132	Bills @ $	11.59	= $	1,530	
Primary	2,499	Bills @ $	153.99	= $	384,821	
Customer CIAC Paid	48	Bills @ $	146.56	= $	7,035	
Transmission	12	Bills @ $	730.32	= $	8,764	
TOTAL	667,722	Bills		$	9,284,692	
Demand Charge:						
Standard						
Secondary						
Billed	17,169,704	kW @ $	4.05	= $	69,537,301	
Primary						
Billed	505,042	kW @ $	3.73	= $	1,803,897	
Transmission						
Billed	-	kW @ $	2.85	= $	-	
Time-of-Use						
Secondary						
On-Peak	15,408,112	kW @ $	3.01	= $	46,378,417	
Base	15,921,337	kW @ $	0.99	= $	15,762,124	
Primary						
On-Peak	3,860,572	kW @ $	3.01	= $	11,620,322	
Base	4,087,946	kW @ $	0.67	= $	2,738,924	
Transm/Primary						
On-Peak	25,426	kW @ $	3.01	= $	76,532	
Base	26,172	kW @ $	(0.20)	= $	(5,234)	
Sec/Pri						
On-Peak	33,035	kW @ $	3.01	= $	99,435	
Base	33,539	kW @ $	0.99	= $	33,204	
Premium Distrib. Charge	239,897	kW @ $	0.87	$	208,710	
TOTAL Billed/Base	37,743,740	kW	TOTAL	$	148,333,542	

EXHIBIT 1, ATTACHMENT A
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Duke Energy Florida

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS, AND TRANSFER GROUP

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness: Slusser

2013 REVENUE CALCULATION FOR RATE SCHEDULE GSD

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Energy Charge:							
Standard							
Secondary	4,773,044	MWH @	$	18.06	=	$	86,201,179
Primary	149,849	MWH @	$	18.06	=	$	2,706,278
Transmission	-	MWH @	$	18.06	=	$	-
Time-of-Use							
Secondary							
On-Peak	2,033,759	MWH @	$	39.32	=	$	79,967,419
Off-Peak	5,134,545	MWH @	$	6.60	=	$	33,887,999
Primary							
On-Peak	556,703	MWH @	$	39.32	=	$	21,889,553
Off-Peak	1,518,032	MWH @	$	6.60	=	$	10,019,011
Transm/Primary							
On-Peak	2,824	MWH @	$	39.32	=	$	111,042
Off-Peak	8,122	MWH @	$	6.60	=	$	53,604
Sec/Pri							
On-Peak	5,274	MWH @	$	39.32	=	$	207,371
Base	14,857	MWH @	$	6.60	=	$	98,059
TOTAL	14,197,010	MWH				$	235,141,515
Adjustments							
Distribution Primary Metering	1%	OF	$	51,565,112	=	$	(515,651)
Transmission Metering	2%	OF	$	[illegible]	=	$	[illegible]
Power Factor	(623,217)	KVar	$	0.23			[illegible]
TOTAL						$	(658,991)
Total GSD-1 Base Revenue						$	392,100,759

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc

Docket No. 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KWs FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X__Projected Test Year Ended 12/31/13
____Prior Year Ended
____Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE CS

PRESENT REVENUE CALCULATIONS

Customer Charge:							
Standard							
Secondary	-	Bills @	$	75.96	=	$	-
Primary	-	Bills @	$	210.93	=	$	-
Transmission	-	Bills @	$	787.26	=	$	-
Time-of-Use							
Secondary	-	Bills @	$	69.61	=	$	-
Primary	48	Bills @	$	193.30	=	$	9,276
Transmission	-	Bills @	$	721.46	=	$	-
TOTAL	48	Bills				$	9,276
Demand Charge:							
Standard							
Secondary							
Billed	-	kW @	$	6.51	=	$	-
Primary							
Billed	-	kW @	$	6.19	=	$	-
Transmission							
Billed	-	kW @	$	5.32	=	$	-
Time-of Use							
Secondary							
On-Peak	-	kW @	$	5.49	=	$	-
Base		kW @	$	0.97	=	$	-
Primary							
On-Peak	97,600	kW @	$	5.49	=	$	535,824
Base	109,115	kW @	$	0.65	=	$	70,925
Transmission							
On-Peak	-	kW @	$	5.49	=	$	-
Base	-	kW @	$	(0.22)	=	$	-
TOTAL Billed/Base	109,115	kW		TOTAL		$	606,749

PROPOSED REVENUE CALCULATIONS

Schedule E-13c	BASE REVENUE BY RATE SCHEDULE - CALCULATIONS	Page 7 of 13
Florida Public Service Commission Company: Progress Energy Florida, Inc Docket No.: 12xxxx-EI	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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP	Type of Data Shown: X Projected Test Year Ended 12/31/13 ___Prior Year Ended ___Historical Year Ended Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE CS

PRESENT REVENUE CALCULATIONS									PROPOSED REVENUE CALCULATIONS
Energy Charge:									
Standard									
Secondary	-	MWH @	$	11.89	=	$	-		
Primary	-	MWH @	$	11.89	=	$	-		
Transmission	-	MWH @	$	11.89	=	$			
Time-of Use									
Secondary									
On Peak	-	MWH @	$	21.81	=	$	-		
Off Peak	-	MWH @	$	6.55	=	$			
Primary									
On-Peak	11,635	MWH @	$	21.81	=	$	253,749		
Off Peak	34,924	MWH @	$	6.55	=	$	228,755		
Transmission									
On-Peak	-	MWH @	$	21.81	=	$	-		
Off-Peak	-	MWH @	$	6.55	=	$	-		
TOTAL	46,559	MWH				$	482,504		
Adjustments									
Distribution Primary Metering	1%	OF	$	1,089,263	=	$	(10,893)		
Transmission Metering	2%	OF	$	-	=	$	-		
Power Factor	3,765	Kvar	$	0.23		$	866		
TOTAL						$	(10,027)		
Total CS-1, CS-2, CS-3 Base Revenue						$	1,068,504		

EXHIBIT 1, ATTACHMENT A
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Duke Energy Florida

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWHS, AND BILLING KWH FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
__ Prior Year Ended
__ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE IS

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:						
Standard						
Secondary	349	Bills @ $	278.95	= $	97,354	
Primary	338	Bills @ $	413.94	= $	139,912	
Transmission	-	Bills @ $	990.26	= $	-	
Time-of Use						
Secondary	177	Bills @ $	278.95	= $	49,374	
Primary	660	Bills @ $	413.94	= $	273,200	
Transmission	108	Bills @ $	990.26	= $	106,948	
TOTAL	1,632	Bills		$	666,788	
Demand Charge:						
Standard						
Secondary - Billed	157,260	kW @ $	5.51	= $	866,613	
Primary - Billed	461,425	kW @ $	5.19	= $	2,394,796	
Transmission - Billed	-	kW @ $	4.32	= $	-	
Billed Sec/Pri	5,571	kW @ $	5.51	= $	30,696	
Billed Transm/Pri	-	kW @ $	4.32	= $	-	
Time-of-Use						
Secondary						
On-Peak	121,605	kW @ $	4.82	= $	586,136	
Base	124,247	kW @ $	0.87	= $	108,095	
Primary						
On-Peak	2,098,117	kW @ $	4.82	= $	10,112,924	
Base	2,285,625	kW @ $	0.55	= $	1,257,094	
Transmission						
On-Peak	750,902	kW @ $	4.82	= $	3,619,348	
Base	841,532	kW @ $	(0.32)	= $	(269,290)	
Sec/Pri						
On-Peak	5,353	kW @ $	4.82	= $	25,801	
Base	5,507	kW @ $	0.87	= $	4,791	
Pri/Transm						
On Peak	14,781	kW @ $	4.82	= $	71,244	
Base	15,792	kW @ $	0.55	= $	8,685	
Transm/Pri						
On Peak	678,259	kW @ $	4.82	= $	3,269,208	
Base	704,531	kW @ $	(0.32)	= $	(225,450)	
TOTAL Billed/Base	4,601,510	kW	TOTAL	$	21,860,692	

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No. 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X__Projected Test Year Ended 12/31/13
___Prior Year Ended
___Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE IS

PRESENT REVENUE CALCULATIONS

Energy Charge:							
Standard							
Secondary	36,701	MWH @	$	7.97	=	$	292,511
Primary	116,935	MWH @	$	7.97	=	$	931,972
Transmission		MWH @	$	7.97	=	$	-
Sec/Pri	1,546	MWH @	$	7.97	=	$	12,323
Transm/Pri	-	MWH @	$	7.97	=	$	-
Time-of-Use							
Secondary							
On-Peak	17,073	MWH @	$	11.16	=	$	190,530
Off-Peak	44,033	MWH @	$	6.51	=	$	286,654
Primary							
On-Peak	244,364	MWH @	$	11.16	=	$	2,727,100
Off-Peak	725,775	MWH @	$	6.51	=	$	4,724,797
Transmission							
On-Peak	66,359	MWH @	$	11.16	=	$	740,563
Off Peak	231,344	MWH @	$	6.51	=	$	1,506,051
Sec/Pri							
On-Peak	791	MWH @	$	11.16	=	$	8,825
Off-Peak	2,310	MWH @	$	6.51	=	$	15,039
Pri/Transm.							
On-Peak	1,062	MWH @	$	11.16	=	$	11,852
Off-Peak	2,750	MWH @	$	6.51	=	$	17,900
Transm/Pri							
On-Peak	59,056	MWH @	$	11.16	=	$	659,061
Off-Peak	154,568	MWH @	$	6.51	=	$	1,006,239
TOTAL	1,704,666	MWH					13,131,415
Adjustments							
Distribution Primary Metering	1%	OF	$	26,955,214	=	$	(269,552)
Transmission Metering	2%	OF	$	5,706,354	=	$	(114,127)
Power Factor	(42,426)	KVar	$	0.23		$	(9,758)
TOTAL						$	(393,437)
Total IS-1, IS-2 Base Revenue						$	35,255,456

PROPOSED REVENUE CALCULATIONS

EXHIBIT 1, ATTACHMENT A
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Duke Energy Florida

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWHS, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE LS

PRESENT REVENUE CALCULATIONS | PROPOSED REVENUE CALCULATIONS

Customer Charge:					
Standard					
Unmetered	728,529	Bills @ $	1.19	= $	866,950
Secondary	9,996	Bills @ $	3.42	= $	34,186
TOTAL	738,525	Bills		$	901,136
Energy & Demand Charge:					
Standard					
Secondary	371,280	MWH @ $	17.07	= $	6,337,750
Adjustments					
n/a				$	-
Total LS-1 Base Revenue				$	7,238,886

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING KW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE SS-1

PRESENT REVENUE CALCULATIONS								PROPOSED REVENUE CALCULATIONS
Customer Charge:								
Primary	36	Bills @	$	235.69	=	$	8,485	
Transmission	12	Bills @	$	812.02	=	$	9,744	
Pri/Transm (Customer Owned)	72	Bills @	$	81.21	=	$	5,847	
Total	120	Bills				$	24,076	
Demand Charge:								
Distribution Charge								
Primary	68,160	kW @	$	1.59	=	$	108,374	
Transmission	385,032	kW @	$	-		$	-	
Generation & Transm								
(Greater of SB Cap/DD)								
Primary								
Specified SB Cap	66,900	kW @	$	0.888	=	$	59,407	
Daily Demand	124,633	kW @	$	0.423	=	$	52,720	
Transmission								
Specified SB Cap	224,850	kW @	$	0.888	=	$	199,667	
Daily Demand	409,315	kW @	$	0.423	=	$	173,140	
Total Specified SB Cap	453,192			Total		$	593,308	
Energy Charge:								
Standard								
Primary	2,816	MWH @	$	7.86	=	$	22,132	
Transmission	9,371	MWH @	$	7.86	=	$	73,658	
Total	12,187	MWH				$	95,790	
Adjustments								
Delivery Voltage Credit	68,160		$	(0.29)		$	(19,765)	
Distribution Primary Metering	1%	OF	$	242,633	=	$	(2,426)	
Transmission Metering	2%	OF	$	446,455	=	$	(8,929)	
Total						$	(31,355)	
Total SS-1 Base Revenue						$	701,819	

EXHIBIT 1, ATTACHMENT A
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Duke Energy Florida

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc.

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenues by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWHS AND BILLING KWH FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
____Prior Year Ended
____Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE SS-2

PRESENT REVENUE CALCULATIONS							PROPOSED REVENUE CALCULATIONS
Customer Charge:							
Primary	12	Bills @	$	438.68	= $	5,264	
Transmission	-	Bills @	$	1,015.02	= $	-	
Transmission (Customer Owned)	12	Bills @	$	284.20	= $	3,410	
Total	24	Bills			$	8,674	
Demand Charge:							
Distribution Charge							
Primary	114,000	kW @	$	1.59	= $	181,260	
Transmission	398,640	kW @			= $	-	
Generation & Transm							
(Greater of SB Cap/DD)							
Primary							
Specified SB Cap	38,003	kW @	$	0.888	= $	33,744	
Daily Demand	2,082,093	kW @	$	0.423	= $	880,725	
Transmission							
Specified SB Cap	25,093	kW @	$	0.888	= $	22,287	
Daily Demand	3,272,984	kW @	$	0.423	= $	1,384,472	
Total Specified SB Cap	737,880			Total	$	2,502,488	
Energy Charge:							
Standard							
Primary	11,862	MWH @	$	7.77	= $	92,167	
Transmission	132,743	MWH @	$	7.77	= $	1,031,414	
Total	144,605	MWH			$	1,123,581	
Adjustments							
Delivery Voltage Credit	114,000		$	(0.29)	$	(33,060)	
Distribution Primary Metering	1%	OF	$	1,187,895	= $	(11,879)	
Transmission Metering	2%	OF	$	2,438,173	= $	(48,763)	
Total					$	(93,702)	
Total SS-2 Base Revenue					$	3,541,041	

Schedule E-13c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

Florida Public Service Commission

Company: Progress Energy Florida, Inc

Docket No.: 12xxxx-EI

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 transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedules E-15. PROVIDE TOTAL NUMBER OF BILLS, MWH'S, AND BILLING kWh FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/13
___ Prior Year Ended
___ Historical Year Ended
Witness:

2013 REVENUE CALCULATION FOR RATE SCHEDULE SS-3

PRESENT REVENUE CALCULATIONS								PROPOSED REVENUE CALCULATIONS
Customer Charge:								
Primary		24	Bills @	$	235.69	$	5,657	
Primary (Customer Owned)		24	Bills @	$	81.21	= $	1,949	
Transmission		-	Bills @	$	812.02	= $	-	
	Total	48	Bills			$	7,606	
Demand Charge:								
Primary		170,340	kW @	$	1.59	= $	270,841	
Transmission		-	kW @			= $	-	
Generation & Transm								
(Greater of SB Cap/DD)								
Primary								
Specified SB Cap		56,760	kW @	$	0.888	= $	50,421	
Daily Demand		643,721	kW @	$	0.423	= $	272,294	
Transmission								
Specified SB Cap		-	kW @	$	0.888	= $	-	
Daily Demand		-	kW @	$	0.423	= $	-	
	Total Specified SB Cap	170,340	kW		Total	$	593,556	
Energy Charge:								
Standard								
Primary		16,448	MWH @	$	7.80	= $	128,294	
Transmission		-	MWH @	$	7.80	= $	-	
	Total	16,448	MWH			$	128,294	
Adjustments:								
Delivery Voltage Credit		170,340		$	(0.29)	$	(49,399)	
Distribution Primary Metering		1%	OF	$	721,850	= $	(7,219)	
Transmission Metering		2%	OF	$	-	= $	-	
	Total					$	(56,618)	
Total SS-3 Base Revenue						$	672,838	

Attachment B

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

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

Rate Schedule	Type of Charge	cents / kWh 2/10/2010 Current/Prior Rate	cents / kWh 1/1/2013 Proposed Settlement Rate	$/kWh Actual Billing Rate (CSS) Current/Prior Rate	$/kWh Actual Billing Rate (CSS) Proposed Settlement Rate
SC-1	Initial Connection - $	61.00	61.00	61.00	61.00
	Reconnection - $	28.00	28.00	28.00	28.00
	Transfer of Account - No LSA Contract - $	28.00	28.00	28.00	28.00
	Transfer of Account - LSA Contract Required - $	10.00	10.00	10.00	10.00
	Reconnect After Disconnect For Non-Pay - $	40.00	40.00	40.00	40.00
	Reconnect After Disconnect For Non-Pay After Hours -$	50.00	50.00	50.00	50.00
	Investigation of Unauthorized Use - (RPI)	75.00	75.00	75.00	75.00
	Late Payment Charge	> $5.00 or 1.5%	> $5.00 or 1.5%	> $5.00 or 1.5%	> $5.00 or 1.5%
	Returned Check Charge	$25 if <= $50	$25 if <= $50	$25 if <= $50	$25 if <= $50
		$30 if <= $300	$30 if <= $300	$30 if <= $300	$30 if <= $300
		$40 if <= $800	$40 if <= $800	$40 if <= $800	$40 if <= $800
		5% if > $800	5% if > $800	5% if > $800	5% if > $800
TS-1	Temporary Service Extension - Monthly $	227.00	227.00	227.00	227.00
RS-1	Customer Charge - $ per Line of Billing				
RST-1	Standard	8.76	8.76	8.76	8.76
RSS-1	Seasonal (RSS-1)	4.58	4.58	4.58	4.58
(RST closed	Time of Use				
2/10/2010)	Single Phase	16.19	16.19	16.19	16.19
	Three 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				
	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 - Off Peak	0.683	0.773	0.00683	0.00773
GS-1,	Customer Charge - $ per Line of Billing				
GST-1	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				
	Single Phase	19.01	19.01	19.01	19.01
	Three Phase	19.01	19.01	19.01	19.01
	Customer CIAC Paid	11.59	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	132.00	132.00	132.00	132.00
	Energy and Demand Charge - cents per KWH				
	Standard	4.326	4.898	0.04326	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				
	Primary	1.0%	1.0%	1.0%	1.0%
	Transmission	2.0%	2.0%	2.0%	2.0%

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

		cents / kWh		$/kWh	
		2/10/2010	1/1/2013	Actual Billing Rate (CSS)	
Rate Schedule	Type of Charge	Current/Prior Rate	Proposed Settlement Rate	Current/Prior Rate	Proposed Settlement Rate
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1.67%
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 GSDT-1	Customer Charge - $ per Line of Billing				
	Standard				
	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				
	Secondary	19.01	19.01	19.01	19.01
	Secondary - Customer CIAC paid	11.59	11.59	11.59	11.59
	Primary	153.99	153.99	153.99	153.99
	Primary - Customer CIAC paid	146.56	146.56	146.56	146.56
	Transmission	730.32	730.32	730.32	730.32
	Transmission Customer CIAC paid	722.90	722.90	722.90	722.90
	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	0.01806	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				
	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%
CS-1 CS-2 CS-3 CST-1 CST-2 CST-3	Customer Charge - $ per Line of Billing				
	Secondary	75.96	75.96	75.96	75.96
	Primary	210.93	210.93	210.93	210.93
	Transmission	787.26	787.26	787.26	787.26
	Demand Charge - $ per KW				
	Standard	6.51	7.37	6.51	7.37
	Time of Use				

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

Rate Schedule	Type of Charge	cents / kWh 2/10/2010 Current/Prior Rate	1/1/2013 Proposed Settlement Rate	$/kWh Actual Billing Rate (CSS) Current/Prior Rate	Proposed Settlement Rate
	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 Curtailable Demand	2.50	3.74	2.50	3.74
	CS-2, CST-2 - $ per KW LF adjusted Demand	2.48	6.53	2.48	6.53
	CS-3, CST-3 - $ per KW of Contract Demand	2.48	6.53	2.48	6.53
	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	0.26
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1.67%
IS-1	Customer Charge - $ per Line of Billing				
IS-2	Secondary	278.95	278.95	278.95	278.95
IST-1	Primary	413.94	413.94	413.94	413.94
IST-2	Transmission	990.26	990.26	990.26	990.26
	Demand Charge - $ per KW				
	Standard	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				
	IS-1, IST-1 - $ per KW of Billing Demand	3.62	4.99	3.62	4.99
	IS-2, IST-2 - $ per KW LF Adjusted Demand	3.31	8.70	3.31	8.70
	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 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	0.26
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%	1.67%	1.67%

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

Rate Schedule	Type of Charge	cents / kWh 2/10/2010 Current/Prior Rate	1/1/2013 Proposed Settlement Rate	$/kWh Actual Billing Rate (CSS) Current/Prior Rate	Proposed Settlement Rate
LS-1	Customer Charge - $ per Line of Billing				
	Standard				
	Unmetered	1.19	1.19	1.19	1.19
	Metered	3.42	3.42	3.42	3.42
	Energy and Demand Charge - cents per KWH				
	Standard	1.707	1.933	0.01707	0.01933
	Fixture & Maintenance Charges - $ per fixture	n/a	n/a	n/a	n/a
	Pole Charges - $ per pole	n/a	n/a	n/a	n/a
	Other Fixture Charge Rate - % of Installed Fixture Cost	1.59%	1.59%	1.59%	1.59%
	Other Pole Charge Rate - % of Installed Pole Cost	1.82%	1.82%	1.82%	1.82%
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
	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
	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-2	Customer Charge - $ per Line of Billing				
	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
	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
	Interruptible Capacity Credit - $ per KW				
	Grandfathered Prior to 1/1/06				
	Monthly Reservation Credit	0.690	0.870	0.690	0.870
	Daily Demand Credit	0.329	0.414	0.329	0.414

Effective 1/1/06

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

		cents / kWh		$/kWh	
		2/10/2010	1/1/2013	Actual Billing Rate (CSS)	
Rate Schedule	Type of Charge	Current/Prior Rate	Proposed Settlement Rate	Current/Prior Rate	Proposed Settlement Rate
	Monthly Reservation Credit	0.331	0.870	0.331	0.870
	Daily Demand Credit	0.158	0.414	0.158	0.414
	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
	Base Rate Energy Customer Charge - cents per KWH	0.780	0.883	0.00780	0.00883
	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 1/1/06				
	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	n/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

Attachment C

Revised Tariff Sheets in clean copy 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
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	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

Progress Energy

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

RATE SCHEDULE RS-1
RESIDENTIAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To residential customers in a single dwelling house, a mobile home, or individually metered single apartment unit or other unit having housekeeping facilities, occupied by one family or household as a residence. The premises of such single dwelling may include an additional apartment with separate housekeeping facilities, as well as a garage and other separate structures where they are occupied or used solely by the members or servants of such family or household. Also, for energy used in commonly-owned facilities in condominium and cooperative apartment buildings subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owner's benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery is separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bill(s) for said service.

Character of Service:

Continuous service, alternating current, 60 cycles per second, single-phase or three-phase, at the Company's standard available distribution voltage. 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:

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
Demand and Energy Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	4.509¢ per kWh
All additional kWh	5.744¢ per 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

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

(Continued on Page No. 2)

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:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

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	4.509¢ per kWh
All additional kWh	5.704¢ per 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

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

Load Management Monthly Credit Amounts:[1,2]

Interruptible Equipment	Interruption Schedule A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

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 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.

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	4.509¢ per kWh
All additional kWh	5.744¢ per 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

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

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

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 continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

Progress Energy

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

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 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, 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:

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 Governing Electric Service."

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 other energy use.

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.

(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.

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE GS-1
GENERAL SERVICE – NON-DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power 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. 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:

Unmetered Account:	$ 6.54
Secondary Metering Voltage:	$ 11.59
Primary Metering Voltage:	$ 146.56
Transmission Metering Voltage:	$ 722.90

Energy and Demand Charges:

Non-Fuel Energy Charge:	4.898¢ per 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

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 Energy Charge 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.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above standard distribution secondary, the applicable following reduction factor shall apply to the Non-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:	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

(Continued on Page No. 2)

Progress Energy

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)

Progress Energy

RATE SCHEDULE GS-2
GENERAL SERVICE – NON-DEMAND
100% LOAD FACTOR USAGE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, with fixed wattage loads operating continuously throughout the billing period (such as traffic signals, cable TV amplifiers and gas transmission substations).

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:

Unmetered Account:	$ 6.54
Metered Account:	$ 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, *Billing Adjustments*, except 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. 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 Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.135¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

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

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes for which no other rate schedule is specifically applicable with a measured annual kWh consumption of 24,000 kWh or greater per year.

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 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:	$ 11.59
Primary Metering Voltage:	$ 146.56
Transmission Metering Voltage:	$ 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, *Billing Adjustments*:	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, *Billing Adjustments*, 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. 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 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 current billing period.

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND
(Continued from Page No. 1)

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 credits:

For Distribution Primary Delivery Voltage:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge 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. 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 the bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of twelve (12) months from commencement of service and shall continue thereafter until receipt of notice by the Company from the customer to disconnect, or upon disconnect by the Company under Florida Public Service Commission or Company Rules.

Customers taking service under another Company rate schedule who elect to transfer to this rate must remain on this rate for a minimum term of twelve (12) months.

(Continued on Page No. 3)

Progress Energy

RATE SCHEDULE GSDT-1
GENERAL SERVICE - DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of the customer, otherwise eligible for service under Rate Schedule GSD-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

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, *Billing Adjustments*:	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, *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 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 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)

Progress Energy

RATE SCHEDULE GSDT-1
GENERAL SERVICE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

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.

(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.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

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

For Distribution Primary Delivery Voltage:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$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 applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with metered 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.

(Continued on Page No. 3)

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

EFFECTIVE: January 1, 2013

Progress Energy

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 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
\$3.60 x **C** + \$0.05[1] x kWh monthly	$0 \le CRH \le 200$
\$4.32 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:

$$C = \frac{\text{kWh annual}}{[\text{CAH} - (\#\text{ of Requests} \times 1/4\text{ hour})]}$$

Definitions:

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.

[1] 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)

Progress Energy

RATE SCHEDULE CS-1
CURTAILABLE 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 purposes where the customer agrees during a period of requested curtailment to curtail as a minimum the greater of: (a) 25 kW or (b) 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 Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable service under this rate schedule is not 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 Charge:	\$ 7.37 per kW of Billing Demand
Plus the Cost Recovery Factors on a \$/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	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, *Billing Adjustments*, 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. 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 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)

Progress Energy

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 demand established during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current Billing Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of 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 delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 per kW of Billing Demand

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:

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 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:	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. 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.

(Continued on Page No. 3)

Progress Energy

SECTION NO. VI
TWELFTH REVISED SHEET NO. 6.235
CANCELS ELEVENTH REVISED SHEET NO. 6.235

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

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 Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not 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 Charge:	$ 7.37 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	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 ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, 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. 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 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)

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

EFFECTIVE: January 1, 2013

Progress Energy

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

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 demand established during the current billing period, but not less than 500 kW.

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 delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 per kW of Billing Demand

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:

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 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:	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 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.

(Continued on Page No. 3)

Progress Energy

RATE SCHEDULE CS-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 2,000 kW or more (based on most recent twelve (12) months or, where not available, projected billing demand for twelve (12) months), and where the customer agrees to curtail its demand by a fixed contractual amount of not less than 2,000 kW upon request of the Company in accordance with the provisions of this rate schedule.

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:	$ 75.96
Primary Metering Voltage:	$ 210.93
Transmission Metering Voltage:	$ 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, *Billing Adjustments*:	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, *Billing Adjustments*, except for the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

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 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 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:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 per kW of Billing Demand

(Continued on Page No. 2)

Progress Energy

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 26¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured 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:	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.

   (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 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 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)

Progress Energy

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

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 not 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, *Billing Adjustments*:	See 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:	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)

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

EFFECTIVE: January 1, 2013

RATE SCHEDULE CST-1
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

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.

(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.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current On-Peak Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of 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 delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$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, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

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

(Continued on Page No. 3)

Progress Energy

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 not 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, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.22 per kW of On-Peak Demand

Curtailable Demand 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)

Progress Energy

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 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.

(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 Periods during the current billing period.

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 delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$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, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

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

(Continued on Page No. 3)

Progress Energy

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:	$ 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, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 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 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 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 $0.99 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*:	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 following Monday shall be excluded from the On-Peak Periods.

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)

RATE SCHEDULE CST-3
CURTAILABLE 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 be the maximum 30-minute kW demand established during the current billing period, but not less than **2,000** kW.

The On-Peak Demand for billing purposes shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule 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:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$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 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 26¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured 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:	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.

(Continued on Page No. 3)

Progress Energy

RATE SCHEDULE CST-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 2)

Special Provisions: (Continued)

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 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 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.

4. A customer will be deemed to have complied with its curtailment responsibility if the maximum 30-minute kW demand established during each period of requested curtailment is lower than what the customer's maximum 30-minute kW demand would otherwise have been during the period of requested curtailment by at least the Fixed Curtailable Demand defined in Special Provision No. 2. This will be determined by the Company using customer's load data of similar day, time and weather conditions where a curtailment was not requested.

5. If a customer has not complied with its curtailment responsibility during a period of requested curtailment, the customer will be billed the following additional charge for all billing periods following the previous period of requested curtailment through the billing period in which such non-compliance 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. To minimize the frequency and duration of curtailments requested under this rate schedule, the Company will attempt to purchase additional energy, if available, from sources outside the Company's system during periods for which curtailment would otherwise be requested. 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. Any energy associated with curtailable loads used during these periods will be subject to the additional charges set forth in the second paragraph of this provision. Customers may avoid these higher charges by curtailing their usage during such periods to at least their Fixed Curtailable Demand pursuant to the third paragraph of these provisions.

   In the event a customer elects not to curtail, 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, for all consumption above the customer's Non-Curtailable Demand during the period for which curtailment would have otherwise been requested. The cost of such purchased energy shall be based on the average cost of all purchased power and energy provided under this rate schedule and under similar provisions in Rate Schedules IS-1, IST-1, CS-1, CST-1, IS-2, IST-2, CS-2, CST-2, CS-3, SS-2 and SS-3 during the corresponding calendar month. If, for any reason during such period, the customer is notified that the energy purchased from outside sources is no longer available, the terms of this Special Provision will cease to apply and curtailments to at least the customer's Fixed Curtailable Demand will be required for the remainder of such period.

   In the event a customer elects to curtail irrespective of the availability of additional energy purchased by the Company and curtails by at least its Fixed Curtailable Demand during the period for which curtailment would have otherwise been requested, the customer will incur no responsibility for the payment of the additional cost of such energy.

7. If the customer increases its power requirements in any manner which requires the Company to install additional facilities for the specific use of the customer, a new Term of Service may be required at the Company's option.

(Continued on Page No. 4)

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 purposes 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:

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:

Customer Charge:

Secondary Metering Voltage:	$ 278.95
Primary Metering Voltage:	$ 413.94
Transmission Metering Voltage:	$ 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, *Billing Adjustments*:	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, *Billing Adjustments*, 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:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 per kW of Billing Demand

(Continued on Page No. 2)

Progress Energy

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 appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, 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) of 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.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of five (5) 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. 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.

2. 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 equipment (metering, under-frequency relay, etc.) 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.

3. The Company may, under the provisions of this rate, at its option, require a special contract with the customer upon the Company's filed contract form.

4. 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 shall be based on the average cost of all purchased power and 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)

Progress Energy

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:

Customer Charge:	
Secondary Metering Voltage:	\$ 278.95
Primary Metering Voltage:	\$ 413.94
Transmission Metering Voltage:	\$ 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, *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, *Billing Adjustments*, 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, 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:	\$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	\$1.35 per kW of Billing Demand

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE
(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, Interruptible Demand Credit, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

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.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of five (5) 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. 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.

2. 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 equipment (metering, under-frequency relay, etc.) 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. Before commencement of service under this rate, the Company shall exercise an interruption for purposes of testing its equipment. The Company shall also have the right to exercise at least one additional interruption each calendar year irrespective of capacity availability or operating conditions. The Company will give the customer notice of the test.

3. The Company may, under the provisions of this rate, at its option, require a special contract with the customer upon the Company's filed contract form.

4. 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 shall be based on the average cost of all purchased power and energy provided under this rate schedule and under similar provisions in Rate Schedules IS-1, IST-1, CS-1, CST-1, IST-2, CS-2, CST-2, CS-3, CST-3, SS-2 and SS-3 during the corresponding calendar month.

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Progress Energy

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 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 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:

Base Demand Charge:	$ 0.99 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	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:

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, *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 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.

(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.

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Progress Energy

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

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current 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:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$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 Charge, 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.

Terms of Payment:

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

(Continued on Page No. 3)

Progress Energy

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 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:	$ 278.95
Primary Metering Voltage:	$ 413.94
Transmission Metering Voltage:	$ 990.26

Demand Charge:

Base Demand Charge:	$ 0.99 per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 5.46 per kW of On-Peak Demand

Interruptible Demand Credit: $ 8.70 per kW of Load Factor Adjusted Demand

Energy Charge:

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, *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 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.
(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.

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Progress Energy

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 Periods 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:	$0.36 per kW of Billing Demand
For Transmission Delivery Voltage:	$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)

Progress Energy

RATE SCHEDULE LS-1
LIGHTING SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Company or customer owned fixtures of the type available under this rate schedule. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party.

Character of Service:

Continuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, single phase, at the Company's standard voltage available.

Limitation of Service:

Availability of certain fixture or pole types at a location may be restricted due to accessibility.

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 Governing Electric Service."

Rate Per Month:

Customer Charge:

Unmetered:	$ 1.19 per line of billing
Metered:	$ 3.42 per line of billing

Energy and Demand Charge:

Non-Fuel Energy Charge:	1.933¢ per 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

Per Unit Charges:

I. Fixtures:

BILLING TYPE	DESCRIPTION	LAMP SIZE [2] INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Incandescent: [1]						
110	Roadway	1,000	105	32	$1.03	$4.07	$0.62
115	Roadway	2,500	205	66	1.61	3.67	1.28
170	Post Top	2,500	205	72	20.39	3.67	1.39
	Mercury Vapor: [1]						
205	Open Bottom	4,000	100	44	$2.55	$1.80	$0.85
210	Roadway	4,000	100	44	2.95	1.80	0.85
215	Post Top	4,000	100	44	3.47	1.80	0.85
220	Roadway	8,000	175	71	3.34	1.77	1.37
225	Open Bottom	8,000	175	71	2.50	1.77	1.37
235	Roadway	21,000	400	158	4.04	1.81	3.05
240	Roadway	62,000	1,000	386	5.29	1.78	7.46
245	Flood	21,000	400	158	5.29	1.81	3.05
250	Flood	62,000	1,000	386	6.20	1.78	7.46

(Continued on Page No. 2)

Progress Energy

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

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 1)

I. Fixtures: (Continued)

BILLING TYPE	DESCRIPTION	LAMP SIZE[2] INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	MAINTENANCE	NON-FUEL ENERGY[3]
	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 [1]	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 [1]	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 [1]	4,000	50	21	5.04	2.04	0.41
316	Colonial Post Top [1]	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-Turnpike [1]	50,000	400	168	8.95	1.76	3.25
343	Roadway-Turnpike [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 [1]	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	0.41
394	Deco Post Top [1]	9,500	100	49	18.16	1.72	0.95

(Continued on Page No. 3)

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

EFFECTIVE: January 1, 2013

Progress Energy

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

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 2)

I. Fixtures: (Continued)

		LAMP 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	$1.26
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 [1]	38,000	400	159	16.70	2.84	3.07
373	MH Deco Rectangular [5]	110,000	1,000	378	15.30	2.96	7.31
386	MH Flood [5]	110,000	1,000	378	13.17	2.96	7.31
389	MH Flood-Sportslighter [5]	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 [5]	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)

Progress Energy

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. 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. 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 shall be $81.21.

2. **Supplemental Service Charges:**

All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution 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.

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 times $0.479/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 in Rate Schedule BA-1, *Billing Adjustments*: 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 ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments*, except for the Fuel Cost Recovery Factor: See Sheet No. 6.105 and 6.106

(Continued on Page No. 4)

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 3)

Rate Per Month: (Continued)

3. Standby Service Charges: (Continued)

D. **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.

E. **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, Non-Fuel Energy Charge, and Delivery Voltage Credit hereunder.

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

F. **Fuel Cost Recovery Factor:**

Time of Use Fuel Charges of applicable metering voltage 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
I.	**Municipal Tax:**	See Sheet No. 6.106
J.	**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. 3 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 $0.92 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:

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.
B.	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.

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.

(Continued on Page No. 5)

Progress Energy

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

RATE SCHEDULE SS-2
INTERRUPTIBLE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. 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. 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:	$ 303.71
Primary Metering Voltage:	$ 438.68
Transmission Metering Voltage:	$ 1,015.02

Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $284.20.

2. **Supplemental Service Charges:**
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution 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.

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 times $0.479 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 in Rate Schedule BA-1, *Billing Adjustments*:	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, or
2. The sum of the daily maximum 30-minute kW demand of actual standby use occurring during On-peak periods times $0.414/kW times the appropriate Billing Month Factor shown in part 3.B. above.

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 distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 33¢ per kW.

(Continued on Page No. 4)

Progress Energy

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:

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.	**Gross Receipts Tax Factor:**	See Sheet No. 6.106
I.	**Right-of-Way Utilization Fee:**	See Sheet No. 6.106
J.	**Municipal Tax:**	See Sheet No. 6.106
K.	**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 $0.92 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:

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.

B. 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.

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.
2. 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)

Progress Energy

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

RATE SCHEDULE SS-3
CURTAILALBE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. 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. 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 shall be $81.21.

2. Supplemental Service Charges:
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. Standby Service Charges:
   A. Distribution 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.

   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 times $0.479/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 in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

   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 times $0.311/kW times the appropriate Billing Month Factor shown in part 3.B. above.

   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, *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 distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 33¢ per kW.

(Continued on Page No. 4)

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

EFFECTIVE: January 1, 2013

Progress Energy

RATE SCHEDULE SS-3
CURTAILABLE 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:

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.	**Gross Receipts Tax Factor:**	See Sheet No. 6.106
I.	**Right-of-Way Utilization Fee:**	See Sheet No. 6.106
J.	**Municipal Tax:**	See Sheet No. 6.106
K.	**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 $0.92 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:

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.

B. 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.

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.

(Continued on Page No. 5)

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
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	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

Progress Energy

RATE SCHEDULE RS-1
RESIDENTIAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To residential customers in a single dwelling house, a mobile home, or individually metered single apartment unit or other unit having housekeeping facilities, occupied by one family or household as a residence. The premises of such single dwelling may include an additional apartment with separate housekeeping facilities, as well as a garage and other separate structures where they are occupied or used solely by the members or servants of such family or household. Also, for energy used in commonly-owned facilities in condominium and cooperative apartment buildings subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owner's benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery is separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bill(s) for said service.

Character of Service:

Continuous service, alternating current, 60 cycles per second, single-phase or three-phase, at the Company's standard available distribution voltage. 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:

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
Demand and Energy Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	4.509~~3.982~~¢ per kWh
All additional kWh	5.744~~5.073~~¢ per 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

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

(Continued on Page No. 2)

Progress Energy

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

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:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

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	~~3.982~~4.509¢ per kWh
All additional kWh	~~5.073~~5.704¢ per 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

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

Load Management Monthly Credit Amounts:[1,2]

Interruptible Equipment	Interruption Schedule A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

Progress Energy

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

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

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 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.

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	~~3.982~~4.509¢ per kWh
All additional kWh	~~5.073~~5.744¢ per 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

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

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

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 continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

Progress Energy

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

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 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, 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:

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 Governing Electric Service."

Rate Per Month:

Customer Charge: $ 16.19

Energy and Demand Charges:

Non-Fuel Energy Charges:	13.924~~12.297~~¢ per On-Peak kWh
	0.773~~0.683~~¢ 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 other energy use.

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.

(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.

(Continued on Page No. 2)

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

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

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

RATE SCHEDULE GS-1
GENERAL SERVICE – NON-DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power 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. 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:

Unmetered Account:	$ 6.54
Secondary Metering Voltage:	$ 11.59
Primary Metering Voltage:	$ 146.56
Transmission Metering Voltage:	$ 722.90

Energy and Demand Charges:

Non-Fuel Energy Charge:	4.898~~4.326~~¢ per 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

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 Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.669~~0.591~~¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above standard distribution secondary, the applicable following reduction factor shall apply to the Non-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:	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

(Continued on Page No. 2)

Progress Energy

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

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~~12.278~~¢ per On-Peak kWh 0.753~~0.665~~¢ 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 0.669~~0.591~~¢ 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,
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: ~~February 10, 2010~~January 1, 2013

Progress Energy

SECTION NO. VI
TWENTY ~~FIFTH~~ SIXTH REVISED SHEET NO. 6.165
CANCELS TWENTY ~~FOURTH~~ FIFTH REVISED SHEET ~~NO. 6.165~~

RATE SCHEDULE GS-2
GENERAL SERVICE – NON-DEMAND
100% LOAD FACTOR USAGE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, with fixed wattage loads operating continuously throughout the billing period (such as traffic signals, cable TV amplifiers and gas transmission substations).

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:

Unmetered Account:	\$ 6.54
Metered Account:	\$ 11.59

Energy and Demand Charges:

Non-Fuel Energy Charge:	1.857~~1.640~~¢ per 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

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 Energy Charge included in the Rate per Month section of this rate schedule shall be increased by 0.135~~0.110~~¢ per kWh for the cost of reserving capacity in the alternate distribution circuit.

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

(Continued on Page No. 2)

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

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

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

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes for which no other rate schedule is specifically applicable with a measured annual kWh consumption of 24,000 kWh or greater per year.

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 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:	$ 11.59
Primary Metering Voltage:	$ 146.56
Transmission Metering Voltage:	$ 722.90

Demand Charge:	$ 4.59~~4.05~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106

Energy Charge:

Non-Fuel Energy Charge:	2.045~~1.806~~¢ 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

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 Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $0.99~~0.87~~ 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 current billing period.

(Continued on Page No. 2)

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

EFFECTIVE: ~~April 1, 2010~~January 1, 2013

RATE SCHEDULE GSD-1
GENERAL SERVICE - DEMAND
(Continued from Page No. 1)

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 credits:

For Distribution Primary Delivery Voltage:	$0.36 ~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 ~~1.19~~ per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge 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~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically .62 times the measured kW demand, and will be decreased 26~~23~~¢ 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. 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 the bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of twelve (12) months from commencement of service and shall continue thereafter until receipt of notice by the Company from the customer to disconnect, or upon disconnect by the Company under Florida Public Service Commission or Company Rules.

Customers taking service under another Company rate schedule who elect to transfer to this rate must remain on this rate for a minimum term of twelve (12) months.

(Continued on Page No. 3)

Progress Energy

RATE SCHEDULE GSDT-1
GENERAL SERVICE - DEMAND
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of the customer, otherwise eligible for service under Rate Schedule GSD-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

Demand Charges:

Base Demand Charge:	$ 1.12 ~~0.99~~ *per kW of Base Demand*
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 3.41 ~~3.04~~ per kW of On-Peak Demand

Energy Charges:

Non-Fuel Energy Charge:	4.452 ~~3.932~~¢ *per On-Peak kWh* 0.747 ~~0.660~~¢ 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 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 Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $0.99 ~~0.87~~ *per kW for the cost of reserving capacity in the alternate distribution circuit.*

(Continued on Page No. 2)

Progress Energy

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

RATE SCHEDULE GSDT-1
GENERAL SERVICE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

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.

(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.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

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

For Distribution Primary Delivery Voltage:	$0.36 ~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$1.35 ~~1.19~~ 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 applicable following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

For customers with metered 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~~23~~¢ for each KVAR by which the reactive demand exceeds numerically .62 times the measured kW demand, and will be decreased 26~~23~~¢ for each KVAR by which the reactive demand is less than, numerically, .62 times the measured kW demand.

(Continued on Page No. 3)

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

EFFECTIVE: ~~February 10, 2010~~ January 1, 2013

Progress Energy

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
$3.60 ~~2.30~~ x C + $0.05[1] x kWh monthly	$0 \le CRH \le 200$
$4.32 ~~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:

$$C = \frac{\text{kWh annual}}{[\text{CAH} - (\#\text{ of Requests} \times \frac{1}{4}\text{ hour})]}$$

Definitions:

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.

[1] 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)

Progress Energy

RATE SCHEDULE CS-1
CURTAILABLE 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 purposes where the customer agrees during a period of requested curtailment to curtail as a minimum the greater of: (a) 25 kW or (b) 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 Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Curtailable service under this rate schedule is not 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 Charge:	$ 7.37~~6.51~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 3.74~~2.50~~ per kW of Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	1.346~~1.189~~¢ 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

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 Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $0.99~~0.87~~ per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

Progress Energy

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

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 demand established during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current Billing Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of 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 delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$-0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$-1.35~~1.19~~ per kW of Billing Demand

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:

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~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 26~~23~~¢ 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. 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.

(Continued on Page No. 3)

Progress Energy

SECTION NO. VI
~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 6.235
~~CANCELS TENTH~~ ~~ELEVENTH REVISED SHEET~~ NO. 6.235

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

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 Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not 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 Charge:	$ 7.37~~6.51~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 6.53~~2.48~~ per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	1.346~~1.189~~¢ 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

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 Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $0.99~~0.87~~ 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

EFFECTIVE: ~~April 1, 2010~~ January 1, 2013

Progress Energy

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

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 demand established during the current billing period, but not less than 500 kW.

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 delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$~~-~~0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$-1.35~~1.10~~ per kW of Billing Demand

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:

Bills computed under the above rate per month charges will be increased 26~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 26~~23~~¢ 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 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.

(Continued on Page No. 3)

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

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

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

RATE SCHEDULE CS-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 2,000 kW or more (based on most recent twelve (12) months or, where not available, projected billing demand for twelve (12) months), and where the customer agrees to curtail its demand by a fixed contractual amount of not less than 2,000 kW upon request of the Company in accordance with the provisions of this rate schedule.

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:	$ 75.96
Primary Metering Voltage:	$ 210.93
Transmission Metering Voltage:	$ 787.26
Demand Charge:	$ 7.37~~6.51~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 6.53~~2.48~~ per kW of Fixed Curtailable Demand
Energy Charge:	
Non-Fuel Energy Charge:	1.346~~1.189~~¢ per kW
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

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 Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $0.99~~0.87~~ 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 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:	$-0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$-1.35~~1.19~~ 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

Progress Energy

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

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 26~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 26~~23~~¢ 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.

   (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 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 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)

Progress Energy

SECTION NO. VI
FIRST REVISED SHEET NO. 6.2392
CANCELS ORIGINAL SHEET NO. 6.2392

RATE SCHEDULE CS-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
~~OPTIONAL TIME OF USE RATE~~
(Continued from Page No. 2)

Special Provisions: (Continued)

4. A customer will be deemed to have complied with its curtailment responsibility if the maximum 30-minute kW demand established during each period of requested curtailment is lower thaen what the customer's maximum 30-minute kW demand would otherwise have been during~~established immediately prior to~~ the period of requested curtailment by at least the Fixed Curtailable Demand defined in Special Provision No. 2. This will be determined by the Company using the customer's load data of similar day, time and weather conditions where a curtailment was not requested.

5. If a customer has not complied with its curtailment responsibility during a period of requested curtailment, the customer will be billed the following additional charge for all billing periods following the previous period of requested curtailment through the billing period in which such non-compliance 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 GSD-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 GSD-1. This calculation shall be exclusive of any additional charges rendered under Special Provision No. 6 of this rate schedule.

6. To minimize the frequency and duration of curtailments requested under this rate schedule, the Company will attempt to purchase additional energy, if available, from sources outside the Company's system during periods for which curtailment would otherwise be requested. 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. Any energy associated with curtailable loads used during these periods will be subject to the additional charges set forth in the second paragraph of this provision. Customers may avoid these higher charges by curtailing their usage during such periods at least their Fixed Curtailable Demand pursuant to the third paragraph of these provisions.

   In the event a customer elects not to curtail, 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, for all consumption above the customer's Non-Curtailable Demand during the period for which curtailment would have otherwise been requested. The cost of such purchased energy shall be based on the average cost of all purchased power and energy provided under this rate schedule and under similar provisions in Rate Schedules IS-1, IST-1, CS-1, CST-1, IS-2, IST-2, CS-2, CST-2, CST-3, SS-2, and SS-3 during the corresponding calendar month. If, for any reason during such period, the customer is notified that the energy purchased from outside sources is no longer available, the terms of this Special Provision will cease to apply and curtailments to at least the customer's Fixed Curtailable Demand will be required for the remainder of such period.

   In the event a customer elects to curtail irrespective of the availability of additional energy purchased by the Company and curtails by at least its Fixed Curtailable Demand during the period for which curtailment would have otherwise been requested, the customer will incur no responsibility for the payment of the additional cost of such energy.

7. If the customer increases its power requirements in any manner which requires the Company to install additional facilities for the specific use of the customer, a new Term of Service may be required at the Company's option.

8. The Company will furnish service under this rate at a single voltage. Any equipment to supply additional voltages or any additional facilities for the use of the customer shall be furnished and maintained by the customer. At its option, the Company may furnish, install and maintain such additional equipment upon request of the customer, in which event an additional monthly charge will be made at the rate of 1.67% times the installed cost of such additional equipment.

9. Customers taking non-firm service under this rate schedule who desire to transfer to a rate schedule providing firm service will be required to give the Company written notice at least thirty-six (36) months prior to such transfer. Such notice shall be irrevocable unless the Company and the customer shall mutually agree to void the notice.

10. *Service under this rate is not available if all or a part of the customer's load serves a facility designated by an appropriate governmental agency for use as a public shelter during periods of emergency or natural disaster*

~~ISSUED BY: MARK A. MYERS, VICE PRESIDENT, FINANCE~~Lori J. Cross, Manager, Utility Regulatory Planning - Florida

EFFECTIVE: ~~March 30, 2004~~January 1, 2013

Progress Energy

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

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 not 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 ~~0.97~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.22 ~~5.49~~ per kW of On-Peak Demand
Curtailable Demand Credit:	$ 3.74 ~~2.50~~ per kW of Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	2.470 ~~2.181~~¢ per On-Peak kWh 0.742 ~~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 $0.99 ~~0.87~~ 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

EFFECTIVE: ~~April 1, 2010~~ January 1, 2013

Progress Energy

RATE SCHEDULE CST-1
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Closed to New Customers as of 04/16/96)
(Continued from Page No. 1)

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.

(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.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Determination of Curtailable Demand:

The Curtailable Demand shall be the difference, if any, between the current On-Peak Demand and the contract Non-Curtailable Demand determined in accordance with Special Provision No. 2 of 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 delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$~~-~~0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$-1.35~~1.19~~ 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, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 26~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased26 ~~23~~¢ 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

(Continued on Page No. 3)

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

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

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 not 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~~0.97~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.22~~5.49~~ per kW of On-Peak Demand

Curtailable Demand Credit: $ 6.53~~2.48~~ per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	2.470~~2.181~~¢ per On-Peak kWh 0.742~~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 $0.99~~0.87~~ 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

EFFECTIVE: ~~April 1, 2010~~ January 1, 2013

Progress Energy

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

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 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.

(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 Periods during the current billing period.

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 delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$ 0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$ 1.35~~1.19~~ 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, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 26~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 26~~23~~¢ 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

(Continued on Page No. 3)

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

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

SECTION NO. VI
~~EIGHTH~~ NINTH REVISED SHEET NO. 6.2490
CANCELS ~~SEVENTH~~ EIGHTH 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:	$ 75.96
Primary Metering Voltage:	$ 210.93
Transmission Metering Voltage:	$ 787.26

Demand Charges:

Base Demand Charge:	$ 1.10~~0.97~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 6.22~~5.49~~ per kW of On-Peak Demand
Curtailable Demand Credit:	$ 6.53~~2.48~~ per kW of Fixed Curtailable Demand

Energy Charge:

Non-Fuel Energy Charge:	2.470~~2.181~~¢ per On-Peak kWh 0.742~~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 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 $0.99~~0.87~~ 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*:	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 following Monday shall be excluded from the On-Peak Periods.

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

EFFECTIVE: ~~April 1, 2010~~January 1, 2103

Progress Energy

RATE SCHEDULE CST-3
CURTAILABLE 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 be the maximum 30-minute kW demand established during the current billing period, but not less than 2,000 kW.

The On-Peak Demand for billing purposes shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate schedule 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:	$-0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$-1.35~~1.19~~ 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 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 26~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured demand, and will be decreased 26~~23~~¢ 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.

(Continued on Page No. 3)

Progress Energy

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

RATE SCHEDULE CST-3
CURTAILABLE GENERAL SERVICE – FIXED CURTAILABLE DEMAND
OPTIONAL TIME OF USE RATE
(Continued from Page No. 2)

Special Provisions: (Continued)

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 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 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.

4. A customer will be deemed to have complied with its curtailment responsibility if the maximum 30-minute kW demand established during each period of requested curtailment is lower thaen what the customer's maximum 30-minute kW demand would otherwise have been during~~established immediately prior to~~ the period of requested curtailment by at least the Fixed Curtailable Demand defined in Special Provision No. 2. This will be determined by the Company using customer's load data of similar day, time and weather conditions where a curtailment was not requested.

5. If a customer has not complied with its curtailment responsibility during a period of requested curtailment, the customer will be billed the following additional charge for all billing periods following the previous period of requested curtailment through the billing period in which such non-compliance 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. To minimize the frequency and duration of curtailments requested under this rate schedule, the Company will attempt to purchase additional energy, if available, from sources outside the Company's system during periods for which curtailment would otherwise be requested. 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. Any energy associated with curtailable loads used during these periods will be subject to the additional charges set forth in the second paragraph of this provision. Customers may avoid these higher charges by curtailing their usage during such periods to at least their Fixed Curtailable Demand pursuant to the third paragraph of these provisions.

   In the event a customer elects not to curtail, 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, for all consumption above the customer's Non-Curtailable Demand during the period for which curtailment would have otherwise been requested. The cost of such purchased energy shall be based on the average cost of all purchased power and energy provided under this rate schedule and under similar provisions in Rate Schedules IS-1, IST-1, CS-1, CST-1, IS-2, IST-2, CS-2, CST-2, CS-3, SS-2 and SS-3 during the corresponding calendar month. If, for any reason during such period, the customer is notified that the energy purchased from outside sources is no longer available, the terms of this Special Provision will cease to apply and curtailments to at least the customer's Fixed Curtailable Demand will be required for the remainder of such period.

(Continued on Page No. 4)

~~ISSUED BY: MARK A. MYERS, VICE PRESIDENT, FINANCE~~~~Lori J. Cross, Manager, Utility Regulatory Planning -~~ Florida

EFFECTIVE: ~~March 30, 2004~~January 1, 2013

Progress Energy

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

In the event a customer elects to curtail irrespective of the availability of additional energy purchased by the Company and curtails by at least its Fixed Curtailable Demand during the period for which curtailment would have otherwise been requested, the customer will incur no responsibility for the payment of the additional cost of such energy.

7. If the customer increases its power requirements in any manner which requires the Company to install additional facilities for the specific use of the customer, a new Term of Service may be required at the Company's option.

(Continued on Page No. 4)

ISSUED BY: ~~MARK A. MYERS, VICE PRESIDENT, FINANCE~~~~Lori J. Cross, Manager, Utility Regulatory Planning -~~ Florida

EFFECTIVE: ~~March 30, 2004~~January 1, 2013

Progress Energy

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

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 purposes 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:

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:

Customer Charge:

Secondary Metering Voltage:	$ 278.95
Primary Metering Voltage:	$ 413.94
Transmission Metering Voltage:	$ 990.26

Demand Charge:	$ 6.24~~5.61~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 4.99~~3.62~~ per kW of Billing Demand

Energy Charge:

Non-Fuel Energy Charge:	0.902~~0.797~~¢ 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

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~~0.87~~ 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.

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:	$~~-~~0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$~~-~~1.35~~1.19~~ per kW of Billing Demand

(Continued on Page No. 2)

Progress Energy

SECTION NO. VI
~~EIGHTEENTH~~ NINETEENTH REVISED SHEET NO. 6.251
CANCELS ~~SEVENTEENTH~~ EIGHTEENTH REVISED
~~SHEET NO. 6.251~~

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 appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, 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) of 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~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 26~~23~~¢ 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.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of five (5) 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. 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.

2. 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 equipment (metering, under-frequency relay, etc.) 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.

3. The Company may, under the provisions of this rate, at its option, require a special contract with the customer upon the Company's filed contract form.

4. 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 shall be based on the average cost of all purchased power and 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 Regulatory Planning - Florida

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

SECTION NO. VI
~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.255
CANCELS ~~ELEVENTH~~ TWELFTH REVISED SHEET NO. 6.255

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:

Customer Charge:

Secondary Metering Voltage:	$ 278.95
Primary Metering Voltage:	$ 413.94
Transmission Metering Voltage:	$ 990.26
Demand Charge:	$ 6.24~~5.51~~ per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 8.70~~3.31~~ per kW of Load Factor Adjusted Demand
Energy Charge:	
Non-Fuel Energy Charge:	0.902~~0.797~~¢ 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

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~~0.87~~ 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:	~~$-~~0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	~~$-~~1.35~~1.19~~ per kW of Billing Demand

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE
(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, Interruptible Demand Credit, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

Bills computed under the above rate per month charges will be increased 26~~23~~¢ for each KVAR by which the reactive demand exceeds, numerically, .62 times the measured kW demand, and will be decreased 26~~23~~¢ 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.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of five (5) 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. 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.

2. 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 equipment (metering, under-frequency relay, etc.) 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. Before commencement of service under this rate, the Company shall exercise an interruption for purposes of testing its equipment. The Company shall also have the right to exercise at least one additional interruption each calendar year irrespective of capacity availability or operating conditions. The Company will give the customer notice of the test.

3. The Company may, under the provisions of this rate, at its option, require a special contract with the customer upon the Company's filed contract form.

4. 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 shall be based on the average cost of all purchased power and energy provided under this rate schedule and under similar provisions in Rate Schedules IS-1, IST-1, CS-1, CST-1, 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)

Progress Energy

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 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 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:

Base Demand Charge:	$ 0.99~~0.87~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 5.46~~4.82~~ per kW of On-Peak Demand
Interruptible Demand Credit:	$ 4.99~~3.62~~ per kW of On-Peak Demand

Energy Charge:

Non-Fuel Energy Charge:	1.264~~1.116~~¢ per On-Peak kWh 0.737~~0.651~~¢ 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 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~~0.87~~ 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:

(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 Period.

(Continued on Page No. 2)

Progress Energy

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

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current 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:	$~~-~~0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$~~-~~1.35~~1.19~~ 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 Charge, 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~~23~~¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 26~~23~~¢ 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.

Terms of Payment:

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

(Continued on Page No. 3)

Progress Energy

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

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 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 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:

Base Demand Charge:	$ 0.99~~0.87~~ per kW of Base Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
On-Peak Demand Charge:	$ 5.46~~4.82~~ per kW of On-Peak Demand

Interruptible Demand Credit: $ 8.70~~3.31~~ per kW of Load Factor Adjusted Demand

Energy Charge:

Non-Fuel Energy Charge:	1.264~~1.116~~¢ per On-Peak kWh 0.737~~0.651~~¢ 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 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~~0.87~~ 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:

(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)

Progress Energy

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 Periods 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:	$-0.36~~0.32~~ per kW of Billing Demand
For Transmission Delivery Voltage:	$-1.35~~1.19~~ 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~~23~~¢ for each KVAR by which the reactive demand exceeds numerically, .62 times the measured kW demand, and will be decreased 26~~23~~¢ 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)

Progress Energy

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

RATE SCHEDULE LS-1
LIGHTING SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer for the sole purpose of lighting roadways or other outdoor land use areas; served from either Company or customer owned fixtures of the type available under this rate schedule. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party.

Character of Service:

Continuous dusk to dawn automatically controlled lighting service (i.e. photoelectric cell); alternating current, 60 cycle, single phase, at the Company's standard voltage available.

Limitation of Service:

Availability of certain fixture or pole types at a location may be restricted due to accessibility.

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 Governing Electric Service."

Rate Per Month:

Customer Charge:

Unmetered:	\$ 1.19 per line of billing
Metered:	\$ 3.42 per line of billing

Energy and Demand Charge:

Non-Fuel Energy Charge:	~~1.707~~1.933¢ per 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

Per Unit Charges:

I. Fixtures:

		LAMP SIZE [2]			CHARGES PER UNIT		
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Incandescent: [1]						
110	Roadway	1,000	105	32	\$1.03	\$4.07	~~\$0.55~~0.62
115	Roadway	2,500	205	66	1.61	3.67	~~1.13~~1.28
170	Post Top	2,500	205	72	20.39	3.67	~~1.23~~1.39
	Mercury Vapor: [1]						
205	Open Bottom	4,000	100	44	\$2.55	\$1.80	~~\$0.75~~0.85
210	Roadway	4,000	100	44	2.95	1.80	~~0.75~~0.85
215	Post Top	4,000	100	44	3.47	1.80	~~0.75~~0.85
220	Roadway	8,000	175	71	3.34	1.77	~~1.21~~1.37
225	Open Bottom	8,000	175	71	2.50	1.77	~~1.21~~1.37
235	Roadway	21,000	400	158	4.04	1.81	~~2.70~~3.05
240	Roadway	62,000	1,000	386	5.29	1.78	~~6.59~~7.46
245	Flood	21,000	400	158	5.29	1.81	~~2.70~~3.05
250	Flood	62,000	1,000	386	6.20	1.78	~~6.59~~7.46

(Continued on Page No. 2)

Progress Energy

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

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 1)

I. Fixtures: (Continued)

		LAMP SIZE [2]			CHARGES PER UNIT		
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE	NON-FUEL ENERGY [3]
	Sodium Vapor:						
300	HPS Deco Rdwy White	50,000	400	168	$14.73	$1.61	~~$2.87~~3.25
301	Sandpiper HPS Deco Roadway	27,500	250	104	13.81	1.72	~~1.78~~2.01
302	Sandpiper HPS Deco Rdwy Blk	9,500	100	42	14.73	1.58	~~0.72~~0.81
305	Open Bottom [1]	4,000	50	21	2.54	2.04	~~0.36~~0.41
310	Roadway [1]	4,000	50	21	3.12	2.04	~~0.36~~0.41
313	Open Bottom [1]	6,500	70	29	4.19	2.05	~~0.50~~0.56
314	Hometown II	9,500	100	42	4.08	1.72	~~0.72~~0.81
315	Post Top - Colonial/Contemp [1]	4,000	50	21	5.04	2.04	~~0.36~~0.41
316	Colonial Post Top [1]	4,000	50	34	4.05	2.04	~~0.58~~0.66
318	Post Top [1]	9,500	100	42	2.50	1.72	~~0.72~~0.81
320	Roadway-Overhead Only	9,500	100	42	3.64	1.72	~~0.72~~0.81
321	Deco Post Top - Monticello	9,500	100	49	12.17	1.72	~~0.84~~0.95
322	Deco Post Top - Flagler	9,500	100	49	16.48	1.72	~~0.84~~0.95
323	Roadway-Turtle OH Only	9,500	100	42	4.32	1.72	~~0.72~~0.81
325	Roadway-Overhead Only	16,000	150	65	3.78	1.75	~~1.11~~1.26
326	Deco Post Top – Sanibel	9,500	100	49	18.16	1.72	~~0.84~~0.95
330	Roadway-Overhead Only	22,000	200	87	3.64	1.83	~~1.49~~1.66
335	Roadway-Overhead Only	27,500	250	104	4.16	1.72	~~1.78~~2.01
336	Roadway-Bridge [1]	27,500	250	104	6.74	1.72	~~1.78~~2.01
337	Roadway-DOT [1]	27,500	250	104	5.87	1.72	~~1.78~~2.01
338	Deco Roadway–Maitland	27,500	250	104	9.62	1.72	~~1.78~~2.01
340	Roadway-Overhead Only	50,000	400	169	5.03	1.76	~~2.88~~3.27
341	HPS Flood-City of Sebring only [1]	16,000	150	65	4.06	1.75	~~1.11~~1.26
342	Roadway-Turnpike [1]	50,000	400	168	8.95	1.76	~~2.87~~3.25
343	Roadway-Turnpike [1]	27,500	250	108	9.12	1.72	~~1.84~~2.09
345	Flood-Overhead Only	27,500	250	103	5.21	1.72	~~1.76~~1.99
347	Clermont	9,500	100	49	20.65	1.72	~~0.84~~0.95
348	Clermont	27,500	250	104	22.65	1.72	~~1.78~~2.01
350	Flood-Overhead Only	50,000	400	170	5.19	1.76	~~2.90~~3.29
351	Underground Roadway	9,500	100	42	6.22	1.72	~~0.72~~0.81
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	~~1.84~~2.09
356	Underground Roadway	50,000	400	168	8.69	1.76	~~2.87~~3.25
357	Underground Flood	27,500	250	108	9.36	1.72	~~1.84~~2.09
358	Underground Flood [1]	50,000	400	168	9.49	1.76	~~2.87~~3.25
359	Underground Turtle Roadway	9,500	100	42	6.09	1.72	~~0.72~~0.81
360	Deco Roadway Rectangular [1]	9,500	100	47	12.53	1.72	~~0.80~~0.91
365	Deco Roadway Rectangular	27,500	250	108	11.89	1.72	~~1.84~~2.09
366	Deco Roadway Rectangular	50,000	400	168	12.00	1.76	~~2.87~~3.25
370	Deco Roadway Round [1]	27,500	250	108	15.41	1.72	~~1.84~~2.09
375	Deco Roadway Round [1]	50,000	400	168	15.42	1.76	~~2.87~~3.25
380	Deco Post Top – Ocala	9,500	100	49	8.78	1.72	~~0.84~~0.95
381	Deco Post Top [1]	9,500	100	49	4.05	1.72	~~0.84~~0.95
383	Deco Post Top-Biscayne	9,500	100	49	14.17	1.72	~~0.84~~0.95
385	Deco Post Top – Sebring	9,500	100	49	6.75	1.72	~~0.84~~0.95
393	Deco Post Top [1]	4,000	50	21	8.72	2.04	~~0.36~~0.41
394	Deco Post Top [1]	9,500	100	49	18.16	1.72	~~0.84~~0.95

(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

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 2)

I. Fixtures: (Continued)

BILLING TYPE	DESCRIPTION	LAMP SIZE [2] INITIAL LUMENS OUTPUT	LAMP SIZE [2] LAMP WATTAGE	kWh	CHARGES PER UNIT FIXTURE	CHARGES PER UNIT MAINTENANCE	CHARGES PER UNIT NON-FUEL ENERGY [3]
	Metal Halide:						
307	Deco Post Top-MH Sanibel P	11,600	150	65	$16.85	$2.68	~~$1.11~~1.26
308	Clermont Tear Drop P	11,600	150	65	19.91	2.68	~~1.11~~1.26
309	MH Deco Rectangular P	36,000	320	126	13.07	2.74	~~2.15~~2.44
311	MH Deco Cube P	36,000	320	126	15.98	2.74	~~2.15~~2.44
312	MH Flood P	36,000	320	126	10.55	2.74	~~2.15~~2.44
319	MH Post Top Biscayne P	11,600	150	65	15.24	2.68	~~1.11~~1.26
327	Deco Post Top-MH Sanibel [1]	12,000	175	74	18.39	2.72	~~1.26~~1.43
349	Clermont Tear Drop [1]	12,000	175	74	21.73	2.72	~~1.26~~1.43
371	MH Deco Rectangular [1]	38,000	400	159	14.26	2.84	~~2.71~~3.07
372	MH Deco Circular [1]	38,000	400	159	16.70	2.84	~~2.71~~3.07
373	MH Deco Rectangular [5]	110,000	1,000	378	15.30	2.96	~~6.45~~7.31
386	MH Flood [5]	110,000	1,000	378	13.17	2.96	~~6.45~~7.31
389	MH Flood-Sportslighter [5]	110,000	1,000	378	13.01	2.96	~~6.45~~7.31
390	MH Deco Cube [1]	38,000	400	159	17.44	2.84	~~2.71~~3.07
396	Deco PT MH Sanibel Dual [5]	24,000	350	148	33.73	5.43	~~2.53~~2.86
397	MH Post Top-Biscayne	12,000	175	74	14.98	2.72	~~1.26~~1.43
398	MH Deco Cube [5]	110,000	1,000	378	20.34	2.96	~~6.45~~7.31
399	MH Flood	38,000	400	159	11.51	2.84	~~2.71~~3.07
	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	~~0.94~~1.06
330	LED Shoebox Type 3	20,664	309	108	41.08	2.84	~~1.84~~2.09
335	LED Shoebox Type 4	14,421	206	72	32.59	2.84	~~1.23~~1.39
336	LED Shoebox Type 5	14,421	206	72	31.65	2.84	~~1.23~~1.39

(Continued on Page No. 4)

Progress Energy

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. 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. 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 shall be $81.21.

2. **Supplemental Service Charges:**

All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution Capacity:**

$1.801 ~~1.59~~ 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.

B. **Generation & Transmission Capacity:**

The charge shall be the greater of:

1. $1.005 ~~0.888~~ 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 $0.479 ~~0.423~~/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 in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106

C. **Energy Charges**

Non-Fuel Energy Charge:	0.890 ~~0.786~~¢ 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

(Continued on Page No. 4)

Progress Energy

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

RATE SCHEDULE SS-1
FIRM STANDBY SERVICE
(Continued from Page No. 3)

Rate Per Month: (Continued)

3. Standby Service Charges: (Continued)

D. **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~~29~~¢ per kW.

E. **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, Non-Fuel Energy Charge, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

F. **Fuel Cost Recovery Factor:**

Time of Use Fuel Charges of applicable metering voltage 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
I.	Municipal Tax:	See Sheet No. 6.106
J.	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. 3 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 $0.92~~0.81~~ 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:

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.
B.	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.

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.

(Continued on Page No. 5)

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

EFFECTIVE: ~~February 10, 2010~~January 1, 2013

Progress Energy

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

RATE SCHEDULE SS-2
INTERRUPTIBLE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. 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. 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:	$ 303.71
Primary Metering Voltage:	$ 438.68
Transmission Metering Voltage:	$ 1,015.02

Note: Where the customer has paid the costs of metering equipment pursuant to a Cogeneration Agreement, the Customer Charge shall be $284.20.

2. **Supplemental Service Charges:**
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution Capacity:**
$1.80~~1.59~~ 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.

B. **Generation & Transmission Capacity:**
The charge shall be the greater of:
1. $1.005~~0.888~~ 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 $0.479~~0.423~~ 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 in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C~~1~~. **Interruptible Capacity Credit ~~for customer accounts established prior to 01/01/2006~~:**
The credit shall be the greater of:
1. $0.870~~0.690~~ 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 $0.414~~0.329~~/kW times the appropriate Billing Month Factor shown in part 3.B. above.

~~C2. Interruptible Capacity Credit for customer accounts established on or after 01/01/2006:~~
~~The credit shall be the greater of:~~
~~1. $0.331 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 $0.158/kW times the appropriate Billing Month Factor shown in part 3.B. above.~~

D. **Energy Charges:**
Non-Fuel Energy Charge: 0.880~~0.777~~¢ *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 distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 33~~29~~¢ per kW.

(Continued on Page No. 4)

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

EFFECTIVE: ~~April 1, 2010~~ January 1, 2013

Progress Energy

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

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:

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.	Gross Receipts Tax Factor:	See Sheet No. 6.106
I.	Right-of-Way Utilization Fee:	See Sheet No. 6.106
J.	Municipal Tax:	See Sheet No. 6.106
K.	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 $0.92~~0.81~~ 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:

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.

B. 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.

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.
2. 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)

Progress Energy

RATE SCHEDULE SS-3
CURTAILALBE STANDBY SERVICE
(Continued from Page No. 2)

Determination of Specified Standby Capacity:

1. 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. 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 shall be $81.21.

2. **Supplemental Service Charges:**
All supplemental power requirements shall be billed in accordance with the demand and energy charges of the otherwise applicable rate schedule.

3. **Standby Service Charges:**

A. **Distribution Capacity:**
$1.80~~1.59~~ 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.

B. **Generation & Transmission Capacity:**
The charge shall be the greater of:
1. $1.005~~0.888~~ 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 $0.479~~0.423~~/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 in Rate Schedule BA-1, *Billing Adjustments*: See Sheet No. 6.105 and 6.106

C~~1~~. **Curtailable Capacity Credit~~ for customer accounts established prior to 01/01/2006~~:**
The credit shall be the greater of:
1. $0.653~~0.345~~ 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 $0.311~~0.164~~/kW times the appropriate Billing Month Factor shown in part 3.B. above.

~~C2. Curtailable Capacity Credit 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~~
~~2. The 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.B. above.~~

D. **Energy Charges:**
Non-Fuel Energy Charge: 0.883~~0.780~~¢ per kWh

Plus the Cost Recovery Factors on a ¢/ kWh basis listed 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 distribution primary delivery voltage, the Distribution Capacity Charge hereunder will be reduced by 33~~29~~¢ per kW.

(Continued on Page No. 4)

Progress Energy

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

RATE SCHEDULE SS-3
CURTAILABLE 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:

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.	Gross Receipts Tax Factor:	See Sheet No. 6.106
I.	Right-of-Way Utilization Fee:	See Sheet No. 6.106
J.	Municipal Tax:	See Sheet No. 6.106
K.	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 $0.92~~0.81~~ 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:

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.

B. 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.

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.

(Continued on Page No. 5)

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

	Capital Ratio	Cost Rates	AFUDC 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%

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

	Capital Ratio	Cost Rates	AFUDC 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%	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%
Total	100.00%		6.00%

PROGRESS ENERGY FLORIDA, INC.
Capital Structure & AFUDC Calculation

	Capital Ratio	Cost Rates	AFUDC 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%	10.70%	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%

	Lewy over 5 years NCRC Impact
RS	0.345 cents/KWH
RS	**3.45 $/1000 KWH**
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.

LEVY COUNTY NUCLEAR UNITS 1 & 2
Site Selection, Preconstruction Costs, and Carrying Costs on Construction Cost Balance
Projection Filing: Summary of Jurisdictional Recovery Amounts

Schedule P-1 - (Revised 6/2/2011)

EXPLANATION: Provide summary calculation of the monthly Projected Amount for each cost category: 1. Site Selection, 2. Preconstruction, and 3. Construction. In the event that no costs were approved for recovery and no costs are being requested, state so. For each category with costs, list and describe the components and levels, identify supporting schedule and line. Include in the Projected calculation applicable Commission approved projection and Projected amounts for the reported year and identify such orders.

[25-6.0423(5)(c)1.c.,F.A.C.]
[25-6.0423 (8)(e),F.A.C.]

COMPANY:
Progress Energy - FL

Witness: Thomas G Foster

DOCKET NO.:
110009-EI

For Year Ended 12/31/2012

Line No.	Description	(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(N) 12 Month Total
		Jurisdictional Dollars						
1.	Projected Site Selection Costs for the Period [25-6.0423(2)(f),F.A..C.]							
a.	Additions (Schedule P-2.1, line 1)	$0	$0	$0	$0	$0	$0	$0
b.	Carrying Costs on Additions (Schedule P-2.1, line 7)	0	0	0	0	0	0	0
c.	Carrying Costs on Deferred Tax Asset (Schedule P-3A.1, line 11)	0	0	0	0	0	0	0
d.	Total Site Selection Amount (Lines 1.a through 1.c)	$0	$0	$0	$0	$0	$0	$0
2.	Projected Preconstruction Costs for the Period [25-6.0423(2)(g),F.A..C.]							
a.	Additions (Schedule P-2.2, line 1)	$1,651,403	$1,658,254	$2,561,754	$2,677,348	$2,552,414	$2,562,189	$25,453,715
b.	Carrying Costs on Additions (Schedule P-2.2, line 9)	918,468	872,274	830,797	785,176	738,288	692,110	11,328,648
c.	Carrying Costs on Deferred Tax (Schedule P-3A.2, line 11)	1,746,948	1,766,560	1,788,019	1,811,546	1,835,053	1,858,328	20,862,411
d.	Total Preconstruction Amount (Lines 2.a through 2c)	$4,316,819	$4,297,088	$5,180,570	$5,274,069	$5,125,756	$5,112,627	$57,644,774
3.	Projected Construction Costs for the Period [25-6.0423(2)(i),F.A..C.]							
	Avg. Net Additions Balance (Schedule P-2.3, line 7)	$130,997,420	$131,983,243	$132,998,419	$133,194,134	$133,571,543	$134,086,267	
a.	Carrying Costs on Additions (Schedule P-2.3, line 9)	1,378,276	1,388,649	1,399,330	1,401,389	1,405,360	1,410,775	16,275,073
b.	Carrying Costs on Deferred Tax (Schedule P-3A.3, line 11)	0	0	0	0	0	0	0
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
4.	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
6.	Prior Period (Over) / Under Recovery							(54,968,206)
7.	Period Collection of Deferred Regulatory Asset							114,968,361
8.	Total Amount for the Projected Period Revenue Requirement (Line 5 + Line 6 + Line 7)							135,325,074
9.	Revenue Tax Multiplier							1.00072
10.	Total 2012 Projected Revenue Requirements							$135,422,508

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

Exhibit 7
Page 2 of 4
Duke Energy Florida

SCHEDULE C-4 | JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME | Page 2 of 48

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 090079-EI

Explanation: Provide jurisdictional factors for net operating income for the test year and the most recent historical year if the test year is projected.

(Thousands)

Type of data shown:
X Projected Test Year Ended 12/31/2010
Prior Year Ended 12/31/2009
Historical Test Year Ended 12/31/2008
Witness: Toomey / Slusser

Line No.	Account	Account Title	(A) Total Company	(B) FPSC Jurisdictional	(C) Jurisdictional Sep Factor
1		OPERATION & MAINTENANCE EXPENSES			
2					
3		PRODUCTION EXPENSES			
4					
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			
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		*Base - Demand - Tallahassee Buyback*	33	-	-
28		Total Operations Supervision Engineering	2,253	1,964	0.87177
29	519	Coolant & Water			
30		*Base - Demand*	4,659	4,121	0.88462
31		*Base - Demand - Tallahassee Buyback*	65	-	-
32		Total Coolant & Water	4,724	4,121	0.87237
33	520	Steam Expenses			
34		*Base - Demand*	13,508	11,949	0.88462
35		*Base - Demand - Tallahassee Buyback*	174	-	-
36		Total Steam Expenses	13,682	11,949	0.87335
37					

Supporting Schedules: C-19, C-20, C-21, C-22 | Recap Schedules: C-1

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FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 090079-EI

Explanation: Provide jurisdictional factors for net operating income for the test year and the most recent historical year if the test year is projected.

(Thousands)

Type of data shown:
X Projected Test Year Ended 12/31/2010
Prior Year Ended 12/31/2009
Historical Test Year Ended 12/31/2008
Witness: Toomey / Slusser

Line No.	Account	Account Title	(A) Total Company	(B) FPSC Jurisdictional	(C) Jurisdictional Sep Factor
1	521	**Nuclear Steam Other Sources**			
2		*Base - Energy*	-	-	0.88462
3		*Base - Energy - Tallahassee Buyback*	-	-	-
4		**Total Nuclear Steam Other Sources**	-	-	-
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		*Base - Demand*	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		*Base - Demand*	42,572	37,660	0.88462
17		*Base - Demand - Tallahassee Buyback*	617	-	-
18		**Total Nuclear - Misc Power Expenses**	43,189	37,660	0.87198
19	525	**Nuclear - Rents**			
20		*Base - Demand*	-	-	0.88462
21		*Base - Demand - Tallahassee Buyback*	-	-	-
22		**Total Nuclear - Rents**	-	-	-
23	528	**Nuclear - Maintenance Supervisor & Engineering**			
24		*Base - Energy*	10,779	10,218	0.94789
25		*Direct Assign Retail - Energy*	1,500	1,500	1.00000
26		*Direct Assign Wholesale*	915		-
27		*Base - Energy - Tallahassee Buyback*	132	-	-
28		**Total Nuclear - Maintenance Supervisor & Engineering**	13,327	11,718	0.87923
29	529	**Nuclear - Maintenance Structures**			
30		*Base - Demand*	2,634	2,330	0.88462
31		*Base - Demand - Tallahassee Buyback*	39	-	-
32		**Total Nuclear - Maintenance Structures**	2,672	2,330	0.87179
33	530	**Nuclear - Maintenance Reactor Plant Equipment**			
34		*Base - Energy*	11,877	11,258	0.94789
35		*Direct Assign Wholesale*	1,009	-	-
36		*Base - Energy - Tallahassee Buyback*	169	-	-
37		**Total Nuclear - Maintenance Reactor Plant Equipment**	13,055	11,258	0.86239

Supporting Schedules: C-19, C-20, C-21, C-22 Recap Schedules: C-1

Exhibit 7
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Duke Energy Florida

SCHEDULE C-4 | JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME | Page 4 of 48

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 090079-EI

Explanation: Provide jurisdictional factors for net operating income for the test year and the most recent historical year if the test year is projected.

(Thousands)

Type of data shown:
X Projected Test Year Ended 12/31/2010
Prior Year Ended 12/31/2009
Historical Test Year Ended 12/31/2008
Witness: Toomey / Slusser

Line No.	Account	Account Title	(A) Total Company	(B) FPSC Jurisdictional	(C) Jurisdictional Sep Factor
1	531	Nuclear - Maintenance Electric Plant			
2		*Base - Energy*	6,223	5,899	0.94789
3		*Direct Assign Wholesale*	528	-	-
4		*Base - Energy - Tallahassee Buyback*	32	-	-
5		Total Nuclear - Maintenance Electric Plant	6,783	5,899	0.86960
6	532	Nuclear - Maintenance Misc Nuclear Plant			
7		*Base - Demand*	2,155	1,906	0.88462
8		*Base - Demand - Tallahassee Buyback*	17	-	-
9		Total Nuclear - Maintenance Misc Nuclear Plant	2,172	1,906	0.87777
10	5472000	Fuel - Other Prod Base			
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		*Non-Recoverable Demand*	-	-	1.00000
27		Total PP CAP - Base - Nonrecoverable - Retail	-	-	-
28	5560000	Sys Control & Dispatch			
29		*Base - Demand*	1,324	1,171	0.88462
30		*Intermediate - Demand*	251	146	0.58105
31		*Peaking - Demand*	577	528	0.91520
32		Total Sys Control & Dispatch	2,152	1,845	0.85745
33	5570001	Other Pwr Supply Expenses	-		
34		Total Other Pwr Supply Expenses	-	-	-
35					
36		TOTAL PRODUCTION O&M EXPENSES	332,822	236,832	0.71159
37					

Supporting Schedules: C-19, C-20, C-21, C-22 | Recap Schedules: C-1

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 greater of:

$0.979 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 $0.466 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.

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

	2013			2014 and Beyond	
	NCRC Impact			NCRC Impact	
RS	0.345	cents/KWH	RS	0.345	cents/KWH
RS	**3.45**	**$/1000 KWH**	**RS**	**3.45**	**$/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

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

Line No.	Pre or Post Retirement Component Classification	category	Subject to Cap	Dry Cask Storage
1				
2	Electric Plant In Service	a	$__	
3	Less Accumulated Depreciation	b	$__	
4	Net plant balance	fallout	$__	
5	Write-Down	b	($295m)	
6	Construction Work In Progress (CWIP)			
7	Steam Generator Replacement (SGR) Project	a	$__	
8	Delam Repair Project	b	$__	
9	License Amendment Request (LAR)	b	$__	
10	Dry Cask Storage	d		$__
11	Fukushima	d	$__	
12	Building Stabilization Project	c	$__	
13	Other - CWIP	d	$__	
14	Nuclear Fuel Inventories	a	$__	
15	Nuclear Materials and Supplies Inventories	a	$__	
16	Deferred expenses	e	$__	
17	Cumulative AFUDC (6.00%)	fallout	$__	$__
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	$__	$__
23	Total revenue requirement	fallout	$__	$__

<u>category</u>

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.

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.

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 (No Change)	2014 ($1 Adj.)	2015 ($1 Adj.)	2016 ($1.50 Adj.)	2017 (No Change)
	Levelized Fuel Factors:					
A	Fuel Factor at Secondary Metering (Sch E1-D, line 8)	$ 3.703	$ 3.703	$ 3.703	$ 3.703	$ 3.703
B	Fuel Adjustment per proposed Settlement	$ -	$ 0.100	$ 0.100	$ 0.150	$ -
C = A+B	Adjusted Fuel Factor at Secondary Metering	$ 3.703	$ 3.803	$ 3.803	$ 3.853	$ 3.703
D = C*0.99	Fuel Factor at Primary Metering	$ 3.666	$ 3.765	$ 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 - Off-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).

ISSUES LIST[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?

Issue 3: 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?

Issue 4: 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?

Issue 5: 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?

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[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?

Issue 14: 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?

Issue 16: 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.

<u>**Issue 20**</u>: 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?

<u>**Issue 23**</u>: 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)

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

<u>**Issue 25**</u>: 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.

<u>**Issue 26:**</u> 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.

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

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 all of its rights relative to the issue (for purposes of pursuing its CR3-related insurance claims with NEIL) 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 DEF's decision to settle it'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?

- FIPUG's proposed revision to former Issue 4: Was Duke Energy Corporation's 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: Did DEF reasonably address all insurance 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?

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.

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC)
2013 Detail - Calculation of the Revenue Requirements
January 2013 through December 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	0	0	0	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.		8,307,468	(5,885)	916	5,893	0	36,832	0	0	0	0	0	0	0	$37,756
	f Total		363,014,861	1,515,929	1,667,128	288,623	1,931,030	8,547,107	36,973	32,973	32,973	20,340	20,340	20,340	20,340	$14,134,096
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		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
	Retail Jurisdictional Factor : Generation	92.885%														
	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)		11,624,453	10,843,389	10,062,325	9,281,260	8,500,196	7,719,132	6,938,068	6,157,004	5,375,940	4,594,876	3,813,812	3,032,748	2,251,683	2,251,683
7	Prior Period Carrying Charge Recovered (b)		9,372,769	781,064	781,064	781,064	781,064	781,064	781,064	781,064	781,064	781,064	781,064	781,064	781,064	
8	Prior Period Under/(Over) Recovery (Prior Month)			0	244,075	(326,485)	(324,782)	(337,153)	(348,067)	(344,985)	(313,771)	(288,877)	(293,344)	(297,862)	(302,463)	
9	Net Investment		$264,826,574	$266,746,446	$267,824,561	$266,721,700	$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)													
	a Equity Component	0.00546	0.00394	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	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	
	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	**O&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	813,285	817,491	821,700	825,912	830,127	834,344	838,564	842,787	804,278
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			0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
	c Interest Provision			$1	68	67	67	68	68	68	69	69	69	70	70	803
	d Total O&M Costs and Interest (Line 16 + Line 21c)			4,630	27,437	37,056	42,734	42,734	42,734	42,735	42,735	42,735	42,736	42,736	42,736	453,738
24	Recovered (Order No. PSC 12-0650-FOF-EI)			28	25	23	20	18	16	13	11	8	6	4	1	173
25	Over/Under Recovery For the Period			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.

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

DUKE ENERGY

INDEX OF RATE SCHEDULES

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

EFFECTIVE:

DUKE ENERGY®

**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:

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) 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.
d) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the 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)

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.

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:

a) 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.
b) Customer must not have a relationship with the previous occupant of the unoccupied premise location.
c) The minimum qualifying new load must be at least 350 kW with a minimum load factor of 50% at a single point of delivery.
d) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
e) The new or expanding business must also meet at least one of the following two requirements at the project location:
   1) The addition of 15 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
   2) Capital investment of $200,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
f) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the 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)

DUKE ENERGY.

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.

INDEX OF STANDARD CONTRACT AND OTHER AGREEMENT FORMS

DUKE ENERGY

DUKE ENERGY FLORIDA, INC.
ECONOMIC DEVELOPMENT RIDER

Service Agreement

For a New Establishment or an Existing Establishment with Expanding Load

____
CUSTOMER NAME

______________________________ ______________________________
ADDRESS TYPE OF BUSINESS

The Customer 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 are incorporated by reference herein.

By signing below, I hereby attest that the availability of this rider is a significant factor in this Customer's location / expansion decision.

Signed: ______________________________ Accepted by: ______________________________
Customer Duke Energy Florida, Inc.

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

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

____
CUSTOMER NAME

______________________________ ______________________________
ADDRESS TYPE OF BUSINESS

The Customer hereto agrees as follows:

1. To establish service at a currently vacant Company premise location and 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. The Company premise location for the new or expanded load has been vacant for at least 90 days.
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 and are incorporated by reference herein.

By signing 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: ______________________________
Customer

Accepted by: ______________________________
Duke Energy Florida, Inc.

Title: ______________________________

Title: ______________________________

Date: ______________________________

Date: ______________________________

DUKE ENERGY

SECTION NO. VI
TWENTY-SECOND~~FIRST~~ REVISED SHEET NO. 6.100
CANCELS TWENTY-FIRST~~IETH~~ REVISED SHEET NO. 6.100

INDEX OF RATE SCHEDULES

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

EFFECTIVE: ~~April 29, 2013~~

DUKE ENERGY

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:

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) 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.
d) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the 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)

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

EFFECTIVE:

DUKE ENERGY

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.

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:

a) 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.
b) Customer must not have a relationship with the previous occupant of the unoccupied premise location.
c) The minimum qualifying new load must be at least 350 kW with a minimum load factor of 50% at a single point of delivery.
d) The new or expanding business must be a targeted industry as defined by the state of Florida's most current economic development policy.
e) The new or expanding business must also meet at least one of the following two requirements at the project location:
    1) The addition of 15 net new full time equivalent (FTE) jobs in the Company's Florida service area; or
    2) Capital investment of $200,000 or greater and a net increase in FTE jobs in the Company's Florida service area.
f) Customer must provide written documentation attesting that the availability of this rider is a significant factor in the 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)

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.

DUKE ENERGY

SECTION NO. VII
FOUR~~THIR~~TEENTH REVISED SHEET NO. 7.000
CANCELS THIRTEENTH~~TWELTH~~ REVISED SHEET NO. 7.000

INDEX OF STANDARD CONTRACT AND OTHER AGREEMENT FORMS

DUKE ENERGY FLORIDA, INC.
ECONOMIC DEVELOPMENT RIDER

Service Agreement

For a New Establishment or an Existing Establishment with Expanding Load

____
CUSTOMER NAME

______________________________ ______________________________
ADDRESS TYPE OF BUSINESS

The Customer 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 are incorporated by reference herein.

By signing below, I hereby attest that the availability of this rider is a significant factor in this Customer's location / expansion decision.

Signed: ______________________________ Accepted by: ______________________________
Customer Duke Energy Florida, Inc.

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

DUKE ENERGY.

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

____
CUSTOMER NAME

____
ADDRESS TYPE OF BUSINESS

The Customer hereto agrees as follows:

1. To establish service at a currently vacant Company premise location and 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. The Company premise location for the new or expanded load has been vacant for at least 90 days.

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 and are incorporated by reference herein.

By signing 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.

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

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 RECOVERY FACTORS

Rate Schedule/Metering Level	Fuel Cost Recovery[1]			ECCR[2]		CCR[3]		ECRC[4]
	Levelized ¢/ kWh	On-Peak ¢/ kWh	Off-Peak ¢/ kWh	¢/ kWh	$/ kW	¢/ kWh	$/ kW	¢/ kWh
RS-1, RST-1, RSL-1, RSL-2, RSS-1 (Sec.)		6.189	3.849	0.270	-	1.274	-	0.138
< 1000	4.323							
> 1000	5.323							
GS-1, GST-1								
Secondary	4.605	6.198	3.854	0.231	-	1.030	-	0.133
Primary	4.559	6.136	3.816	0.229	-	1.020	-	0.132
Transmission	4.513	6.074	3.777	0.226	-	1.009	-	0.130
GS-2 (Sec.)	4.605	-	-	0.179	-	0.701	-	0.125
GSD-1, GSDT-1, SS-1*								
Secondary	4.647	6.255	3.890	-	0.79	-	3.35	0.129
Primary	4.601	6.193	3.851	-	0.78	-	3.32	0.128
Transmission	4.554	6.130	3.812	-	0.77	-	3.28	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	-	2.22	0.123
Primary	4.601	6.193	3.851	-	0.59	-	2.20	0.122
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 appropriate General 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.

(Continued on Page No. 2)

DUKE ENERGY

SECTION NO. VI
SEVENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.105
CANCELS ~~SEVENTIETH~~ SEVENTY-FIRST REVISED SHEET NO. 6.105

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 RECOVERY FACTORS									
Rate Schedule/Metering Level	**Fuel Cost Recovery[1]**			**ECCR[2]**		**CCR[3]**		**ECRC[4]**
	Levelized ¢/ kWh	**On-Peak ¢/ kWh**	**Off-Peak ¢/ kWh**	**¢/ kWh**	**$/ kW**	**¢/ kWh**	**$/ kW**	**¢/ kWh**
RS-1, RST-1, RSL-1, RSL-2, RSS-1 (Sec.)		6.189	3.849	0.270	-	~~1.619~~1.274	-	0.138
< 1000	4.323							
> 1000	5.323							
GS-1, GST-1								
Secondary	4.605	6.198	3.854	0.231	-	~~1.282~~1.030	-	0.133
Primary	4.559	6.136	3.816	0.229	-	~~1.269~~1.020	-	0.132
Transmission	4.513	6.074	3.777	0.226	-	~~1.256~~1.009	-	0.130
GS-2 (Sec.)	4.605	-	-	0.179	-	~~0.883~~0.701	-	0.125
GSD-1, GSDT-1, SS-1*								
Secondary	4.647	6.255	3.890	-	0.79	-	~~4.19~~3.35	0.129
Primary	4.601	6.193	3.851	-	0.78	-	~~4.15~~3.32	0.128
Transmission	4.554	6.130	3.812	-	0.77	-	~~4.11~~3.28	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~~2.22	0.123
Primary	4.601	6.193	3.851	-	0.59	-	~~3.10~~2.20	0.122
Transmission	4.554	6.130	3.812	-	0.59	-	~~3.07~~2.18	0.121
IS-1, IST-1, IS-2, IST-2, SS-2*								
Secondary	4.647	6.255	3.890	-	0.71	-	~~3.52~~2.83	0.122
Primary	4.601	6.193	3.851	-	0.70	-	~~3.48~~2.80	0.121
Transmission	4.554	6.130	3.812	-	0.70	-	~~3.45~~2.77	0.120
LS-1 (Sec.)	4.332	-	-	0.097	-	~~0.235~~0.183	-	0.114
*SS-1, SS-2, SS-3								
Monthly								
Secondary	-	-	-	-	0.078	-	~~0.410~~0.328	-
Primary	-	-	-	-	0.077	-	~~0.406~~0.325	-
Transmission	-	-	-	-	0.076	-	~~0.402~~0.321	-
Daily								
Secondary	-	-	-	-	0.037	-	~~0.195~~0.156	-
Primary	-	-	-	-	0.037	-	~~0.193~~0.154	-
Transmission	-	-	-	-	0.036	-	~~0.191~~0.153	-
GSLM-1, GSLM-2	See appropriate General Service rate schedule							

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

EFFECTIVE: ~~January 1, 2015~~

(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)

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

Rate Class		(1) 12CP 1/13 AD Demand Allocator (%)	(2) Effective mWh at Secondary Level (MWh)	(3) Capacity Production Demand Costs ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(7) Capacity CCR Factor (c/kWh)	(8) Levy CCR Factor (c/kWh)	(9) CR3 CCR Factor (c/kWh)	Capacity & Nuclear CCR Factor (c/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1									**0.345**	**0.200**	
	Secondary	61.248%	19,390,958	$208,177,843	$66,898,805	$38,739,021	$313,815,669	**1.074**			
General Service Non-Demand											**1.619**
GS-1, GST-1									**0.252**	**0.162**	
	Secondary		1,264,199					**0.868**	**0.249**	**0.160**	
	Primary		4,384					**0.859**	**0.247**	**0.159**	
	Transmission		3,741					**0.851**			**1.282**
	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									**0.182**	**0.110**	
GS-2	Secondary	0.257%	147,708	872,374	268,829	162,337	1,303,539	**0.591**			
General Service Demand											**0.883**
GSD-1, GSDT-1, SS-1											
	Secondary		12,149,615								
	Primary		2,311,921								
	Transmission		5,729								
	TOTAL GSD	31.449%	14,467,265	106,891,929	31,830,333	19,891,111	158,613,373				
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
	Secondary		-								
	Primary		35,746								
	Transmission		-								
	TOTAL CS	0.052%	35,746	178,297	86,524	33,179	297,999				
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
	Secondary		89,325								
	Primary		1,621,463								
	Transmission		324,813								
	TOTAL IS	3.567%	2,035,601	12,124,063	3,511,060	2,256,121	17,891,244				
Lighting									**0.052**	**0.029**	
LS-1	Secondary	0.177%	389,030	600,567	202,296	111,757	914,620	**0.154**			
									[illegible]	[illegible]	[illegible]
Total		100.000%	37,738,631	$339,894,492	$106,003,803	$63,249,670	$509,147,965	**0.901**			
					0.000%	0.000%					
											1.351

Notes:

(1) From Schedule E12-D, Column 10
(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
(9) (Column 5 / 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

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

ATTACHMENT C
(Page 2 of 4)

Rate Class		(1) **12CP 1/13 AD** Demand Allocator (%)	(2) Effective mWh at Secondary Level (MWh)	(3) Capacity Production Demand Costs ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(11) Billing KW Load Factor (%)	(12) Projected Effective KW at Meter Level (kW)	(13) Capacity CCR Factor ($/kW-mo)	(14) Levy CCR Factor ($/kW-mo)	(15) CR3 CCR Factor ($/kW-mo)	(16) Capacity & Nuclear CCR Factor ($/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		1,264,199										
	Primary		4,384										
	Transmission		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		12,149,615							**2.82**	**0.84**	**0.52**	**4.19**
	Primary		2,311,921							**2.79**	**0.83**	**0.51**	**4.15**
	Transmission		5,729							**2.76**	**0.82**	**0.51**	**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				
Curtailable													
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3													
	Secondary		-							**1.88**	**0.91**	**0.35**	**3.13**
	Primary		35,746							**1.86**	**0.90**	**0.35**	**3.10**
	Transmission		-							**1.84**	**0.89**	**0.34**	**3.07**
	TOTAL CS	0.052%	35,746	178,297	86,524	33,179	297,999	51.50%	95,082				
Interruptible													
IS-1, IST-1, IS-2, IST-2, SS-2													
	Secondary		89,325							**2.38**	**0.69**	**0.44**	**3.52**
	Primary		1,621,463							**2.36**	**0.68**	**0.44**	**3.48**
	Transmission		324,813							**2.33**	**0.68**	**0.43**	**3.45**
	TOTAL IS	3.567%	2,035,601	12,124,063	3,511,060	2,256,121	17,891,244	54.80%	5,088,493				
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	$63,249,670	$509,147,965						
					0.000%	0.000%							

Notes:
(1) From Schedule E12-D, Column 10
(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
(9) (Column 5 / 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

***Calculation of Standby Service kW Charges:**

	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

Rate Class		(1) **12CP 1/13 AD** Demand Allocator (%)	(2) Effective mWh at Secondary Level (MWh)	(3) Capacity Production Demand Costs ($)	(4) Levy Production Demand Costs ($)	(5) CR3 Production Demand Costs ($)	(6) Capacity + Nuclear Production Demand Costs ($)	(7) Capacity CCR Factor (c/kWh)	(8) Levy CCR Factor (c/kWh)	(9) CR3 CCR Factor (c/kWh)	(10) Capacity & Nuclear CCR Factor (c/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
	Secondary	61.248%	19,390,958	$208,177,843	$0	$38,739,021	$246,916,864	**1.074**	**0.000**	**0.200**	**1.274**
General Service Non-Demand											
GS-1, GST-1											
	Secondary		1,264,199					**0.868**	**0.000**	**0.162**	**1.030**
	Primary		4,384					**0.859**	**0.000**	**0.160**	**1.020**
	Transmission		3,741					**0.851**	**0.000**	**0.159**	**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		12,149,615								
	Primary		2,311,921								
	Transmission		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, CST-3, SS-3											
	Secondary		-								
	Primary		35,746								
	Transmission		-								
	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		89,325								
	Primary		1,621,463								
	Transmission		324,813								
	TOTAL IS	3.567%	2,035,601	12,124,063	0	2,256,121	14,380,184				
Lighting											
LS-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**
					0.000%	0.000%					

Notes:
(1) From Schedule E12-D, Column 10
(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)
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(15) Column 5 / Column 12
(16) Column 6 / Column 12

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

ATTACHMENT 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)
<u>Residential</u>												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	61.248%	19,390,958	$208,177,843	$0	$38,739,021	$246,916,864						
<u>General Service Non-Demand</u>												
GS-1, GST-1												
Secondary		1,264,199										
Primary		4,384										
Transmission		3,741										
TOTAL GS	3.251%	1,272,323	11,049,420	0	2,056,144	13,105,565						
<u>General Service</u>												
GS-2 Secondary	0.257%	147,708	872,374	0	162,337	1,034,711						
<u>General Service Demand</u>												
GSD-1, GSDT-1, SS-1												
Secondary		12,149,615							**2.82**	**0.00**	**0.52**	**3.35**
Primary		2,311,921							**2.79**	**0.00**	**0.51**	**3.32**
Transmission		5,729							**2.76**	**0.00**	**0.51**	**3.28**
TOTAL GSD	31.449%	14,467,265	106,891,929	0	19,891,111	126,783,040	52.30%	37,893,254				
<u>Curtailable</u>												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
Secondary		-							**1.88**	**0.00**	**0.35**	**2.22**
Primary		35,746							**1.86**	**0.00**	**0.35**	**2.20**
Transmission		-							**1.84**	**0.00**	**0.34**	**2.18**
TOTAL CS	0.052%	35,746	178,297	0	33,179	211,475	51.50%	95,082				
<u>Interruptible</u>												
IS-1, IST-1, IS-2, IST-2, SS-2												
Secondary		89,325							**2.38**	**0.00**	**0.44**	**2.83**
Primary		1,621,463							**2.36**	**0.00**	**0.44**	**2.80**
Transmission		324,813							**2.33**	**0.00**	**0.43**	**2.77**
TOTAL IS	3.567%	2,035,601	12,124,063	0	2,256,121	14,380,184	54.80%	5,088,493				
<u>Lighting</u>												
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, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
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(14) Column 4 / Column 12
(15) Column 5 / Column 12
(16) Column 6 / Column 12

***Calculation of Standby Service kW Charges:**

	Capacity + Nuclear Cost Cost	Effective kW	$/kW
Total GSD, CS, IS	$141,374,699	43,076,828	3.28
<u>SS-1, 2, 3 - $/kW-mo</u>	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