FLORIDA POWER & LIGHT COMPANY
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ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/CAMR/CAVR FILING
APRIL 2, 2008

Per Order No. 07-0922-FOF-EI, issued on November 16, 2007, the discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR)/ BART Projects.

Clean Air Interstate Rule (CAIR) Compliance Project Update:

SJRPP SCR and Ammonia Injection Systems - The installation of Selective Catalytic Reduction Systems (SCR) and Ammonia Injection Systems on St. Johns River Power Park (SJRPP) Units 1 and 2 remains at $45.5 million. Construction of the SCRs is on schedule with the Unit 2 SCR nearing completion and Unit 1 ductwork fabrication and installation underway.

Estimated CAIR O&M expenses for 2008 and 2009 are $360,000 and $600,000 respectively. Estimated annual O&M expenses beginning 2012 are $1.2 million (FPL 20% ownership). O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment.

Scherer SCR and FGD - Current capital cost estimates for the installation of Wet Flue Gas Desulfurization (FGD) Scrubber and Selective Catalytic Reduction System (SCR) with Ammonia Injection System on Scherer Unit 4 is $392.6 million. The construction of plant infrastructure required for the reagent supply and waste by-product removal from the emission controls being implemented at Plant Scherer is currently underway and FPL's share of the costs for those facilities needed for support of Unit 4 are included in the project costs. Specific engineering and design work on the FGD & SCR for Unit 4 has begun and costs for these activities will be presented for review and recovery. The Scherer Unit 4 control installation costs were evaluated to ensure that the proposed project remains a prudent expenditure for FPL's customers, through an analysis that included projected future costs for CO2 and other emissions from Electric Generating Units (EGUs) as well as the project's emission control costs. The results of the study indicate that customers are projected to receive substantial savings though the implementation of the controls rather than prematurely shutting down Unit 4 in order to avoid incurring compliance costs.

Georgia Power Company has not provided O&M estimates for the SCR and FGD for 2012 and beyond. O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

800 MW unit cycling project - The 800 MW unit cycling project is currently underway, with anticipated completion in 2010 at the Martin and Manatee Plants. Mr. LaBauve introduced this project in his September 1, 2006 testimony and had subsequently provided an estimate for implementation of the projects with a total capital cost of $103.8 million. Project work at the Martin and Manatee Plants for 2008 will include condenser tube replacements, steam turbine projects, boiler projects, and balance of plant changes for one unit at each plant for a total estimated capital cost of $40.1 million and an estimated O&M expense of $1.7 million. Similar project work for the remaining 800 MW units at Martin and Manatee is planned for 2009 with an estimated Capital Cost of $41.2 million and an O&M cost estimated at $2.1 million. FPL plans to complete the project work at the Manatee and Martin plants in 2010 with an estimated total project cost of $104.8 million in Capital costs and $5.3 million in O&M expenses.

The Reburn and Low NOx Burner projects at Cape Canaveral, Port Everglades, Turkey Point and Putnam plants are still on hold.

Rule Challenge - FPL's appeal of the Division of Administrative Hearings (DOAH) ruling in favor of the Florida Department of Environmental Protection (FDEP) was denied on November 7, 2007. The Third District Court of Appeals ruled that the DOA was justified in determining that the FDEP CAIR rules were a valid exercise of delegated legislative authority. FPL is participating with other litigants in the federal appeal of the CAIR rule where the court has established a schedule for briefing the issues. Initial briefs were filed March 5, 2007 by FPL. In July 2007 FPL attorneys participated in the development of "reply briefs" to other litigants. Final briefs have now been submitted. Oral arguments were presented to the DC Circuit Court on March 25, 2008 and a final decision by the court is expected later in 2008.

CEMS Plan for GTs - The Low Mass Emitting (LME) Continuous Emissions Monitoring Systems (CEMS) have been installed at the Fort Myers, Port Everglades, and Fort Lauderdale Gas Turbine Parks as required by the Clean Air Interstate Rule (CAIR). The entire capital project was completed in 2007 with no additional capital expense expected at the current time.

During 2008, the CEMS systems must be tested to verify that they meet the EPA and DEP performance specifications for the CAIR program. It is anticipated that $65,000 will be spent on these testing activities. The testing activities will be required every five years at current operating conditions. In addition, it is anticipated that $5,000 per year will be spent on routine maintenance of the CEMS systems. It should be noted that the LME option is available for a gas turbine only if its emissions remain under EPA-prescribed thresholds. If any gas turbine emits more than 50 tons of NOx or 25 tons of SO2 in a given calendar year, the testing for that gas turbine will be required every year, instead of every 5 years. That would increase the testing costs for non-qualifying gas turbines to $65,000 per year, along with $5,000 per year for maintenance.

Purchases of allowances - Future purchases of allowances will be made as needed for compliance with the annual and ozone season NOx requirements. FPL has revised its estimate to reflect the changes which were made in the projected operation of FPL fossil generating units and purchase power. Reductions in NOx emissions from the implementation of the 800 MW unit cycling project have been included in the forecasted unit emissions. FPL's revised estimate projects a shortage of both NOx Ozone Season and NOx Annual Allowances for the initial 2009 and 2010 compliance years, but projects an excess of annual NOx allowances in subsequent years. FPL has projected Ozone Season NOx Allowance compliance costs of $1.2 million and $0.3 million in 2009 and 2010 respectively. FPL also projects Annual NOx Allowance compliance costs of $10.3 million and $2.7 million for 2009 and 2010 respectively. FPL projects an excess of both NOx Ozone Season and NOx Annual Allowances beginning in 2011 and continuing in subsequent years as a result of reductions in system emissions as the West County Energy Center Units come on line. FPL has estimated an average annual excess of approximately $14.8 Million for the 2011 through 2020 period. Please note, however, that FPL's actual NOx allowance requirements depend upon a number of factors that are difficult to predict, and it is possible that FPL's actual allowance requirements will differ significantly from the future year allowance projection. It is also likely that the future actual prices for the NOx allowances will differ substantially from the projected prices.

Climate Change - FPL continues to monitor the development of CO2 compliance policy and regulation as it relates to electric generating facilities. FPL believes that the future implementation of CO2 regulation on power plants may become an important consideration in the evaluation and implementation of pollution controls on generating units including those required to comply with CAIR and the Georgia Multi-pollutant rule. On July 13, 2007 Governor Charlie Christ signed three Executive Orders initiating Florida's energy policy: Executive Order 07-126, titled "Leadership by Example: Immediate Actions to Reduce Greenhouse Gas Emissions from Florida State Government"; Executive Order 07-127, "Immediate Actions to Reduce Greenhouse Gas Emissions within Florida"; and Executive Order 07-128, "Florida Governor's Action Team on Energy and Climate Change." Executive Order 07-127 directed the FDEP to initiate rulemaking to establish maximum emission levels of greenhouse gases for electric utilities. The standard will require a reduction of emissions to 2000 levels by 2017, to 1990 levels by 2025, and by 80 percent of 1990 levels by 2050. The FDEP proposes to create new rule Chapter 62-285, F.A.C., Greenhouse Gas Emissions Reduction, and develop new Rule 62-285.300, F.A.C., Electric Utility Greenhouse Gas Reduction Program, to accomplish this purpose. The effect of the rule would be to reduce greenhouse gas emissions from EGUs. The FDEP held two workshops in 2007 for the development of rule 62-285 to implement the Governor's executive order 07-127 to provide an opportunity for comments and recommendations at the outset of the proposed rule development projects. The FDEP did not offer any rule proposals at these workshops. FPL is participating in the Rule Development Workshops to represent the interests of its customers.

Specific rulemaking has not been proposed by the FDEP detailing how electric utilities would be impacted by the new rule, including the point of regulation for the Greenhouse Gas emissions. FPL has evaluated its present CO2 emissions from electric generation including the projected emissions through 2017. Future reductions of CO2 emissions may be required depending on the final rule. FPL is currently evaluating strategies which can be implemented to reduce CO2 emissions which include, but not limited to: expansion of nuclear generation; expanded use of Demand Side Management and Energy Efficiency programs; repowering of existing fossil generating plants; an increased use of renewable generation that includes solar, wind, and biomass; Carbon Capture and Sequestration at fossil generating plants. As FPL evaluates its needs for additional generating sources in its annual planning cycle during the preparation of the Ten Year Site Plan, the Greenhouse Gas emissions from existing and new sources will be evaluated for compliance with the targets established within the Governor's Executive Order 07-127.

FPL has not proposed a specific project at this time for compliance with the Governor's Executive Order. FPL anticipates that if reductions are required to comply with the targets established in a new rule to implement the order, specific projects may be required to reduce emissions below the current projected emissions from the generation of electricity to meet the customer demand. If FPL has to reduce emissions, specific projects will be identified to provide the reductions required to meet the CO2 targets. These will be provided to the Commission with the appropriate details and costs for review. FPL has conducted a review of the 800 MW cycling project, the Plant Scherer CAIR and Mercury controls, and the SJRPP CAIR and Mercury projects and has concluded that the continuation of the projects would be more cost effective than the alternative of discontinuing those projects.

Actual CAIR Capital expenses through 2007 are $26.1 million.

CAIR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2008**	**2009**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	17.0	7.9	45.5
Scherer-SCR/FGD	45.6	90.6	392.6
800 MW Unit Cycling - Martin	24.4	22.7	50.1
800 MW Unit Cycling - Manatee	15.7	18.5	54.7
CEMS at GTs	Capital project completed	Capital project completed	Capital project completed
Allowances	N/A	N/A	N/A
CO2 Compliance	Not yet available	Not yet available	Not yet available

Actual CAIR O&M expenses through 2007 are $1.8 million.

CAIR O&M COST ESTIMATES ($Millions)			
PROJECT	**2008**	**2009**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	.360	.600	$1.2 (2012+ annual operating costs are on-going)
Scherer-SCR/FGD	0	0	Not yet available
800 MW Unit Cycling – Martin	.890	1.1	2.4
800 MW Unit Cycling – Manatee	.842	1.016	2.9
CEMS at GTs	0.070	0.005	0.075
Allowances	0	11.5	N/A
CO2 Compliance	Not yet available	Not yet available	Not yet available

Note: FPL is projecting $3.0 million for purchases of allowances in 2010.

Clean Air Mercury Rule (CAMR) Compliance Project Update:

On February 8, 2008 the U.S. District Court of Appeals ruled that EPA's delisting rule for Mercury emissions from coal-fired EGUs utility boilers and the Clean Air Mercury Rule were unlawful and vacated both rules. EPA may appeal the decision of the Court of Appeals before the Supreme Court prior to March 24, 2008. The vacature of the CAMR rule places in jeopardy the rules of many states, including Florida and Georgia that had been approved to implement the CAMR requirements using the federal rule as the enforceable standard.

The Georgia Environmental Protection Division (EPD) promulgated two major rules to implement mercury reductions within Georgia that included a rule to adopt the CAMR federal mercury cap and trade program: Rule 391-3-1-.02(15) – "*Georgia Mercury Trading Rule*" and a Georgia state specific Multi-pollutant rule: Rule 391-3-1-.02(2)(sss) – " *Multipollutant Control for Electric Utility Steam Generating Units*". The Multipollutant rule was promulgated to specify the implementation of specific air pollution control equipment for reductions in mercury, sulfur dioxide, and nitrogen oxides emissions from coal-fired EGUs. The rule requires controls to be implemented on specific EGUs within the state to control the emissions of Sulfur Dioxide (SO2), Nitrogen Oxides (NOx) and mercury (Hg). Section 4(i) of the Multipollutant Rule requires that Scherer Unit 4 may not be operated after April 30, 2010, unless it is equipped and operated with sorbent injection and a baghouse. A copy of the relevant sections of 391-3-1-.02(2) (sss) have been provided as Exhibit 1.

With the vacature of the Delisting rule EPA is now likely to proceed with evaluation and implementation of the existing rule requiring Maximum Available Control Technology (MACT) for mercury emissions from coal-fired EGUs. Prior to the implementation of the Delisting and CAMR rules the MACT analyses had determined that the use of sorbant injection systems were effective in the removal of mercury and established the CAMR Phase I and II mercury budgets based on the implementation of the technology on coal-fired EGUs by 2018. The Georgia Multipollutant rule requires that each of the four units at Plant Scherer implement a Sorbant injection system with a baghouse collection device for removal of mercury. Therefore, installation of the mercury controls that would have been needed to comply with the CAMR requirements remains necessary to comply with the requirements of the Georgia Multipollutant rule, so the vacature of CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. Installation of the Mercury Continuous Emissions Monitoring System (HgCEMS) that was planned to comply with CAMR likewise will be needed to comply with the monitoring and reporting requirements of the Multipollutant rule and ultimately to demonstrate compliance with monitoring of the final MACT rule. Specifically, FPL will comply with the mercury reduction requirements of the Georgia Multi-Pollutant rule using the following projects identified previously under CAMR:

1. Installation of Fabric Filter Bag House and Mercury Sorbant Injection System on Scherer Unit 4.
2. Installation of HgCEMS on Scherer Unit 4.
3. Installation of HgCEMS on SJRPP Units 1 & 2 that are currently under construction (certification testing and operation delayed until the monitoring requirements begin for Mercury MACT compliance.)

FPL has revised the cost estimates for the installation of mercury controls at plant Scherer as a result of estimated increases in labor and material costs.

FPL plans to petition the Commission for approval of a modification to its Clean Air Mercury Rule (CAMR) Project to recognize that the activities planned for Plant Scherer to comply with the now-vacated CAMR will be implemented instead to comply with the Georgia Multi-Pollutant Rule. FPL continues to believe that mercury controls being installed at Plant Scherer to comply with the Georgia rule will be equivalent to those which are likely to be required under a MACT rule. For the SJRPP units FPL, and majority owner JEA, had planned to comply with the Phase I of the CAMR through the co-benefits removal of mercury by the SCR and Scrubber for units burning bituminous coals. The planned addition of the SCR on both SJRPP units to comply with CAIR would achieve the co-benefit reductions as both units had been constructed with Scrubbers installed. FPL will evaluate the future mercury control requirements for Plant Scherer and SJRPP as the EPA reviews its options in response to the CAMR vacature. FPL and JEA will evaluate the appropriate technology for implementation at SJRPP to comply with a future Mercury reduction requirement.

Actual CAMR Capital expenses through 2007 are $6.0 million.

CAMR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2008**	**2009**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	.060	0	.475
Scherer-Sorbant Injection/Baghouse/ Mercury CEMS	40.0	49.5	99.6

Clean Air Visibility Rule (CAVR) / Best Available Retrofit Technology (BART) Project Update:

FPL has successfully demonstrated through modeling that all the applicable units under the particulate control portion of the BART regulations, with the exception of Turkey Point Units 1 & 2, do not cause a significant amount of particulate visibility impairment. Due to this demonstration, no further action will be required to comply with particulate emissions, except at Turkey Point Units 1&2.

Negotiations are continuing with the FDEP regarding Turkey Point Units 1 & 2. The last information provided to the FDEP revolved around two different compliance options for particulate control:

1. Installation of Electrostatic Precipitators (ESPs)
2. Alternative Emission Reduction Strategy
    a. Installation of modern multi-cyclone separators, and
    b. Switching to a lower sulfur fuel (1.0% to 0.7%)

FPL continues discussions with the FDEP to convince the agency that ESPs are not reasonable due to significant capital and on-going O&M costs. The multi-cyclone separators and fuel option provides more visibility improvement at a much lower overall cost.

The two projects compare as follows:

1. ESPs - $92 MM Capital with $13MM increased O&M/year
2. Alternative Emission reduction strategy - $7.3 MM Capital with $1.9MM increased O&M/Year

The FDEP's final decision is expected by May 2008. Once the final requirements have been determined, the required implementation date will not be until December 2013. However, installation will be conducted using a staged approach, with work done during the unit outages currently scheduled between now and 2013, in order to minimize effect on total system load and availability.

By December 2012, FPL will be required by the FDEP's Reasonable Further Progress rule to submit additional CAVR reduction evaluations for sulfur dioxide emissions from the following units:

1. Turkey Point Units 1 & 2
2. Port Everglades Units 3 & 4
3. Manatee Units 1 & 2

FPL is considering various option strategies to achieve the required reductions in sulfur dioxide emissions from these eight units cost-effectively. At this time the cost of compliance for the required sulfur dioxide emissions is not known. It should be noted that there is a potential that future sulfur dioxide emission controls required for CAVR compliance would provide co-benefit to the Company for compliance with CAIR.

Actual CAVR Capital expenses through 2007 are $0.0. Capital estimates for 2008 and beyond for Turkey Point Units 1 & 2 Particulate Control efforts and SO2 reductions at Turkey Point Units 1&2, Port Everglades Units 3&4, and Manatee Units 1&2 are not yet available.

Actual CAVR O&M expenses through 2007 are $0.040 Million. O&M estimates for 2008 are $20,000 for negotiations with the FDEP. O&M estimated for 2009 are undetermined.

ATTACHMENT 1

GEORGIA DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION
AIR PROTECTION BRANCH

RULES FOR AIR QUALITY CONTROL
CHAPTER 391-3-1
EFFECTIVE: JULY 25, 2007

RULE 391-3-1-.02(2) (sss) - MULTIPOLLUTANT CONTROL FOR ELECTRIC UTILITY STEAM GENERATING UNITS
PAGES 141-147

RULES FOR
AIR QUALITY CONTROL
CHAPTER 391-3-1

EFFECTIVE: JULY 25, 2007

GEORGIA DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION
AIR PROTECTION BRANCH

4244 INTERNATIONAL PARKWAY, SUITE 120
ATLANTA, GEORGIA 30354
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(iii) has potential emissions (from the individual fuel burning equipment) of nitrogen oxides, expressed as nitrogen dioxide, equal to or exceeding one ton per year; and either

(iv) was installed before May 1, 1999 and has a maximum design heat input capacity of less than 100 million BTU per hour, or

(v) was installed on or after May 1, 1999 and has a maximum design heat input capacity of less than 10 million BTU per hour.

5. For the purposes of this paragraph, the term "natural gas curtailment" means any period during which the supply of natural gas is not available for firing in an affected unit, for reasons beyond the control of and not related to any action or decision of the owner or operator.

6. An affected unit shall be exempt from the requirements of subparagraph 1, provided the owner or operator submits such documentation as specified in the facility's air quality permit confirming that the affected unit will not be operated during the months of May through September.

(sss) Multipollutant Control for Electric Utility Steam Generating Units

1. **Effective December 31, 2008**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Bowen Unit 4 unless such source is equipped and operated with selective catalytic reduction and flue gas desulfurization.

(ii) Plant Bowen Unit 3 unless such source is equipped and operated with selective catalytic reduction and flue gas desulfurization.

(iii) Plant Wansley Unit 1 unless such source is equipped and operated with selective catalytic reduction and flue gas desulfurization.

(iv) Plant Hammond Unit 1 unless such source is equipped and operated with flue gas desulfurization.

(v) Plant Hammond Unit 2 unless such source is equipped and operated with flue gas desulfurization.

(vi) Plant Hammond Unit 3 unless such source is equipped and operated with flue gas desulfurization.

(vii) Plant Hammond Unit 4 unless such source is equipped and operated with selective catalytic reduction and flue gas desulfurization.

(viii) Plant Yates Unit 1 unless such source is equipped and operated with flue gas desulfurization.

2. **Effective June 1, 2009**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Bowen Unit 2 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

(ii) Plant Scherer Unit 2 unless such source is equipped and operated with sorbent injection and a baghouse.

(iii) Plant Scherer Unit 3 unless such source is equipped and operated with sorbent injection and a baghouse.

3. **Effective December 31, 2009**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Scherer Unit 1 unless such source is equipped and operated with sorbent injection and a baghouse.

(ii) Plant Wansley Unit 2 unless such source is equipped and operated with selective catalytic reduction and flue gas desulfurization.

4. **Effective April 30, 2010**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Scherer Unit 4 unless such source is equipped and operated with sorbent injection and a baghouse.

5. **Effective June 1, 2010**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Bowen Unit 1 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

6. **Effective December 31, 2011**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Scherer Unit 3 unless such source is equipped and operated with selective catalytic reduction, flue gas desulfurization, sorbent injection, and a baghouse; provided that the owner or operator is not required to operate the selective catalytic reduction system during the non-ozone season months of January through April and October through December of each year.

7. **Effective December 31, 2012**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

(i) Plant Scherer Unit 4 unless such source is equipped and operated with selective catalytic reduction, flue gas desulfurization, sorbent injection, and a baghouse, provided that the owner or operator is not required to operate the selective catalytic reduction system during the non-ozone season months of January through April and October through December of each year.

(ii) Plant McDonough Unit 1 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

8. **Effective December 31, 2013**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

   (i) Plant Branch Unit 3 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

   (ii) Plant McDonough Unit 2 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

   (iii) Plant Scherer Unit 2 unless such source is equipped and operated with selective catalytic reduction, flue gas desulfurization, sorbent injection, and a baghouse, provided that the owner or operator is not required to operate the selective catalytic reduction system during the non-ozone season months of January through April and October through December of each year.

9. **Effective June 1, 2014**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

   (i) Plant Branch Unit 4 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

10. **Effective December 31, 2014**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

   (i) Plant Branch Unit 1 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

   (ii) Plant Branch Unit 2 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

   (iii) Plant Scherer Unit 1 unless such source is equipped and operated with selective catalytic reduction, flue gas desulfurization, sorbent injection, and a baghouse; provided that the owner or operator is not required to operate the selective catalytic reduction system during the non-ozone season months of January through April and October through December of each year.

11. **Effective June 1, 2015**, no person shall cause, let, permit, suffer or allow the operation of the following units except as specified below:

   (i) Plant Yates Unit 6 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

   (ii) Plant Yates Unit 7 unless such source is equipped and operated with selective catalytic reduction (SCR) and flue gas desulfurization (FGD).

12. **Effective January 1, 2018**, should the annual heat input (from coal combustion) of an affected unit or group of affected units exceed the levels specified in each subparagraph 12.(i) through 12.(iv), the owner/operator will comply with the requirements specified in subparagraphs 12.(v):

(i) Plant Kraft Units 1, 2, and 3 with a total annual heat input of 17,911,898 million Btu;

(ii) Plant McIntosh Unit 1 with a total annual heat input of 14,557,638 million Btu;

(iii) Plant Mitchell Unit 3 with a total annual heat input of 8,621,580 million Btu;

(iv) Plant Yates Units 2, 3, 4, and 5 with a total annual heat input of 33,608,398 million Btu.

(v) The owner/operator shall evaluate the economic and technical feasibility of additional mercury controls on the applicable affected unit(s) specified in subparagraphs 12.(i) through 12.(iv), and submit a report on their findings to the Division no later than September 1 of the calendar year following the calendar year that the annual heat input exceeded the applicable level specified in subparagraphs 12.(i) through 12.(iv).

(vi) The Division will review the report submitted in accordance with subparagraph 12.(v) and determine if additional mercury controls are required and, if additional mercury controls are required, establish deadlines for submission of a permit application(s) to the Division and for start-up of such mercury controls.

(vii) The Division will document the results of its evaluation conducted in accordance with subparagraph 12.(vi) and notify the owner and/or operator within a timely fashion whether additional mercury controls are required.

13. Control Equipment Monitoring Design: For the anticipated range of operations of the applicable EGUs specified in subparagraphs 1. through 11., the designated representative shall follow the procedures given in Section 2.124 of the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants** for the establishment of optimized operating parameters for the applicable control equipment installed as required in subparagraphs 1. through 11.

14. **Alternative Control Technology:** The owner/operator of an affected unit specified in subparagraphs 1. through 11. may operate alternative control technology or alternative method of emissions reductions from that specified in the applicable subparagraphs 1. through 11. if the following requirements are met:

(i) The Division has approved the operation of the alternative control technology or the alternative method of emission reductions as being capable of achieving reductions of NOx, SO_2 and/or mercury emissions equivalent to or greater than the control technology requirement specified in applicable subparagraphs 1. through 11. for an individual emissions unit or the respective plant site as a whole; and

(ii) The owner/operator has submitted the appropriate permit application(s) to the Division at least twelve months before the effective date of the applicable subparagraph 1. through 11.

15. The owner or operator of any EGU subject to this subsection may submit a request to the Director to delay implementation of any of the controls required by subparagraphs 1. through 11. for a specific EGU if there is a delay caused by reasonably unforeseen circumstances beyond the control of the owner operator. Any delay allowed under this subparagraph is subject to review and approval by the Division. Reasonably unforeseen circumstances beyond the control of the owner or operator shall include, without limitation, the following:

(i) Failure to secure timely and necessary federal, state or local approvals, responses, notifications or permits to install the controls, provided that such approvals or permits have been timely and diligently sought;

(ii) Act of God, act of war, insurrection, civil disturbance, flood or other extraordinary weather conditions, vandalism, contractor or supplier strikes or bankruptcy, or unanticipated breakage or accident to machinery or equipment despite diligent maintenance; and

(iii) Any other delay caused by unforeseeable circumstances beyond the reasonable control of owner or operator as reasonably determined by the Director.

16. On and after the effective date of each subparagraph 1. though 11. for a specific EGU, the applicable owner or operator is not required to operate the required control technology under the following conditions:

(i) Restarting an EGU when all EGUs at a facility are down and off-site power is not available (also known as a "Black Start").

(ii) Periods of startup of an EGU in accordance with best operational practices to minimize emissions.

(iii) Periods of shutdown of an EGU in accordance with best operational practices to minimize emissions.

(iv) Periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage of the respective EGU.

(v) Periods of malfunction of EGU and/or control technology equipment provided that such periods are consistent with the requirements of paragraph 391-3-1-.02(2)(a)7.

(vi) Periods when the owner/operator is required to conduct the Relative Accuracy Test Audit on the Continuous Emissions Monitoring System located on the bypass stack pursuant to 40 CFR Part 75, Appendix B.

(vii) Division approved periods of research and development of emission control technologies, provided that the unit does not exceed other applicable emission limits. For purposes of this subparagraph, the owner/operator shall submit a request for approval under this subparagraph at least 120 days prior to such date as well as including the following items: (1) length of time of research and development (R&D) period; (2) identification of steps to take to minimize emissions in accordance with best operational practices during R&D period.

(viii) Any other occasion not covered by subparagraph 16.(i) through (vii), as approved by the Division.

17. The requirements of subparagraph 16 do not relieve the owner or operator from the requirement to comply with any other applicable requirements of Georgia Rules for Air Quality Control Chapter 391-3-1.

18. Technology and Mercury Impact Review – Periodic Evaluation: The Director shall submit a report to the Georgia Department of Natural Resources Board by December 31, 2023. The report shall constitute an evaluation of available and relevant information to determine if additional reductions of mercury emissions from

EGUs are necessary or appropriate. This report shall include an evaluation that includes, but is not limited to, the following:

(i) mercury concentrations in fish tissue in water bodies in the State and any changes or trends of such concentrations over time;

(ii) the sources of mercury (including air, land, and water sources) that might influence in-state mercury concentrations in fish tissue;

(iii) the state of the science regarding the relationship among sources of mercury, mercury speciation and mercury concentrations in fish tissue in water bodies in the State;

(iv) the health impact of mercury contamination in fish tissue;

(v) technically and economically feasible controls for the reduction of mercury emissions from coal-fired EGUs or other sources;

(vi) whether additional reductions of mercury from coal-fired EGUs or other sources and/or whether additional time or study is appropriate and necessary in light of items (i) through (v);

(vii) recommendations for any necessary revisions to paragraph (sss) or other actions as needed to address other sources; and

(viii) recommendations for an appropriate timeline for the development of any such additional regulations; provided, however, that implementation and operation of any such additional controls shall be required no earlier than January 1, 2027.

(ttt) Mercury Emissions from New Electric Generating Units

1. No person shall cause, let, suffer, permit, or allow the emissions of mercury, from any affected unit described below that is installed on or after January 1, 2007, to exceed the following:

(i) Such affected unit has been approved by the Director as meeting the appropriate requirements for best available control technology in controlling those emissions of mercury.