DOCKET NO. 150148-EI

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Dianne M. Triplett
ASSOCIATE GENERAL COUNSEL
Duke Energy Florida, Inc.

May 22, 2015

VIA ELECTRONIC FILING

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Petition of Duke Energy Florida, Inc. for Approval to Include in Base Rates the Revenue Requirement for the CR3 Regulatory Asset

Dear Ms. Stauffer:

Please find enclosed for filing on behalf of Duke Energy Florida, Inc. ("DEF"), documents to open a new docket. The filing includes the following:

- DEF's Petition as referenced above; and redacted versions of
- Direct Testimony of Terry Hobbs with attached Exhibit Nos. ___ (TH-1) through (TH-6);
- Direct Testimony of Mark Teague with attached Exhibit Nos. ___ (MT-1) through (MT-4);
- Direct Testimony of Marcia Olivier with attached Exhibit Nos. ___ (MO-1) through (MO-6);
- Notice of Intent to Request Confidential Classification

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

s/ Dianne M. Triplett
Dianne M. Triplett

DMT/at
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Duke Energy Florida, Inc. For Approval to Include in Base Rates the Revenue Requirement for the CR3 Regulatory Asset	Docket No. ____________ Submitted for Filing May 22, 2015

DUKE ENERGY FLORIDA, INC.'S PETITION FOR APPROVAL TO INCLUDE IN BASE RATES THE REVENUE REQUIREMENT FOR THE CR3 REGULATORY ASSET

Duke Energy Florida, Inc. ("DEF" or the "Company"), pursuant to Sections 366.04(1) and 366.05, Florida Statutes, and in accordance with the 2013 Revised and Restated Stipulation and Settlement Agreement ("RRSSA") approved by the Florida Public Service Commission ("PSC" or the "Commission") on November 12, 2013, in Order No. PSC-13-0598-FOF-EI in Docket No. 130208-EI, respectfully petitions the Commission for approval to include in base rates the revenue requirement for the Crystal River Unit 3 ("CR3") Regulatory Asset.

DEF has complied with the RRSSA, including the calculations set forth in Exhibit 10 to the RRSSA, and is therefore entitled to recover the value of the CR3 Regulatory Asset in base rates. DEF also used all reasonable and prudent efforts to maximize salvage value and minimize costs that were charged to the CR3 Regulatory Asset for the benefit of DEF's customers. DEF's disposition efforts resulted in a total of $127.3 million in reductions to the CR3 Regulatory Asset. The final value of the CR3 Regulatory Asset is $1.298 billion, below the $1.466 billion Asset Cap negotiated in the RRSSA.

As explained in greater detail below, DEF intends to file a subsequent petition for a financing order, pursuant to the securitization legislation recently passed by the Florida House and Senate if the legislation ultimately becomes law. Any such petition would impact the manner in which the CR3 Regulatory Asset is placed into rates. This potential filing would reduce the residential rate increase on a typical 1,000 kWh bill.

In support of this Petition, DEF is submitting the direct testimony and exhibits of DEF witnesses Marcia Olivier, Mark Teague, and Terry Hobbs.

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:

Dianne M. Triplett
Dianne.triplett@duke-energy.com
Duke Energy Florida, Inc.
299 1st Avenue North
St. Petersburg, Florida 33701
727- 820-4962 / (727) 820-5041 (fax)

Matthew Bernier
Matthew.bernier@duke-energy.com
Duke Energy Florida, Inc.
106 E. College Avenue, Ste. 800
Tallahassee, FL 32301
(850) 521-1428 / (850) 521-1437 (fax)

3. DEF is the utility primarily affected by the request in this Petition. DEF is an investor-owned electric utility, regulated by the Commission, and is a wholly owned subsidiary of Duke Energy Corporation. The Company's principal place of business is located at 299 1st Avenue North, 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 35 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.

II. Background

5. On March 8, 2012, in Order No. PSC-12-0140-FOF-EI, the Commission approved a 2012 Settlement Agreement between DEF, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and White Springs Agriculture Chemicals, Inc. d/b/a PCS Phosphate ("White Springs") (hereinafter collectively "Settlement Signatories"). The 2012 Settlement Agreement contained some provisions that impacted the CR3 Regulatory Asset at issue in this docket.

6. The Settlement Signatories then negotiated and executed the RRSSA, which supplanted the 2012 Settlement Agreement. The Commission approved the RRSSA in Order No. PSC-13-0598-FOF-EI on November 12, 2013. The complete RRSSA, with Exhibits 10 and 11, is attached as an exhibit to the testimony of Ms. Olivier. The RRSSA resolved a number of outstanding issues, and it incorporated some provisions from the 2012 Settlement. Specifically, both the 2012 Settlement and the RRSSA permitted DEF to create the "CR3 Regulatory Asset" to include capital cost amounts and revenue requirements associated with all CR3-related costs, including the categories listed on Exhibit 10 to the RRSSA.

7. Pursuant to paragraph 5e of the RRSSA[1], DEF is authorized to increase its base rates by the revenue requirement for the CR3 Regulatory Asset upon the expiration of the Levy Nuclear Project ("LNP") fixed charge of $3.45, provided for in paragraph 11 of the RRSSA. DEF petitioned to terminate that LNP fixed charge on March 2, 2015, effective in May 2015, and the Commission approved that request in Order No. PSC-15-0176-TRF-

[1] For ease of reference, this Petition will only cite references to the RRSSA, because this agreement supplanted the 2012 Settlement Agreement. The distinction is noted here to explain why the CR3 Regulatory Asset was created before the execution of the RRSSA.

EI on May 6, 2015. Accordingly, DEF is making this request to increase its base rates for the CR3 Regulatory Asset.

III. The CR3 Regulatory Asset

8. Paragraph 5 and Exhibit 10 of the RRSSA set forth the provisions under which DEF must account for the costs included in the CR3 Regulatory Asset. Paragraph 5a states, "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." Pursuant to paragraph 5b, upon DEF's February 5, 2013 decision to retire CR3, DEF implemented "deferral accounting through the creation of a regulatory asset or assets to address the capital cost amounts and revenue requirements associated with all CR-3 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 . . . 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 . . . collectively referred to herein as the "CR3 Regulatory Asset," the components of which are shown on Exhibit 10."

9. DEF complied with these provisions, and created the CR3 Regulatory Asset in December 2012. The components of the CR3 Regulatory Asset include the plant investment net of accumulated depreciation, a $295 million write-down, the cost of construction projects, nuclear fuel inventories, nuclear materials and supplies inventories, deferred nuclear expenses, a 6% after-tax accrued carrying charge, and the portion of the cost of removal regulatory asset associated with CR3 pursuant to Order No. PSC-10-0398-

S-EI. Paragraph 7a of the RRSSA also authorizes DEF to collect charges through the fuel clause to accelerate recovery of the carrying charge on the CR3 Regulatory Asset. In calculating the final amount of carrying charge associated with the CR3 Regulatory Asset, DEF adjusted the carrying charge by the amounts received through the fuel clause charge, consistent with the methodology set forth in Exhibit 11 to the RRSSA. In the fuel clause docket, DEF will be requesting to end the accelerated recovery of the carrying charge as of December 2015.

10. Exhibit 10 to the RRSSA sets forth in detail the types of costs to be included in the CR3 Regulatory Asset. It also includes specific categories regarding the scope of parties' rights to challenge or otherwise question the amount of costs included in the CR3 Regulatory Asset, and accordingly, the amount of costs that are potentially at issue and subject to challenge by the Settlement Signatories in this proceeding are limited. Ms. Olivier, in her testimony and exhibits, presents each line item of Exhibit 10 and explains the Company witness that will be supporting the amount contained in that line item, to the extent the costs presented in that line item are at issue in this proceeding.

11. DEF notes that the calculation of the CR3 Regulatory Asset does not include any costs associated with the dry cask storage ("DCS") facility. When DEF entered into the RRSSA, it had not yet made the decision to complete a DCS to store spent nuclear fuel at CR3. Subsequent to the approval of the RRSSA, DEF completed that analysis and opted to construct a DCS (also referred to as an Independent Spent Fuel Storage Installation or "ISFSI"). DEF petitioned the Commission for approval of its decision in Docket No. 140113. In that docket DEF also requested that the Commission approve an accounting order to defer amortization pending recovery of those construction costs from the Department of Energy ("DOE"), to minimize the rate impact to customers. The Commission approved DEF's request in Order No. PSC-15-0027-PAA-EI, issued on

January 7, 2015. Accordingly, DEF will recover the return on investment for ISFSI costs through the Capacity Cost Recovery Clause ("CCR") until the litigation against the DOE has concluded. At that point DEF will begin recovering in rates the return of and on the remaining unrecovered investment. DEF is not seeking approval of the inclusion of any ISFSI or DCS costs into the calculation of the CR3 Regulatory Asset.

12. With respect to line item 14, Nuclear Fuel Inventories, of Exhibit 10, DEF took prudent actions to maximize the salvage value for this inventory. However, the resulting contract for the sale of some of the inventory will not be fully executed until a future date beyond the base rate increase for the CR3 Regulatory Asset. While DEF could have included the full amount of the inventories in this filing and only credited the proceeds received from third parties in a later proceeding (thus waiting for receipt of the actual proceeds), DEF wanted to give maximum benefit to customers today and minimize the amount of the CR3 Regulatory Asset. Accordingly, DEF proposes to reduce the projected CR3 Regulatory Asset for estimated future nuclear fuel proceeds, recover the carrying charge on those outstanding nuclear fuel proceeds through the CCR until they have been received, and then true-up that estimate to actual proceeds through the CCR upon receipt of those proceeds. This methodology will help mitigate the initial base rate increase and avoid charging customers for amortization of the portion of the balance that DEF expects to recover in the future as nuclear fuel proceeds. This proposed treatment is explained more fully in Ms. Olivier's testimony.

13. After including the accounting adjustments required by the RRSSA, the final balance of the CR3 Regulatory Asset at December 31, 2015, is projected to be $1.298 billion. This balance is $168 million below the Asset Cap of $1.466 billion [see RRSSA Paragraph 5.e.(2)]. Using the methodology and return rate authorized in Exhibit 10 to the RRSSA results in an annual revenue requirement of $170.3 million for the CR3

Regulatory Asset. Ms. Olivier's testimony and exhibits include a rate sheet with the expected rate impact to the various customer classes. Ms. Olivier has not included proposed tariff sheets to reflect this rate change, given that it is DEF's present intention to file for approval of a financing order under proposed securitization legislation and that future filing would impact the amount to be included on customers' bills. If the financing order is not approved, and the base rate increase requested in this Petition is approved instead, then DEF will submit revised tariff sheets to reflect the approved base rate increase at that point.

IV. DEF's Actions to Minimize the CR3 Regulatory Asset Value

14. DEF took reasonable and prudent actions to minimize the CR3 Regulatory Asset Value for its customers. Upon the announcement of the retirement of CR3, DEF promptly carried out the necessary steps to transition the site from a fully staffed and operational plant to a decommissioning site. DEF also submitted several License Amendment Requests ("LARs") to the Nuclear Regulatory Commission to reduce regulatory requirements that resulted in DEF's ability to reduce costs and workforce levels. At the time of the retirement, there were also several pending projects at the site, as noted on Exhibit 10 to the RRSSA (line items 7-9 and 11-13). DEF took reasonable and prudent actions to safely and timely close out those projects.

15. DEF also used reasonable and prudent efforts to sell or otherwise salvage assets that would otherwise be included in the CR3 Regulatory Asset. As explained in Mr. Teague's testimony, after the retirement decision, the Company promptly formed an Investment Recovery Team and utilized a stepwise process for assessing and dispositioning the CR3 Assets. DEF used a variety of methods to maximize value received, including offering assets on industry utility parts websites like RAPID and Pooled Inventory Management, conducting bid events and an auction, and pursuing sales

options with the original manufacturers of some parts. The disposition of the Company's nuclear fuel inventory was handled in a similar manner, but due to the particular market conditions for nuclear fuel components, DEF will not receive proceeds until a future date. The proposed accounting treatment for these proceeds is discussed above and further in Ms. Olivier's testimony. As a result of DEF's efforts, the CR3 Regulatory Asset has been reduced by a total of $127.3 million, including $119.4 million for future nuclear fuel proceeds and $7.9 million for sales proceeds and salvage on the assets at CR3.

V. Securitization Legislation and Filing

16. House Bill 7109 has passed the Florida Legislature and could be signed by the Governor. This bill allows for the potential "securitization" of assets like the CR3 regulatory asset, which would allow DEF to access low-cost funds through "nuclear asset recovery bonds" issued pursuant to a financing order issued by the Commission. If that bill becomes law, DEF has the present intent to petition the Commission for a financing order per the new statute, thereby mitigating the rate increase requested in this Petition. Under the new statute, this Petition is the first step in the process of "securitizing" the CR3 Regulatory Asset. The Commission must approve the amounts requested by DEF to include in the CR3 Regulatory Asset. Under the proposed legislation, DEF will also petition the Commission for a financing order which would authorize DEF to issue low cost "nuclear asset recovery bonds" and recover the principal, interest and financing costs (associated with the total approved amount to be included in the CR3 Regulatory Asset) from customers via a separate charge on customer bills.

17. Pursuant to Paragraph (2)(a)7(b) of the proposed bill, DEF would not be able to file for a petition for a financing order until 60 days after filing this Petition for approval of the principal costs to be included in the CR3 Regulatory Asset. Therefore, if the

legislation is enacted, DEF has the present intent to file a petition for a financing order as early as July 21, 2015. The legislation also establishes a 120 day period from the time the utility files its petition for the financing order until the Commission must vote on that request. Therefore, if DEF files a petition for a financing order in July, then the Commission would vote on that petition in November. The bonds could then be issued and the "nuclear asset recovery charge" could be implemented as early as February 2016 in place of the January 2016 base rate increase pursuant to the RRSSA described herein. If DEF requests and the Commission issues the financing order, then rather than increasing base rates with the first billing cycle for January 2016 consistent with the RRSSA, DEF would begin recovering a "nuclear asset recovery charge" as a separate line item on customer bills to recover the Commission approved principle, interest and financing costs upon issuance of the Nuclear Asset Recovery Bonds.

18. Given current interest rates, if DEF were to securitize the CR3 Regulatory Asset, it expects residential customer bills to be lower with securitization than without. The final details of how much residential customer bills will decrease, however, will not be known until DEF petitions for and receives the financing order and then issues the Nuclear Asset Recovery Bonds. If the Commission does not approve DEF's petition for a financing order, then DEF would request that the Commission approve the base rate increase as set forth in this Petition.

VI. Effective Date and Next Steps

19. The Company wishes to implement the requested base rate increase effective with the first billing cycle for January 2016. As noted above, the impact of the likely future filing in 60 days under the new securitization statute, if it becomes law, will change the

requested base rate increase and timing of said increase. The specific details will be set forth in that future filing.

20. When DEF files the petition for the financing order, it will likely request that this docket be consolidated with that future docket, because the two dockets are so inter-related. The amount of the CR3 Regulatory Asset is directly related to the amount that would be the subject of the Nuclear Asset Recovery Bonds. The details and support for the docket consolidation will be set forth more specifically in the forthcoming filing, but DEF notes the future potential outcome for informational purposes.

VII. Conclusion

21. For all the reasons provided above, as supported by the testimonies and exhibits of Ms. Olivier, Mr. Teague and Mr. Hobbs, DEF respectfully requests that the Commission approve DEF's Petition for approval to include in base rates the revenue requirement for the CR3 Regulatory Asset.

Respectfully submitted this 22nd day of May, 2015.

s/ Dianne M. Triplett
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Duke Energy Florida, Inc. For Approval to Include in Base Rates the Revenue Requirements of the CR3 Regulatory Asset	Docket No. ____________

Submitted for Filing
May 22, 2015

DIRECT TESTIMONY OF MARCIA OLIVIER

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

IN RE: PETITION FOR APPROVAL TO INCLUDE IN BASE RATES THE REVENUE REQUIREMENTS OF THE CR3 REGULATORY ASSET

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. ___________

DIRECT TESTIMONY OF MARCIA OLIVIER

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Marcia Olivier. My current business address is 299 First Avenue North, Saint Petersburg, FL 33701.

Q. By whom are you employed and what are your responsibilities?

A. I am employed by Duke Energy Business Services, Inc. as Director of Rates and Regulatory Planning for Florida. I am responsible for overseeing rate cases, reporting actual and projected earnings surveillance results, and supporting state regulatory initiatives.

Q. Please summarize your educational background and professional experience.

A. I hold a Bachelor of Science degree in Accounting and a Bachelor of Science degree in Finance from the University of South Florida and have over 18 years of utility experience, primarily in the Rates and Regulatory Strategy department.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My testimony supports DEF's request to begin recovering the lessor of $1.466 billion (the "Asset Cap") or the projected or final (when final) total CR3 regulatory asset value in base rates consistent with the Revised and Restated Stipulation and Settlement Agreement ("RRSSA"). The Levy Nuclear Plant ("LNP") cost recovery charge terminated in May 2015; therefore, DEF is requesting to increase base rates to begin recovering the CR3 regulatory asset with the first billing cycle for January 2016. The two components of the CR3 regulatory asset include the cost to construct the dry cask storage facility and the costs that are subject to the Asset Cap. The dry cask storage facility component was addressed separately in Docket No. 140113, so this docket only addresses the costs that are subject to the Asset Cap. I will provide the amounts that comprise the Asset Cap component, which I will refer to as the "CR3 regulatory asset," the calculation of the associated projected revenue requirement, and the impact on base rates. Second, I will present and explain our proposal to reduce the CR3 regulatory asset for estimated future nuclear fuel proceeds. Finally, I will describe the impact of potential "securitization" legislation on this request in the event this bill becomes enacted into law and DEF files a request to securitize the CR regulatory asset pursuant to that law.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___(MO-1), RRSSA with Exhibits 10 and 11,
- Exhibit No. ___(MO-2), RRSSA Exhibit 10 Template Populated,
- Exhibit No. ___(MO-3), RRSSA Exhibit 11 Template Populated,
- Exhibit No. ___(MO-4), Rate Schedules,
- Exhibit No. ___(MO-5), Estimated Nuclear Fuel Proceeds (Confidential), and
- Exhibit No. ___(MO-6), CCR Nuclear Fuel Illustrative Impact (Confidential).

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. Exhibit No. ___(MO-1), "RRSSA with Exhibits 10 and 11", is for reference. RRSSA Exhibit 10 provides the components of the CR3 regulatory asset by line and includes a column titled "Subject to Cap". Exhibit No. ___(MO-2), "RRSSA Exhibit 10 Template Populated", provides by line item the balances that were transferred to the CR3 regulatory asset on December 31, 2012 as well as the current actual balance on April 30, 2015 and the estimated balance on December 31, 2015. This exhibit also calculates the revenue requirement on that December 31, 2015 balance. As a reduction to the cumulative carrying charge on line 17 in RRSSA Exhibit 10, RRSSA paragraph 7.a. provides for an accelerated recovery of that carrying charge through the fuel clause. The calculation of that amount is provided in Exhibit No. ___(MO-3), "RRSSA Exhibit 11 Template Populated". The base rate increase by rate class is provided in Exhibit No. ___(MO-4), "Rate Schedules". Because some of the nuclear fuel sales proceeds will not be received until after the base rate increase takes effect, DEF proposes to reduce the projected CR3 regulatory asset for those estimated future nuclear fuel proceeds, recover the carrying charge on the outstanding balance through the Capacity Cost Recovery Clause ("CCR") until the proceeds are received, and then true-up that estimate to actual proceeds through the CCR upon receipt of the proceeds. The estimated amount and timing of the nuclear fuel proceeds are provided in Exhibit No. (MO-5), "Estimated Nuclear Fuel Proceeds", and the impact of this methodology on the CCR is illustrated in Exhibit No. ___(MO-6), "CCR Nuclear Fuel Illustrative Impact". This methodology will reduce the initial base rate increase by reducing the CR3 regulatory asset balance while ensuring DEF earns the allowed return on those proceeds through the CCR until they have been received. Finally, House Bill 7109 has passed the Florida Legislature and could become law. This bill would allow "securitization" of the CR3 regulatory asset, which would allow DEF to access low-cost funds through "nuclear asset recovery bonds" issued pursuant to a financing order issued by the Commission. If the bill becomes law, this provision will be codified in Section 366.95, Florida Statutes. If DEF requests and the Commission approves the "securitization" financing order, as contemplated by the potential legislation, then DEF will replace the RRSSA base rate increase described in this filing with a separate "Nuclear Asset Recovery Charge" to recover the principal, interest and financing costs on the issued bonds.

III. CR3 REGULATORY ASSET COST ESTIMATE

Q. Please describe what comprises the CR3 regulatory asset.

A. The CR3 Regulatory Asset is defined in the RRSSA. Specifically, paragraph 5.a. states; "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." Exhibit 10 of the RRSSA, titled "Template for Calculation of the CR3 Regulatory Asset Value and Revenue Requirement", provides all the components of the CR3 regulatory asset [see Exhibit No. ___(MO-1)]. Note that the column titled "Subject to Cap" includes the amounts that are at issue in this proceeding, because the "Dry Cask Storage" costs have been addressed separately in Docket No. 140113. The line items in this exhibit include the plant investment net of accumulated depreciation, a $295 million write-down, the cost of construction projects, nuclear fuel inventories, nuclear materials and supplies inventories, deferred nuclear expenses, a 6% accrued carrying charge, and the portion of the cost of removal regulatory asset associated with CR3 pursuant to Order No. PSC-10-0398-S-EI.

Q. Who will be responsible for testifying on the various line items from the RRSSA Exhibit 10?

A. I will testify to the calculations included in Exhibit No. ___(MO-2). Terry Hobbs will testify to the activities that have taken place at CR3 supporting the charges to the CR3 regulatory asset. Finally, Mark Teague will testify to the activities that have taken place to sell or otherwise salvage assets that had been included in the CR3 regulatory asset. With respect to the line items in RRSSA Exhibit 10, the following table illustrates who will be responsible for each component of each line item.

Line	Description	Witness
2	Electric Plant in Service	Hobbs – Charges Olivier – Accounting
3	Less Accumulated Depreciation	Hobbs – Charges Teague – Salvage Olivier – Accounting
4	Net Plant balance	Olivier
5	Write-down	Olivier
6	Construction Work in Progress	n/a
7	Steam Generator Replacement (SGR) Project	Olivier – Accounting
8	Delam. Repair Project	Hobbs – Charges Olivier – Accounting
9	License Application Renewal	Hobbs – Charges Olivier – Accounting
10	Dry Cask Storage	n/a
11	Fukushima	Hobbs – Charges Teague - Salvage Olivier - Accounting
12	Building Stabilization Project	Hobbs – Charges Olivier – Accounting
13	Other - CWIP	Hobbs – Charges Teague – Salvage Olivier – Accounting
14	Nuclear Fuel Inventories	Teague – Salvage Olivier – Accounting
15	Nuclear Materials & Supplies Inventories	Teague – Salvage Olivier – Accounting
16	Deferred Expenses	Hobbs – Charges Olivier – Accounting
17	Cumulative AFUDC (6.00%)	Olivier
18	Cost of Removal Reg Asset – CR3 Portion	Olivier
19	Total CR3 Regulatory Asset	Olivier
20	Rate of Return	Olivier
21	Return	Olivier
22	Amortization Expense	Olivier
23	Total Revenue Requirement	Olivier

Q. **What makes up line 16, “Deferred expenses” in Exhibit No. ___(MO-2)?**

A. Line 16 includes deferred operations and maintenance (“O&M”) expense, property tax expense and payroll tax expense. RRSSA paragraph 5.b. provides that upon

DEF's February 5, 2013 decision to retire CR3, DEF is authorized to defer to the CR3 regulatory asset all CR3-related costs. This paragraph also requires DEF to record in regulatory liabilities the O&M and property tax savings for actual costs that are lower than amounts included in DEF's 2010-test year rate case minimum filing requirements. This deferral treatment ceased on January 1, 2014 for O&M (including administrative and general expenses) and property tax expense pursuant to paragraph 5.c. As a result of this RRSSA provision, DEF has recorded total deferred expenses of $105.2 million to the CR3 regulatory asset and total savings of $10.7 million to the CR3 regulatory liability.

Q. **Are there any other provisions in the RRSSA that impact the calculation of the CR3 Regulatory Asset?**

A. Yes. RRSSA Paragraph 7.a. provides for a retail fuel rate recovery of $1.00 per megawatt hour in 2014 and 2015 and $1.50 per megawatt hour in 2016. These increases were intended to offset the impact of carrying charges on the CR3 regulatory asset. Accordingly, DEF did not defer for recovery the carrying charge on the portion of the CR3 Regulatory Asset supported by the revenues received from the increased fuel rate. Please see Exhibit No. ___(MO-3) for the actual and estimated recoveries of the carrying charge through fuel.

Q. How was the carrying charge on Line 17 "Cumulative AFUDC (6.00%)" in Exhibit No. ___(MO-2) calculated?

A. Pursuant to the RRSSA Paragraph 5.b., Exhibit 3, and Exhibit 10, we multiplied the monthly net balances in the CR3 regulatory asset/liability accounts by the monthly rate that compounds to an annual rate of 6%. That monthly rate is .48676% when applying the formula used to discount the 6% annual AFUDC rate pursuant to Rule 25-6.0141 (3), F.A.C. This carrying charge was reduced by the accelerated recovery of $29.7 million from January 2014 through April 2015 pursuant to RRSSA Paragraph 7.a. (explained above). We have also included an estimate of $16.4 million for May through December 2015 [see Exhibit No. ___(MO-3)]. Since DEF is requesting to begin recovering the CR3 regulatory asset in base rates effective January 2016, the accelerated recovery of the carrying charge in fuel will cease with the last billing cycle for December 2015. The 2016 fuel projection filing in Docket No. 150001 will exclude this accelerated recovery.

Q. How does the estimated balance of the CR3 regulatory asset as of December 31, 2015 compare to the Asset Cap established in the RRSSA?

A. The balance at December 31, 2015 is projected to be $1,298.0 million as reflected in Exhibit No. ___(MO-2) (line 19). This balance has been reduced by estimated outstanding nuclear fuel proceeds of $119.4 million (line 14). The treatment of future nuclear fuel proceeds is explained in greater detail below. This balance is $168.0 million below the Asset Cap of $1,466.0 million [see RRSSA Paragraph 5.e.(2)]. While the Asset Cap could have been increased as a result of an event of Force Majeure pursuant to RRSSA Paragraph 5.e.(2) and 5.i, there have been no events of Force Majeure; therefore, the Asset Cap remains at $1,466.0 million.

Q. What is the revenue requirement and the base rate increase?

A. Consistent with the methodology and return rate authorized in the RRSSA Exhibit 10, the calculated annual revenue requirement is $170.3 million. Please see Exhibit No. ___(MO-2), line 23. RRSSA Paragraph 5.g. provides that the base rate increase “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…” The most recent projection clause filing was on May 1, 2015 filed in Docket No. 150009, the Nuclear Cost Recovery Clause (“NCRC”). Based on the revenue requirements provided in Exhibit No. ___(MO-2) and the billing determinants from that May 1, 2015 NCRC filing, we have calculated the base rate increase to be $5.01 per 1000 kWh on the residential bill. Each of the rate increases by customer class is provided in Exhibit No. ___(MO-4).

Q. Have you attached tariff sheets to your testimony?

A. No. If the securitization legislation becomes law, then DEF expects to file its petition for the financing order no earlier than 60 days after filing this request, which is a requirement of that legislation. We will include tariff sheets with that filing to reflect the “nuclear asset recovery charge”. In anticipation of filing that petition, we have not included tariff sheets with this request. However, we have provided the rate impacts in Exhibit No. ___(MO-4) and will file revised tariff sheets in the event that securitization, for any reason, is not implemented. I will explain the impact of the securitization legislation further below.

IV. PROPOSED TREATMENT OF FUTURE NUCLEAR FUEL PROCEEDS

Q. What is the current status on the sale of DEF's nuclear fuel inventory?

A. As further explained in the Direct Testimony of Mark Teague, there are two categories of nuclear fuel inventory included in the CR3 regulatory asset: the assembled nuclear fuel located at CR3 ("Batch 19") and the upstream uranium inventories which are not located at CR3. DEF has entered into a contract to sell Batch 19, but the proceeds will not be received until after implementation of the January 2016 base rate increase. The upstream uranium can be broken down into two components; uranium hexafluoride ("UF_6") and enriched uranium product ("EUP"). DEF has sold the UF_6 and the proceeds are expected to be received in August 2015. DEF has not yet sold the EUP, but an estimate of the proceeds has been provided as explained in Mr. Teague's testimony. DEF has provided the estimated amount of proceeds and the impact on the CR3 regulatory asset in Exhibit No. ___(MO-5).

Q. Please explain your proposed treatment for future nuclear fuel inventory proceeds.

A. Because some of the proceeds are expected in 2015 and others are expected after the January 2016 implementation of the base rate increase, and in order to minimize the base rate increase, DEF proposes to give customers credit for the estimated future nuclear fuel proceeds by reducing the balance of the CR3 regulatory asset upon which the revenue requirement and base rate increase are calculated. This credit is reflected in Exhibit No. ___(MO-2), Line 14, Column D. Any estimated nuclear fuel proceeds that are expected to be received after the base rate increase takes effect will be included in the CCR at the pre-tax 8.12% rate of return per the RRSSA Exhibit 10 until those proceeds are received, as shown in Exhibit No. ___(MO-6). Once all proceeds have been received, if they are different from the amount of the credit to the CR3 regulatory asset, then the difference will be amortized over a period to be established through the annual Fuel and Purchased Power cost Recovery clause proceedings.

Q. How will customers benefit from this proposed treatment of the future nuclear fuel inventory proceeds?

A. DEF's proposed treatment gives customers credit upfront for those future estimated proceeds which reduces the CR3 regulatory asset balance, thereby reducing the revenue requirement and upfront base rate impact. In addition, if the fuel proceeds are potentially not received for several years, customers will have paid unnecessarily for the amortization of that portion of the CR3 regulatory asset balance [see line 22 in Exhibit No. ___(MO-2)] until base rates can be trued-up once the balance becomes "final" consistent with the true-up provisions in Paragraphs 5.e.(2) and 5.g. of the RRSSA.

VI. IMPACT OF SECURITIZATION

Q. Please describe the securitization legislation and its effect on this filing.

A. If the bill becomes law, this legislation would be codified in Section 366.95, Florida Statutes, titled “Financing for certain nuclear generating asset retirement or abandonment costs.” It would be similar to the legislation established in 2005 by the Florida Legislature, codified in Section 366.8260, Florida Statutes, titled “Storm-Recovery Financing”. It would allow electric utilities to petition the Commission for a financing order which would authorize the utility to issue low cost “nuclear asset recovery bonds” and recover the principal, interest and financing costs from customers via a separate, non-bypassable charge on customer bills. If DEF requests and the Commission issues the financing order, then rather than increasing base rates with the first billing cycle for January 2016 consistent with the RRSSA, DEF would begin recovering a “nuclear asset recovery charge” as a separate line item on customer bills to recover the Commission approved principle, interest and financing costs upon issuance of the Nuclear Asset Recovery Bonds.

Q. Why doesn’t DEF wait until the legislation is enacted to file for recovery of the CR3 regulatory asset at the same time as filing the request for the financing order?

A. House Bill 7109, Paragraph (2)(a)7(b) states; “If an electric utility is subject to a settlement agreement that governs the type and amount of principal costs that could be included in nuclear asset-recovery costs, the electric utility must file a petition, or have filed a petition, with the commission for review and approval of those principal costs no later than 60 days before filing a petition for a financing order pursuant to this section.” Therefore, if the legislation is enacted, then DEF could file a petition for a financing order as early as July 21, 2015. The legislation also establishes a 120 day period from the time the utility files its petition for the financing order until the Commission must vote on that request. Therefore, if DEF files a petition for a financing order in July, then the Commission would vote on that petition in November. The bonds could then be issued and the "nuclear asset recovery charge" could be implemented as early as February 2016 in place of the January 2016 base rate increase pursuant to the RRSSA described herein.

Q. How is your proposed treatment for future nuclear fuel proceeds impacted by the Securitization?

A. Under securitization, once the amount of the CR3 regulatory asset has been approved by the Commission in the financing order, the CR3 regulatory asset balance cannot be adjusted. Section (2)(c)6. of the legislation states the following: "Subsequent to the transfer of nuclear asset-recovery property to an assignee or the issuance of nuclear asset-recovery bonds authorized thereby, whichever is earlier, a financing order is irrevocable and…the commission may not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust nuclear asset-recovery charges approved in the financing order." Therefore, the treatment for the future estimated nuclear fuel proceeds described in this testimony is not only feasible under securitization, it will be essential in order to ensure customers receive the benefit of those future nuclear fuel proceeds expeditiously by lowering the bond issuance amount.

Q. Will there be any components of the CR3 regulatory asset other than the nuclear fuel sales that won't be final at the time the Commission issues the financing order?

A. Yes, the other component that won't be final is the accelerated recovery of the carrying charge applied to the CR3 regulatory asset. As explained above and as provided in Exhibit No. ___(MO-3), that accelerated recovery through the Fuel clause is dependent on the number of megawatt hours sold. Therefore, while DEF can reasonably estimate that amount, the exact amount will not be known until early January 2016, well after the November 2015 due date of the Commission vote on the financing order petition. Therefore, DEF plans to propose in its petition for the financing order to apply the estimated accelerated recovery for May through December 2015 to the CR3 regulatory asset and allow the difference between the estimated and actual revenues to remain as part of the final fuel true-up for 2015.

Q. How will you propose to treat the dry cask storage component of the CR3 regulatory asset under securitization?

A. On January 7, 2015, Order No. PSC-15-0027-PAA-EI was issued which approved construction of the Independent Spent Fuel Storage Installation ("ISFSI") and an accounting order to defer amortization pending recovery of those construction costs from the Department of Energy ("DOE") pursuant to litigation. Under securitization, the ISFSI component would not be included in the petition for a financing order since DEF is pursuing recovery from the DOE. Since the ISFSI would be the only remaining component of the CR3 regulatory asset, DEF proposes to replace the base rate increase and 20-year recovery period under the RRSSA with recovery through the CCR for the return on the investment until it is recovered from the DOE, as was approved in Order No. PSC-15-0027-PAA-EI, and the return of and on the remaining unrecovered investment upon conclusion of all litigation against the DOE. The appropriate CCR recovery period would be established at that time by the Commission.

Q. What actions will you take if the legislation is signed into law?

A. If the legislation becomes law, then DEF could file in as early as 60 days from the date of this petition, a request for a financing order. If the financing order is approved, then DEF would proceed with the process established in that financing order. If the financing order is not approved, then DEF would request the base rate increase under the settlement approach as described herein.

VII. NEXT STEPS

Q. Please summarize the next steps DEF will take with respect to this filing.

A. This filing requests a base rate increase effective with the first billing cycle for January 2016. In the event HB 7109 becomes law, DEF currently expects to file a petition for a financing order as early as July 21, 2015. At that time, DEF will request to consolidate these two dockets. If DEF files the petition for the financing order on July 21, 2015, then under the proposed Section 366.95, F.S., the Commission would vote on DEF's request for the financing order no later than November 18, 2015 and the financing order would be issued 15 days later, on December 3, 2015. Then depending on the amount of time it takes to issue the bonds, DEF could implement the "nuclear cost recovery charge" as early as February 2016.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

REVISED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

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

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

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

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

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

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

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

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

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

WHEREAS, the Parties further recognize and agree that this Revised and Restated Settlement Agreement determines, in a comprehensive manner, the issues related to the circumstances surrounding the delaminations and repairs of CR3, the decision to retire CR3, the decision to settle the CR3 insurance claims with NEIL, issues involving the CR3 EPU project, and certain future actions regarding the Levy Nuclear Project as described herein, and resolves uncertainties related to these issues that may adversely affect the Company and its customers including the future need for additional power generation brought about by the retirement of CR3 and other issues; and

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

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

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

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

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

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

CR3:

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.

[Remainder of page left intentionally blank]

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
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118 North Gadsden Street
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White Springs Agricultural Chemicals, Inc.

By ______________________

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Florida Retail Federation

By Robert Scheffel Wright

Robert Scheffel Wright, Esquire
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Exhibit 10
Page 1 of 1
Duke Energy Florida

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

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	$__	$__

category

a The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs except that the Intervenor Parties retain the right to challenge whether DEF took reasonable and prudent actions to minimize the future CR3 Regulatory Asset value after February 5, 2013 and to sell or otherwise salvage assets after February 5, 2013 that would otherwise be included in the CR3 Regulatory Asset.

b The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs.

c The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover costs incurred by the Company before February 5, 2013. The Intervenor Parties retain the right to challenge the prudence of any costs incurred after and applicable to the period after February 5, 2013 that are submitted for recovery by the Company.

d The Intervenor Parties retain the right to challenge the prudence of any costs submitted for recovery by the Company.

e The Intervenor Parties retain the right to verify that the Company has complied with paragraph 5b of the Revised and Restated Settlement Agreement.

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

Exhibit 11
Page 1 of 1
Duke Energy Florida

Example of Recovery of CR3 Regulatory Asset Carrying Cost

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

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

Duke Energy Florida
RRSSA Exhibit 10 Template Populated
Template for Calculation of the CR3 Regulatory Asset Value and Revenue Requirement
Portion Subject to Cap Only (Excludes Dry Cask Storage Component)
($ thousands)

			(A)	(B)	(C)	(D)	(E)
Line No.	**Pre or Post Retirement Component Classification**	***category***	**Historical Balance Dec '12**	**Historical Activity Jan'13-Apr'15**	**Actual Balance Apr '15**	**Projected Activity May-Dec '15**	**Projected Balance Dec '15**
1							
2	Electric Plant In Service	a	$840,360	($11,649)	$828,711		$828,711
3	Less Accumulated Depreciation	b	431,752	(8,346)	423,406		423,406
4	Net plant balance	fallout	408,608	(3,303)	405,305		405,305
5	Write-Down	b		(295,000)	(295,000)		(295,000)
6	Construction Work In Progress (CWIP)						
7	Steam Generator Replacement (SGR) Project	a	369,915	(9,695)	360,220		360,220
8	Delam Repair Project	b	165,500	1,764	167,264		167,264
9	License Amendment Request (LAR)	b	18,832	720	19,552		19,552
10	Dry Cask Storage	d	n/a	n/a	n/a		n/a
11	Fukushima	d	1,553	940	2,493		2,493
12	Building Stabilization Project	c		23,640	23,640		23,640
13	Other - CWIP	d	45,826	7,388	53,214		53,214
14	Nuclear Fuel Inventories	a	243,564	11,968	255,532	(119,363)	136,169
15	Nuclear Materials and Supplies Inventories	a	49,055	1,168	50,223		50,223
16	Deferred expenses	e	8,373	86,087	94,460		94,460
17	Cumulative AFUDC (6.00%)	fallout		140,890	140,890	32,115	173,005
18	Cost of Removal Reg Asset - CR3 Portion (Order No. PSC 10-0398-S-EI)	b	18,500	88,969	107,469		107,469
19	Total CR3 Regulatory Asset	fallout	$1,329,726	$55,535	$1,385,261	($87,248)	$1,298,012
20	Rate of Return (Settlement Agreement Exhibit 3: 6% grossed up for taxes)	b					8.12%
21	Return	b					$105,399
22	Amortization expense (20 years)	b					$64,901
23	Total revenue requirement	fallout					$170,299

category

a The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs except that the Intervenor Parties retain the right to challenge whether DEF took reasonable and prudent actions to minimize the future CR3 Regulatory Asset value after February 5, 2013 and to sell or otherwise salvage assets after February 5, 2013 that would otherwise be included in the CR3 Regulatory Asset.

b The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs.

c The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover costs incurred by the Company before February 5, 2013. The Intervenor Parties retain the right to challenge the prudence of any costs incurred after and applicable to the period after February 5, 2013 that are submitted for recovery by the Company.

d The Intervenor Parties retain the right to challenge the prudence of any costs submitted for recovery by the Company.

e The Intervenor Parties retain the right to verify that the Company has complied with paragraph 5b of the Revised and Restated Settlement Agreement.

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

Duke Energy Florida
RRSSA Exhibit 11 Template Populated
(in thousands)

Line		(A) Actual Jan-Dec 2014	(B) Actual Jan-Apr 2015	(C) Est. May-Dec 2015	(D) Total Jan-Dec 2015	(E) Total 2014-15
1	Fuel Rate Increase ($/mwh)	$1.00	$1.00	$1.00	$1.00	$1.00
2	Multiply by Retail mWhs	37,240	11,039	26,715	37,753	74,993
3	Equals Total Revenue Recovered in Rates	$37,240	$11,039	$26,715	$37,753	74,993
4	Less Income Tax Expense	($14,365)	($4,258)	($10,305)	($14,563)	(28,929)
5	Equals Avoided Increase in CR3 Regulatory Asset	$22,875	$6,780	$16,409	$23,190	$46,065

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

Duke Energy Florida
Rate Schedules
Development of Unbilled Revenue @ Present Rates and Summary of Total Present and Proposed Class Revenue

Line	Rate Schedule	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		Billed Sales (MWH)	Customer Charge ($000)	Demand and Energy Charge ($000)	Total Base Revenue Billed ($000)	Demand and Energy Charge ($/MWH)	Unbilled Sales (MWH)	Unbilled Revenue ($000)	Total Class Revenue ($000)	Total Demand and Energy Revenue Including Unbilled ($000)	Base Rate Increase at Uniform Percent ($000) 10.08%	Total Class Revenue with Increase ($000)
No.		*	**	**	(2) + (3)	(3) / (1)	**	(5) x (6)	(4) + (7)	(3) + (7)	(9) x %	(8) + (10)
1	RS-1	19,495,155	$160,832	$1,052,389	$1,213,222	$53.98	104,986	$5,667	$1,218,889	$1,058,057	$106,656	$1,325,545
2	GS-1	1,588,204	17,096	84,921	102,017	53.47	7,215	386	102,403	85,307	8,599	111,002
3	GS-2	165,610	1,872	3,391	5,262	20.47	842	17	5,280	3,408	344	5,623
4	GSD-1	14,413,009	8,906	476,447	485,353	33.06	65,304	2,159	487,512	478,606	48,245	535,757
5	CS-1, CS-2, CS-3	119,488	5	3,472	3,477	29.05	305	9	3,485	3,480	351	3,836
6	IS-1, IS-2, IS-3	1,840,259	606	44,533	45,140	24.20	5,175	125	45,265	44,659	4,502	49,767
7	SS-1	20,186	25	993	1,018	49.20	66	3	1,021	996	100	1,122
8	SS-2	177,394	18	5,247	5,264	29.58	470	14	5,278	5,261	530	5,809
9	SS-3	3,520	1	468	469	132.97	13	2	471	470	47	518
10	LS-1	385,378	0	9,138	9,138	23.71	1,478	35	9,173	9,173	925	10,098
11	TOTAL	38,208,203	$189,360	$1,681,000	$1,870,360		185,854	$8,417	$1,878,777	$1,689,417	$170,299	$2,049,076

12
13 * Based on 2016 MWH sales forecast in 2015 Ten Year Site Plan used in NCRC May 1, 2015 projection filing
14 ** Based on revenue forecast consistent with 2016 MWH sales forecast in 2015 Ten Year Site Plan used in NCRC May 1, 2015 projection filing
15
16
17

¶ 5e. Recovery of the CR3 Regulatory Asset:	$170,299

18

Residential 1st Tier Rate Impact:	Current ($/mwh)	Increase ($/mwh)	Proposed ($/mwh)
Cust Charge	$8.76		$8.76
Energy Charge	$49.74	$5.01	$54.75
Total Charge	$58.50	$5.01	$63.51

19
20
21
22
23

Duke Energy Florida
Rate Schedules
Detailed Unit Charges by Rate Schedule
2013 Re-Settlement for 1/1/2016 Effective Date

Rate Schedule	Type of Charge	**1/1/2015** Current/Prior Rate	**1/1/2016** Proposed Rate
SC-1	Initial Connection - $	61.00	61.00
	Reconnection - $	28.00	28.00
	Transfer of Account - No LSA Contract - $	28.00	28.00
	Transfer of Account - LSA Contract Required - $	10.00	10.00
	Reconnect After Disconnect For Non-Pay - $	40.00	40.00
	Reconnect After Disconnect For Non-Pay After Hours -$	50.00	50.00
	Investigation of Unauthorized Use - (RPI)	75.00	75.00
	Late Payment Charge	> $5.00 or 1.5%	> $5.00 or 1.5%
	Returned Check Charge	$25 if <= $50	$25 if <= $50
		$30 if <= $300	$30 if <= $300
		$40 if <= $800	$40 if <= $800
		5% if > $800	5% if > $800
TS-1	Temporary Service Extension - Monthly $	227.00	227.00
RS-1	Customer Charge - $ per Line of Billing		
RST-1	Standard	8.76	8.76
RSS-1	Seasonal (RSS-1)	4.58	4.58
RSL-1	Time of Use		
RSL-2	Single Phase	16.19	16.19
(RST closed	Three Phase	16.19	16.19
2/10/2010)	Customer CIAC Paid	8.76	8.76
	TOU Metering CIAC - $ One Time Charge	90.00	90.00
	Energy and Demand Charge - cents per KWH		
	Standard		
	0 - 1,000 KWH	4.974	5.475
	Over 1,000 KWH	6.336	6.975
	Time of Use - On Peak	15.360	16.908
	Time of Use - Off Peak	0.853	0.939
GS-1	Customer Charge - $ per Line of Billing		
GST-1	Standard		
	Unmetered	6.54	6.54
	Secondary	11.59	11.59
	Primary	146.56	146.56
	Transmission	722.90	722.90
	Time of Use		
	Single Phase	19.01	19.01
	Three Phase	19.01	19.01
	Customer CIAC Paid	11.59	11.59
	Primary	153.99	153.99
	Transmission	730.32	730.32
	TOU Metering CIAC - $ One Time Charge	132.00	132.00
	Energy and Demand Charge - cents per KWH		
	Standard	5.403	5.948
	Time of Use - On Peak	15.335	16.881
	Time of Use - Off Peak	0.831	0.915
	Premium Distribution Charge - cents per KWH	0.738	0.812
	Meter Voltage Adjustment - % of Demand & Energy Charges		
	Primary	1.0%	1.0%

Duke Energy Florida
Rate Schedules
Detailed Unit Charges by Rate Schedule
2013 Re-Settlement for 1/1/2016 Effective Date

Rate Schedule	Type of Charge	1/1/2015 Current/Prior Rate	1/1/2016 Proposed Rate
	Transmission	2.0%	2.0%
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%
GS-2	Customer Charge - $ per Line of Billing		
	Standard		
	Unmetered	6.54	6.54
	Metered	11.59	11.59
	Energy and Demand Charge - cents per KWH		
	Standard	2.048	2.254
	Premium Distribution Charge - cents per KWH	0.149	0.164
GSD-1	Customer Charge - $ per Line of Billing		
GSDT-1	Standard		
	Secondary	11.59	11.59
	Primary	146.56	146.56
	Transmission	722.90	722.90
	Time of Use		
	Secondary	19.01	19.01
	Secondary - Customer CIAC paid	11.59	11.59
	Primary	153.99	153.99
	Primary - Customer CIAC paid	146.56	146.56
	Transmission	730.32	730.32
	Transmission Customer CIAC paid	722.90	722.90
	Demand Charge - $ per KW		
	Standard	5.06	5.57
	Time of Use		
	Base	1.24	1.36
	On Peak	3.76	4.14
	Delivery Voltage Credits - $ per KW		
	Primary	0.40	0.44
	Transmission	1.49	1.64
	Premium Distribution Charge - $ per KW	1.09	1.20
	Energy Charge - cents per KWH		
	Standard	2.256	2.483
	Time of Use - On Peak	4.911	5.406
	Time of Use - Off Peak	0.824	0.907
	Meter Voltage Adjustment - % of Demand & Energy Charges		
	Primary	1.0%	1.0%
	Transmission	2.0%	2.0%
	Power Factor - $ per KVar	0.29	0.32
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%
CS-1			
CS-2	Customer Charge - $ per Line of Billing		
CS-3	Secondary	75.96	75.96
CST-1	Primary	210.93	210.93
CST-2	Transmission	787.26	787.26
CST-3			
	Demand Charge - $ per KW		

Duke Energy Florida
Rate Schedules
Detailed Unit Charges by Rate Schedule
2013 Re-Settlement for 1/1/2016 Effective Date

Rate Schedule	Type of Charge	**1/1/2015** Current/Prior Rate	**1/1/2016** Proposed Rate
	Standard	8.13	8.95
	Time of Use		
	Base	1.21	1.33
	On Peak	6.86	7.55
	Curtailable Demand Credit		
	CS-1, CST-1 - $ per KW of Curtailable Demand (CST=on peak)	4.68	4.68
	CS-2, CST-2 - $ per KW LF adjusted Demand	8.16	8.16
	CS-3, CST-3 - $ per KW of Contract Demand	8.16	8.16
	Delivery Voltage Credits - $ per KW		
	Primary	0.40	0.44
	Transmission	1.49	1.64
	Premium Distribution Charge - $ per KW	1.09	1.20
	Energy Charge - cents per KWH		
	Standard	1.485	1.635
	Time of Use - On Peak	2.725	3.000
	Time of Use - Off Peak	0.819	0.902
	Meter Voltage Adjustment - % of Demand & Energy Charges		
	Primary	1.0%	1.0%
	Transmission	2.0%	2.0%
	Power Factor - $ per KVar	0.29	0.32
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%
IS-1	Customer Charge - $ per Line of Billing		
IS-2	Secondary	278.95	278.95
IST-1	Primary	413.94	413.94
IST-2	Transmission	990.26	990.26
	Demand Charge - $ per KW		
	Standard	6.88	7.57
	Time of Use		
	Base	1.09	1.20
	On Peak	6.02	6.63
	Interruptible Demand Credit		
	IS-1, IST-1 - $ per KW of Billing Demand (IST= on peak)	6.24	6.24
	IS-2, IST-2 - $ per KW LF Adjusted Demand	10.88	10.88
	Delivery Voltage Credits - $ per KW		
	Primary	0.40	0.44
	Transmission	1.49	1.64
	Premium Distribution Charge - $ per KW	1.09	1.20
	Energy Charge - cents per KWH		
	Standard	0.995	1.095
	Time of Use - On Peak	1.394	1.535
	Time of Use - Off Peak	0.813	0.895
	Meter Voltage Adjustment - % of Demand & Energy Charges		
	Primary	1.0%	1.0%

Duke Energy Florida
Rate Schedules
Detailed Unit Charges by Rate Schedule
2013 Re-Settlement for 1/1/2016 Effective Date

Rate Schedule	Type of Charge	1/1/2015 Current/Prior Rate	1/1/2016 Proposed Rate
	Transmission	2.0%	2.0%
	Power Factor - $ per KVar	0.29	0.32
	Equipment Rental - % of Installed Equipment Cost	1.67%	1.67%
LS-1	Customer Charge - $ per Line of Billing		
	Standard		
	Unmetered	1.19	1.19
	Metered	3.42	3.42
	Energy and Demand Charge - cents per KWH		
	Standard	2.132	2.347
	Fixture & Maintenance Charges - $ per fixture	per type	per type
	Pole Charges - $ per pole	per type	per type
	Other Fixture Charge Rate - % of Installed Fixture Cost	1.59%	1.59%
	Other Pole Charge Rate - % of Installed Pole Cost	1.82%	1.82%
SS-1	Customer Charge - $ per Line of Billing		
	Secondary	100.71	100.71
	Primary	235.69	235.69
	Transmission	812.02	812.02
	Customer Owned	81.21	81.21
	Base Rate Energy Customer Charge - cents per KWH	0.982	1.081
	Distribution Charge - $ per KW		
	Applicable to Specified SB Capacity	1.99	2.19
	Generation and Transmission Capacity Charge		
	Greater of : - $ per KW		
	Monthly Reservation Charge		
	Applicable to Specified SB Capacity	1.109	1.221
	Peak Day Utilized SB Power Charge of:	0.528	0.581
	Delivery Voltage Credits - $ per KW		
	Primary	0.36	0.40
	Transmission	n/a	n/a
	Premium Distribution Charge - $ per KW	1.01	1.11
SS-2	Customer Charge - $ per Line of Billing		
	Secondary	303.71	303.71
	Primary	438.68	438.68
	Transmission	1,015.02	1,015.02
	Customer Owned	284.20	284.20
	Base Rate Energy Customer Charge - cents per KWH	0.971	1.069
	Distribution Charge - $ per KW		
	Applicable to Specified SB Capacity	1.99	2.19
	Generation and Transmission Capacity Charge		
	Greater of : - $ per KW		
	Monthly Reservation Charge		
	Applicable to Specified SB Capacity	1.109	1.221
	Peak Day Utilized SB Power Charge of:	0.528	0.581

Duke Energy Florida
Rate Schedules
Detailed Unit Charges by Rate Schedule
2013 Re-Settlement for 1/1/2016 Effective Date

Rate Schedule	Type of Charge	**1/1/2015** Current/Prior Rate	**1/1/2016** Proposed Rate
	Interruptible Capacity Credit - $ per KW		
	Monthly Reservation Credit	0.979	0.979
	Daily Demand Credit	0.466	0.466
	Delivery Voltage Credits - $ per KW		
	Primary	0.36	0.40
	Transmission	n/a	n/a
	Premium Distribution Charge - $ per KW	1.01	1.11
SS-3	Customer Charge - $ per Line of Billing		
	Secondary	100.71	100.71
	Primary	235.69	235.69
	Transmission	812.02	812.02
	Customer Owned	81.21	81.21
	Base Rate Energy Customer Charge - cents per KWH	0.974	1.072
	Distribution Charge - $ per KW		
	Applicable to Specified SB Capacity	1.99	2.19
	Generation and Transmission Capacity Charge		
	Greater of : - $ per KW		
	Monthly Reservation Charge		
	Applicable to Specified SB Capacity	1.109	1.221
	Peak Day Utilized SB Power Charge of:	0.528	0.581
	Curtailable Capacity Credit - $ per KW		
	Monthly Reservation Credit	0.734	0.734
	Daily Demand Credit	0.350	0.350
	Delivery Voltage Credits - $ per KW		
	Primary	0.36	0.40
	Transmission	n/a	n/a
	Premium Distribution Charge - $ per KW	1.01	1.11
	Gross Receipts Tax	2.5641%	2.5641%
	Rate Adjustment	0.00%	0.00%
	Rate Adjustment Effective Date	2/10/2010	2/10/2010
Various	Supplemental Service under SS-1, SS-2, SS-3 - (otherwise applicable rate)		
	Customer Charge	0.00	0.00
GSLM-2	Capacity Credit		
	<= 200 CRH	4.50	4.50
	> 200 CRH	5.40	5.40

REDACTED

Docket No. _______
Witness: Olivier
Exhibit No. (MO-5)

Duke Energy Florida
Estimated Nuclear Fuel Proceeds
($ thousands)

		Total	Est. Only				
			UF6 Aug-15	EUP TBD	Batch 19 Total	Batch 19 Dec-16	Batch 19 Dec-17
Net fuel proceeds		$141,906	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Less joint owner	8.2194%	(11,664)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Retail/Whls portion		130,242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Less wholesale portion	8.353%	(10,879)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Retail portion to CR3 reg asset		$119,363	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

Docket No. _______
Witness: Olivier
Exhibit No. (MO-6)
Page 1 of 1

Duke Energy Florida
CCR Nuclear Fuel Illustrative Impact
(In Thousands)

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total-16
Sale of Batch 19	[redacted]												
Beginning Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proceeds - Batch 19												[redacted]	[redacted]
Ending Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Carrying Charge*	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	
CCR Rev. Req.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Resid. Rate ($/mwh)													$0.08

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total-17
Beginning Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proceeds - Batch 19												[redacted]	[redacted]
Ending Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Carrying Charge*	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	
CCR Rev. Req.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Resid. Rate ($/mwh)													$0.04

* Rate is consistent with Revised and Restated Stipulation and Settlement Agreement, Exhibit 10, approved in Order No. PSC-13-0598-FOF-EI.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Duke Energy Florida, Inc.
For Approval to Include in Base Rates the Revenue
Requirement for the CR3 Regulatory Asset

Docket No. ____________

Submitted for Filing
May 22, 2015

REDACTED

DIRECT TESTIMONY OF MARK R. TEAGUE

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Marcus ("Mark") R. Teague. My current business address is 400 South Tryon Street, Charlotte, North Carolina.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Business Services, LLC as Managing Director of Major Projects Sourcing ("MPS") in the Supply Chain department.

Q. Have you previously provided testimony to the Commission?

A. Yes, I have provided testimony in the Nuclear Cost Recovery Clause docket to support the Company's investment recovery efforts related to the Extended Power Uprate ("EPU") assets.

Q. What are your responsibilities as the Managing Director of MPS?

A. My role includes providing management oversight in the disposition of the Crystal River Unit 3 ("CR3") assets by ensuring that Supply Chain employees at CR3 follow DEF's processes and procedures. I also have responsibility for the Supply Chain functions for Duke Energy International and with most Duke Energy Corporation ("Duke Energy") Major Projects, both regulated and non-regulated.

Q. Please summarize your educational background and professional experience.

A. I have a Bachelor's of Technology degree in Civil Engineering from the University of North Carolina at Charlotte and a Masters of Business Administration from Wake Forest University. I have 32 years of experience with Duke Energy and I am a licensed Professional Engineer in the state of North Carolina. My prior roles at Duke Energy include design engineering professional, project controls professional, and project management professional in both Nuclear Generation and Fossil/Hydro Generation and I have also managed each of those functional roles in the past. For the last four years, I have served as Managing Director in the Supply Chain organization – two years leading the Fossil/Hydro Supply Chain organization and two years leading the Major Projects Sourcing Supply Chain organization.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the prudent efforts the Company undertook to disposition assets as a result of the decision to retire and decommission the CR3 nuclear power plant. I will explain the status of the investment recovery project efforts to disposition CR3 assets and materials and the related proceeds from those efforts. I will also demonstrate how the Company's actions are consistent with its obligations in the 2013 Revised and Restated Settlement and Stipulation ("RRSSA"). My testimony will explain certain adjustments reflected in the following categories listed on Exhibit 10 to the RRSSA: line 3, (accumulated depreciation), line 11 (Fukushima), line 13 (Other-CWIP), line 14 (Nuclear Fuel Inventories), and line 15 (Nuclear Materials and Supplies Inventories).

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No.___(MT-1), the CR3 Administrative Procedure, AI-9010, Conduct of CR3 Investment Recovery, Revision 1;
- Exhibit No. ____ (MT-2), the CR3 Investment Recovery Project, Project Execution Plan, Revision 0;
- Exhibit No. ___(MT-3), the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development; and
- Exhibit No. ____(MT-4), the confidential Integrated Change Form for the retention of an auction company used to sell CR3 plant assets.

These exhibits were prepared by the Company, and they are generally and regularly used by the Company in the normal course of its business, and they are true and correct.

Q. Please summarize your testimony.

A. Since the Company's decision to retire CR3 in 2013, DEF has worked to disposition CR3 plant assets using a step-wise approach under its investment recovery policies and procedures to obtain the most prudent value for those assets for DEF's customers. In mid-2014, after conducting extensive internal and external solicitation efforts pursuant to DEF's procedures, DEF made the decision to hire an auction company to conduct a global auction for the remaining CR3 assets. The decision to hire an auction company is outlined in Exhibit MT-4, Integrated Change Form (ICF). The auction was conducted in September 2014 and DEF successfully sold various CR3 plant assets at the auction. As a result of DEF's efforts, the CR3 Regulatory Asset was credited a total of $7.9 million for the benefit of customers.

With respect to the nuclear fuel inventory, DEF actively marketed the different types of nuclear fuel to maximize the potential value for customers. As a result of DEF's efforts, DEF currently expects to reduce the value of the CR3 Regulatory Asset by $119.4 million.

III. DEVELOPMENT OF INVESTMENT RECOVERY PROCESS.

Q. Will you please describe the actions DEF took after the announcement of CR3's retirement?

A. After the retirement decision, in mid-2013, DEF created the Investment Recovery Project ("IRP") to have a single group that was responsible for management and disposition of all of the CR3 plant assets. The objective of the IRP is to take reasonable and prudent efforts to sell or otherwise salvage CR3 assets by implementing a program under which marketable CR3 plant assets are identified, maintained, marketed, sold, and removed from the site in an efficient manner.

Q. Can you describe the overall governance for asset disposition?

A. Yes. As explained further in the testimony of Mr. Terry Hobbs in this docket, following the decision to retire and decommission the CR3 plant, the Company began the process of setting up the CR3 Decommissioning Transition

Organization ("DTO"). Unlike many generating stations that are retired at the end of their useful life, CR3 has material and equipment that retain some value. As a result, as part of the DTO, DEF created the IRP to manage the asset disposition process.

First the IR team was tasked with creating specific governance documents and a procedure for the process of disposition. Specifically, DEF implemented the CR3 Administrative Procedure AI-9010, Conduct of CR3 Investment Recovery, Revision 1 ("AI-9010"), attached hereto as Exhibit No. ___(MT-1). Procedure AI-9010 outlines the asset pricing requirements and minimum reviews and approvals required for the execution of transactions, and the record keeping requirements necessary for the disposition of assets from CR3 during the DTO phase. Second, the IR team created the CR3 Investment Recovery Project, Project Execution Plan, Revision 0 ("Project Plan"), attached hereto as Exhibit No. __(MT-2). This project plan supplies the overall governance for the IR project and defines the organization, work processes, and systems necessary for the successful disposition of all CR3 assets. Finally, the IR team developed the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development ("IRGD-001"), attached hereto as Exhibit No. ___(MT-3). IRGD-001 provides additional guidance on tracking and documenting sales made by the IRP.

Q. Did DEF perform benchmarking of other utilities as it created and implemented its disposition and wind-down plans?

A. Yes. DEF benchmarked several of the most recently decommissioned nuclear power plants including Zion Units 1 & 2 in Illinois, San Onofre Nuclear Generating Station (SONGS) in California, and the Kewaunee Unit in Wisconsin. DEF sought out, reviewed, and implemented lessons learned from these plants' decommissioning efforts as it created its DTO and IR processes.

Q. What disposition strategy did DEF use for the sale of CR3 plant assets?

A. Under the investment recovery procedure, assets were first offered for internal transfer to Duke Energy affiliates in accordance with the Affiliate Asset Transfer Transactions policy. If DEF was unable to locate an appropriate internal transfer opportunity, DEF then solicited external interest from distributors, original equipment manufacturers ("OEM"), and re-sellers and, if there was sufficient interest, DEF conducted a bid event using Power Advocate (an electronic bidding tool). DEF also marketed CR3 plant material (*154 Inventory*) and equipment (Pre-Cap) on RAPID, a utility parts website, and worked with Pooled Inventory Management ("PIM"), a program run by the Southern Company to market major components for joint purchase by multiple utilities for components to keep as "spares" in the event of a future need. Several CR3 plant components were transferred internally in 2013 and 2014 and some components were sold at bid events.

For the remaining equipment, as I describe in more detail below, the investment recovery team decided to utilize the assistance of an auction company to enable DEF to reach the widest audience possible for its CR3 assets. For the assets that were not sold at the auction, DEF has concluded that the EPIS equipment and installed CWIP equipment is to be abandoned in place. These installed assets are typically engineered specialty equipment for CR3, have no warranty, have no performance guarantee, may be contaminated, and any potential buyer will have to pay for removal and shipping costs. Unless a potential buyer has an emergent need for specific engineered equipment, it is generally not economical for a potential buyer to pursue. Smaller commodities are readily available in the market place with a warranty, a performance guarantee, and no removal costs.

Q. You mentioned that DEF auctioned some of the assets. Why did DEF decide to use an auction company to sell the CR3 equipment?

A. In accordance with its policies and procedures, DEF made the decision to disposition CR3 assets at fair market value through competitive bidding processes for direct sales to third parties or transfers to Duke Energy affiliates. DEF had already followed its process under these policies and procedures and offered CR3 assets for sale or transfer internally, solicited the market and offered assets for direct sale externally to third parties, including soliciting buy-back from equipment OEMs. After those steps, in mid-2014, DEF decided to evaluate using an outside auction company to sell the remaining CR3 plant assets. DEF determined in this evaluation that if DEF used an auction company to sell assets, compared to singular bid events for the assets, DEF would be able to access the aggressive marketing of the auction company and reach a broader, indeed, world-wide market. This evaluation is reflected in DEF's Integrated Change Form ("ICF") included as Exhibit No. ___ (MT-4).

Q. Can you please describe who DEF retained to conduct the auction and when it was conducted?

A. Yes. DEF retained Heritage Global Partners Asset Advisory & Auction Services to conduct the auction. This auction was advertised world-wide to over 100,000 potential buyers through various mediums including print and electronic advertising and direct e-mail solicitation, in addition to personal contact with power plants world-wide. The auction was conducted over three days on September 24-26, 2014 in Crystal River, Florida.

Q. Are there any CR3 plant assets that remain to be sold or salvaged?

A. While there are some CR3 assets other than EPU-related assets, which are the subject of the NCRC proceeding, that were not sold, there will be no further sales or salvage amounts credited to the CR3 Regulatory Asset.

As explained above, DEF has concluded that the EPIS equipment and installed CWIP equipment is to be abandoned in place. These installed assets are typically engineered specialty equipment for CR3, have no warranty, have no performance guarantee, may be contaminated, and any potential buyer will have to pay for removal and shipping costs. Unless a potential buyer has an emergent need for specific engineered equipment, it is generally not economical for a potential buyer to pursue. Smaller commodities are readily available in the market place with a warranty, a performance guarantee, and no removal costs. In addition, there are some materials and supplies that may still be needed for use at the site, which have not been sold or salvaged. If, however, DEF is approached to sell any of the CR3 assets, DEF will evaluate the request and, if there is a net benefit, it will make that sale and credit the nuclear decommissioning trust fund with any proceeds received.

Q. Please describe what sale, transfer, or salvage proceeds have been received since the 2013 retirement decision and explain how DEF accounted for these proceeds.

A. DEF has received approximately $8.6 million in gross proceeds from the sale, transfer, or salvage of CR3 plant assets (not including nuclear fuel or sales associated with EPU assets or the transfer of buildings out of the CR3 regulatory asset). As described in the testimony of Ms. Marcia Olivier, the Company has credited the retail portion of these proceeds, $7.9 million, against the CR3 Regulatory Asset, for the benefit of DEF's customers. Specifically, Line 3 (accumulated depreciation) of Exhibit 10 reflects $0.5 million of proceeds, Line 11 (Fukushima) shows $0.3 million of proceeds, Line 13 (Other-CWIP) shows $2.3 million of proceeds, and Line 15 (Nuclear Materials and Supplies Inventory) reflects $4.8 million of proceeds.

Q. Are the costs presented in this testimony separate from the EPU-related costs presented in the NCRC docket?

A. Yes, my testimony in this proceeding only covers those costs that were incurred by the IRP to disposition both the EPU and CR3 assets combined. Given the nature of the work done by the IRP, it was not practical to separately account for these joint costs, so all the costs incurred to disposition the assets were charged to the CR3 Regulatory Asset, as reflected in Line 15 of Exhibit 10 to the RRSSA. Separate from CR3 Regulatory Asset costs are the EPU Equipment Preservation Costs and the EPU project close-out costs that are not included in this testimony, because they are included in the NCRC proceeding.

V. DISPOSITION OF NUCLEAR FUEL.

Q. Did DEF have any nuclear fuel assets to disposition after the retirement of CR3?

A. Yes, DEF had two categories of nuclear fuel-related assets. The first type was completed fuel assemblies referred to as "Batch 19." The other nuclear fuel was upstream uranium.

Q. Please provide a brief overview of the life cycle of nuclear fuel.

A. The life cycle of nuclear fuel is a complicated, highly technical process. First, both excavation and in situ techniques are used to recover uranium ore. Through milling, uranium oxide (U_3O_8) is extracted from the uranium ore by a chemical process. This product is commonly known as yellow cake. Uranium oxide is not directly usable as a fuel for a nuclear reactor and additional processing, specifically conversion and enrichment, are required. In the conversion process U_3O_8 is transformed into a gas – uranium hexafluoride (UF_6). The main enrichment process in commercial plants uses centrifuges, with thousands of rapidly-spinning vertical tubes. The product of this stage of the nuclear fuel cycle is enriched uranium hexafluoride, which is reconverted to produce enriched uranium oxide. Finally, reactor fuel is generally in the form of ceramic pellets. These are formed from pressed uranium oxide (UO_2) which is sintered (baked) at a high temperature (over 1400°C). The pellets are then encased in metal tubes to form fuel rods, which are arranged into a fuel assembly ready for introduction into a reactor.

Q. Did DEF use the same process for dispositioning the Batch 19 fuel assemblies and upstream uranium?

A. No, given the nature of the nuclear fuel market, DEF had to use different methods to disposition the fuel. I will explain each in detail below.

A. Batch 19 Fuel Assemblies **REDACTED**

Q. Please describe the Batch 19 fuel assemblies.

A. DEF purchased and received the Batch 19 fuel assemblies from Areva in 2009. There were [redacted] assemblies, each one containing [redacted] fuel rods. The fuel assemblies were designed and manufactured specifically for the Babcock and Wilcox (B&W) pressurized water reactor installed at CR3. The Batch 19 fuel assemblies were part of the Cycle 17 core reloaded on November 21, 2010. Given the extended outage, the fuel assemblies were offloaded to the spent fuel pool on May 28, 2011, and the fuel assemblies remain there today.

Q. Is there anything unique about these fuel assemblies that impacts how they can be used by third parties?

A. Yes. Fuel assemblies must be specifically designed for the type of reactor. Because these fuel assemblies were manufactured for a B&W pressurized water reactor, if another nuclear plant owner wants to utilize the fuel assemblies "as is," the nuclear plant must also be a B&W pressurized water reactor. The fuel assemblies may also be de-fabricated to recover the enriched UF_6.

Q. What disposition strategy did DEF use to disposition the Batch 19 fuel assemblies?

A. DEF issued a request for proposals ("RFP") on March 26, 2014 to obtain bids from interested bidders. DEF issued a national press release in several energy-related publications to advertise the RFP to the industry. It also invited twenty-six potential buyers (including all known nuclear owners with B&W pressurized water reactors). DEF operated the RFP through PowerAdvocate, and internally created separate bid and evaluation teams, with an ethical screen between the two teams. DEF also engaged a third party consultant to assist with issuing the RFP and evaluating the proposals.

Q. Please describe the results of the RFP.

A. After issuing the RFP, DEF held a bidder's meeting on April 11, 2014 to answer questions. DEF also asked for parties who intended to bid to provide a notice of intent of bidding, and DEF received such notices from four companies. Part of the bidding process included site visits at CR3 for the potential bidders to inspect the fuel assemblies. DEF received proposals on June 30, 2014, but only received two proposals from one company. The other three companies who submitted notices of intent to bid did not submit bids.

The two bids DEF did receive were from Duke Energy Carolinas/Duke Energy Progress ("DEC/DEP"). The first bid was [redacted]. The other bid was [redacted] After evaluating the proposals, DEF decided on August 4, 2014 to award the RFP to DEC/DEP for its "as is use" proposal. DEF executed the contract on January 26, 2015.

REDACTED

Q. Please describe in further detail the contract to sell the fuel assemblies.

A. The contract provides a price of [redacted] for the fuel assemblies, and [redacted]

[redacted] **REDACTED**

Q. Given that DEF will not receive any proceeds under this contract until 2016 and 2017, how does DEF propose treating those costs in this proceeding?

A. Witness Marcia Olivier will explain the treatment of the expected proceeds in her testimony.

B. Upstream Uranium

Q. Please describe DEF's upstream uranium inventory holdings.

A. DEF has in inventory two types of upstream uranium. The first is uranium hexafluoride or UF_6. The other type is EUP or enriched uranium product. These inventory holdings are at locations outside of CR3, in Europe and North America. The amounts of inventory holdings are shown in the tables below.

Table 6. EUP Inventory Holdings	
Location: AREVA Richland, WA Quantity: **14,015.726 kgU** of EUP at 4.959$^{w}/_{o}$ U^{235}	
Feed Equivalent* (kgU as UF_6)	**SWU Equivalent*** (SWU)
~130,530.0	**~122,711.4**
Notes: *Components based on 4.959$^{w}/_{o}$ product assay and 0.20$^{w}/_{o}$ tails assay. **The SWU origin for all of the SWU is WR (Russia). Russian HEU for US legal use.	

Table 5. UF_6 Inventory Holdings				
Location	**Quantity** (kgU as UF_6)	**Obligation Code**	**Mining Origin**	**Conversion Origin**
GBII	288,332.608	C	CA	CA
Cameco	35,401.6	C	CA	CA

	154,447.0	P	WA	CA
LES	104,000.0	S	AU	CA
	42,391.3	S	AU	UK
URENCO	98,928.947	C	CA	CA
	21,706.153	A	R1	UK
Total:	**745,207.608**			

Q. Is there anything unusual about the uranium market?

A. Yes. Unlike the Batch 19 fuel assemblies, uranium is not commoditized. This means that it does not have a formal open public market or standardized public data about supply, demand, and cost. Accordingly, it is not the type of market in which potential sellers can simply issue a nation-wide RFP and evaluate responses from potential buyers. To the contrary, if sellers of uranium put large amounts of uranium into the market all at once, with no regard for other factors impacting the market, it is very likely that the flooding of the uranium supply would disrupt the limited market and drive down prices.

Q. Given the unique nature of the uranium market, what strategy did DEF use to disposition its upstream uranium inventory?

A. DEF executed a competitive bidding process to select a consulting firm. The duties of the consulting firm include two phases. In Phase I, the consulting firm defines the strategy to sell the uranium inventory in the marketplace at maximum value. Phase II involves the consulting firm executing the approved selling strategy. DEF provides oversight and approves the development and execution of the strategy. To choose the consulting firm, DEF issued an RFP and evaluated responses from various bidders. After this review, DEF selected Ux Consulting.

Ux Consulting is one of the nuclear industry's leading consulting companies. They publish market reports about supply, demand, and prices for uranium, enrichment, conversion, and fabrication, as well as provide consulting services on a variety of topics including divestiture of nuclear fuel. DEF considered several factors when selecting Ux Consulting, including: their expertise level, personnel and infrastructure; references and sample material; market data and market relationships; cost of consulting services; and brokerage fees.

Q. Why did DEF need to engage a consulting firm to assist with the disposition of upstream uranium?

A. Given the unique nature of the market, DEF needed to engage the expertise of a consulting firm with more experience and knowledge about the intricacies of the market. A third party consulting firm like Ux Consulting is able to identify key market drivers and help DEF develop the best strategy for introducing DEF's upstream uranium inventories in a manner that will maximize value for our customers.

Q. What specific strategy has DEF, with the assistance of Ux Consulting, developed for the upstream uranium sales?

A. DEF and Ux Consulting first considered what type of sale pricing to utilize. There are several options. One is market-related pricing, in which the price is not fixed until the time of delivery. Prices are generally indexed to published industry indicators. Using this option would increase price uncertainty. Another pricing option is base-escalated pricing, which is a price mechanism where the start price is set at the time of the contract and escalated until the time of delivery using either an index (like the U.S. G.N.P.) or a fixed percentage index. Given the current market conditions for uranium, however, few contracts are being signed with traditional base-escalation terms. The final alternative is fixed pricing, where all delivered prices are fixed at the time of the contract. An iteration of this final option is to fix the prices off of a forward price curve. This use of a forward price curve has been increasingly used in today's market. In fact, due to prolonged differentials between spot and term indicators, a mid-term market has developed where spot prices are escalated forward using forward price curves. This provides better pricing options to the buyer than traditional base-escalated term offers, but better options to the seller than spot pricing. Given this benefit, DEF and Ux Consulting agreed to [redacted] **REDACTED**

The next consideration for the upstream uranium sales was the process for entering the market and making the sales. There are three potential sales approaches, and there are benefits and downsides to each approach. One approach is reverse auction. This is similar to the RFP process explained above for the fuel assemblies. History shows, however, that using this approach results in sales prices below the market with limited participation. This approach tends to appear as a distressed seller flooding the market with the uranium product. Another approach is broker assisted sales. With this approach, the seller works with brokers to disposition the fuel, typically for a brokerage fee. The final approach is a traditional seller/direct contact sales, where the utility finds buyers directly and sells them the fuel.

After weighing the potential approaches, DEF decided to do [redacted]

REDACTED

Q. Have DEF and Ux Consulting begun to execute this strategy?

A. Yes. DEF and Ux Consulting executed a contract on July 18, 2014. Ux Consulting has been providing ongoing information about nuclear fuel market conditions to DEF. Ux Consulting is [redacted]

[redacted] Ux Consulting has provided information, and will continue to do so, on: when to sell material; whether the particular sale is the best price and if discounts will be required; what quantity and what form the sale should take; and the best process to use for the next batch of fuel. Also, given the unique characteristics of the uranium market, the disposition will most likely not take place in one fell swoop.

Specifically, at the end of March 2015, Ux Consulting [redacted]

REDACTED

Q. What did DEF decide to do in response to the bids received?

A. With respect to the [redacted] DEF determined that accepting the bid from [redacted] yielded the most favorable results for customers. [redacted] DEF expects to receive gross proceeds of [redacted] not including [redacted]. The retail portion of these proceeds is reflected on Line 14 (Nuclear Fuel Inventories) on Exhibit 10 to the RRSSA.

With respect to the EUP inventory, [redacted] In order to give customers the benefit of the anticipated potential proceeds from selling the EUP fuel, however, DEF proposes to credit the CR3 Regulatory Asset with the expected proceeds [redacted]. Accordingly, DEF is showing a credit to Line 14 on Exhibit 10 to the RRSSA of approximately $[redacted] [redacted] ($[redacted] [redacted] gross proceeds). If the ultimate disposition of the EUP inventory results in a different amount received, DEF will treat those proceeds in a similar manner as that used to account for the Batch 19 fuel proceeds, as described in Ms. Olivier's testimony. All of the estimated nuclear fuel sales proceeds are provided in Exhibit No. ___(MO-5) attached to Ms. Olivier's testimony.

V. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Please explain the project management and cost control oversight processes used for the investment recovery efforts associated with the CR3 plant assets.

A. The investment recovery project is governed by procedure number AI-9010 as discussed above and attached hereto as Exhibit No. ___(MT-1). AI-9010 was developed specifically for CR3 asset disposition and outlines the pricing requirements, minimum reviews, and approvals required for the execution of transactions and the record keeping requirements necessary for the disposition of assets from CR3. AI-9010 provides specific instructions on expectations, assets pricing, disposition transaction review and approvals, project assurance and removal of installed assets and provides approved forms to document asset disposition.

The investment recovery Project Plan continues to be used and supplies the overall governance for the investment recovery project and defines the organization, work processes, and systems necessary for the successful disposition of all CR3 assets. See Project Plan attached hereto as Exhibit No. __

(MT-2). In 2014, DEF also issued the Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development. See Exhibit No. ___(MT-3) to my testimony. This document provides additional instruction to conduct sales and develop complete documentation packages for the investment recovery project

Q. What other oversight mechanisms did DEF use to oversee the IR process?

A. The Company utilized Key Performance Indicators ("KPIs") to monitor the status of the investment recovery project. These KPIs were reviewed by the investment recovery team on a regular basis. Additionally, weekly progress/status meetings were held to review open issues in the project including action items, trends, key schedule milestones and other issues. Monthly progress reports were issued reporting financial results for the overall project, for the prior month. Additionally, risk review meetings were held on a regular basis in accordance with PJM-0013-ENTSTD, Project Risk Management, and a formal risk register was maintained for the investment recovery project and updated as necessary.

Q. Does this conclude your testimony?

A. Yes, it does.

DUKE ENERGY

I
Information Use

CRYSTAL RIVER UNIT 3

ADMINISTRATIVE PROCEDURE

AI-9010

Conduct of CR3 Investment Recovery

REVISION 1

TABLE OF CONTENTS

1.0 PURPOSE

1. This procedure outlines the asset pricing requirements and minimum reviews and approvals required for the execution of transactions and the record keeping requirements necessary for the disposition of assets (materials and equipment) from Crystal River Unit 3 (CR3) during the Decommissioning Transition Organization (*DTO*) phase. Additionally, the disposition of CR3 new nuclear fuel (fabricated and at CR3) is governed by this procedure. Upstream supplies (Enriched Uranium Product and UF6 Converter material) will be governed by this procedure.

1.1 Scope

1. Transactions include, but are not limited to the following:
   - Transfer of assets to Duke affiliated companies (*both regulated and non-regulated*)
   - Sale of assets
   - Sale of assets as scrap
   - Donating assets to charitable organizations
   - Disposal of assets.
2. Transactions under this procedure must conform to all existing applicable company policies.
3. It is essential that asset divesture records of all transactions are documented and preserved.
4. In accordance with the governance, the review and approval of each asset disposition is documented on a form similar to Attachment 1, Asset Disposition Review.
5. This procedure does not cover Real Property.
6. All transactions will comply with tax regulations. Internal transfers within DEF, or to DEC, DEP, DEO, DEI, and DEK do not require a tax surcharge as these entities have a Direct Pay Permit. A copy of these Direct Pay Permits is on file with Supply Chain at Crystal River 3.

2.0 REFERENCES

1. ADM-SUBS-00106, Project Assurance Nuclear Cost Recovery Clause Library (NCRCL) Program Manual
2. AI-9003, System Evaluation, Categorization and Abandonment
3. CR3 Investment Recovery Project Execution Plan
4. MCP-NGGC-0001, NGG Contract Initiation, Development and Administration
5. RDC-0001, Records Management Program
6. SCD211, Affiliate Asset Transfer Transactions
7. Affiliate Asset Transfer e-form on the Duke Energy PORTAL
8. Delegation of Authority (DOA)
9. Code of Business Ethics
10. Records Management Policy
11. Sales/Use and Excise Tax Policy
12. Purchasing Authority Policy
13. PMC-PRC-NA-AD-0013, Project Assurance Program Manual

3.0 DEFINITIONS

1. **154 Inventory** – Material that is put into an inventory system (Passport, EMAX or Nuclear Asset Suite (NAS)) and whose dollars are captured in FERC account 0154 at time of receipt. As part of the CR3 Settlement Agreement, all previous account 0154 Inventory is now part of the Regulated Asset, though for simplicity these are referred to in this procedure as 0154 Inventory.
2. **AAT – Affiliate Asset Transfer** - Transferring material internally between regulated, non-regulated and non-utility affiliates subject to governance under various federal and state guidelines and is documented on the Affiliate Asset Transfer Electronic Form found on the PORTAL. Only Regulated assets are transferred in accordance with the Intercompany Affiliate Transfer Agreement. The Code of Conduct and other applicable rules and regulations dictate how assets move between Regulated and Non-regulated or Non-utility affiliates.

3.0 DEFINITIONS (continued)

3. **Assets** - Described in the following categories and sub-categories.

   a. **Inventory** – These include materials in the 154 Account.

   b. **Pre-Expensed O&M Material** - Material bought directly for O&M work and not put in Inventory. Disposition at cost following the Inventory disposition guidance in this document; however, the accounting treatment may be different.

   c. **Other** – These include other materials and equipment that are not in the 154 Inventory Account and are not pre-expensed O&M material.

      1) Training equipment, trailers, etc.

      2) **Purchased but not installed** capital equipment in the Construction Work In Progress (CWIP) 107 Account.

         - For example, the LP Rotor(s) for the EPU project
         - Typically, these assets have little value as they are without warranty, and without performance guarantees.
         - These assets may be disposed during the actual Decommissioning phase of the project.

      3) **Purchased and installed but never been put in-service** capital equipment in the CWIP 107 Account.

         - For example, the Steam Generators
         - Typically, these assets have little value as they are without warranty, and without performance guarantees.
         - These assets are normally disposed during the actual Decommissioning phase of the project.

      4) **Installed and in-service** capital equipment in the Electric Plant In Service (EPIS) 101 and 106 Accounts.

         - The 101 Account is final and the 106 Account represents equipment that has not been unitized.
         - Typically, these assets have little value as they are used, without warranty, and without performance guarantees.
         - These assets are normally disposed during the actual Decommissioning phase of the project.

4. **Asymmetrical Pricing** - A pricing rule established by FERC which states that the franchised utility must receive the higher of cost or market price for providing non-power goods or services to a nonutility / non-regulated utility affiliate, and must not pay more than market price for a non-power good or service received from a non-utility / non-regulated utility affiliate.

5. **AUP - Average Unit Price** - An inventory item’s average unit cost. In the Nuclear Asset Suite system, this is referred to as CUP (Calculated Unit Price)

3.0 DEFINITIONS (continued)

6. **Capital Material** – Typically other material whose cost is captured in a capital project at time of purchase, or was 0154 inventory that has already been issued out to a capital project.
   - Some of this material can also be described as a Pre-Capitalized Asset, or material whose quantity is tracked in PassPort, and at the time of issue, no additional accounting entries are generated.
7. **Disposition** – The disposal of an asset through sale, transfer, or discarding.
8. **FMV – Fair Market Value** - The current price at which an asset can be bought or sold in the market.
9. **IATA - Intercompany Asset Transfer Agreement** - A document between Duke Energy's regulated, franchised affiliates (DEC, DEI, DEK, DEO-T&D, DEP & DEF) which has been approved or accepted on an interim basis by the state commissions.
10. **NBV – Net Book Value** – The capital asset original cost, estimated, if not known, less the amounts credited to accumulated depreciation with respect to such property.

4.0 RESPONSIBILITIES

1. **GM Decommissioning** or their designee is responsible for the approval of this procedure.
2. **Corporate Communications** is responsible for following the guidance in Attachment 4, Duke RFP Guidelines if an Affiliate Bid is Anticipated when applicable.
3. **CR3 Financial Services Manager** and **Director Florida Accounting** are responsible for ensuring the correct accounting is used for transactions and determining net book value.
4. **Director – Major Projects Finance** and the **Managing Director – Major Projects Supply Chain** are responsible for the content of this procedure.
5. **Crystal River 3 Supply Chain Management** is responsible for:
   - Communicating the requirements of this procedure to all persons involved in the Investment Recovery processes.
   - Maintaining adequate internal controls over the Investment Recovery process and utilizing effective contract management processes.

5.0 INSTRUCTIONS

5.1 Expectations

1. This procedure applies to the governance of the CR3 Investment Recovery (IR) processes used in Major Project's Supply Chain.
2. The CR3 Investment Recovery Project, Project Execution Plan is documented at: https://nuc.duke-energy.com/sites/CR3DDR. All levels of management in the CR3 organization and Major Projects Supply Chain should be briefed on these documents.
3. All disposition transactions shall be performed in a prudent manner.
4. Transactions, including related contracts or other legally binding agreements, must be approved by the appropriate authority prior to execution by Duke Energy.
5. Individual transactions cannot be separated into multiple transactions for the purpose of circumventing an individual's authorized approval limit. However, transactions may be evaluated for required authority limits individually where the transactions are discrete, separate and independent of each other. The Delegation of Authority amounts and Purchasing Authority amounts apply to each transaction.
6. All CR3 Inventory (154) spare part material is listed as "For Sale" in the power industry RAPID database (www.rapidpartsmart.com). This material can be sold for AUP/CUP to other utilities via this tool at any time. Once internal fleet transfers are complete, we may sell RAPID spare parts for less than AUP/CUP to other utilities or to affiliates (see exception in Step 9).
7. Under the IR Project, all Inventory (Account 154) assets will be disposed of in the following manner:
    a. Utilize Duke Energy internal Inventory transfers to the fleet per the Affiliate Asset Transfer e-form and process. This should follow an approach where multiple lines of CR3 inventory are matched to an affiliate and to a specific plant.
        - The one exception to using the Affiliate Asset Transfer e-form is transferring material from CR3 within Duke Energy Florida (DEF). In these cases, a Material Transfer or Material Request can be utilized within Passport to document this transfer.
    b. Account 154 Inventory is normally transferred among regulated affiliated utilities at AUP/CUP. However, asymmetrical pricing is generally used for non-regulated utility affiliates and non-utility affiliates.
        - There is an exception in which a transfer to a regulated affiliate can take place at less than AUP/CUP. (See Step 9 for that exception.)

5.1 Expectations (continued)

c. If not transferred internally, then segregate and bid out inventory or obtain price quotes from distributors, other utilities and/or Original Equipment Manufacturer's (OEM's), and/or re-sellers. Asset Recovery Supply Chain and/or Auction Companies can be utilized to sell material to distributors, OEM's, and re-sellers as well.

- This establishes the FMV of bulk inventory disposal and generally yields a higher value than salvage or scrap pricing.
- Obsolete inventory may be marketed at a target market directly or through third party vendors.

d. For remaining Inventory, utilize Asset Recovery Supply Chain or Auction Companies for disposition at salvage or scrap value. Note some inventory items (consumable materials, commodities, short lead time material, low value, etc.) may be salvaged or scrapped immediately.

8. Under the IR Project, all **Other** assets (non-inventory) will be dispositioned as identified below:

a. Generally, **Other** assets may be transferred among regulated affiliated utilities at NBV or at cost for pre-expensed O&M material if the regulated affiliates identify a need. However, asymmetrical pricing, for transfers, is used for non-regulated utility affiliates and non-utility affiliates when those entities identify a need. There is an exception in which a transfer to a regulated affiliate can take place at less than NBV. (See Step 9 for that exception.)

b. If not transferred internally, determine the FMV by obtaining price quotes, bids, or market intelligence as applicable and bid out. In some cases, Duke affiliates may want to bid and compete against the external market. These type of sales transactions must be conducted at arm's length to ensure the integrity of the process. Additionally, any Duke affiliate winning bid is subject to approval by State Commissions and perhaps by FERC via a waiver (FERC waiver/ approval required if the winning bid is a Duke non-utility affiliate or a Duke non-regulated utility affiliate), Attachment 4, Duke RFP Guidelines if an Affiliate Bid is Anticipated provides information to be followed in these cases.

1) The bidding process for the disposition of materials and equipment shall be conducted as follows:

a) The bidding process shall follow MCP-NGGC-0001.

b) The Power Advocate sourcing tool or similar should be used for all bid events, thereby maintaining consistency with all bid event sales and document retention.

c) The standard approved legal form contracts or those prepared by Duke Energy's Legal Department shall be used for all third party asset contract sales in accordance with MCP-NGGC-0001.

5.1 Expectations (continued)

c. For remaining **Other** material, utilize Asset Recovery Supply Chain or an Auction Company for disposition at salvage or scrap value.

9. There may be instances where NBV or AUP/CUP may be at a higher value than FMV, in these cases, Commission(s) approval will be required to transfer at less than NBV or AUP/CUP.

   a. Internal transfers may not have a warranty or performance guarantee associated with the Other material and consideration should also be made for any removal and shipping costs. These costs or values should be considered when comparing NBV to FMV (of an equivalent asset) and can result in a win/win for Duke Energy Florida and the internal transferee regulated affiliate.

   A hypothetical example could be that Equipment A at CR3 has a NBV of $15,000,000 dollars and a regulated affiliate needs this type of equipment; however, the current FMV from a manufacturer is $17,000,000 delivered. The regulated affiliate has to pay $1,000,000 in shipping costs from CR3, $5,000,000 to modify Equipment A for their use, and the warranty and performance guarantees are estimated to be worth $1,500,000; thus, the regulated affiliate doesn't want to pay any more than $9,500,000 for Equipment A from CR3. From the standpoint of CR3, current salvage value (current FMV in this hypothetical example) on Equipment A is $500,000; thus, both parties (CR3 and the other regulated affiliate) would both be potentially better off at a less than NBV and this transaction would require utility commission approval in both jurisdictions.

5.2 **Asset Pricing**

1. **Duke Energy Internal Transfers** - Assets are priced at either: Average Unit Price (AUP/CUP), Net Book Value (NBV), or Fair Market Value (FMV) and transferred internally via the AAT form for those assets under $10,000,000 dollars as per the AAT process.

   - The pricing used is dependent, in part, on whether the disposition is to a Duke Regulated Affiliate or not. Pricing governance is contained in Attachment 3, Investment Recovery Asset Pricing Governance (subject to the exception described in Section 5.1, Step 9).

2. **Sales Disposition** – Assets are priced at FMV and sold via a quote or bid process.

5.3 Disposition Transaction Review and Approvals

1. **Duke Energy Internal Asset Transfers** – An AAT e-form will be completed for Duke internal asset transfers and this e-form requires the appropriate DOA (sufficient approval authority in accordance with Purchasing Authority Policy) for transfer request and transfer sending. The AAT e-form has its own set of approvals. Note that an AAT e-form and Attachment 1, Asset Disposition Review are not required for internal DEF transfers, these are documented in Passport per the Material Transfer process and must be transferred at cost (AUP/CUP or NBV).

   a. Prior to any Duke Energy internal transfer approval, the IR Project Manager, Supply Chain Management, Engineering Manager, Director Florida Accounting, and the CR3 Finance Manager shall sign off as reviewers on Attachment 1, Asset Disposition Review - see further clarifications below.

      - The review is required by the CR3 Finance manager if the internal transfer is over $100,000 and the Director Florida Accounting is required to review if the internal transfer is greater than $250,000. The Tax Manager will sign off if the internal transfer is not within DEF, or to DEC, DEP, DEO, DEI or DEK.

   b. If the Asset value is over $1,000,000, then the following approvals (not DOA specific) shall be required and delineated on Attachment 1, Asset Disposition Review:

      - GM Decommissioning or designee
      - Rates and Regulatory Strategy Director or designee
      - Florida Regulatory Legal Associate General Counsel or designee.

   c. If any asset is to be transferred internally and the facts demonstrate that AUP/CUP or NBV is greater than FMV, then State Commission(s) approval would be required to transfer at a lower value than NBV and perhaps FERC approval as well.

   d. Review and Approval documents, including the AAT e-form, shall be filed and maintained by Configuration Control.

5.3 Disposition Transaction Review and Approvals (continued)

2. **Sales Disposition** –Sales disposal should be based on FMV as determined via quotes, bids or market intelligence.

   a. Prior to any Duke Energy sale the following shall sign off as reviewers on Attachment 1, Asset Disposition Review:

      - IR Project Manager
      - Supply Chain Management
      - Engineering Manager
      - Tax Manager
      - CR3 Finance Manager [1)]
      - Director Florida Accounting [1)]

      1) The review is required by the CR3 Finance manager if the internal transfer is over $100,000 and the Director Florida Accounting is required to review if the internal transfer is greater than $250,000.

   b. Approvals will follow the business unit DOA and Supply Chain Purchasing Authority.

   c. If the Asset value is over $1,000,000 dollars, then the following approvals (not DOA specific) shall be required and delineated on Attachment 1, Asset Disposition Review:

      - GM Decommissioning or designee
      - Rates and Regulatory Strategy Director or designee
      - Florida Regulatory Legal Associate General Counsel or designee

   d. In some cases, Duke affiliates may want to bid and compete against the external market during a sales event. These type of sales transactions must be conducted at arm's length to ensure the integrity of the process. Additionally, any Duke affiliate winning bid is subject to approval by State Commissions and perhaps by FERC via a waiver (FERC waiver/ approval required if the winning bid is a Duke non-utility affiliate or a Duke non-regulated utility affiliate), Attachment 4, Duke RFP Guidelines if an Affiliate Bid is Anticipated provides information to be followed in these cases. Where a bid event is conducted and another Duke Energy entity is the winning bidder, then the hardcopy contract document signatures will satisfy the internal DOA requirements.

5.4 Project Assurance

1. All decisions involving asset disposition shall be made and, where practical and appropriate, documented in such a manner as to demonstrate that each decision is reasonable and prudent based upon the information reasonably available to the Company at the time the decision was made.
2. Documentation of this decision making process will be prepared to justify to the Company's regulators that best effort towards investment recovery has been made.
3. The CR3 IR Project maintains applicable project documentation in accordance with the Records Management Program. Identification and handling of Quality Assurance records shall be performed using the Investment Recovery Project Assurance Plan and RDC-0001, CR3 Records Management Program.

5.5 Removal of Installed Assets

1. The removal of installed assets must be performed in a manner that maintains configuration control and supports relied upon system functionality, as established by the system abandonment process (AI-9003) and schedule.
2. To ensure compliance with the system abandonment process, each installed asset requested shall be evaluated and approved by plant management.
   a. Approval is documented on a form similar to Attachment 2, Installed Plant Equipment Removal Agreement.

6.0 RECORDS

1. The following documents are records when completed. Submit to Site or Corporate Configuration Control and Information Services personnel for processing and storage in accordance with RDC-0001, Records Management Program or ADM-SUBS-00106, Project Assurance Nuclear Cost Recovery Clause Library (NCRCL) Program Manual:
   - Attachment 1, Asset Disposition Review
   - Attachment 2, Installed Plant Equipment Removal Agreement
   - Review and Approval documents including AAT e-form

Asset Disposition Review

Buyer Info

Date: ____________ Sold by: ______________________ ____________
Name Phone

Affiliate Asset Transfer (AAT)? ☐ Yes ☐ No AAT e-Form #: ______________________

Purchasing Entity (buyer): ______________________________
Company or Duke Operating Unit

Asset for Disposition

Description*:

Asset Offered Internally? ☐ Yes ☐ No (If No, Provide Justification*)

**Attach additional pages as necessary*

Asset Disposition Accounting

Pricing:

Asset Value: ☐ NBV $_________ ☐ AUP/CUP $___________

Asset Sales Price: $____________ Shipping & Handling $_________ Sales Quantity $__________

Sales Tax $_____________ **OR** Non-Taxable Code ________
(External sales only) (See examples and note below)

Cost to Remove (if applicable): $_____________ Total Cost to Buyer: $________________

Accounting (check one):

☐ Inventory Account 154 ☐ CWIP Account 107 EPU ☐ CWIP Account 107 POD
☐ CWIP Account 107 SGR ☐ CWIP Account 107
☐ EPIS Account 101 ☐ EPIS Account 106 Other (specify) __________________

Accounting WBS: _________ ________ _________ _____________
Resp Ctr Project Activity Resource

Note: If non-taxable, a code should be entered indicating the reason and supporting documentation should be attached or available.

Examples of Non-Taxable Codes

- NT/EC - NT Exemption Certificate
- NT/DP – NT Direct Pay Permit
- NT/IC – NT Intercompany Transfer
- NT/OS – NT Out-Of-State Transaction

Asset Disposition Review (continued)

Disposition Review and Approval

Asset Reviews:

Asset not required in support of CR3: ______________________ / __________
CR3 Engineering Mgr Date

______________________ / __________
Tax Mgr Date
(Not required for internal transfers within DEF, or to DEC, DEP, DEO, DEI, and DEK)

______________________ / __________
CR3 Financial Services Mgr Date
If Asset value is > $100,000.00

______________________ / __________
Director Florida Accounting Date
If Asset Value is > $250,000.00

IR Project Review:

______________________ / __________
Supply Chain Mgmt Date

______________________ / __________
CR3 IR Project Mgr Date

Asset Approvals:

______________________ / __________
GM Decommissioning Date
If Asset Value is > $1,000,000.00

______________________ / __________
FL Assoc Gen'l Counsel II Date
If Asset Value is > $1,000,000.00

______________________ / __________
Rates & Reg Strategy-FL Date
If Asset Value is > $1,000,000.00

Installed Plant Equipment Removal Agreement

Request

Date: ____________ Prepared by: ______________________________ ____________
Name Phone

Affiliate Asset Transfer (AAT)? ☐ Yes ☐ No AAT e-Form #: ______________________

AAT Requestor Charge Number: __________________

Requesting Entity (buyer): ______________________________
Company or Duke Operating Unit

Requestor Contact:__________________ ____________
Name Phone

Component Requested

System Abandoned? ☐ Yes ☐ No

Description*: (include boundaries as applicable and why feasible to remove)

Unique Risk Exposure to Removal*:

Estimated Removal Timeframe: _____________ ____________
Start Finish

**Attach additional pages as necessary*

Installed Plant Equipment Removal Agreement (continued)

Estimated Cost

Man-hours

Engineering ____________ Operations __________ Health Physics ____________

Craft ____________ Planning ____________ Oversight ________________

Other (specify)____________

Total Labor Cost: $__________________

Other

Dose _______ mRem Shipping & Handling $ __________ Other (specify) _________

Component Cost: ☐ NBV $_________ ☐ AUP/CUP $_________ ☐ FMV $_________

Total Cost Buyer: $__________________

Agreement to Remove
(Record name of individual contacted and date)

Receipt/Need by Date: _______________

______________________________/______
CR3 Engineering Manager Date

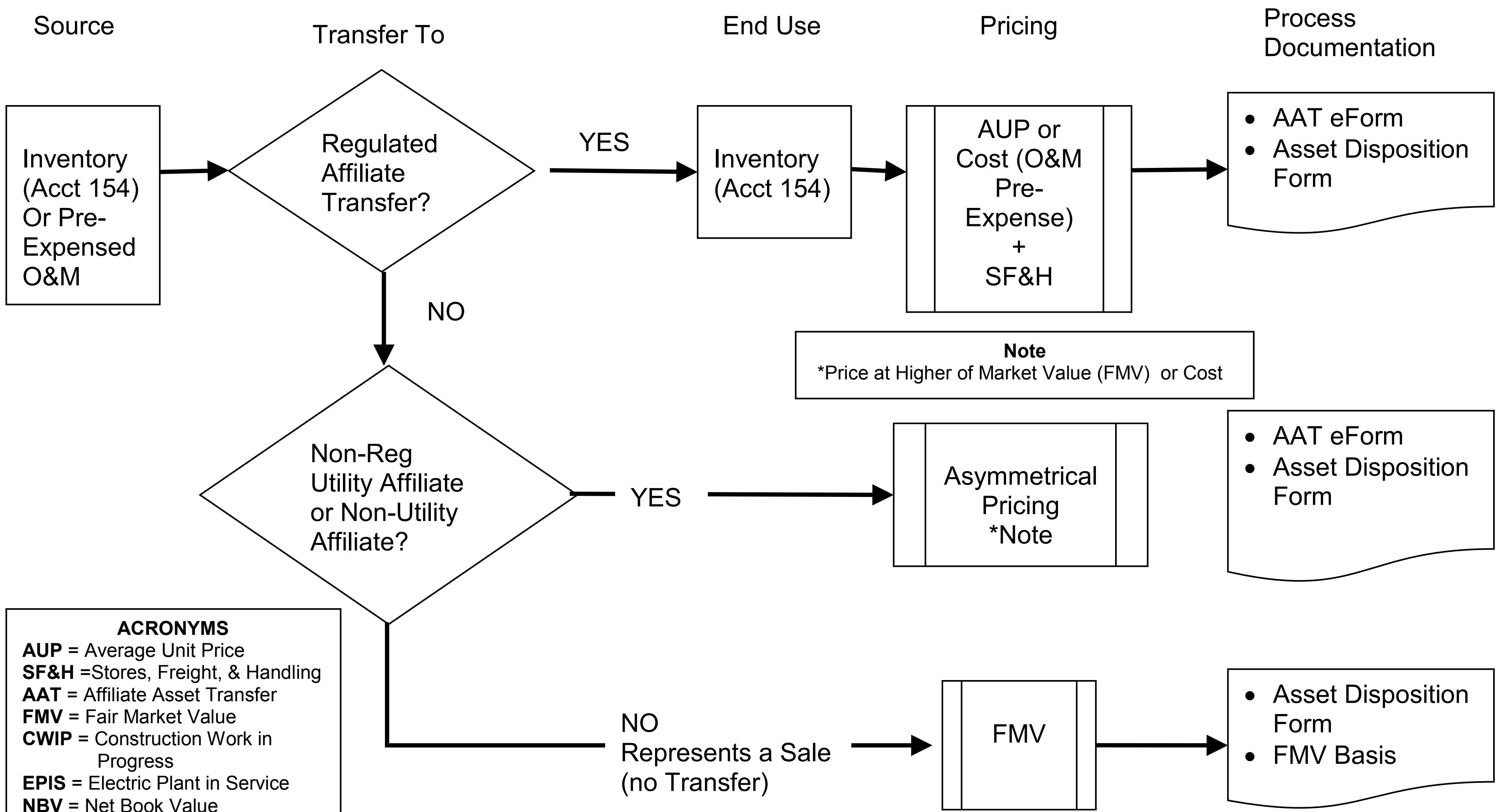
______________________________/______
CR3 Operations Manager Date

______________________________/______
CR3 Maintenance Manager Date

______________________________/______
CR3 Plant Manager Date

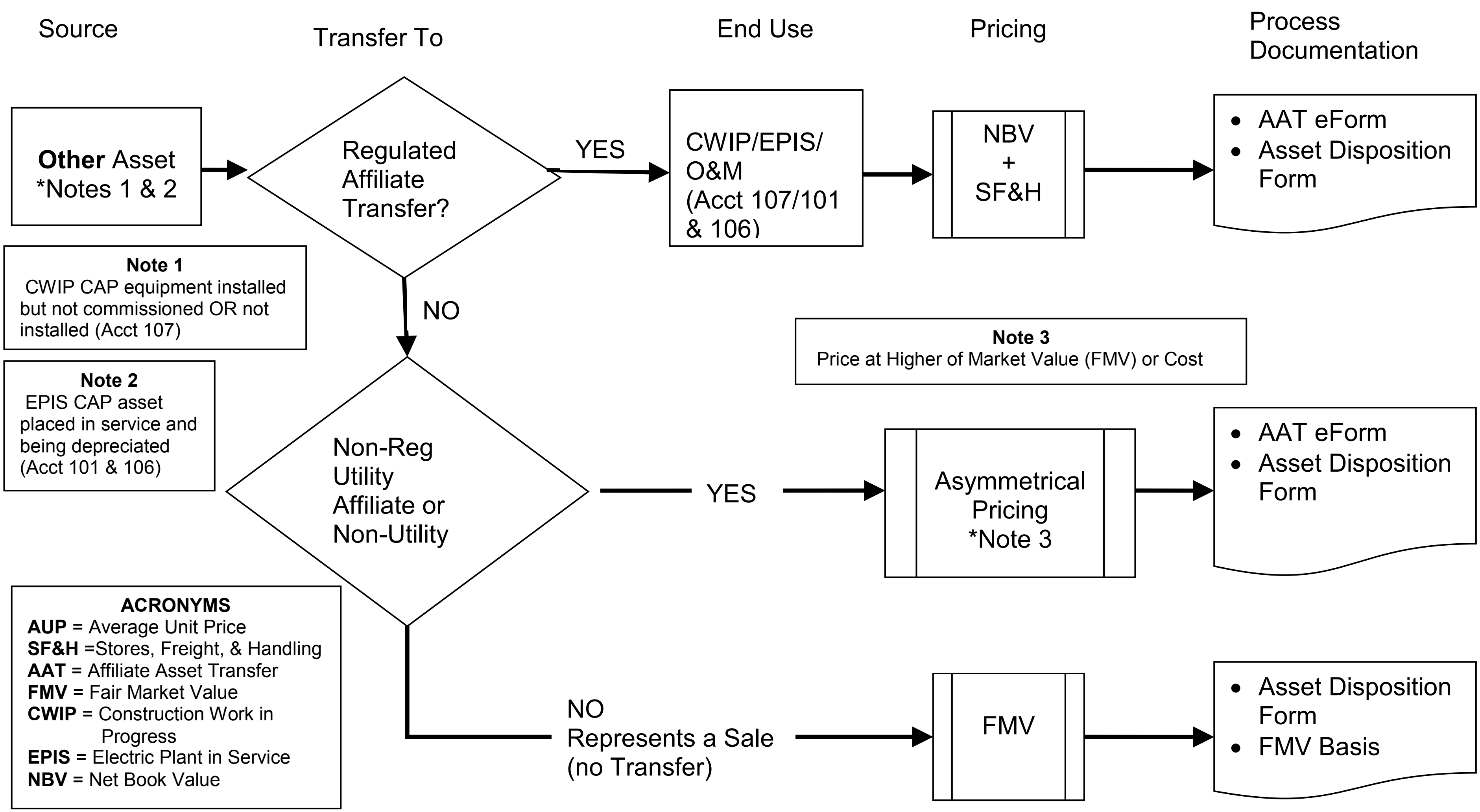
______________________________/______
CR3 GM Decommissioning Date

Investment Recovery Asset Pricing Governance



ACRONYMS
AUP = Average Unit Price
SF&H =Stores, Freight, & Handling
AAT = Affiliate Asset Transfer
FMV = Fair Market Value
CWIP = Construction Work in Progress
EPIS = Electric Plant in Service
NBV = Net Book Value

Investment Recovery Asset Pricing Governance (continued)



September 20, 2007

Duke RFP Guidelines if an Affiliate Bid is Anticipated

The fundamental objective of the guidelines is to assure that an affiliate will have *no undue advantage over non-affiliates* in an RFP issued by a regulated entity. These guidelines do not apply if no affiliate is bidding or as soon as there are no affiliates in contention.[1]

FERC has ruled that compliance with the guidelines is not mandatory, but has said that compliance will greatly increase the likelihood of FERC approval of an affiliate transaction without a lengthy and expensive hearing. These guidelines were established by FERC in the *Edgar, Allegheny, and Ameren* cases.

Legal should be consulted prior to the design of the RFP when the RFP issuer wishes to allow or anticipates affiliate bids. These guidelines apply to both asset transfers and power purchase agreements.

Standards of Conduct and Code of Conduct apply whether or not an affiliate is bidding.

FOUR PRINCIPLES

1. TRANSPARENCY

- No bidder should have an informational advantage.
- Simultaneously release information to all bidders.
- Allow all interested parties to bid instead of sending invitations to specific bidders.
- Widely publicize the RFP (e.g., post RFP on web site and issue a press release).
- All communications between Duke (or an independent third party on behalf of Duke) and any bidder should be made available to all other bidders (e.g., receiving questions and posting answers on web site).
- Negotiation after a short list has been compiled or a winner has been selected is acceptable. If an affiliate is involved, an independent third party should participate in the negotiation on behalf of the issuer.
- Generally, a Duke shared support group which provides information or services to the issuer in connection with the RFP should not also provide information or services to the affiliate bidder in connection with the RFP unless such information is provided simultaneously to all bidders. Seek a legal opinion under the specific facts if this situation arises.

[1] In Ohio, CAM is an affiliate of DE Ohio Retail for Ohio Code of Conduct purposes and should be treated as an affiliate for the purpose of these guidelines.

2. DEFINITION

- RFP should reflect clear and nondiscriminatory definition of products sought including all relevant aspects.
- Capacity and term desired should be stated along with other relevant characteristics which usually will include fuel type, plant technology, and transmission requirements for example.
- If there are changes in the product specification, re-bids should be allowed.
- The RFP should not define products in a way that favors affiliates.

3. EVALUATION

- RFP should clearly specify evaluation criteria.
- Price criteria should specify the relative importance of each item.
- Non-price criteria should specify the relative importance of items (e.g., firm transmission reservation requirements, acceptable delivery points, credit evaluation, plant technology, plant performance requirements, and plant in-service date).

4. OVERSIGHT

- Use an independent third party ("ITP") in the design, administration, and evaluation stages.
- ITP should have no financial interest in any of the bidders or in the outcome.
- ITP should not own or operate facilities that participate in the market affected by the RFP.
- ITP should be able to make a determination that the RFP process is transparent and fair and that the issuer's decision is not influenced by any affiliate relationships.
- ITP should be the sole link for transmitting information between issuer and bidders throughout the RFP process.
- ITP should be able to assess all bids based on both price and non-price factors. ITP should have access to the same information that the issuer uses in evaluation.

If any questions arise, you can consult FERC Legal at 980-373-6609.

SUMMARY OF CHANGES
PRR 670281

SECTION/STEP	CHANGE
1.0.1, 1.1.5	Allows AI-9010 to be the governing document for CR3 New Fuel sales (*76 new fuel assemblies at CR3*) and upstream uranium sales (*enriched and converted*). "Nuclear Fuel" deleted from Step 1.1.5.
1.1.1, 5.1.8.b, 5.3.2.d, Att 4	Allows other Duke entities to compete in the open market for any CR3 sales – this can be used for the LP Rotors for example and identifies additional commission/ FERC approvals / waivers that may be needed in case Duke is the winning bidder for any of these type events.
3.0.1	Added clarification to the definition of 0154 Inventory
3.0.10	Refined the definition of Net Book Value in accordance with FERC description.
4.0.2, 4.0.3	Added additional responsibilities for Corporate Communications, CR3 Financial Services Manager, and Director Florida Accounting.
5.1.6	Added new step to describe the RAPID database.
5.1.7, 5.1.9	Added new Step 9 and references to it to describe instances where NBV or AUP/CUP may be at a higher value than FMV.
5.1.7.c	Added Auction Companies to the statement and extended sales audience
5.1.7.d	Added Auction Companies to the statement & added scrapped
5.1.8.b.1.c	Added Duke Energy's Legal Department could provide an approved legal form
5.1.8.c	Added Auction Company
5.1.9.a	Added "current" to clarify FMV where applicable
5.2.1	Clarified that the AAT form is for those Assets less than $10,000,000 dollars
5.3.1, 5.3.2, Att 1	Added Supply Chain Management as an approval authority for internal transfers.
Various	Changed title from FL Reg and Property Accounting Mgr to Director Florida Accounting. Replaced Asset Transaction Price with Asset Value to align terminology.
5.3.2.d	Added and clarified that hardcopy Contract signatures can satisfy DOA requirements
4.0.1	Replaced VP Project Management & Construction with GM Decommissioning or their designee
5.3.1.b	Replaced VP Project Management & Construction with GM Decommissioning
5.3.2.c	Replaced VP Project Management & Construction with GM Decommissioning
Attachment #1, Page 2 of 2	Replaced VP-PMC with GM Decommissioning
Attachment #2, Page 2 of 2	Removed Director and added GM

CR3 Investment Recovery Project (IRP) Project Execution Plan

Rev 0

Project Management and Construction Department

Duke Energy

Please Note: This document contains confidential information and is subject to Duke Energy's Code of Business Ethics Policy. Please limit distribution accordingly.

Approval

Revision Summary				
Rev. Number	**Effective Date**	**Prepared By**	**Approved By**	**Approved By**
0	2/25/14	Jeff LaPratt	Magdy Bishara	Terry Hobbs

Table of Contents

Appendices **Page**

PROJECT SPONSORS

Role, Department / Group	Name	Phone No.
GM – Decommissioning	T. Hobbs	[redacted]

KEY PROJECT STAKEHOLDERS

Role, Department / Group	Name	Phone No.
VP-PMC	Mike Delowery (acting)	[redacted]
State Reg General Council	John Burnett	[redacted]
State President – FL	Alex Glen	[redacted]
VP-Chief Procurement Officer	Ron Reising	[redacted]
MGR EGR-DTO	Emin Ortalan (acting)	[redacted]

PROJECT MANAGEMENT CONTACTS

Role, Department / Group	Name	Phone No.
PM - PMC	Jeff LaPratt	[redacted]
SC Lead	Chris Hendricks	[redacted]
MGR – Major Projects	Magdy Bishara	[redacted]

*The location of the Expanded Contact list is included in the Appendix.

PLAN REVISION CONTROL

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Project Manager	Initial Issue	02/25/14

1.0 INTRODUCTION & PROJECT DESCRIPTION

[NOTE: This is classified as a White project per PMCoE standards. Deviations from the standard PMC Project Execution Plan (PEP) template are highlighted in bracketed notes similar to this one. These deviations are deemed acceptable by approval of this PEP.]

This document presents the Project Execution Plan for the CR3 Investment Recovery Project (hereinafter "IRP" or "Project").

Name of Station	Location	Project	Completion Date
CR3 Nuclear Plant	Crystal River, Florida	Investment Recovery	April 30, 2015

Project Description

In accordance with the August 1, 2013 Settlement Agreement (Doc No. 04433-13, Docket No. 130208-EI) with the Florida Public Service Commission (FPSC) Duke Energy is committed to using reasonable and prudent efforts to sell or otherwise salvage assets that would otherwise be included in the CR3 Regulatory Asset.

This project will develop and implement a program under which saleable CR3 plant assets are identified, maintained, marketed, sold, and removed from the site.

2.0 PROJECT OBJECTIVES & APPROVALS

The primary objective of this plan is to deliver the Project scope of maximizing return to customers and shareholders on CR3 assets through asset identification, redeployment, and disposition. The scope is to be delivered with quality, on budget, on time, and in a safe environmentally sound and prudent manner.

This project is undertaken with the following secondary objectives:

- Minimize cost and impact to CR3 decommissioning activities and trust fund, customers and shareholders.
- Identify preservation needs to avoid premature obsolescence of otherwise marketable assets.
- Coordinate with the Decommissioning Project to avoid conflicts.
- Ensure asset removal activities are performed event free.
- Ensure all decisions are made in a prudent manner and thoroughly documented.
- Ensure all sales/affiliate asset transfers are properly classified for proper accounting treatment.
- Comply with all applicable laws, rules, regulations and ordinances.
- Minimize risk associated with the re-sale and subsequent use or disposal of project assets.

Total Authorized, Current Projections

Table 1: Key Project Objectives	
Scope	Reduce the CR3 Reg Asset through the disposition of assets in the following categories: • Inventory (FERC 154 Account) • Construction Work in Progress (CWIP) • Electric Plant In-service (EPIS)
Total Project Cost	$3,408,104
Schedule [Project Completion Date]	April 30, 2015
Quality [Performance Objective]	Obtain prudence determination on all asset dispositions or transfers as appropriate

Internal Project Approvals

The IRP is a White, non-construction project that doesn't fit the traditional PMC construction stage-gate process. Per PMCoE standard PJM-00001-POLICY, *Achieving Excellence in Project Management*, for white projects, compliance with PMCoE Standards is at department discretion; therefore, elements of this PEP and approvals are tailored specifically for this project.

Duke Energy, and CR3 by extension, committed to performing the IRP as part of the August 1, 2013 Settlement Agreement with the FPSC, and acts as the authorization to implement this Project. Duke Energy Finance, Legal, and Regulatory Rates & Strategies have determined that because disposition proceeds go to reduce the Regulatory Asset (Reg Asset), that costs associated with the disposition shall be added to the Reg Asset for a net reduction. As such, no traditional funding approvals are necessary (e.g.; 201, WPCO). The Project Sponsor acknowledges estimated costs contained in the Project Charter. In no case is it prudent for costs to exceed disposition proceeds; the Project monitors these and will initiate discussion on project continuance should costs approach disposition proceeds.

PMC management has determined that the following project elements be developed and maintained for the Project:

- Project Charter
- Class 3 (or better) estimate
- Baseline Schedule
- Risk Assessment and Analysis
- PEP

The approval of this PEP recognizes the above positions in addition to project approach.

3.0 IRP SCOPE BASELINE

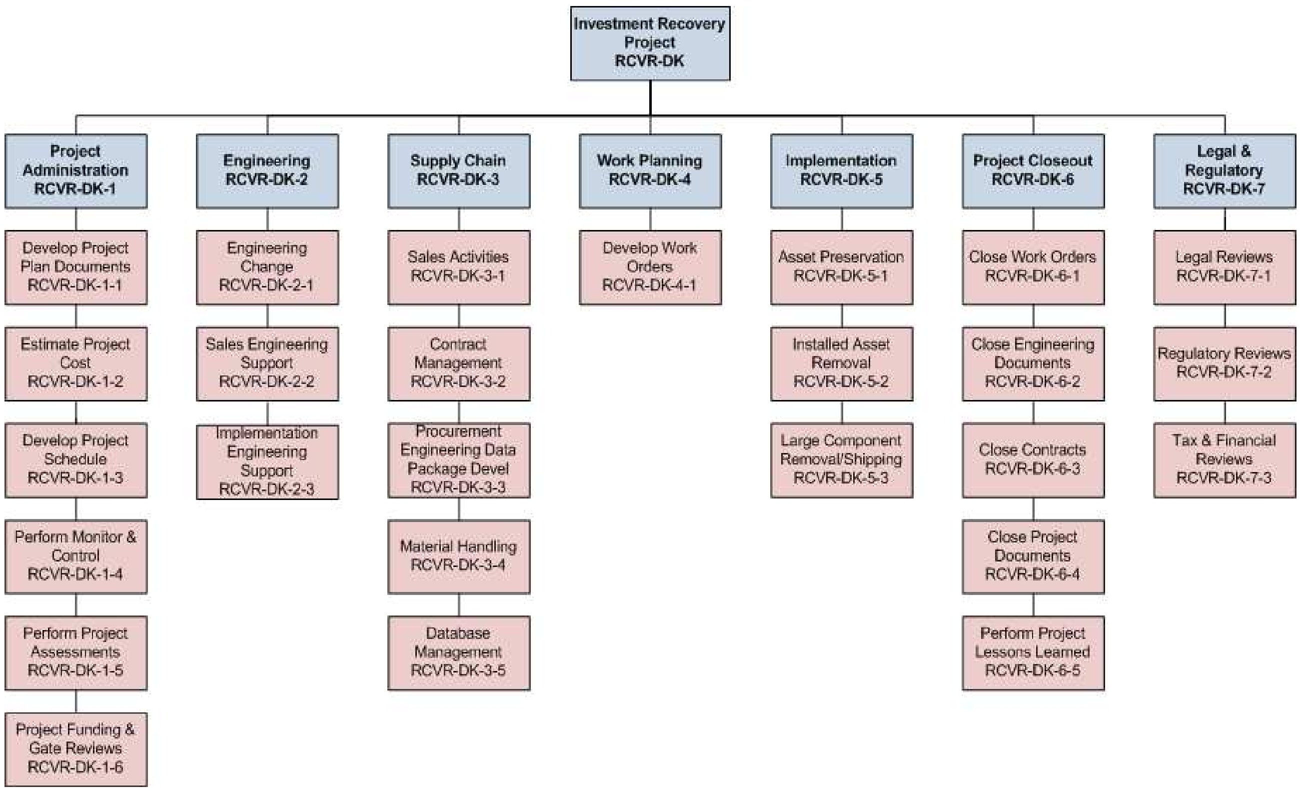
The CR3 Investment Recovery Project consists of the following scope:

- Inventory and catalogue saleable assets.
- The financial analysis to determine asset value.
- The engineering, procurement, and construction activities necessary to preserve saleable assets.
- Sales and marketing activities, including the establishment of strategic partnerships.
- Contract development and execution for necessary engineering, procurement, maintenance/preservation, asset removal and shipment, and warranty.
- Limited to the following plant equipment assets:
  - Warehouse inventory (FERC Account 154)
  - Construction Work in Progress (CWIP) (FERC Account 107); which is further subdivided into:
    - EPU
    - EPU Point of Discharge (POD) helper cooling towers
    - SGR
    - Other
  - Electric Plant In-Service (EPIS) (FERC Accounts 101 and 106)
- The scope specifically excludes nuclear fuel and real property.

The level 1 Scope of Work (SOW) for the Project is broken into a PMC WBS package. The work scope in the WBS includes activities necessary to plan, organize, integrate, budget, measure, and control performance. These activities ensure that the Project accomplishes the mission on schedule in a safe, prudent, and cost-effective manner.

WORK BREAKDOWN STRUCTURE

The WBS is used to organize and integrate the Project Scope Baseline. Figure 1 shows the top levels of the Project.



4.0 SCHEDULE BASELINE

The Project Baseline Schedule approval form is provided in Appendix F. The Project Controls Manager is responsible for establishing and documenting the schedule Baseline process and to assist the Project Manager in setting up the Schedule Management system for the Project.

The following major milestones are contained in the schedule:

Milestone	Baseline	Forecast Date	Actual Date	Critical Path
Initial funding milestone with Project Charter	Jul 13	Jul 13	Jul 13	N
Develop Project Scope and Level 1 Schedule	Jul 13	Jul 13	Jul 13	N
Build Team and Processes	Aug 13	Aug 13	Aug 13	N
Begin Investment Recovery	Aug 13	Aug 13	Aug 13	N
Approve Governance	Oct-13	Oct-13	Oct-13	N
Commence Market of CWIP Large Components (internal)	Oct-13	Oct-13	Oct-13	N
Develop Duke Inventory Match Lists	Nov-13	Nov-13	Nov-13	N
Commence Market of CWIP Large Components (external)	Nov-13	Nov-13	Nov-13	N
Commence Market of EPIS Components (external)	Nov-13	Nov-13	Nov-13	N
Commence Tranche 6 Disposition	Jan-14	Jan-14	Jan-14	N
Commence Tranche 1 Disposition	Feb-26	Feb-26		N
Nuclear Fleet Review Completed – Commence Pull & Ship	Mar-14	Mar-14		N
Commence Tranche 2 Disposition	Apr-14	Apr-14		N
Complete Market of CWIP Large Components (internal)	Apr-14	Apr-14		N
Complete Tranche 1 Disposition	Apr-14	Apr-14		N
Fossil Fleet Review Completed – Commence Pull & Ship	Apr-14	Apr-14		N
Commence Tranche 3 Disposition	May-14	May-14		N
Complete Tranche 2 Disposition	May-14	May-14		N
Complete Market of EPIS Components (external)	Jun-14	Jun-14		N
Commence Tranche 4 Disposition	Jul-14	Jul-14		N
Complete Tranche 3 Disposition	Jul-14	Jul-14		N
Commence Tranche 5 Disposition	Aug-14	Aug-14		N
Complete Tranche 4 Disposition	Aug-14	Aug-14		N
Complete Market of CWIP Large Components (external)	Aug-14	Aug-14		N
Complete Tranche 5 Disposition	Sep-14	Sep-14		N
Complete Tranche 6 Disposition	Sep-14	Sep-14		N
Cleanup & Project Closeout Complete	Apr-15	Apr-15		N
Complete Investment Recovery	Apr-15	Apr-15		N

5.0 COST BASELINE

Upon approval of the Initiate Gate Package by Duke Energy Management, the Project Cost Baseline will be established and documented through the Cost Baseline approval process. The Initiate Gate approved estimate will be used as the basis of the Cost Baseline. The Project Controls Lead is responsible for establishing and documenting the Cost Baseline process and assisting the Project Manager to set up the Cost Management System for the Project.

The Project Cost Breakdown Structure (CBS) is as follows:

Project Level 2 Number	Oracle Level 1 Task	Level 1 Task Description	Oracle Level 2 Task	Level 2 Task Description	Passport WO #
20104219	1000	Project Management	1001	Project Management	1868133-13
			1002	Contracts	1868133-13
			1003	Materials/Other	1868133-13
			1004	Project Management Other	1868133-13
	2000	Sales	2001	Sales Labor	1868133-14
			2002	Sales Material Handling	1868133-15
			2003	Sales Contracts	1868133-14
	3000	Removal Costs	3001	Removal Costs - LPT	1868133-15
			3002	Removal Costs - POD	1868133-15
			3003	Removal Costs - CWP	1868133-15
			3004	Removal Costs - EPU Preservation	1868133-15
			3005	Removal Costs - POD Preservation	1868133-15
			3006	Removal Costs - Other Preservation	1868133-15
			3999	Removal Costs - Non-reimbursable	1868133-15

The Project Cost Baseline and subsequent performance reporting to key stakeholders and sponsors will be made in the Financial View. The Project does not receive any AFUDC charges and none will be reported.

TOTAL PROJECT COST BASELINE & ESTIMATE AT COMPLETION (EAC) FORECAST

The Total Project Cost Baseline will include PMC and other entities baselines.

Total Project Cost Baseline [Financial View]

Cost Baseline	Expected	Range
PMC	$3,408,104	$3,067,294 - $4,089,725 (Min – Max)
Other Entities	$0.0	$0.0
Total Project	$3,408,104	$3,067,294 - $4,089,725 (Min – Max)

Total Project Cost History [As Approved by Project Charter]

Charter Revision	Expected	Range	Approval Date
Rev 0 (initial)	$1,500,000	$1,500,000	07/16/13
Rev 1/EAC	$3,408,104	$3,067,294 - $4,089,725 (Min – Max)	02/20/14

6.0 IRP ORGANIZATION

See Appendix A for IRP Organization Chart

DUTIES AND RESPONSIBILITIES FOR EACH PROJECT MEMBER/ORGANIZATION

Project Sponsor
The Project Sponsor is an executive level manager who functions as the primary customer of the Project team. The success of the Project is determined by the satisfaction of the Sponsor. The Project Sponsor for this project is the GM Decommissioning.

Project Manager (PM)
The PM has the overall authority and responsibility for execution of the Project in order to achieve all work safely, within budget, and on schedule. The work must be completed in compliance with all required local, state, and federal laws and regulations. The PM is responsible for planning, executing, controlling, and closing the Project. This is largely accomplished by coordinating the efforts of the Project team to develop and implement the Project Execution Plan and by taking corrective action when Project objectives are in jeopardy. The PM reports to the Manager of Nuclear Projects.

Specific responsibilities of the PM include:

- Preparation of the Project Execution Plan
- Directing and managing the Project team for the execution of the Project

- Organizing and leading the Monthly Executive Meeting of the Project
- Managing the interfaces between stakeholders and within the Project team
- Manage and develop project team organization
- Identify and obtain resources to ensure project success (either matrix or directly assigned)
- Responsible for resolution of critical issues/opportunities
- Provide direction to project team leaders to promote project success, continuity, and consistency
- Monitor and report project performance and initiate any needed corrective action to keep the project on track
- Primary interface with CR3 Decommissioning Management. Includes providing status updates and resolving critical issues/opportunities needing management awareness or involvement
- Primary interface with the PMC Leadership Team. Includes providing status updates and resolving critical issues/opportunities needing senior management awareness or involvement
- Reviews and assesses overall schedule for achievability of critical milestones and adequacy of contingency plans

Supply Chain Functions

The Supply Chain (SC) Organization is the primary resource for IRP asset dispositions and is the largest contributor to the Project. The SC roles in the IRP are:

Supply Chain IRP Lead

The IRP Supply Chain Lead has overall supervisory responsibility for the IRP sales organization. The IRP Sales Lead and direct reports in **Contracts** and **Sales**, have responsibility for the following:

- Compile a list of site assets, inventory, and other items of value that will be redeployed, sold or scrapped.
- Provide a level of oversight for on-site asset recovery dispositions.
- Manage the population of the Investment Recovery Database.
- Identify potential buyers and determine sale/marketing plan for various assets.
- Develop / coordinate the contract bid, evaluation and execution process for assets that will be sent out for bid.
- Provide technical input on requested assets as required by potential customers.
- Qualify bidders to assure credit worthiness, or advance payment where credit worthiness is in doubt.
- Provide technical input and manage the results / inquiries from Recovery Seeker

- Assure that a signed contract is in hand, based on standard forms approved by the Legal department, or an alternate form approved by the Legal Department before releasing the project asset to the buyer.
- For international sales (direct or indirect), assure that all regulatory approvals are obtained before releasing the project asset to the buyer.
- Complete Affiliate Asset Transfer Forms for all assets transferred to other Duke Energy affiliates.
- Work with Field Organizations/Contractors for the coordination to release assets from the site.
- Package and ship smaller assets to successful purchasers.
- Manage the retrieval of documentation and generation of Certificates of Conformance required for the sale of safety related assets.
- Coordinate assets that will be dispositioned by the Corp Asset Group
- Manage and Monitor invoicing and outstanding receivables.

Major Projects Materials Lead

- Coordinates accounting and control of CWIP materials.
- Supports removal and shipping of CWIP materials.

Supply Chain Support – Asset Recovery

- Primary interface for salvage of equipment.
- Supports asset disposition through their known channels.

Financial Analyst

- Provide leadership and management of finance.
- Track costs and value of divested materials.
- Ensures proper accounting of monies received from assets divested.
- Provides NBV and other cost information.

Legal / Regulatory / Tax Support

- Contract form development and negotiation support.
- Provide legal interpretation/guidance on contractual issues.
- Assist in contract dispute resolution, as necessary.
- Support the Affiliate Asset Transfer process.
- Provide support to ensure that the project remains within governance and demonstrates prudency.
- Supply advice and assistance on export control regulations.

- Provide guidance on tax issues.

Engineering

- On an as-needed basis, provides support for the removal of major assets.
- Provides technical information on assets.

Major Projects Implementation

- Provide leadership and management of large or complex asset removal tasks.
- Assist the Task Managers in monitoring contractor's work planning and execution for removal tasks
- Work with the Task Managers to resolve any work practices considered significantly inefficient, ineffective or unsafe.
- Performs necessary inspections of the Contractor's work to assure compliance with QA/QC policies and procedures.
- Identifies any deficiencies and works with the appropriate Task Managers to have these resolved by the Contractor.
- Assure that the Contractor assigns sufficient qualified workers to meet planned performance.
- Assist the Task Managers with monitoring corrective and preventive actions taken on incident investigations and non-conformances (NCRs).
- Report any barriers to the Task Managers to achieving key milestones and/or any recovery plans in place to mitigate barriers.
- Interface with the appropriate Task Managers to address any potential scope or technical issue.
- Participate in the oversight of the Contractor's implementation of their site-specific safety and environmental programs.
- Coordinate and oversee the Contractor's implementation of Duke Energy's lifting and rigging program.

Project Controls (PC) Supv / Principal PC Specialist / Scheduler

- Review schedule updates for accuracy, reasonableness and impacts.
- Interface with Station scheduling regarding tie-ins and resource requirements.
- Prepare schedule update summaries (e.g., Key Milestones, Critical Path and Look Ahead, etc.) as requested by the IRP PM.
- Evaluate schedule variance corrective actions for appropriateness and reasonableness and provide results to the Project Manager and other appropriate Project team members.
- Evaluate forecasts regarding accuracy, appropriateness and reasonableness of schedule logic, durations and resources for remaining activities.

- Develop and maintain project cost estimate/cash flow forecast, analyze trends and provide current information to the PM, other appropriate Project team members and appropriate Project and Department Management.
- Review Monthly Work-Hour and Cost Transaction Reports for appropriateness and reasonableness of labor, materials and subcontract charges made to the project, including where charges may not be covered or where they exceed the Project Funding Authorization. Follow up with appropriate personnel regarding any inappropriate and/or unreasonable charges.
- Maintain Change Management System for identified changes in project cost, schedule, and cash flow. This includes Change Orders for work scopes. Develop cost / schedule forecast for identified scope changes.
- Support annual Corporate Budgeting process and provide monthly cash flow projections.
- Provide schedule updates for Duke Energy's subproject within the integrated project schedule.
- Incorporate contractual and key stakeholder activities into overall project schedule.
- Provide project reports to Project Leadership Team on overall Project performance and forecasts compared to key milestones, Project funding, and annual budgets.

Project Assurance Advisor

The Project Assurance Advisor provides support to the Project through education and awareness of Company policy. The Advisor ensures that all material decisions involving expenditures for which cost recovery is sought are made and documented in a manner that will allow Duke Energy to achieve full and fair recovery through the regulatory process. They execute duties specific to the Project include: developing and delivering education and awareness programs to Project personnel and ensuring that documentation of Project decisions is adequate to explain the basis for the decision, and reasonableness thereto. They also develop the Project Assurance Plan for the Project.

RACI CHART FOR PROJECT ORGANIZATION

A Responsible, Accountable, Consult, Inform (RACI) chart that further clarifies organizational responsibilities by activity is provided in Appendix B.

7.0 DISPOSITION STRATEGY & MANAGEMENT

[NOTE: Section titled changed from Procurement Strategy to Disposition Strategy due to the unique nature of the Project]

Strategic Approach and Rational

The Project will disposition assets in a manner that maximizes the reduction of the Regulatory Asset. The methodology employs a systematic, sequential approach as illustrated in Appendix D – DISPOSITION STRATEGY FLOWCHART.

The illustrated systematic approach focuses on internal transfer of the asset first as, per the Affiliate Asset Transfer Agreement (AATA) and Affiliate Asset Transfer (AAT) process, assets transferred internally are at Average Unit Price (AUP). Large asset distribution efforts have historically returned a fractional percentage of AUP overall, therefore, receiving AUP or greater for an asset is advantageous to our customers.

Following internal transfers, in terms of expected returns, are marketing to utilities, then 3rd party resellers, then salvage and scrap (in order from high to low).

Assets are segregated (or "bucketed") by AUP tranches. Large asset distribution efforts have also shown that the overwhelming amount of total value is returned by a small amount of the asset set. In the case of the CR3 inventory asset set of 1.4M items, Tranches 1 through 5 represent approximately 12,000 items and approximately 85% of inventory value. The project will place special focus on Tranches 1 through 5 and the requisite marketing effort they demand.

Disposition of Tranche 6 is labor intensive to disposition due to the significant number of items, with expected return being low.

Governance

Governance for the Project is provided in AI-9010, *Conduct of CR3 Investment Recovery*. The strategic approach outlined above is congruent with the requirement stated in AI-9010.

Guidance

Guidance for consistent implementation of each sales track (Affiliate Transfer, Utility/OEM, 3rd Party Reseller, and Scrap/Salvage) is contained in Investment Recovery Guidance Document IRGD-001, *Sales Track Guidance and Documentation Package Development*. This guidance document also provides information on Project Assurance (PA) SharePoint organization and file naming convention for PA documents; with each disposition having a completed checklist of required actions completed.

8.0 IMPLEMENTATION AND IMPLEMENTATION MANAGEMENT

[NOTE: Section titled changed from Construction to Implementation due to the unique nature of the Project]

Removal of Installed Assets

The removal of installed assets must be performed in a manner that maintains configuration control and supports relied upon system functionality, as established by the system abandonment process (AI-9003, *System Evaluation and Categorization*) and schedule.

To ensure compliance with the system abandonment process, each installed asset requested will be evaluated and the removal approved by plant management. This approval process will also review risks associated with the removal to ensure that the plant is willing to accept those risks for the sake of disposition. Approval is documented on a form contained in AI-9010, *Conduct of Investment Recovery*.

Large Component Removal and Shipping

Multiple large CWIP components that are not installed, such as the Low and High Pressure Turbines, POD Cooling Tower, and feed water heaters, will be removed for shipping by the Major Projects Implementation group. These are significant efforts requiring specialized skills and equipment.

The removal of an installed asset or large component removal and shipping activities are handled as a stand-alone task with a specific task plan developed. Costs to remove installed assets will be the sole responsibility of the buyer.

Implementation oversight shall be provided by Duke Energy's PMC department.

9.0 INTEGRATION, COMMISSIONING AND TURNOVER STRATEGY & MANAGEMENT

[This section is not applicable to the Project as there are no integration, commissioning or turnover activities associated in this non-construction project.]

10.0 SCOPE MANAGEMENT

The Scope Baseline will be controlled and maintained by the Project Manager in accordance with PJM-00008-ENTSTD. Changes to the Scope Baseline will be managed through the Integrated Change Control (ICF) process utilizing Integrated Change Control Forms (ICF)processed in the PassPort system.

11.0 SCHEDULE MANAGEMENT

The Project will use Primavera P6 or higher version as the primary scheduling software.

The Project Scheduler is responsible for the following weekly activities at a minimum:

1. Quality of the fully Integrated schedule
2. Weekly schedule review meetings
3. Schedule updates
4. Change trends.

Schedule Development

A detailed, resource loaded Level 3, including Duke Energy critical interface points is developed for all disposition activities. Additional schedule elements for the removal of installed assets and large component removal and shipping activities will be developed and added to the overall integrated schedule.

The Project Controls Manager will then implement the PMC Schedule Baseline approval process as per the PMC-PRC-00-AD-0009 PMC Project Schedule Management procedure. This process establishes the fully Integrated Baseline schedule. The Project Scheduler will refer to the PMC-PRC-00-AD-0009 PMC Schedule Management procedure regarding file naming, data archive, and overall schedule management process details for the Project.

Upon approval/sign-off on the Project Schedule Baseline, the Project Manager then officially accepts the Level 3 schedule as the Baseline schedule.

The Schedule Baseline will then be controlled and maintained by the Project Manager with assistance from the Scheduler. Changes to the Schedule Baseline will be managed through the ICF process. The Project will utilize Primavera P6.8.1 or higher version as the primary scheduling software.

Schedule Analysis

The Schedule will be reviewed and analyzed for float, completeness, logic, open ends, contractual dates, and milestones, on a weekly basis by the on-site Project Controls personnel. Any feedback or corrections on the schedule will be communicated by Project Controls to the contractor and also noted as minutes from the weekly on-site Project Controls meeting.

Earned Value Reporting and Analysis

One of the key responsibilities of the Scheduler is to track, analyze, and audit the Earned Value. The analysis will be communicated through the internal weekly Project Controls reports as well as monthly reports which will be circulated to the Project Manager and other key individuals. For this Project, Earned Value metrics will include:

- Schedule Variance

- Cost Variance
- Estimate at Completion (EAC)
- Estimate to Completion (ETC)

12.0 COST AND FINANCIAL MANAGEMENT

Upon Establishing the Project Cost Baseline Structure, Project Controls develops a Cost and Finance Management system for the Project in accordance with PJM-00012 and PMC-PRC-NA-AD-0014 Cost & Contingency Management Procedure.

The Project will maintain and communicate total cost-to-date, un-awarded costs, pending change orders, ETC, and EAC through monthly reports.

Accruals will be recorded in compliance with the corporate accrual policy. The Cost Baseline will be controlled and maintained by the Project Manager with assistance from Project Controls and Finance Lead.

The Project Cost Lead is responsible for assembling the updated Project Cost package by the 10th of each month for team review. The team includes the Project Director, Finance Lead, Implementation Manager, and or Supply Chain.

The Project Manager will approve the final communication package regarding Project cost performance prior to mass distribution.

The Project Controls Cost Lead and Finance Lead will assist the PM to control and maintain the total Cost Baseline of the Project. Changes to the Cost Baseline will be managed in accordance with PMC-PRC-NA-AD-0014 Cost & Contingency Management Procedure.

Contingency Management

Per PMC-PRC-NA-AD-0014 Cost & Contingency Management Procedure, project contingency (Estimate uncertainty & Risk Contingency) drawdown will process through Change Control process utilizing ICFs. ICFs and contingency drawdown will be analyzed on a monthly basis and will document use of Contingency drawdown and Deviations against appropriate CBS. Contingency balance will be assessed against ETC and Risk profile and adequate explanation will be added in the report.

Risk update meeting will be conducted to evaluate updated Risk EMV for the project, Risk coverage ratio will be determined and analysis will be communicated in the analysis section to reflect the project's assessment on update risk profile.

Accounting Considerations

Accounting considerations are contained in Investment Recovery Guidance Document IRGD-001, *Sales Track Guidance and Documentation Package Development*. This provides a "roadmap" to how the IRP accounting is setup and how the Project ensures that it is accurately capturing and reporting IRP costs and sales, and that IRP net sales are correctly reflected as a reduction to the Reg Asset.

CBS and WBS Relationship

The CBS and WBS are aligned as follows:

Project Level 2 Number	Oracle Level 1 Task	Level 1 Task Description	Oracle Level 2 Task	Level 2 Task Description	WBS Element(s)
20104219	1000	Project Management	1001	Project Management	RCVR-DK-1-1, RCVR-DK-1-2, RCVR-DK-1-3, RCVR-DK-1-4, RCVR-DK-1-6, RCVR-DK-6-4, RCVR-DK-6-5
			1002	Contracts	RCVR-DK-3-2, RCVR-DK-6-3 PM contracts only
			1003	Materials/Other	TBD
			1004	Project Management Other	RCVR-DK-1-5, RCVR-DK-7-1, RCVR-DK-7-2, RCVR-DK-7-3
	2000	Sales	2001	Sales Labor	RCVR-DK-2-1, RCVR-DK-2-2, RCVR-DK-2-3, RCVR-DK-3-1, RCVR-DK-3-3, RCVR-DK-3-5, RCVR-DK-6-2
			2002	Sales Material Handling	RCVR-DK-3-4
			2003	Sales Contracts	RCVR-DK-3-2, RCVR-DK-6-3
	3000	Removal Costs	3001	Removal Costs - LPT	RCVR-DK-4-1, RCVR-DK-5-3, RCVR-DK-6-1
			3002	Removal Costs - POD	RCVR-DK-4-1, RCVR-DK-5-3, RCVR-DK-6-1
			3003	Removal Costs - CWP	RCVR-DK-4-1, RCVR-DK-5-2, RCVR-DK-6-1
			3004	Removal Costs - EPU Preservation	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1
			3005	Removal Costs - POD Preservation	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1
			3006	Removal Costs - Other Preservation	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1
			3999	Removal Costs - Non-reimbursable	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1

13.0 RESOURCE MANAGEMENT

Staffing

The Project will utilize a cross functional team to plan, execute, monitor, control and close the Project as mentioned under "Organization Duties & Responsibilities and Approval Entities" section. Personnel that are working on the Project will charge their time and expenses as per the appropriate CBS. The hours and expenses of the internal personnel charging to the Project will be reviewed on a monthly basis. The Finance Lead will be responsible for running the Duke Energy direct labor report and will review the report, along with the Project Controls Lead and the Project Manager, to ensure that all time and expenses being charged to the Project have been done so appropriately.

Kick-off Meeting

The Project Manager will conduct a Project Kick-Off Meeting on-site with all members of the Project team to go over execution strategy in detail including processes, procedures, roles and responsibilities, ground rules on-site, contract management at Site level, interface with other entities during execution phase, communication plan and rules, etc.

CR3 SUPPORT

Plant Operations

The project will interface with operations to obtain necessary equipment clearances to allow work to proceed safely and to maintain configuration control and protect spent fuel pool interface systems.

Training

The project leadership team is committed to ensuring only properly trained and qualified individuals are assigned to work independently. Existing CR3, Duke Energy fleet or industry training material will be used whenever possible to minimize the need to develop new training material. When needed, additional training will be designed and specific training material will be developed. Fleet training procedures will be used as a reference to guide project training activities.

As each individual is hired, specific initial and continuing training needs will be identified by comparing the individual's knowledge, skill, and experience with the position-to-training matrix. In addition, individual qualification requirements will be identified. Training personnel and project supervision will collaborate to determine the topics from which training exemptions will be granted. Training and qualification requirements and completion status will be maintained in the station's personnel qualification database.

Radiation Protection

Radiation Protection and Control will be implemented for the project in accordance with Site Radiation Control & Protection Manual. The project will interface with the site Radiation Protection staff responsible for ALARA planning, work permit development, and briefings. The project will integrate with station field resources for RP coverage and surveys.

Radiation Protection will also be responsible for oversight of vendor plans for material removal. This includes responsibility for survey and release of any material leaving the radiation controlled area and site.

Engineering

Duke Energy staff will have the primary responsibility for the design and field implementation support of the project. Vendors will be utilized as required to provide specialized analysis and skills.

CR3 Site Engineering will support project development, contractor adherence to performance requirements, maintain knowledge of current project issues, facilitate the resolution of technical issues, and ensure internal stakeholders adequately and expeditiously review project deliverables.

Security

Duke Energy will maintain responsibility for site security and protection. All project site activities will be subject to the site security plan. The project will interface with the site security supervisor to integrate project activities with Security.

14.0 QUALITY MANAGEMENT

The Project will abide to CR3 Nuclear Oversight Program and Policies. The CR3 Nuclear Oversight Staff will be utilized to accomplish these functions. The goal of the Nuclear Oversight (NOS) is to provide nuclear oversight for the execution of the Project in accordance with the CR3 QA Program manual and Nuclear Oversight policies and Procedures including AD-NO-ALL-0500, Major and Complex Project Oversight.

Lessons Learned

Application of lessons learned and operating experience will be integrated into the planning and execution of the Project. Lessons learned and operating experience from other Duke generating plant retirements and industry operating experience from similar work activities will be incorporated. Formal disposition of Operating Experience will be in accordance with CAP0200, Conduct of Performance Improvement as applicable.

Corrective Action Program

The Corrective Action Program (CAP) establishes the processes and responsibilities for documenting and resolving problems, including conditions adverse to quality. The program is designed to address problems in a manner consistent with the nature of the condition and its importance to nuclear safety, industrial safety, or equipment reliability. The Project will utilize the station corrective action program throughout the duration of the project to address all issues related to owner and vendor actions.

Safety Conscience Work Environment

Project leadership will work to maintain a safety conscience work environment on the project. The project will integrate into the station Safety Culture Program, ADM0119.

15.0 RISK MANAGEMENT

The Risk Management process through-out the Project will be in accordance with in accordance with PJM-00004, PJM-00013, PJM-00013 Guide and PMC-PRC-NA-AD-0016 Risk Management Procedure.

The Project will utilize a Risk Register, Top Ten Post Response Strategy Risk Matrix, Risk Radar and Risk Trend tools to monitor, control, and communicate the status of Project risks on monthly basis at a minimum.

The Project will utilize the current available template of the Risk Register tool as provided on the PMCoE SharePoint Site. The PMC Project Controls Lead will ensure that the Project risk register is updated on a monthly basis, in advance of and in support of the monthly Project review meeting.

16.0 COMMUNICATION MANAGEMENT

Emergency Incidents

The affected party will immediately notify the Duke Energy Project Manager. The PMC Project Manager maintains the Incident Notification log through-out the Project life-cycle for record and audit purposes.

For Safety Incidents

- The first person at the site of an accident or incident where medical assistance is required shall immediately call 5555 or the appropriate emergency number for the work location.
- The Site Safety Lead or Project Implementation Manager will notify the PMC Project Manager & PMC Safety Lead (Charlotte) per the Management Intervention Plan (MIP).
- The Site Safety Lead will complete the first notice of serious event or OSHA recordable, approved by Site management & distributed as instructed through Plantview (PMC internal only), per the Management Intervention Plan (MIP) .

- The PMC Project Manager will make notifications per the Management Intervention Plan (MIP).
- The Project Implementation Manager will make notifications per the Management Intervention Plan (MIP).

For Environmental Incidents

- The Site Environmental Lead or Project Implementation Manager will make notifications per the Management Intervention Plan (MIP).
- The Site Environmental Lead or PMC Site Construction Manager will immediately notify the PMC Project Director & PMC Environmental Lead (Charlotte).
- The PMC Project Director will notify the GM-PMC and Plant/Station manager.
- The PMC Site Construction Manager will notify the PMC Manager-Site Construction.

NOTE: The PMC Environmental Lead (Charlotte) coordinates and manages all agency notifications through Duke Energy EHSS. Contractors will not make agency notifications or public comment releases to the press.

Meeting Schedules

Project meetings will be held on a weekly and monthly basis.

Key Decisions

The Project Manager will use the ICF Change Control Process to seek VP, PMC approval prior to implementing a key decision on the Project which is not addressed at any other forum. For instance, the Project decision to Re-Baseline schedule will be tracked and approved through this process.

Lessons Learned Management

Lessons Learned will be documented in accordance with the PMC-PRC-00-AD-0007 Performance Improvement (PI) procedure.

All Project lessons learned will be documented in Plantview and also reported through the monthly report review process.

After Action Review (AAR)

Following critical evolutions and other major events the Project team will conduct AARs in accordance with the PMC PI procedure.

Post-Project Debriefing

During the Project's close phase, the Project team will perform a post-Project debriefing to facilitate identification of lessons learned in accordance with the PJM-00019-ENTSTD Project Close Management Standard.

17.0 COMPLIANCE MANAGEMENT [SAFETY, ENVIRONMENTAL, AND REGULATORY]

Safety Plan

The Site occupational health and safety focus incorporates Duke Energy Corporate procedures applicable to the Site, Corporate Development Group - Health and Safety Management System, and applicable operating plant health and safety procedures.

Occupational health and safety expectation includes adequate oversight and continuous improvement throughout the Project.

Environmental Permits

There are no environmental permits expected for the Project. The need for permits required to support large component removal and shipment will be addressed in the individual Task Plan(s) developed.

Environmental Compliance

The Environmental Compliance Plan (ECP) for individual Task Plans will consist of the development and implementation of a Site specific environmental execution plan based on each scope.

Regulatory

Specific guidance for execution of the Project is provided in AI-9010, *Conduct of CR3 Investment Recovery*. Regular review and audit is performed under the purview of the Duke Rates and Regulatory Strategy department.

18.0 DOCUMENT CONTROL & PROJECT ASSURANCE

Document Control

The CR3 Decommissioning Document Retention SharePoint site will be used for capturing and storing Project records. In addition to the documents specified in the Project Assurance Plan, a "working" section is established to store in-progress project documents (e.g.; action items, contracts, AAT forms, IRP Master Database, Photos, POs, sales data, etc.)

Project Assurance

The Project Manager and other entities involved in planning and executing the Project are responsible for ensuring that the Project is implemented in a reasonable and prudent manner. The role of Project Assurance is to ensure that Project stakeholders understand the regulatory cost recovery process and the importance of managing the Project in a manner that will allow the company to recover Project costs as permitted by relevant laws, rules and regulations. A designated Project Assurance Advisor will be appointed to support and advise the Project management team based on Project type/requirements. The advisor will collaborate with the Project Manager to identify Project decisions and decision milestones that may be subject to regulatory scrutiny and will be available to review and/or advise upon the documentation necessary to demonstrate that those decisions were reasonable and prudent.

Project Assurance issues will be sent via e-mail with copy to the Project email address. Refer to PMC-PRC-NA-AD-0013 Project Assurance Manual for details and process information.

19.0 PROJECT REPORTING AND PERFORMANCE MEASUREMENT TOOL

Project Performance Measurement Tool

The Project Performance Measurement Tool consist of two (2) categories/Key Performance Indicators (KPI) – proceeds / cost, and asset work down curve. Updates of both KPIs will be evaluated and communicated at an agreed frequency (Weekly and Monthly) as per the weekly/monthly reporting distribution sheet. The Project will use the PMC management approved Monthly Report template to communicate performance updates.

Project Reporting – PMC internal

Project reporting includes both weekly and monthly generated reports.

On a weekly basis, the Project Manager will use an exception based weekly report to status the Project update. The weekly report is a SharePoint web report and is to be completed by the Project Director by the close of business every Thursday.

On a monthly basis, the Project core team will jointly update the Project Monthly report for KPIs performance updates in detail. The Project Manager will host a monthly Project progress meeting for PMC management. The meeting will cover all of the items that are to be noted in the monthly report.

The monthly Project team meeting will be held to facilitate a forum for key stakeholders to gain an understanding of the Project status and engage in key issues and risks.

The following are a list of reports regularly generated by the Project team:

- Monthly Project Reports
    - Cost & Financials Analytics
    - Asset work down curves
    - Schedule milestone performance
- Weekly Project Reports
    - Exceptions

20.0 WARRANTY MANAGEMENT

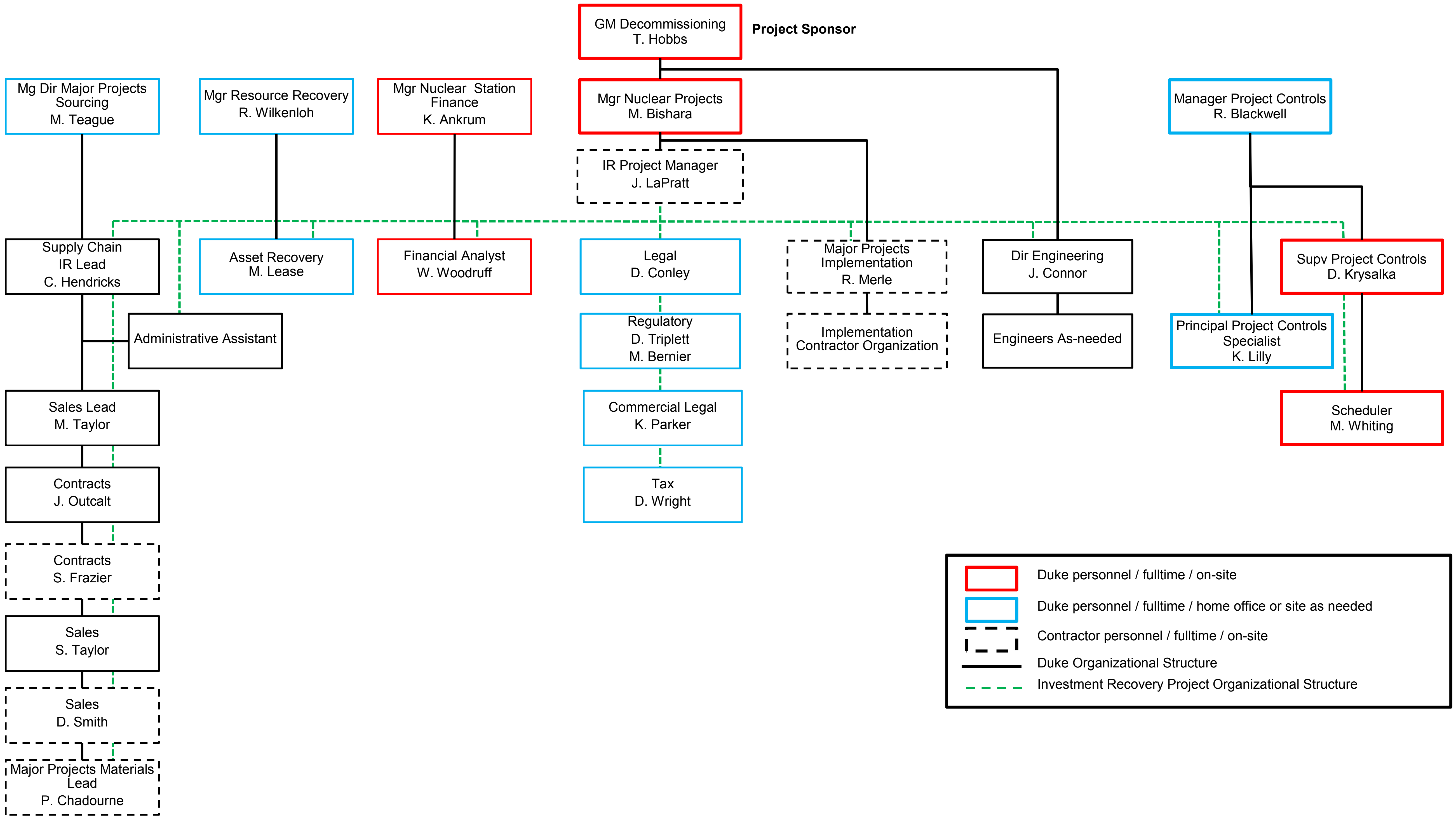
CR3 assets dispositioned to non-Duke entities by this Project are sold as-is, where-is with no warranty by Duke. Supply Chain Contracts personnel will work with asset suppliers as needed to facilitate transfer of manufacturer/supplier warranties when assets are transferred to a Duke affiliate.

21.0 PROJECT CLOSE-OUT MANAGEMENT

Project Close-Out Management will be in accordance with PJM-00019-ENTSTD and PMC-PRC-00-AD-0004 PMC Project Stage Gate Review and Approval procedure. These procedures provides guidance on the Project close-out process, accounts closing, contract closing, final job report, documents transfer, and reporting of standard post Project benefit assessments.

A final Project Close-Out meeting will be held during which the Project Manager and PMC General Manager will review open items and remaining scope of the work. The Project Manager will also review any contractual agreements. This may include any open items for audits, incident investigations, or corrective actions.

APPENDIX A – ORGANIZATION CHART



APPENDIX B – ORGANIZATION RACI[1] CHART

Activity	Project Manager	Supply Chain Lead	SC Contracts Lead	Proj Cont Specialist/ Supervisor	Proj Cont Scheduler	Proj Cont Estimator	Financial Analyst/ Manager	Project Engineer	Impl Manager	Reg Lead	Legal Lead	Lead Planner
	Project Team Member											
DK-1 Project Administration												
DK1-1 Develop Project Plan Documents	A/R	C	C	C	I	I	C	C	C	C	C	I
DK1-2 Estimate Project Costs	A	C	C	C	C	R	C	C	C	C	C	I
DK1-3 Develop Project Schedule	A	C	I	C	R	I	I	C	C	I	I	C
DK1-4 Perform Monitor and Control	A/R	R	C	R	R	I	R	C	C	C	C	I
DK1-5 Perform Project Assessments	A	C	C	C	C	C	C	C	C	R	R	C
DK1-6 Project Funding and Gate Reviews	A/R	C	C	C	C	C	C	C	C	C	C	C
DK-2 Engineer												
DK2-1 Engineering Change	A	I	I	I	I	I	I	R	C	I	I	I
DK2-2 Sales Engineering Support	A	C	C	I	I	I	I	R	I	I	I	I
DK2-3 Implementation Engineering Support	A	I	I	I	C	I	I	R	C	I	I	C
DK-3 Supply Chain												
DK3-1 Sales Activities	A	R	C	I	I	I	C	C	C	I	I	I
DK3-2 Contract Management	A	C	R	I	I	C	C	C	C	I	I	I
DK3-3 Procurement Engineering Data Package Dev	A	R	C	I	I	I	I	C	I	I	I	I
DK3-4 Material Handling	A	R	I	I	I	I	I	I	I	I	I	I
DK3-5 Database Management	A	R	C	C	I	I	C	C	I	I	I	I
DK-4 Work Planning												
DK4-1 Develop Work Orders	A	I	C	I	C	I	I	C	C	I	I	R
DK-5 Implementation												
DK5-1 Asset Preservation	A	C	C	I	C	I	I	C	R	I	I	C
DK5-2 Installed Asset Removal	A	C	C	I	C	I	I	C	R	I	I	C
DK5-3 Large Component Removal/Shipping	A	C	C	I	C	I	I	C	R	I	I	C
DK-6 Project Closeout												
DK6-1 Close Work Orders	A	C	C	I	C	I	I	C	C	I	I	R
DK6-2 Close Engineering Documents	A	C	C	I	I	I	I	R	C	I	I	C
DK6-3 Close Contracts	A	C	R	I	I	I	C	C	C	I	I	I
DK6-4 Close Project Documents	A/R	C	C	C	C	C	C	C	C	C	C	C
DK6-5 Perform Project Lessons Learned	A/R	C	C	C	C	C	C	C	C	C	C	C
DK-7 Legal & Regulatory Oversight												
DK7-1 Legal Reviews	A	C	C	C	C	C	C	C	C	C	R	C
DK7-2 Regulatory Reviews	A	C	C	C	C	C	C	C	C	R	C	C
DK7-3 Tax & Financial Reviews	A	C	C	C	C	C	R	C	C	C	C	C

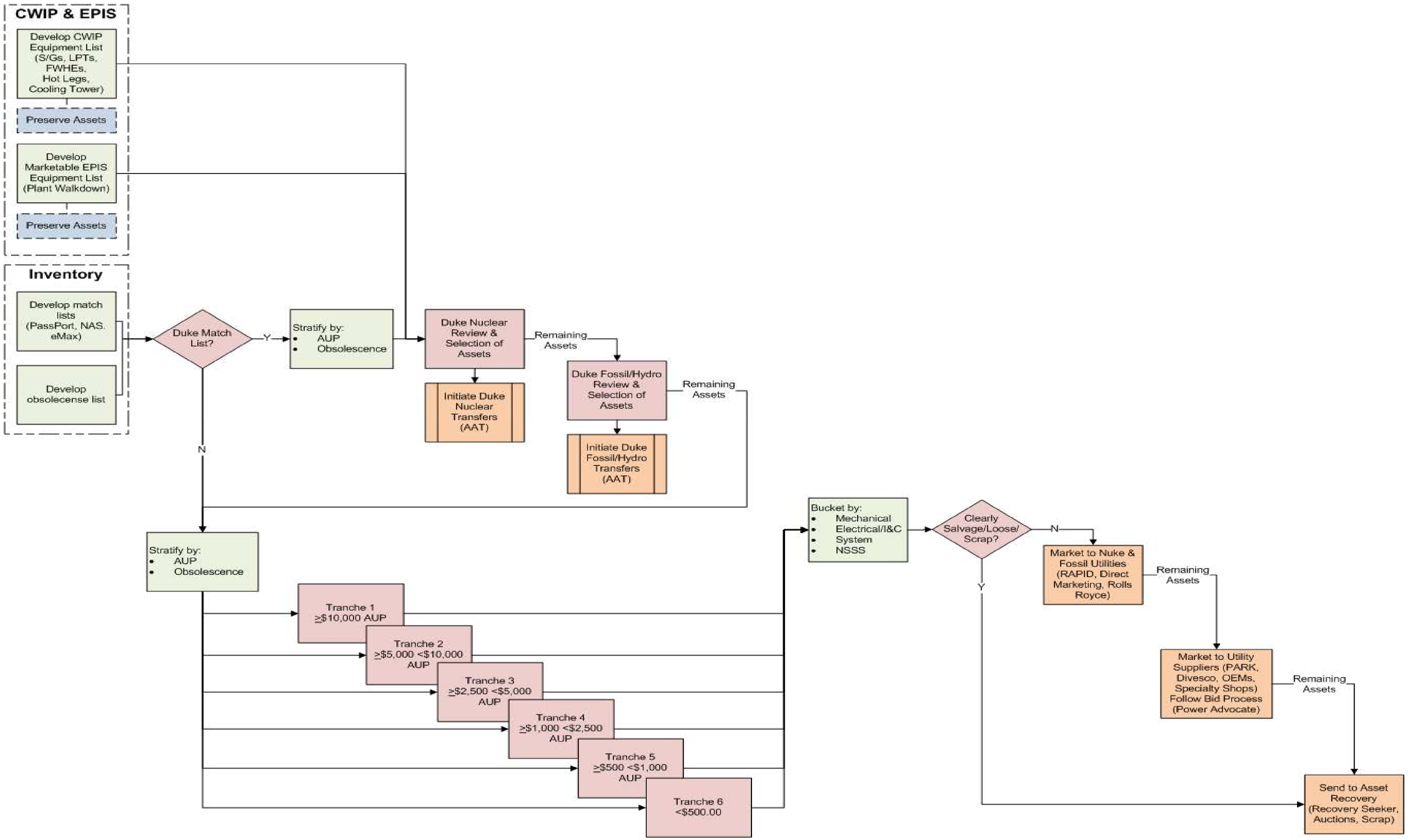
[1] **R [responsible]** Those who do work to achieve the task. **A [accountable]** The resource ultimately answerable for the correct and thorough completion of the task. **C [consult]** The resources whose opinions are sought on various activities. This is a two-way communication. **I [inform]** The resources that need to be kept up-to-date on progress. This is a one-way communication.

APPENDIX C – CONTACT LIST

Project Management				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
LaPratt	Jeff	PM	[redacted]	[redacted]
Bishara	Magdy	MGR Nuclear Projects	[redacted]	[redacted]
Project Controls & Support				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Krysalka	Dan	Supv Project Controls	[redacted]	[redacted]
Lilly	Kathy	Prnc Proj Controls Specialist	[redacted]	[redacted]
Woodruff	Wendy	Sr Financial Analyst	[redacted]	[redacted]
Whiting	Mark	Sr Proj Controls Specialist	[redacted]	[redacted]
Supply Chain				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Teague	Mark	Mgng Dir Major Projs Sourcing	[redacted]	[redacted]
Hendricks	Chris	Mgr Nuc Site Supply Chain	[redacted]	[redacted]
Taylor	Mike	Mgr Nuclear Procurement	[redacted]	[redacted]
Smith	Dave	Contractor – IRP Specialist	[redacted]	[redacted]
Taylor	Steve	Sr Tech Specialist	[redacted]	[redacted]
Outcalt	Jay	Contacts	[redacted]	[redacted]
Frazier	Shannon	Contracts	[redacted]	[redacted]
Chadourne	Paul	Materials Lead	[redacted]	[redacted]
Lease	Michelle	Asset Recovery Coordinator	[redacted]	[redacted]
Engineering				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Connor	Jim	Dir Nuclear Engineering	[redacted]	[redacted]
Implementation				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Merle	Russ	Implementation Manager	[redacted]	[redacted]

Legal / Regulatory / Tax				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Conley	Dave	Associate Gen Counsel	[redacted]	[redacted]
Triplett	Dianne	Associate Gen Counsel	[redacted]	[redacted]
Bernier	Matt	Sr Counsel	[redacted]	[redacted]
Parker	Kristy	Associate Gen Counsel	[redacted]	[redacted]
Wright	Dave	Dir Non-income & Property Tax	[redacted]	[redacted]
Olivier	Marcia	Dir Rates & Reg Strategy	[redacted]	[redacted]

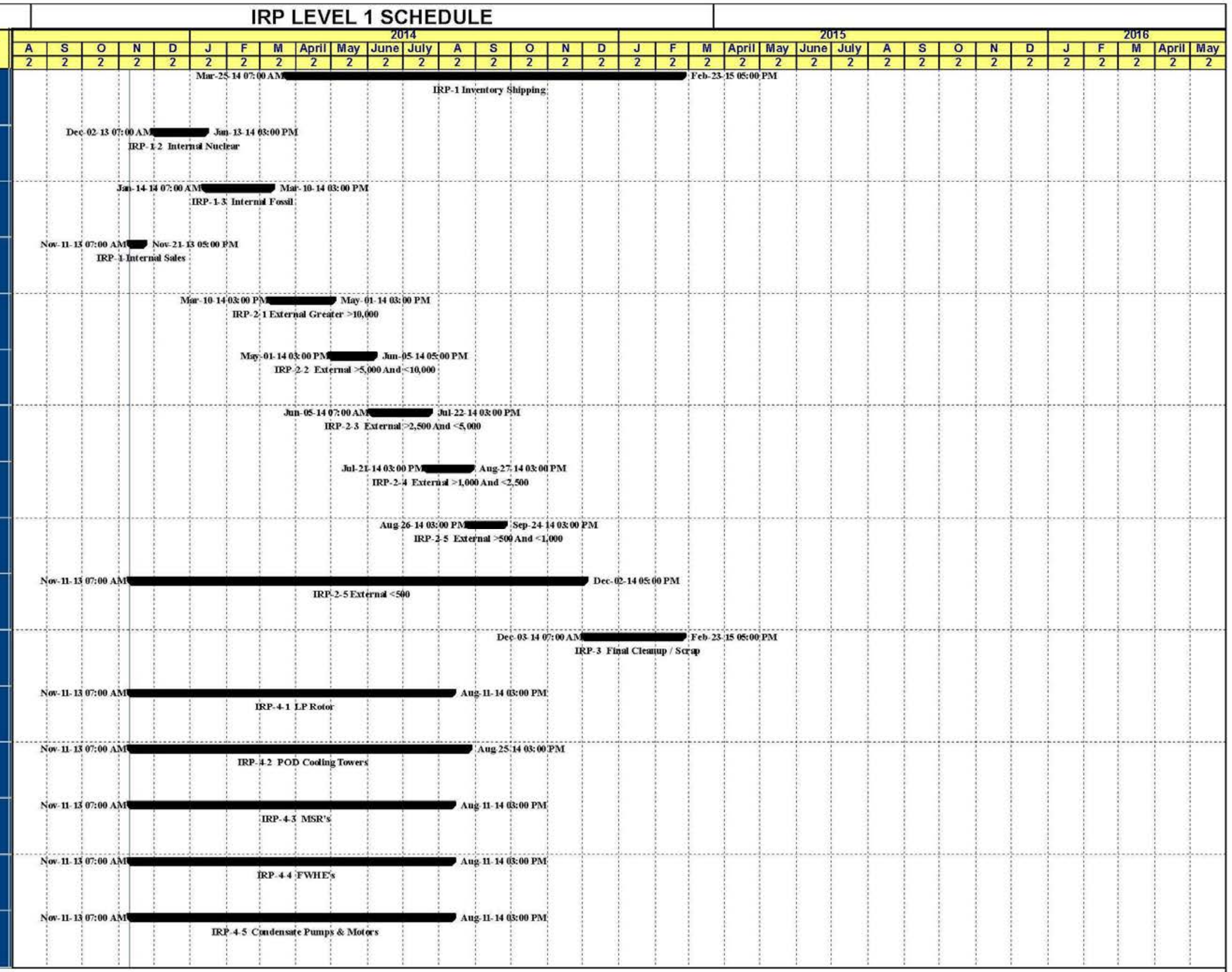
APPENDIX D – DISPOSITION STRATEGY FLOWCHART



APPENDIX E – LEVEL 1 SCHEDULE

CR3 INVESTMENT RECOVERY SCHEDULE

Activity ID	Activity Name	Start	Finish	Hrs	Activity Type
IRP-1 Inventory Shipping		Mar-25-14 07:00 AM	Feb-23-15 05:00 PM	1830h	
IRP-1-2 Internal Nuclear		Dec-02-13 07:00 AM	Jan-13-14 03:00 PM	218h	
IRP-1-3 Internal Fossil		Jan-14-14 07:00 AM	Mar-10-14 03:00 PM	318h	
IRP-1-Internal Sales		Nov-11-13 07:00 AM	Nov-21-13 05:00 PM	80h	
IRP-2-1 External Greater >10,000		Mar-10-14 03:00 PM	May-01-14 03:00 PM	300h	
IRP-2-2 External >5,000 And <10,(		May-01-14 03:00 PM	Jun-05-14 05:00 PM	192h	
IRP-2-3 External >2,500 And <5,00		Jun-05-14 07:00 AM	Jul-22-14 03:00 PM	258h	
IRP-2-4 External >1,000 And <2,50		Jul-21-14 03:00 PM	Aug-27-14 03:00 PM	220h	
IRP-2-5 External >500 And <1,000		Aug-26-14 03:00 PM	Sep-24-14 03:00 PM	160h	
IRP-2-5 External <500		Nov-11-13 07:00 AM	Dec-02-14 05:00 PM	2100h	
IRP-3 Final Cleanup / Scrap		Dec-03-14 07:00 AM	Feb-23-15 05:00 PM	440h	
IRP-4-1 LP Rotor		Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-2 POD Cooling Towers		Nov-11-13 07:00 AM	Aug-25-14 03:00 PM	1578h	
IRP-4-3 MSR's		Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-4 FWHE's		Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-5 Condensate Pumps & Mo		Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	



Summary

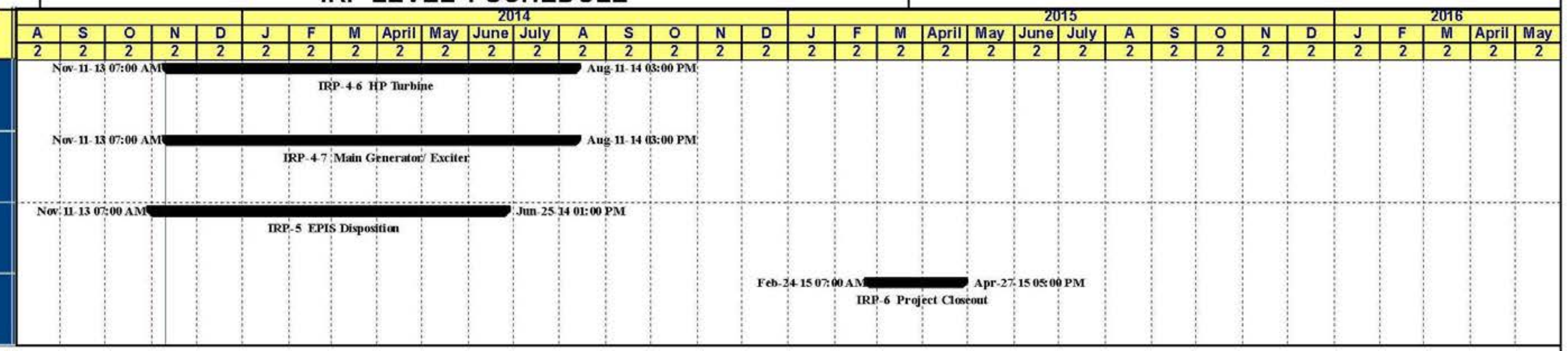
Report Date Jan-21-14

Data Date Nov-11-13 1

CR3 INVESTMENT RECOVERY SCHEDULE

IRP LEVEL 1 SCHEDULE

Activity ID	Activity Name	Start	Finish	Hrs	Activity Type
IRP-4-6	HP Turbine	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-7	Main Generator/ Exciter	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-5	EPIS Disposition	Nov-01-13 07:00 AM A	Jun-25-14 01:00 PM	1246h	
IRP-6	Project Closeout	Feb-24-15 07:00 AM	Apr-27-15 05:00 PM	360h	



Summary

Report Date Jan-21-14

Data Date Nov-11-13

2

APPENDIX F – PMC DOCUMENT APPROVAL FORM

DUKE ENERGY.

Project Management & Construction
Document Approval Form (DAF)

Section A: Document identification and type of action

Document Number: N/A	**Revision Number: 0**
Document Title: CR3 Investment Recovery Project Project Execution Plan	
Type of Action: ☒ New ☐ Suspension ☐ Revision ☐ Ownership Change ☐ Cancellation ☐ Periodic review completed	**Effective Date:** 2/25/2014
Applies to: Project Management & Construction	**Group:** CR3 Decommissioning Transition Org

Applicable to Forms Only
Does form have a parent procedure? ☒ No ☐ Yes Procedure #:

☐ Communication plan established N/A ☐ Impact Reviews Completed N/A

Description of document action or summary of changes:

The document presents the Project Execution Plan for the CR3 Investment Recovery Project (IRP).

Preparer(s): Jeff LaPratt, IRP PM

Section B: Approval

Name	Signature	Date
Jeff LaPratt/IRP PM Approval recommended (print name)	Jeff LaPratt	2/24/14
Magdy Bishara/MGR Major Projects Approval recommended (print name)	Magdy Bishara	2/24/14
for **Terry Hobbs/GM Decommissioning** Final Approval (print name)	Magdy Bishara	2/24/14
N/A Approved (for approval of interface documents only)	Signature	Date

RETURN SIGNED FORM TO PMC GOVERNANCE

INVESTMENT RECOVERY GUIDANCE DOCUMENT

IRGD-001

Revision 0

Sales Track Guidance and Documentation Package Development

An Uncontrolled Reference and Assistance Document

Note: If any conflicts exist between the current Directives and Procedures and the information contained within this guidance document all directives and procedures shall govern the work described herein.

Sales Guidance and Documentation Package Development

TABLE OF CONTENTS

Sales Guidance and Documentation Package Development

1.0 PURPOSE

This Guidance Document provides instruction to conduct sales and develop complete documentation packages for the Crystal River Unit 3 (CR3) Investment Recovery Project (IRP).

2.0 APPLICABILITY

This Guidance Document applies to the IRP. More specifically, this Guidance Document applies to the sale/transfer of material and the development and retention of sales and other supporting documentation.

3.0 ROLES AND RESPONSIBILITIES

Manager Nuclear Procurement or designee is the single point of contact for reviewing all documentation packages and ensuring all documents are uploaded to the Share Point Site and sales tracking database.

Investment Recovery Project Manager (IRPM) provides oversight of the sales process and documentation retention activities. Additionally, the Investment Recovery PM is responsible for facilitating the removal of equipment installed in the plant.

Investment Recovery Sales Team (IRST) is the point of contact for obtaining sales leads, negotiating the sale, closing the sale, and documenting all aspects of the sale transaction. The CR3 IRST is also responsible for loading all documentation on the Investment Recovery Share Point Site and sales tracking database.

Asset Recovery Sales Team (ARST) processes all salvage transactions, and is responsible for invoicing vendors after Inter-Utility (RAPID), external third party, and salvage sales are completed.

CR3 Financial Analyst determines the Net Book Value (NBV) for Duke Affiliate Transfers and Duke Internal Sales, when available. Completes first half of the Capital-to-Capital or Capital-to-Inventory template and tracks Journal Entries processed by Asset Accounting and performs Journal Entries for transfers within the state of Florida.

4.0 IRP SALES STRATEGY

Organize – Develop a list of and categorize all items available for immediate sale with an explanation of how the sale criteria and categorization was achieved.

Preserve – Determine what preventive maintenance (PM) and preservation activities are required to allow the highest rate of return for all CR3 assets. Develop and implement a plan for the preventive maintenance (PM) and preservation activities.

Analyze – Determine the most effective method for each category and create a schedule for the sale of these items.

Disposition – Distribute the “match” lists within the Duke organization to obtain the highest rate of return. Follow the AI9010 Administrative Procedure for the remaining equipment and material.

5.0 SALES PROCESS AND REQUIRED DOCUMENTATION

5.1 Duke Affiliate Transfer

1. IF non-inventory Capital material, THEN the financial analyst will determine the Net Book Value (NBV) and completes either:
   a. Capital-to-Capital template and sends to requesting location; or
   b. Capital-to-Inventory template and sends to requesting location.
2. IF Inventory material, THEN Calculated Unit Price (CUP) from the CAT ID shall be used for the asset value.
3. Requesting Location shall initiate the Affiliate Asset Transfer (AAT) eForm and route to CR3 Investment Recovery (SCD211, Rev.1).
   a. Completed Capital-to-Capital or Capital-to-Inventory template shall be attached, if required.
4. The IRST shall complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
5. IF equipment is installed in the plant, THEN:
   a. IRST will initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
   b. IRPM facilitates the removal of the equipment with the IRP Implementation group.
6. Manager Nuclear Procurement, or designee, shall review the AAT eForm and if such AAT eForm is satisfactory (see Attachment A for requirements), approval shall be granted.
7. FL legal shall review the AAT eForm and if such eForm is satisfactory, approval shall be granted.
8. IF the equipment is installed in the plant, is Safety Related and is required to maintain a Safety Related classification, return to stock under the appropriate CAT ID, if one does not exist, create a new CAT ID per the established Nuclear Procedures:
   a. Initiate a PICK Ticket, for all listed/sold material, if the plant is Non-Nuclear the requesting site shall create an Material Request (MR).
   b. CR3 Adjust Minimum/Maximum to zero (0) in PassPort to prevent re-order.
9. IF inventory material, THEN:
   a. Initiate a PICK Ticket, if required, for all listed/sold material.
   b. CR3 IRST Adjust Minimum/Maximum to zero (0) in PassPort to prevent re-order.
10. Obtain shipping arrangements from requesting location.
11. Forward a copy of the AAT eForm and shipping information to the warehouse.
12. Ship material to the requesting location.

Sales Guidance and Documentation Package Development

13. For Capital assets the AAT eForm is sent to Asset Accounting to perform a Journal Entry which transfers the funds.
    a. Journal entry should include the asset value (shipping, stores, etc.) as well as the removal costs, if required.
    b. True-up of actual costs is obtained through the journal entry and attached to the AI9010.
14. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. AAT eForm, including all Attachments
    b. Asset Disposition Review (AI-9010, Attachment 1)
    c. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    d. PICK Ticket, if required
    e. Issue Ticket, if required
    f. Shipping documentation
    g. E-mails
    h. Journal entry documentation, if required

5.2 Duke Florida Internal Transfer

1. IF Non-inventory, THEN determine value of asset:
    a. Contact Financial Analyst to determine the NBV of the equipment.
    b. If NBV is not available, the IRST should determine Fair Market Value (FMV).
2. IF Safety Related material is requested, THEN
    a. IRST shall verify the material is not on the Match List.
    b. CAT ID shall be downgraded to Quality Level 4.
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
    a. IF non-inventory asset, THEN AI-9010, Attachment 1 is required.
    b. IF inventory asset, THEN AI9010, Attachment 1 is NOT required.
4. IF equipment is installed in the plant, THEN:
    a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
    b. IRPM facilitates the removal of the equipment with the IRP Implementation group.
5. IF the item has a CAT ID in the PassPort System and the:
    a. Item is Safety Related (QL 1, 2, 3)
        i. A Material Request shall be completed by the requesting site.

Sales Guidance and Documentation Package Development

ii. CR3 shall Adjust Minimum/Maximum to “0” to prevent a re-order.

b. Item is non-safety related (QL 4)

i. A Pick Form should be completed by the sending site.

ii. CR3 shall Adjust Minimum/Maximum to “0” to prevent a re-order.

6. Shipping arrangements are coordinated by requesting plant and shipping information shall be sent to the warehouse personnel.
7. Material is shipped to the requesting facility.
8. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. Asset Disposition Review (AI-9010, Attachment 1)
    b. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    c. Pick Ticket/Transfer/Material Request, if required
    d. Issue Ticket, if required
    e. Shipping documentation
    f. E-mails
    g. True-up of actual costs documentation, if required
    h. Journal entry documentation, if required
9. A monthly report of all Duke Florida Internal Inventory sales shall be uploaded to the SharePoint site.
10. IF in-state transfer was purchased as or currently is EPIS, Inventory or O&M (101 or 106 accounts), THEN the material can be transferred and the receiving organization will not realize the costs at the time of the transfer.
11. IF in-state transfer was purchased as or currently is CWIP (107 account), THEN the cost is recognized by the receiving organization at the time of the transfer.

5.3 Inter-Utility (RAPID) Sale

1. Price is negotiated at CUP or better, Terms and Conditions are in accordance with the Inter-Utility Sales agreement. Note: Some sale prices may be lower than the CUP due to material condition, shelf life, etc. Approval of the modified sale price shall be obtained prior to sale closure by either the Manager Of Nuclear Procurement or Site Supply Chain Manager.
2. CR3 receives the Purchase Order (PO).
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
4. IF equipment is installed in the plant, THEN:
    a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).

   b. IRPM facilitates the removal of the equipment with the IRP Implementation group.

5. IF inventory, THEN CR3 IRP completes a Material Request and adjusts Minimum/Maximum to "0" to prevent re-order.
6. Shipping arrangements coordinated by requesting plant and CR3 warehouse.
   a. MR and PO are forwarded to CR3 warehouse for issuing and shipping instructions.
7. Material shipped to requesting facility.
   a. Forward shipment tracking information to buyers upon request.
8. Copy of shipping information/issue ticket sent to CR3 IRP.
9. Enter information into Investment Recovery RAPID database spreadsheet.
10. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. Asset Disposition Review (AI-9010, Attachment 1)
    b. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    c. Purchase Order
    d. Material Request, if required
    e. Issue Ticket, if required
    f. Shipping documentation
    g. E-mails
    h. Copy of invoice
    i. Tax exempt form

5.4 Duke External Third Party Sale

1. Price is negotiated in accordance with the Terms and Conditions for CR3 Investment Recovery sales. Note: Buyer pays for all shipping and handling (including removal from plant if installed) costs.
   a. See Material Bidding Process 6.0
2. CR3 Receives the Contract/Purchase Order (PO).
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
4. IF equipment is installed in the plant, THEN:
   a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
   b. IRPM facilitates the removal of the equipment with the IRP Implementation group.

Sales Guidance and Documentation Package Development

5. IF Inventory, THEN CR3 IRP completes a Material Request (MR) and adjusts Minimum/Maximum to “0” to prevent re-order.
6. Shipping arrangements coordinated by requesting company in accordance with Contract/PO.
    a. MR and Contract/PO are forwarded to CR3 warehouse for issuing and shipping instructions.
7. Material shipped to requesting company.
    a. Forward shipment tracking information to buyers upon request.
8. Copy of shipping information/issue ticket sent to CR3 IRP.
9. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. PowerAdvocate documents, if required
    b. Buyer Contract/Purchase Order
    c. Asset Disposition Review (AI-9010, Attachment 1)
    d. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    e. Material Request, if required
    f. Issue Ticket, if required
    g. Shipping documentation
    h. E-mails
    i. Copy of invoice
    j. Tax exempt form
    k. Signed IR Terms and Conditions

5.6 Duke Salvage Sale

1. Price is negotiated in accordance with the Terms and Conditions for CR3 Investment Recovery sales.
    a. See Material Bidding Process 6.0
2. CR3 Receives the Contract/Purchase Order (PO).
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
4. IF equipment is installed in the plant, THEN:
    a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
    b. IRPM facilitates the removal of the equipment with the IRP Implementation group.

Sales Guidance and Documentation Package Development

5. CR3 IRP completes a Material Request (MR) and adjusts Minimum/Maximum to “0” to prevent re-order.
6. Shipping arrangements coordinated by requesting company in accordance with Contract/PO.
    a. MR and Contract/PO are forwarded to CR3 warehouse for issuing and shipping instructions.
7. Material shipped to requesting company.
    a. Forward shipment tracking information to buyers upon request.
8. Copy of shipping information/issue ticket sent to CR3 IRP.
9. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. PowerAdvocate documents, if required
    b. Buyer Contract/Purchase Order
    c. Asset Disposition Review (AI-9010, Attachment 1)
    d. Installed Plant Equipment Removal Agreement (AI-9010 Attachment 2), if required.
    e. Material Request, if required
    f. Issue Ticket, if required
    g. Shipping documentation
    h. Pertinent e-mails
    i. Copy of invoice
    j. Tax exempt form
    k. Signed IR Terms and Conditions

6.0 MATERIAL BIDDING PROCESS

1. IRSTs shall decide on a method of disposition based on the following criteria:
    a. Asset value < $15,000.00 - Items may be marketed and sold at the IRST’s discretion
    b. $15,000.00 < Asset value < $100,000.00 – Items must be sold using one of the following methods:
        i. Asset Recovery’s Online Surplus Marketplace
            1. Online marketing and sales tool may utilize one or more of the following sales methods:
                a. Auction
                b. Fixed Price Sale
                c. Classified Ad

Sales Guidance and Documentation Package Development

2. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. List of companies/individuals automatic emails were disseminated to.
    b. List of companies/individuals who received phone calls.
    c. List of Bidders.
    d. All communications:
        i. Emails
        ii. Posted comments
            1. Questions
            2. Responses
        iii. calls logged with notes regarding conversation.
    e. Amount of each bid.
    f. Number of visitors (names if possible).
    g. All documentation:
        i. T&Cs
        ii. AI-9010 Form
        iii. Screen shots
    h. Time Auction started/ended.

ii. Formal Bid
    1. E-mail bid which includes a bid package containing at a minimum:
        a. Bid Cover Letter or Information letter
        b. Instructions to bidder
        c. List of Materials for Sale
        d. Terms and Conditions for CR3 Investment Recovery sales
        e. Bidder Response form

iii. Power Advocate Bid Event

c. Asset Value > $100,000.00
    i. Items must be sold using a Power Advocate Bid Event

2. Exception from standard Material Bidding Process
    a. IF an instance occurs where IR is required to make an exception for an asset sale, THEN they shall be documented by the IRST and approved by the Manager of Nuclear Procurement or designee.
    b. Examples of when an exception may occur include, but are not limited to the following:
        i. Contractual restraints only allow sale to one party (original manufacturer)
        ii. Expedited time frame for sale required and the sale price is above CUP

Sales Guidance and Documentation Package Development

7.0 VENDOR SITE ACCESS

Prior to admittance to the CR3 site all vendor personnel shall have an approved Site Access Form. Prior to picking up material or equipment the vendor shall sign a Duke Energy agreement which includes acceptance of:

- Insurance requirements
- Safety and Security procedures
- Waiver of liability

8.0 CR3 ACCOUNTING STRUCTURE

8.1 CR3 Assets

All CR3 Assets are in one of the following categories:

Account	Description		Account	Description
101	Electric Plant In Service (EPIS)		154	Inventory
107	Construction Work In Progress (CWIP)		163	Stores
106	Capital Cost Not Classified (CCNP)		183	Study

The financial analyst will determine which of the following accounts a Capital Sale will be credited to:

Credit Account	Description
20100423 - SLVGE	Capital Co-Owned
20100426 - SLVGE	Capital Non-Co-Owned
EPU - DISP	EPU
20069122 - SLVGE	EPU POD

Stores Loading rate is not added to Capital items when sold internally to a Duke Energy Affiliate or to Duke Energy Florida.

8.2 CR3 Inventory

All inventory sales are credited as follows:

Credit Account	Description
20016324	Inventory

Stores Loading rate is included on all inventory sales and transfers.

8.3 CR3 Tax Collection

8.3.1 When is Sales Tax Collected

All Duke entities are required by the various states in which they operate to collect sales tax on the sales of used equipment ***<u>unless</u>*** the customer can prove their exemption. Transactions can be exempt because of who the customer is or because of how the customer will be using the item purchased. In either case, the customer would need to provide exemption documentation to in order to avoid having sales tax added to their bill.

Below are examples of common exemptions:

Entity Based Exemption	**Use Based Exemptions**
Government Entities	Reselling
Nonprofits	Manufacturing
Religious Organization	Research and Development
Educational Institutions	Utility use

Exemptions and exemption documentation will vary from state to state. Not every state will recognize all the exemptions above. When exemption documentation is received verify that it is properly completed and retain a copy for audit purposes. (Some exemption documentation may need to be signed or have an explanation.)

8.3.2 Accounting Structure for Collecting Sales Tax

Operating Unit	0193
Responsibility Center	0193
Location	002090209 (Citrus County, Florida)
GL Account	0241320
Resource Type	99810

Other counties and municipalities and special tax collection rates use different location codes.

All Florida counties and special tax situations will be coded into “The Retail Solution”.

8.3.3 Collecting Sales Tax

Sales for equipment and materials at Crystal River will be made using “The Retail Solution”, the software point of sale system used by Asset Recovery. Before any sale can be made to a customer, a record is created for the customer that includes basic information, such as name, address, phone number, etc. Also included is information pertinent to the collection of state and county sales tax:

a. Tax Location – The tax location is where the sale occurs. In the case of Crystal River, all sales will be completed from Citrus County. Tax coding will be coded in “The Retail Solution” for all municipalities, and the system will calculate the appropriate rate of tax for the sale. If sales are made from other counties, we will provide the necessary coding in “The Retail Solution” to handle these collections as well.

b. Tax Exempt – If the customer is exempt from payment of sales taxes, they must provide Duke Energy exemption documentation (see above). The exemption documentation will include a number, which is recorded in “The Retail Solution”, and the customer record will be coded “no tax”. When sales are processed, the system will not calculate sales tax based on this coding. noted above, Duke Energy must keep a record of the exemption certificate on file for audit purposes.

Sales tax is collected in the county in which the sale is made. For sales made from Crystal River, all applicable tax will be collected and submitted back to Citrus County.

A journal entry is created using a report from "The Retail Solution", in which the funds collected for specific sales will be credited to the appropriate accounting. Funds collected for Florida tax receipts will be credited to the appropriate tax accounting.

8.3.4 How Sales Tax is Handled Through an External Auction Company

The auction company is responsible for verification of the taxable status of the auction registrant. If the auction registrant provides proof of exemption to the auction company, not sales tax is collected or paid to the state or municipality from the sale. If the auction registrant is not tax-exempt, the auction company collects the sales tax from the location from which the sale was actually made.

9.0 SHAREPOINT

9.1 File Naming Convention

Every document shall have the Identification number, which corresponds to the Sales Tracking Database on the Investment Recovery SharePoint Site, and a brief description of the Document type. The following protocol shall be utilized to name files within the Investment Recovery Sales SharePoint Site:

Sale Type	Document Title	Document Title Example
Affiliate Asset Transfers	E-Form Folder Number_Document Title	Efr152v1-000982_eform Efr152v1-000982_AI9010
Florida – Internal Duke	FID Number_Document Title	FID00001_AI9010 FID00001_emails
Inter-Utility (RAPID)	RAPID ID Number_Document Title	R251752_PO R251752_AI9010
Non-Duke (3rd party)	Contract/PO Number_Document Title	ND178596_PO ND178596_AI9010
Salvage	Salvage Number_Document Title	SLVG00001_AI9010 SLVG00001_emails
Disposition – Not Sold	Not Sold Number_Document Title	NS00001_emails
Donations	Donation Number_Document Title	DON00001_AI9010 DON00001_letter
Disposal	Disposal Number_Document Title	DIS00001_AI9010 DIS00001_emails

* Additional documentation for complete sale may be required as delineated in this guidance document.

9.2 File Structure

The file structure, Attachment B, is a quick reference tool designed to assist the project team in determining where documents are stored.

10.0 DEFINITIONS

Duke Affiliate Sale: Any sale which occurs internally between regulated, non-regulated and non-utility affiliate within the Duke Energy organization. These sales require an

Affiliate Asset Transfer Form and consist of moving material outside of the state of Florida.

Duke Florida Internal Sale: Any sale or transfer which occurs internally between regulated, non-regulated and non-utility group within the Duke Energy Florida organization.

Duke Inter-Utility (RAPID) Sale: Any sale which occurs externally between regulated and non-regulated Utilities under the Terms and Conditions as defined on the Readily Accessible Parts Integrated Database (RAPID) web site. (Initiated by the Purchasing utility).

Duke External Third Party Sale: Any sale which occurs externally between regulated, non-regulated and non-utility companies. (Initiated by CR3 IRST).

Duke Salvage Sale: Any sale which occurs externally between a Duke Energy approved salvage company. Material will be sold by Duke Energy Asset Recovery.

Material Request: The process used when material is transferred within the Duke Energy Enterprise, may be used when plants have common CAT IDs but must be used if a no common CAT ID is available.

Pick Ticket or Transfer: The process used when material is transferred within the Duke Energy Enterprise and a common CAT ID is available. Should be initiated by shipping site.

PowerAdvocate: A sourcing website which allows the sales team to provide all pertinent information to the bidders, allows for communication between bidder and seller and accepts all bids and bidder exceptions. PowerAdvocate sourcing tool should be used when the estimated value, CUP or Combined CUP of material is greater than or equal to one hundred thousand dollars (≥ $100,000).

SharePoint: a web based collaboration tool which allows the Project team and work group to perform more effectively by providing a central, virtual location for sharing of information quickly.

11.0 REFERENCES

AI-9010 – Conduct of CR3 Investment Recovery

Affiliate Asset Transfer Form – Enterprise Forms

SCD211, Rev. 1 Affiliate Asset Transfer Transactions

Investment Recovery Project, Project Assurance Plan

MCP-NGGC-0001 – NGG Contract Initiation, Development and Administration

MCP-NGGC-0401 – Material Acquisition (Procurement, Receiving, and Shipping)

12.0 ATTACHMENTS

Attachment A: Affiliate Asset Transfer Information Section eForm Template

Attachment B: IRP Sales Document Retention File Structure

Attachment C: Sales Track Quick Reference Guide

Attachment D: SharePoint Documentation Package Checklist

Sales Guidance and Documentation Package Development

Attachment A: **Affiliate Asset Transfer Information Section eForm Template**

Use this Template as a "copy/paste" tool while completing the Affiliate Asset Transfer eForm, "Asset Transfer Information Section."

CAT ID #'s (NAS & Passport):

Item Description:

Qty transferring:

Capital Item?:

Safety Related?: (If Yes, provide Suitability or PEEVAL # & UTC #)

Contacts at Sending & Receiving locations:

Issue Accounting:

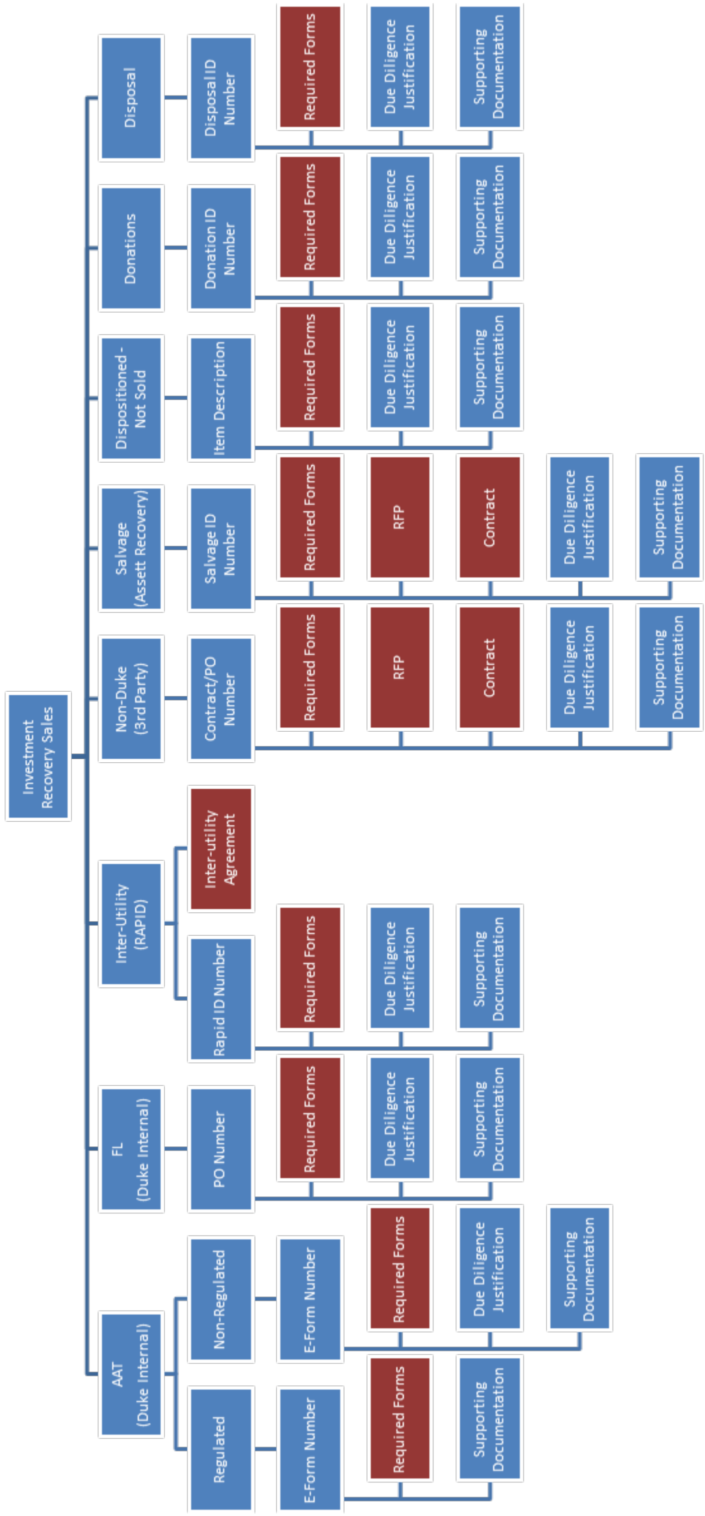
Receiving Accounting:

For transactions between DEF & DEP, note MR #.

Shipping Instructions:

Sales Guidance and Documentation Package Development

Attachment B: Investment Recovery Sales Document Retention File Structure



Sales Guidance and Documentation Package Development

Sales Guidance and Documentation Package Development

Attachment D: SharePoint Documentation Package Checklist

Sale ID No.:____________________

Sale Date:______________________

		AI-9010, Attachment 1	AI-9010 Attachment 2*	Material Request*	Issue Ticket*	Shipping documentation*	Copy of invoice Proof of Payment	E-mails	AAT eForm	Buyer Contract Purchase Order	Tax exempt form	RFP Documents	RFP Review	RFP Justification
☐	Affiliate	☐	☐	☐	☐	☐	☐	☐	☐					
☐	DEF	☐	☐	☐	☐	☐	☐	☐						
☐	RAPID	☐	☐	☐	☐	☐	☐	☐		☐	☐			
☐	External	☐	☐	☐	☐	☐	☐	☐		☐	☐	☐	☐	☐
☐	Salvage	☐	☐	☐	☐	☐	☐	☐		☐	☐	☐	☐	☐
☐	Scrap	☐	☐	☐	☐	☐	☐	☐		☐	☐	☐	☐	☐

*Documents may not be required for all sales or transfers

Originator: ________________________________

☐ Final Date: ______________________________

☐ Draft

☐ EPU

☐ Non-EPU

Integrated Change Form (ICF)

REDACTED

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

[redacted]

Integrated Change Form (ICF)

REDACTED

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

Approve ICF

[redacted]

REASON FOR CHANGE (CHECK ALL THAT APPLY)

OWNER		REGULATORY		OTHER:____________
ENGINEER		VENDOR / NAME		
CONSTRUCTION		OTHER / DESCRIBE		DESCRIBE:

COST IMPACT

CRAFT LABOR	CRAFT	HOURS	RATE		TOTAL

MATERIALS	DESCRIPTION	QTY	COST	TOTAL
	N/A			

EQUIPMENT	DESCRIPTION	QTY	COST	TOTAL
	N/A			

SUB CONTRACTOR	DESCRIPTION	COST	TOTAL
	N/A		

PROF. SERVICES	DESCRIPTION	TOTAL

TOTAL IMPACT COST	

ESTIMATED BY:		DATE	

REDACTED

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

IRP Auction Justification

[redacted]

REDACTED

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

Governance / Plan

[redacted]

[redacted]

REDACTED

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

[redacted]

REDACTED

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

[redacted]

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Duke Energy Florida, Inc.
For Approval to Include in Base Rates the Revenue
Requirement for the CR3 Regulatory Asset

Docket No. ____________

Submitted for Filing
May22, 2015

DIRECT TESTIMONY OF TERRY HOBBS

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

IN RE: PETITION FOR APPROVAL TO INCLUDE IN BASE RATES THE REVENUE REQUIREMENT FOR THE CR3 REGULATORY ASSET

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. ___________

DIRECT TESTIMONY OF TERRY HOBBS

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is Terry Hobbs. My current business address is 15760 West Power Line St., Crystal River, FL 34428.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, Inc. ("DEF" or the "Company") and I am the General Manager (GM) of Decommissioning at the Crystal River 3 ("CR3") nuclear unit.

Q. What are your responsibilities as the GM of Decommissioning?

A. In this role I am the senior manager who has oversight responsibility for the Decommissioning of the Crystal River Unit 3 ("CR3") plant, including the safe storage of spent nuclear fuel, continued operations and maintenance of the facility and oversight for regulatory submittals to the United States Nuclear Regulatory Commission ("NRC") associated with the decommissioning. I also had responsibility for the Decommissioning Transition Organization ("DTO").

Q. Please summarize your educational background and professional experience.

A. I have held a Senior Reactor Operator license issued by the NRC, and I currently hold a project management professional credential through the Project Management Institute. I have served in many various management positions within Duke Energy (formerly Progress Energy) since 1986 including Operations Manager at the Harris Nuclear Plant in North Carolina, Quality Assurance manager both at CR3 and the Robinson Nuclear Plant in South Carolina, Project Controls manager at CR3, and Plant General Manager at CR3. Prior to joining the Company in January 1986, I spent eight years in the United States Navy in the nuclear submarine program.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. Pursuant to the 2013 Revised and Restated Stipulation and Settlement Agreement ("RRSSA"), I understand that DEF is requesting that the CR3 Regulatory Asset be placed into base rates. My testimony explains the process we used to transition CR3 from an operating nuclear plant to a decommissioning organization, including various NRC submittals intended to reduce the regulatory compliance costs. My testimony supports the prudence of costs that have been charged to the CR3 Regulatory Asset since February 5, 2013, specifically portions of the following categories listed on Exhibit 10 to the RRSSA: line 2 (Electric Plant in Service), line 8 (delam repair project), line 9 (License Amendment Request), line 11 (Fukushima), line 12 (building stabilization project), line 13 (Other – CWIP), and line 16 (deferred expenses).

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (TH-1), decommissioning transition organization ("DTO") organizational chart;
- Exhibit No. __(TH-2), new SAFSTOR organization chart;
- Exhibit No. __ (TH-3), a list of the License Amendment Requests ("LARs") completed and submitted to the NRC;
- Exhibit No. __ (TH-4), a chart showing staffing reductions since February 2013;
- Exhibit No. __ (TH-5), Exhibit 10 to the RRSSA; and
- Exhibit No. __ (TH-6), list of projects that make up "Other CWIP."

These exhibits were prepared by the Company, and they are generally and regularly used by the Company in the normal course of its business, and they are true and correct to the best of my information and belief.

Q. Please summarize your testimony.

A. After the Company's decision to retire CR3, DEF immediately began work to transition the site from an operating site into decommissioning. DEF also made several submittals with the NRC to reduce the scope and costs of compliance with certain regulations. This work allowed DEF to reduce staffing levels at the site. DEF also closed out projects that had been ongoing at the time of the retirement announcement. DEF initiated the Building Stabilization Project shortly after the announcement. The project was needed to ensure that the containment building would remain stable throughout the up to 60 year decommissioning process. This project was completed ahead of schedule and under budget.

Through these efforts, as more fully described below, DEF minimized costs that would have otherwise been charged to the CR3 Regulatory Asset. DEF also prudently incurred costs to ensure a safe transition to decommissioning mode.

III. NUCLEAR DECOMMISSIONING TRANSITION ORGANIZATION AND NRC LICENSE FILINGS.

Q. What did DEF first do to transition the site after the Company announced the retirement of CR3 on February 5, 2013?

A. DEF first developed a plan to define the process of transitioning from an operating plant to a decommissioning plant. That plan implemented actions which streamlined work processes, eliminated work associated with equipment not needed for decommissioning, and designed a new organization to replace the operational organization. The new organization was called the Decommissioning Transition Organization ("DTO"). This organization was responsible for maintaining and simplifying the structures, systems and components ("SSC") necessary for the safe storage of spent nuclear fuel while continuing to comply with all nuclear security and other license requirements. To accomplish this the organization prepared and submitted various decommissioning filings with the NRC. Among these were the Post Shutdown Decommissioning Activities Report ("PSDAR") which contains the decommissioning plan, schedule and a detailed cost estimate. Additional filings, called license amendment requests ("LAR"), were submitted to support the regulatory transition to decommissioning. Engineering efforts were necessary to facilitate the simplification or abandonment of plant systems not needed in decommissioning. Other actions reduced or eliminated legacy radioactive and hazardous waste that would have needed to be stored on site. Processes were developed that allowed the reduction in staff necessary to support the plant's needs. The DTO was fully operational in June 2013. The DTO organization chart is attached as my Exhibit No. ___ (TH-1).

Q. You mentioned that the DTO assisted with the preparation of the PSDAR. What is a PSDAR?

A. The purpose of the PSDAR is to provide the NRC and the public with a general overview of the licensee's proposed decommissioning activities and to inform the NRC staff of the licensee's expected activities and schedule so that the staff can plan for inspections and make decisions about its oversight activities. The PSDAR is also a mechanism that informs the public of the proposed decommissioning activities before the conduct of those activities. The PSDAR also includes an updated decommissioning cost estimate ("DCE") performed in support of the decontamination and dismantlement activity schedule contained in the PSDAR.

Regulation 10 CFR 50.82(a)(4)(i) requires the licensee, DEF, to submit a PSDAR to the NRC either before or not later than 2 years after permanent cessation of operations. The permanent cessation of operation of CR3 was established in February 2013 and the PSDAR was submitted to NRC in December 2013 with a copy submitted to the State of Florida. DEF made the filing ahead of the NRC schedule to get access to the Nuclear Decommissioning Trust ("NDT") as soon as possible. The decommissioning cost study filed in the PSDAR was then filed on March 21, 2014 with the FPSC in Docket No. 140057 and approved on December 22, 2014 in Order No. PSC-14-0702-PAA-EI.

Q. Briefly, what was the result of the PSDAR filing?

A. The PSDAR showed that, using the Safe Storage ("SAFSTOR") decommissioning method (sixty years), the NDT would be adequately funded to support the decommissioning activities. The CR3 decommissioning plan uses the full 60 years allowed by regulation to achieve license termination. The basic plan is to move the spent nuclear fuel to dry storage by 2019, place the power plant in a dormant condition, support the Department of Energy ("DOE") efforts to transfer the spent nuclear fuel to a DOE facility by 2036, and decontaminate and demolish the plant between years 2069 and 2073. The plant license will be terminated in 2073 and final site restoration will be completed in 2074.

After DEF filed the PSDAR, the NRC made the document available to the public for comment. The NRC conducted a public meeting in January 2014 in Crystal River, Florida. The NRC staff reviewed the public comments and the document and concluded that the PSDAR met all valid requirements and that no changes were necessary. Ninety days after the submittal of the PSDAR and the DCE, DEF had access to the NDT funds.

Q. What other work was DEF performing while the PSDAR was being prepared and considered by the NRC?

A. DEF completed the containment stabilization project during this same time period. In addition, DEF closed many in-flight projects and projects that had been delayed until the Company made the decision to repair or retire CR3. This work is discussed in greater detail in section IV below. DEF continued to retire SSCs not needed for decommissioning and simplify or eliminate program and procedural requirements to reduce the staff size. DEF also initiated and completed many plant modifications to reduce the size of the staff needed for decommissioning. For example, several underground pipes were permanently sealed and many delay barriers were installed throughout the plant which allowed a sizable reduction in the site security force.

The Company also installed two new plant systems, a new chill water system and a new seawater pump, that supported the permanent shutdown of several large plant systems. The Company simplified the plant alternating and direct current distribution systems. These changes allowed the Company to reduce the number of operations, maintenance, and engineering personnel needed at CR3. DEF also initiated a radioactive waste shipping project to permanently remove containment equipment and tools no longer needed to support decommissioning. This project further reduced the number of radiation protection personnel needed at the site.

Finally, DEF initiated an Investment Recovery Project to manage the disposition of CR3 assets to maximize value for DEF's customers. Those efforts are described in the testimony of Mr. Mark Teague.

Q. Does DEF plan to utilize the DTO organization while decommissioning is completed at CR3?

A. No, the DTO is a temporary organization intended to transition the site from operating to decommissioning. In early 2014, the management team completed the design of the first dormancy organization, called the SAFSTOR organization, that will become effective in July 2015. The staffing selections for the SAFSTOR organization was completed in October 2014. An organization chart for the new SAFSTOR organization is attached as Exhibit No. __ (TH-2).

Q. Why did it take more than a year after the retirement date to define the SAFSTOR organization?

A. Typically, the retirement date for a nuclear unit is known years in advance and a site can begin planning for the transition before the retirement, in parallel with operation of the unit. However, given that the CR3 retirement was unexpected, DEF did not have the ability to pre-plan. Despite this inability to plan while the plant was still in operation, DEF designed and implemented the DTO in less than five months after the retirement announcement. It based this work on benchmarking, lessons learned, and operating experience from other nuclear operators.

Q. Did DEF make any filings with the NRC to further reduce costs at the site?

A. Yes, DEF submitted several LARs in 2013 to the NRC. Several of those filings were intended to reduce the costs incurred by DEF by alleviating NRC requirements. A list of the LARs DEF submitted is attached as my Exhibit No. __ (TH-3).

One of the filings included on this exhibit is the permanently defueled emergency plan ("PDEP"), which DEF filed on September 26, 2013. The NRC approved DEF's PDEP on March 31, 2015. The PDEP was fully implemented on April 8, 2015, which means that DEF initiated the implementing procedures and retired old procedures. The PDEP approval also allowed DEF to shut down the off-site facilities, and reduce the level of support DEF supplies to various state and local governments. With this approval, DEF no longer has to fund the emergency planning function for Levy County, Citrus County, FEMA, and the state of Florida. The PDEP approval will facilitate further staff reductions at CR3.

Q. Please describe DEF's workforce reduction strategy.

A. To efficiently and effectively minimize the workforce at CR3 following retirement, plant and human resources management met in February 2013 to determine the policies that would be needed to transfer employees within the Company, outplace employees from the Company and place employees in the new organization at CR3. DEF first determined whether any employees could be re-deployed immediately. Although DEF was not operating CR3 at the time of the retirement decision, the NRC still imposes many regulations and requirements that required substantially all of the workforce to remain on site. However, for those employees who could immediately be reassigned from CR3, DEF either offered redeployment of other positions within Duke Energy or voluntary severance from the company. As explained above, the DTO organization was designed and approved in April 2013, and was staffed and in effect on June 3, 2013. The selection process consisted of allowing each impacted employee to specify their employment preference with the choices of remain at CR3 in the DTO, redeploy within the Company or leave the Company. The Company was able to grant the employees first preference in practically all cases. The DTO was filled with the employees that made staying at CR3 their highest priority. This assured a work force committed to formulating and implementing the decommissioning activities.

As various work was completed on projects and NRC submittals, the Company was able to reduce the size of the DTO as described above. The SAFSTOR organization will have substantially fewer employees than the DTO organization. Specifically, not counting security, there were approximately 590 DEF employees at CR3 in February 2013, and DEF reduced that number to 300 employees in July 2013 and 140 employees in December 2014. By July 2015, DEF plans to only employ 75 employees at CR3. Please see attached Exhibit No. __ (TH-4), a chart showing staffing reductions since February 2013.

In addition to the decrease in the number of Duke Energy employees at CR3, we also completed physical plant changes to eliminate the need for armed security officers to monitor specific locations of the plant. In February 2013, there were 212 officers and 12 staff positions within the CR3 security organization. In December 2013, there were 171 officers and 7 staff positions. These reductions were possible because DEF made physical changes to the site, such as the permanent plugging of the major water systems connecting the Gulf of Mexico to the plant and the permanent blocking of an access portal to plant vital areas.

Q. Has DEF done any benchmarking with other nuclear units in decommissioning mode to determine best practices?

A. Yes. The company did extensive benchmarking at several decommissioned plants including the Zion station in Illinois and the Kewanee station in Wisconsin during the design of the DTO in early 2013. Other plants were also contacted. These benchmarking activities currently also include the San Onofre Nuclear Generating Station (SONGS) in California and the Vermont Yankee station. In addition to bench-marking, we have established functional working groups from each station, such as licensing, security and radiation protection, that exchange information and lessons learned routinely. The company is also engaged with the Nuclear Energy Institute committees associated with decommissioning activities.

Q. How did DEF set up the charging to ensure that costs were properly allocated between the CR3 Regulatory Asset and the NDT?

A. The Company established a cost breakdown structure to ensure the complete and accurate documentation of costs as incurred. This is accomplished by using the enterprise financial systems to track costs using the Project Accounting Code Block Element to track specific line items that map to either the Regulatory Asset or Nuclear Decommissioning Trust. The projects were linked to individual general ledger accounts ensuring actual costs attributable to the CR3 Regulatory Asset and Decommissioning efforts are recorded separate and apart.

IV. EXHIBIT 10 LINE ITEMS

Q. Are you familiar with Exhibit 10 to the RRSSA?

A. Yes, although I was not directly involved with its development. I do have responsibility for several projects that resulted in costs being charged to some of the line items included in Exhibit 10. Specifically, those line items are: line 2 (Electric Plant in Service), line 3 (Accumulated Depreciation), line 8 (delam repair project), line 9 (License Amendment Request), line 11 (Fukushima), line 12 (building stabilization project), line 13 (Other – CWIP), and line 16 (deferred expenses). For ease of reference, Exhibit 10 is attached to my testimony as Exhibit No. __ (TH-5).

Q. Regarding line 2, Electric Plant in Service, and line 3, Accumulated Depreciation, what costs were credited after the retirement date?

A. As part of the CR3 retirement, several buildings and structures no longer needed by CR3 were transferred to other business units within Duke Energy. The ownership transfer reduced the regulatory asset by the structure's gross plant balance net of the accumulated depreciation. Specifically, DEF transferred an administrative building, a warehouse, conference building, and a training facility from CR3 to Fossil Operations for their continued use. Two structures at the CR3 waterfront were transferred to Duke Energy project management and construction for use associated with the proposed Citrus County Combined-Cycle natural gas plant. Finally, the emergency offsite facility and simulator were transferred to non-utility property. These transfers totaled approximately $16 million (retail).

Q. Regarding line 8, Delam Repair Project, what costs were incurred and charged after the retirement date?

A. DEF incurred approximately $5 million (system) in costs associated with the close-out of this project after February 5, 2013. These costs consisted of demobilization, clean-up and contract closure.

Q. What is the License Amendment Request referenced in line 9 of Exhibit 10?

A. This refers to the work DEF was doing on the license renewal request. This project would have extended the CR3 operating license an additional 20 years out through 2036. Much of the project was the engineering and licensing work necessary to support the extended operating period. Once the retirement decision was made, DEF withdrew its request with the NRC to extend the license, and incurred approximately $720,000 (retail) for project close out.

Q. Please explain line item 11, Fukushima.

A. On March 11, 2011, following a major earthquake and tsunami, three Fukushima Daiichi nuclear reactors in Japan lost power supply and cooling, resulting in a nuclear accident and melting of the three nuclear cores. As a result of this nuclear accident, the NRC formed a task force to review the circumstances of the event to determine what lessons could be learned. The NRC approved a series of recommendations made by the task force to enhance U.S. reactor safety. As the NRC issued orders and rulemaking regarding the subject, DEF incurred costs to analyze and determine the applicability of the new requirements on CR3. These new requirements consisted of reanalysis of the impacts of floods and seismic events at CR3. After the retirement decision, DEF was granted relief from the orders given the permanently shutdown state of CR3. Accordingly, since February 5, 2013, DEF incurred approximately $1.2 million (retail) in project close out costs related to Fukushima.

Q. What is the Building Stabilization Project on line 12?

A. The scope of the building or containment stabilization project included the implementation of physical work for the purpose of stabilizing the structure. Completion of the work resulted in a safe industrial work site as well as a structure with long term predictable behavior that supports fuel storage activities and preserves the capability of the reactor building polar crane to safely move heavy loads in the future. There were three phases of the project. The first phase included the de-tensioning of hoop tendons necessary to reduce the stresses in building to meet the applicable design code requirements. The second phase included applying a weatherproofing material to the external areas of the building that were delaminated. The third phase included the installation of a restraint system on the two damaged bays of the building. The physical work was completed in 2014.

Q. What was the budget for the project and how did the actual cost compare to that budget?

A. DEF budgeted $35 million to complete this project, but DEF came in under budget at $29 million (system). This project has been completed and was closed in March 2015.

Q. Did DEF encounter any issues with completing the containment stabilization project on time and in accordance with the original scope?

A. No, DEF completed the entire work scope and completed the project under budget and earlier than scheduled. DEF performed the work in accordance with the designed engineering change packages.

Q. What projects are included in Line 13, Other-CWIP, of Exhibit 10?

A. DEF incurred $53 million in connection with a number of projects that had been in-flight, suspended, or delayed during the time in which the Company considered repairing the delamination. These projects consisted of work that was required by NRC regulations. Examples include the NFPA 805 projects associated with the CR3 fire protection program, and several equipment reliability improvement projects, such as the control complex chiller and radiation monitoring replacement projects. Once the retirement decision was made, these projects were closed. A detailed list of the projects that make up the $53 million total is attached to my testimony as Exhibit No. __ (TH-6).

Q. How much did DEF incur in operations and maintenance ("O&M") costs from February through December 2013 that were included on Line 16, Deferred Expenses?

A. Of the total deferred expenses on line 16, which includes O&M, payroll tax and property tax, DEF incurred approximately $95 million for O&M and payroll tax. The O&M costs were minimized through steep staffing reductions described earlier in my testimony. Ms. Olivier's testimony explains the savings recorded in the regulatory liability pursuant to the RRSSA.

V. COMPLIANCE WITH 2013 RRSSA AND CONCLUSION

Q. Do you believe that DEF has satisfied its burden in the 2013 RRSSA to "minimize the future costs of the CR3 Regulatory Asset and use reasonable and prudent efforts to curtail future avoidable costs"?

A. Yes. As demonstrated above, DEF worked efficiently to transition from an operating unit to a site in decommissioning mode. It closed out various projects that were no longer needed given the decision to retire. DEF identified and expeditiously pursued opportunities with the NRC to limit and eliminate regulatory requirements that resulted in direct cost savings. All of these actions resulted in reduced workforce and cost savings to customers.

Q. Does this conclude your testimony?

A. Yes, it does.

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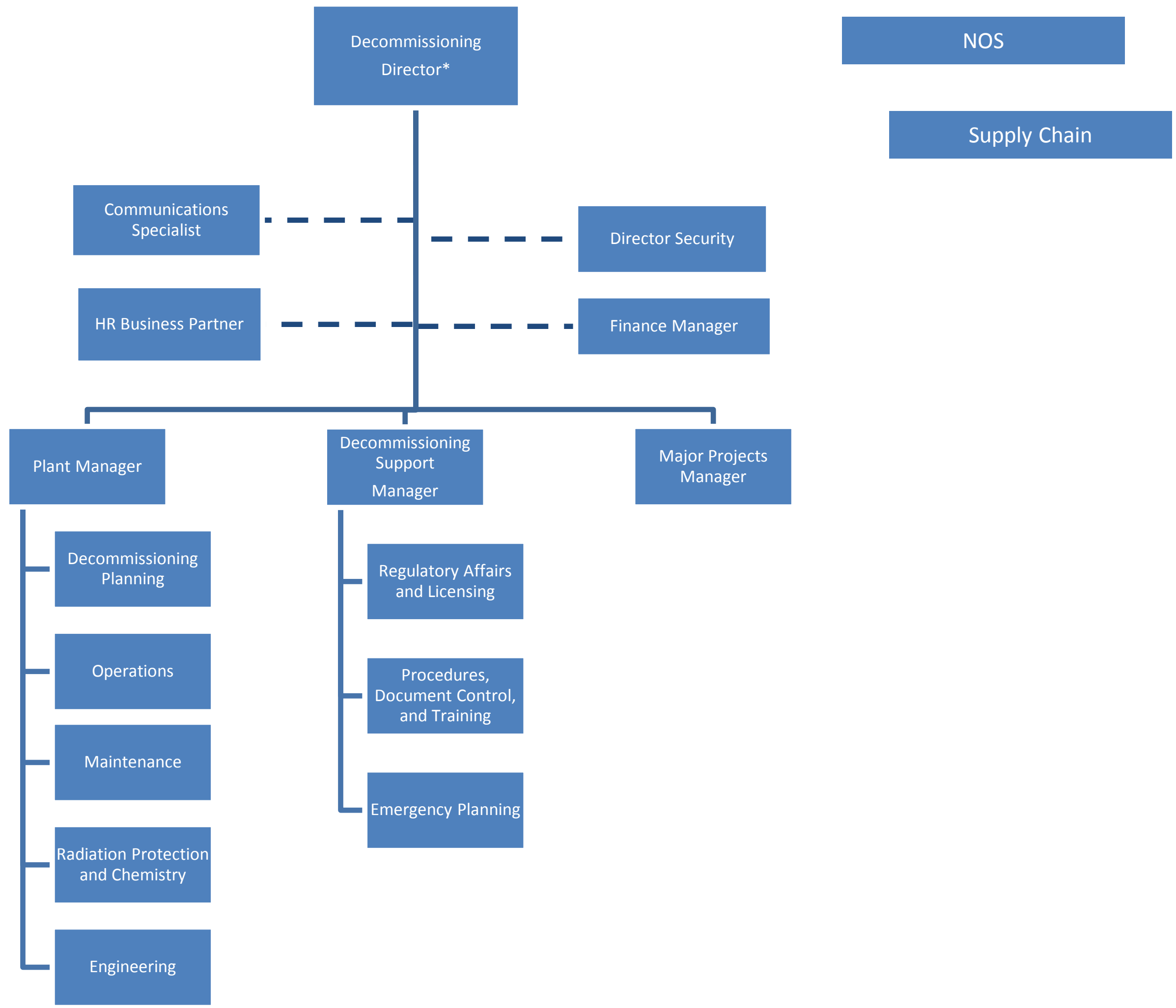
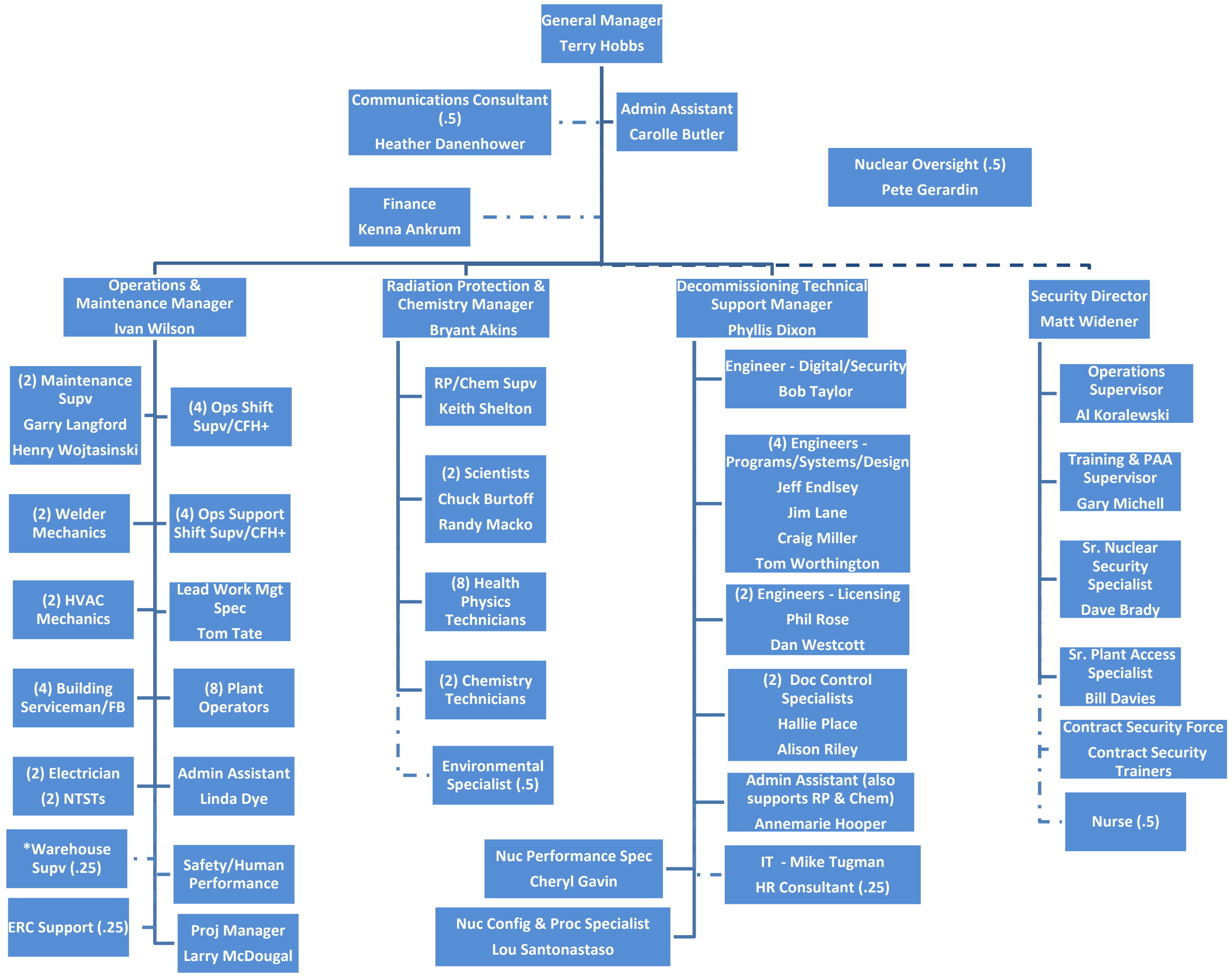
Exhibit No. ___ (TH-1)
Page 1 of 1

DTO Organizational Chart



Docket No. ____________
Witness: Hobbs
Exhibit No. ___ (TH-2)
Page 1 of 1

SAFSTOR I - effective on or before July 1, 2015



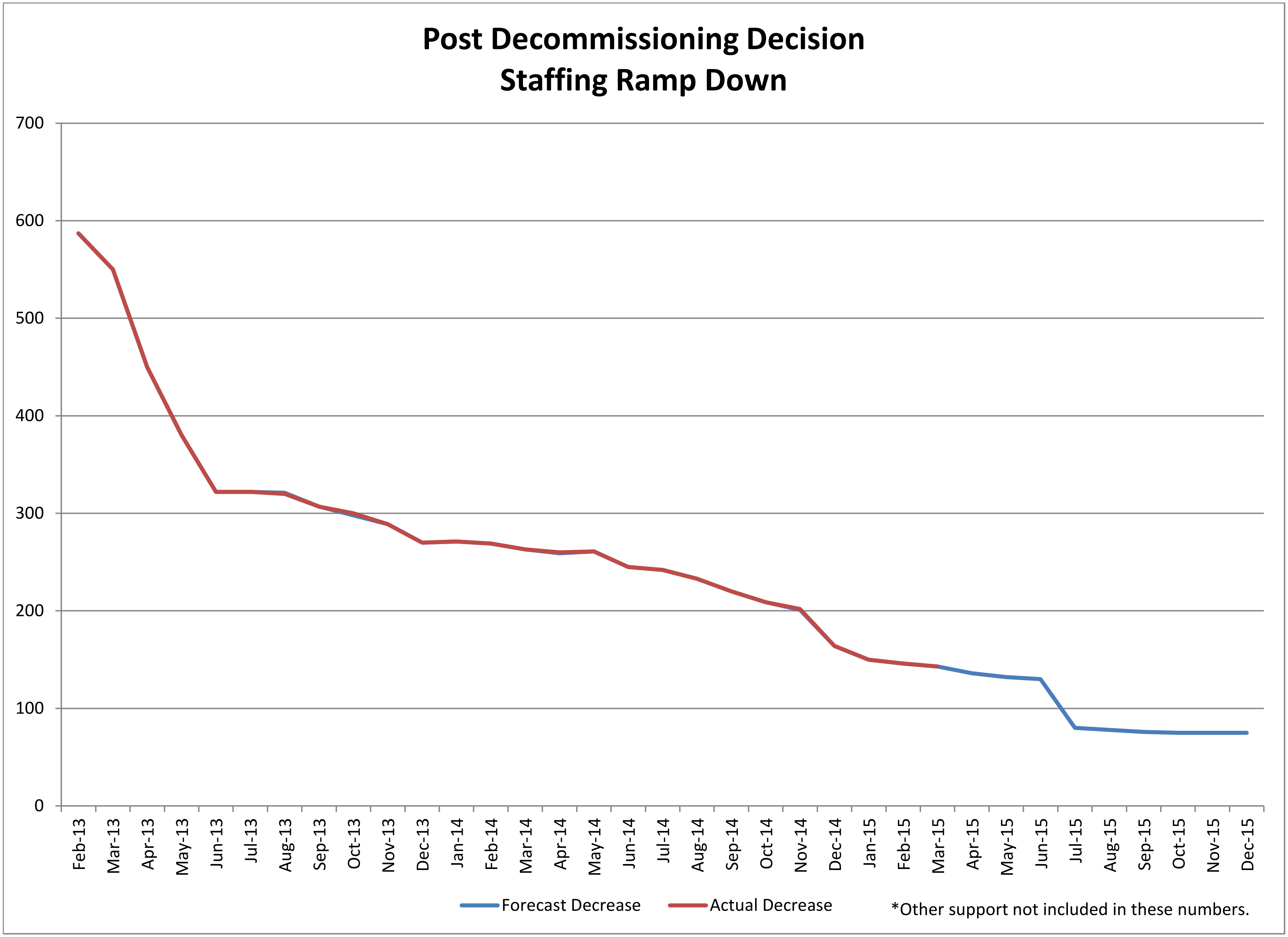
+Warren Deagle, Tony Doruff, Bryan Ferguson, Mark Garrison, John Jernigan, Larry Moffatt, Randy Oates

*Supply Chain includes storekeeper (.5), Contracts Specialist (.25), Procurement Specialist (.25) and QC Inspector (.25)

Exemption	Submitted	Status	Emergency Preparedness	Security	Decommissioning Funding	Liability Insurance
Exemption Request from 10 CFR 73 Physical Security Requirements (to Allow Certified Fuel Handler to Suspend Security Measures)	July 17, 2013	Exemption granted by letter dated December 9, 2014		X		
Permanently Defueled Emergency Plan and Request for Exemption to Certain Radiological Emergency Response Plan Requirements Defined by 10 CFR 50	September 26, 2013	Exemption granted by letter dated March 30, 2015	X			
Request for Exemptions from 10 CFR, Appendix B, General Criteria for Security Personnel (Annual Force-on-Force Exercise)	January 15, 2014	Withdrawn by CR-3 by letter dated June 30, 2014		X		
Request for Exemptions from 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) (Decommissioning Trust Fund Use)	March 28, 2014	Exemption granted by letter dated January 26, 2015			X	
Exemption Request from 10 CFR 140.11 Regarding Minimum Requirement for Offsite Liability Insurance and Release from Participation in the Secondary Retrospective Rating Pool	May 7, 2014	Exemption granted April 27, 2015				X

License Amendment Request	Submitted	Status
License Amendment Request #313, Revision 0: Revision to Improved Technical Specifications Administrative Controls for Permanently Defueled Conditions	April 25, 2013	License Amendment No. 244 granted by letter dated July 11, 2014
License Amendment Request #314, Revision 0: Facility Operating License for Change of Licensee Name	March 20, 2013	License Amendment No. 243 granted by letter dated October 18, 2013
License Amendment Request #315, Revision 0: Permanently Defueled Emergency Plan and Emergency Action Level Scheme, and Request for Exemption to Certain Radiological Emergency Response Plan Requirements Defined by 10 CFR 50	September 26, 2013	License Amendment No. 246 granted by letter dated March 31, 2015
License Amendment Request #316, Revision 0: Revise and Remove License Conditions and Revision to Improved Technical Specifications to Establish Permanently Defueled Technical Specifications	October 29, 2013	Pending
License Amendment Request – Cyber Security Plan Implementation Schedule Milestone 8	December 19, 2013	License Amendment No. 245 granted by letter dated December 19, 2014
Application for Order Approving Transfer of License and for Conforming License Amendment Pursuant to 10 CFR 50.80 and 10 CFR 50.90	November 7, 2014	Pending
License Amendment Request # 317 Revision to Improved Technical Specifications Administrative Controls Section to reflect organizational and title changes being made as part of the transition to the SAFSTOR organization.	May 7, 2015	Pending

Docket No.______________
Witness: Hobbs
Exhibit No. ____(TH-4)



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	$__	$__

category

a The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs except that the Intervenor Parties retain the right to challenge whether DEF took reasonable and prudent actions to minimize the future CR3 Regulatory Asset value after February 5, 2013 and to sell or otherwise salvage assets after February 5, 2013 that would otherwise be included in the CR3 Regulatory Asset.

b The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover these costs.

c The Intervenor Parties fully and forever waive, release, discharge and otherwise extinguish any and all of their rights to contest DEF's right to recover costs incurred by the Company before February 5, 2013. The Intervenor Parties retain the right to challenge the prudence of any costs incurred after and applicable to the period after February 5, 2013 that are submitted for recovery by the Company.

d The Intervenor Parties retain the right to challenge the prudence of any costs submitted for recovery by the Company.

e The Intervenor Parties retain the right to verify that the Company has complied with paragraph 5b of the Revised and Restated Settlement Agreement.

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

Exhibit 10 "Other CWIP" Proejcts (Summary)
April 2015

Project Name	Apr-15
Retail PS&I Account 183 - Nuclear Fire Protection Act 805	13,192,286
CC Chiller Replacement	6,098,282
IT/Software	5,889,077
Hot Leg Alloy	5,822,241
RMA Replacements	5,564,764
Raw Water Pump	4,939,132
NFPA 805 Fire Protect.	2,601,986
Motor Rewind	1,838,707
Radio System	1,477,822
Water System Resin	1,403,019
Circ Water System	1,304,263
Retail PS&I Account 183 - CREC	797,633
Switchboard Relays	656,833
Turbine Controls	576,949
Reactor Cooling System	560,199
Feedwater Pump Filter	461,181
Security	423,852
CW Pipe Plugs	328,400
NSOC HVAC	321,144
Feed Pump Turbine Motors	315,056
Admin Trailer	304,066
Ultrasonic Flow Meter	294,315
Chemical Feeding System	282,707
Motor Control Switches	254,679
Retail PS&I Account 183 - Pipeline	243,386
Magnesium Motor Rotor	196,663
Turbine Building Circuits	146,110
LEFM Replacement	124,851
Seawater Pump Valve	122,252
Roof Handrails	79,078
Intake Canal	74,183
Volt Meters	69,144
Outage Storage Building	66,793
Retail PS&I Account 183 - Relay Single Phase Voltage Prot	51,288
Turbine Pipe Coating	46,204
Gas Monitors	43,990
Turbine Building Roof	43,409
Instrument Air Compressor	42,809
Snubber	33,807
Turbine Building Piping	29,436
Heat Exchangers	26,263
DC System Vent Valves	21,262
Cooling System Valves	21,093
Sump Pump	20,375
Metering	9,066
Media Scanning Kiosks	6,201
Inst Gen Monitoring @Nuclear	3,401
Air Handling Replacement	2,786
Walkway Covering	1,518
Remote Shutdown Monitor	(463)
Reactor ION Chamber	(49,170)
Nuclear outage reserve	(1,826,174)
Salvage	(2,144,585)
Total:	**53,213,568**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Duke Energy Florida, Inc. For Approval to Include In Base Rates the Revenue Requirement for the CR3 Regulatory Asset	Docket No. ____________ Submitted for Filing May 22, 2015

NOTICE OF INTENT TO REQUEST CONFIDENTIAL CLASSIFICATION REGARDING PORTIONS OF DUKE ENERGY FLORIDA, INC.'S TESTIMONY AND EXHIBITS

Duke Energy Florida Inc. ("DEF" or the "Company"), pursuant to Section 366.093, Florida Statutes (F.S.), and Rule 25-22.006, Florida Administrative Code (F.A.C.), submits this Notice of Intent to Request for Confidential Classification of confidential portions of DEF's testimony and exhibits filed contemporaneously with this notice. Confidential documents have been filed with the clerk and the redacted versions have been filed as part of DEF's Petition and Testimony filing. Specifically, portions of DEF's testimony and exhibits contain confidential business information relating to the disposition of nuclear fuel assets. The disclosure of that information to the public would adversely impact DEF's competitive business interests. Disclosure of that information to the public would also adversely impact the competitive business interests of parties purchasing DEF's assets.

A highlighted copy of the above-referenced confidential testimony and exhibits, labeled as Exhibit A, has been filed under a separate cover letter.

Pursuant to Rule 25-22.006(3)(a)(1), PEF will file its Request for Confidential Classification for the confidential information contained herein within twenty-one (21) days of filing this request.

RESPECTFULLY SUBMITTED this 22nd day of May, 2015.

s/ Dianne M. Triplett
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