LEGISTAR #130642A

MEMORANDUM

Office of the City Attorney

Phone: 334-5011/Fax 334-2229
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TO: Mayor and City Commissioners **DATE:** December 19, 2013

FROM: Nicolle M. Shalley, City Attorney NMS

SUBJECT: Equitable Adjustment for Change of Law of the Power Purchase Agreement

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Questions

Did the General Manager for Utilities have the authority to sign the "Equitable Adjustment for Change of Law of the Power Purchase Agreement" or did he act outside the scope of his authority (i.e., an "ultra vires" act)? If it was an ultra vires act, should the City bring legal action to seek to invalidate the "Equitable Adjustment for Change of Law of the Power Purchase Agreement"?

Short Answers and Recommendations

It appears from the inquiry conducted by this Office that the execution of the "Equitable Adjustment for Change of Law of the Power Purchase Agreement" was an ultra vires act; however, it is the opinion of this Office that legal action would not likely be successful because the City Commission was provided notice of the "Equitable Adjustment for Change of Law of the Power Purchase Agreement" within one month after its execution, because of certain exception language contained in the City's Purchasing Policy and Procedures and because the document was approved as to form and legality. In the conclusion section below, this Office recommends further action steps to help prevent a similar situation from occurring in the future.

Background

At the conclusion of the Special City Commission meeting on Monday, October 7, 2013, Commissioner Randy Wells asked if the City Attorney had a copy of a memorandum prepared by GRU's outside counsel ("Orrick") regarding the reclaimed water line to the City of Alachua. The City Attorney was not aware of same and advised Commissioner Wells to ask Attorney Lyon with Orrick (who was present at the meeting) about the memorandum. Commissioner Wells did so and Attorney Lyon informed him that Orrick prepared a memorandum regarding a change in law under the Power Purchase Agreement (the "PPA"), but not regarding the reclaimed water line to the City of Alachua. The GRU Utilities Attorney provided a copy of an

Orrick memorandum dated December 20, 2010 (the "Orrick Memo") to the City Attorney, who then provided a copy to Commissioner Wells.

Upon review of the Orrick Memo, the City Attorney discussed same with the Utilities Attorney. The Utilities Attorney was aware of the Orrick Memo and a related document titled "Equitable Adjustment for Change of Law of the Power Purchase Agreement" dated as of March 16, 2011 (the "PPA Amendment") in that the documents were contained in files she obtained from the former Utilities Attorney. However, there was no reason for her to examine or question a transaction that occurred prior to her employment with the City.

The executed PPA Amendment was transmitted to the former Utilities Attorney by letter dated March 30, 2011 from Young Van Assenderp, P.A. (attorneys for GREC). The text of the letter states only that it is transmitting the unredacted PPA, it does not mention the PPA Amendment. However, the PPA Amendment was attached at the very end of the unredacted PPA. The PPA Amendment increases certain of the rates to be paid under the PPA and obligated GRU to pay for the cost of the reclaimed water line to the City of Alachua.

As a result of Commissioner Wells inquiry, this Office began to question how and why the former General Manager for Utilities entered into the PPA Amendment, given that the attorneys for GRU at the time (both in-house and outside counsel) were clearly of the opinion that no change in law had occurred. In particular, this Office sought to determine whether the former General Manager for Utilities acted outside of the scope of his authority in signing the PPA Amendment (i.e., an "ultra vires" act) such that would allow the City to seek to have the PPA Amendment invalidated in a court of law.

From October 2013 to present, attorneys with this Office have reviewed available files and discussed the Orrick Memo and the PPA Amendment with Orrick attorneys, Tim McDermott (outside counsel for the City), Bob Hunzinger (former General Manager for Utilities), John Stanton (General Manager for Energy Supply), Jennifer Hunt (former GRU Chief Financial Officer), Skip Manasco (former Utilities Attorney), Marion Radson (former City Attorney), Lewis Walton (GRU Marketing and Communications Manager), Ed Reagan (former GRU Assistant General Manager for Strategic Planning), JoAnn Dorval (GRU Purchasing Manager) and Mark Benton (City Finance Director). In addition, on Friday, November 8th, the former General Manager of Utilities provided his file on this matter to the Interim General Manager and this Office reviewed that file as well.

Facts and Legal Analysis

Section 3.2 of the PPA provides for an adjustment in Contract Prices if there is a Change in Law, it reads as follows:

"3.2 <u>Change in Law</u>. The parties recognize and agree that the Contract Prices are based on the current regulatory requirements for generating and selling the Products. A "Change in Law" shall be a change in any applicable law, regulation, permit, ordinance, market rule, or order of any governmental or regulating authority, market regulator, court or arbitration tribunal enacted after the Effective Date where such change in law specifically increases or decreases the actual cost of generating and selling the Products, but it shall not include any such change in law that is not specifically directed toward generating facilities or which just has general economic effects that indirectly increase or decrease Seller's costs, nor shall it include any change in law with respect to Production Tax Credits, Renewable Energy Grant or Investment Tax Credits. If there is a Change in Law, then the Contract Prices shall be equitably adjusted to cover the additional costs, or pass on the additional savings, associated with generating and selling the Products. No claim for extra compensation based on a change in law that results in an increase in Seller's costs shall be presented by Seller or considered by Purchaser unless Seller shall first have provided written notice of such claim to Purchaser. No claim for a reduction in payments shall be presented by Purchaser or considered by Seller unless Purchaser shall first have provided written notice of such claim to Seller. Receipt of such notice shall in no event constitute acceptance by either Party of the validity of such claim for extra compensation. In the event of a dispute over a claim for extra compensation, Seller represents and agrees that it shall promptly and without interruption proceed with the generation of Products while any claim for a change in Contract Prices is being resolved. Seller shall comply with any Change in Law in the most effective commercially reasonable manner."

In June 2010, American Renewables (the predecessor to GREC) began to communicate with GRU staff concerning certain emissions requirements of FDEP that American Renewables believed to constitute a Change in Law. It appears that the former AGM for Strategic Planning agreed that a Change in Law occurred; however the GM for Energy Supply and the former Utilities Attorney disagreed. This Office was unable to determine whether the former General Manager for Utilities believed a change in law occurred. He stated only that he believed the PPA Amendment was necessary at that time to resolve a dispute and keep the project on track. On November 15, 2010, American Renewables sent a detailed memorandum re: Changes in Regulatory Environment to GRU staff (attached as **Exhibit "A."**) In response, the former Utilities Attorney requested an opinion from outside legal counsel regarding whether a Change in Law had occurred. On December 20, 2010, the Orrick Memo was issued (attached as **Exhibit "B"**) and it concluded "[t]he FDEP's decision to require the use of a SCR system does not fall within the change-in-law provision because there was, quite simply, no change in law."

It appears that throughout January and February 2011, American Renewables staff and GRU staff continued to communicate regarding FDEP's regulatory requirements and purported change in law. On March 15, 2011, American Renewables provided a written memorandum to GRU for the purpose of putting GRU on written notice of a claim under Section 3.2 <u>Change in Law</u> of the PPA (attached as **Exhibit "C."**) It appears that on or about that date, American Renewables also provided a draft of the PPA Amendment.

The PPA Amendment appears to be a settlement agreement as it is described in the Whereas clauses as a "full satisfaction of any claims arising out of Changes in Law that have occurred" and contains an entire section titled "Full Satisfaction of Change of Law Claims." However, its effect is to amend the PPA by increasing certain PPA contract prices by $4.40/MWh and obligating GRU, to the extent not funded by grants received, to fund the cost of connecting the biomass facility to the reclaimed water system of the City of Alachua. The PPA Amendment was signed effective as of March 16, 2011 by the former GRU CFO (at the direction of and in the absence of the then General Manager for Utilities) and was approved as to form and legality by the former Utilities attorney (attached as **Exhibit "D"**).

The PPA Amendment was not placed on a City Commission agenda or approved by the City Commission. However, one of the Whereas clauses in the PPA Amendment states that by action of the City Commission on May 7, 2009, the General Manager of Utilities has been duly authorized to implement the PPA on behalf of the City and to execute and deliver any instruments in connection therewith. It appears that a copy of the PPA and the PPA Amendment were provided to the City Commission shortly before April 6, 2011 via a memorandum from the GRU Marketing and Communications Manager (attached as **Exhibit "E"**), which stated that the packet to the Commission included "[t]he Equitable Adjustment Agreement to accommodate new state and federal regulations." This Office located an unsigned version of this memo in the file of the former General Manager for Utilities and was unable to determine whether it was actually delivered to the City Commission. However, a GRU e-line news release was sent via email to the City Commission and the news media on April 6, 2011 (attached as **Exhibit "F"**). The news release discusses the un-redacted PPA and briefly mentions the PPA amendment as follows: "GRU was also able to release today an adjustment to the power purchase agreement that addresses negotiated costs associated with recent changes in federal environmental regulations and state permitting requirements. Hunzinger said the changes will have a minimal impact on customers."

Under Florida law, an ultra vires act is one that is unauthorized; beyond the scope of power allowed or granted by a corporate charter or law.[i] Generally speaking, each City Charter Officer derives his authority from the City Charter, from adopted City Policies and Procedures and from specific action of the City Commission. So here, it could be argued that the General Manager derived his authority from: 1) the City Commission action on May 7, 2009 (as stated in the Whereas clause of the PPA Amendment), or 2) the City's Purchasing Policies.

As to 1, the item before the City Commission on May 7, 2009 was the draft PPA that GRU staff had negotiated with GREC. Pursuant to the recommendation for that item, the City Commission received a presentation, approved the executed PPA and "authorized the General Manager or his designee to execute such documents and take all steps as may be necessary to implement the terms of the PPA, including but not limited to filing of all required applications with jurisdictional governmental bodies and agencies; and the lease of and easements over portions of the Deerhaven Generating Station site necessary for the construction and operation of the biomass generating plant." However, a plain dictionary definition of "implement" means to carry out or give practical effect to a decision already made[ii], it does not mean to amend the decision, nor does it mean to settle legal claims arising out of the decision.

As to 2, Article III, Section 3.01 of the City Charter vests the Charter Officers with the authority to purchase and contract for services required to perform their assigned duties subject to the rules adopted by the City Commission and grants the Charter Officers the authority to bind the City for all purchases unless prior approval of the City Commission is required. The City Commission adopted such rules (the "Purchasing Policy") on December 11, 2006 by Resolution No. 060732. Section 7 of the Purchasing Policy states that every purchase in excess of $50,000 requires approval of the City Commission. Section 7 also provides certain exceptions to that general rule. One of the exceptions is "any adjustment to a contract previously approved by the City Commission . . . . which constitutes an addition to the purchase amount of ten (10%) percent or less of the previously approved amount."

In addition, City staff and GRU staff have promulgated Purchasing Procedures to implement the Purchasing Policy. Section 28 of the GRU Purchasing Procedures Manual addresses modifications to contracts and states that "[f]or . . . . contracts that have City Commission approval, changes up to 10% above the City Commission approval amount is allowed without additional City Commission approval."

In discussing this exception with both the GRU and City Purchasing Departments, it appears that the 10% exception was intended and has been used for amendments to contracts for which funds were already budgeted (either in a department budget or in project contingency) or for which the department is obtaining City Commission approval of a budget amendment for the increase in the cost of the project. The Purchasing Departments did not believe it was intended, nor has it been used, for contract amendments where no money is budgeted or no budget amendment is sought to cover the increase, such as the PPA Amendment which will require future rate or fuel adjustment increases to cover the increased cost.

Section 7 of the Purchasing Policy requires that reports be made to the City Commission of purchases greater than $50,000 for which approval of the City Commission is not required pursuant to the Purchasing Policy. To comply with this requirement, GRU Administrative Services issues monthly memoranda to the City Commission.

In this case, the amount of the PPA amendment is approximately $106.1 million; which exceeds $50,000; however, since the amount to be paid over the 30 year term of the PPA is approximately $3.1 billion, the PPA amendment represents an increase of less than 10%. The PPA Amendment was not disclosed to the City Commission in a monthly purchases memorandum. As such, it does not appear that the former General Manager for Utilities was relying on the 10% exception in executing the PPA Amendment without City Commission approval.

It should also be noted that, pursuant to written policy of this Office, all settlements of legal claims that exceed $20,000 require City Commission approval. So if the PPA Amendment were construed as a settlement, as described in the Whereas clauses and in Section 3, it should have been presented to the City Commission for approval.

Another issue concerns the effect of the former GRU Utilities Attorney approving the PPA Amendment as to "form and legality." Article III, Section 3.03 of the City Charter states that the City Attorney shall endorse contracts, bonds and other instruments as to form and legality. In addition, Section 1 of the Purchasing Policy requires that approval of the City Attorney be obtained on all written contracts, except where standardized documents approved by the City Attorney's Office are used. However, neither describes the intent or effect of such approval. While the City would argue the purpose is for the City's attorneys to assure the client (the City) that the document is in the proper form and not unlawful, GREC may argue that it relied on that signature as an assurance by the City that the document was properly executed and binding on the City.

In the course of our inquiry into this matter, this Office also became aware of another document that amended the PPA without City Commission approval. This document is titled a "Consent and Agreement" dated as of June 30, 2011 (attached as **Exhibit "G"**) and appears to have been provided in the context of GREC obtaining financing for the biomass facility. This document assigns a collateral interest in the PPA for the benefit of GREC's lender and makes 10 amendments to the PPA (as set forth in section 5 of the document.)

Conclusion and Recommendations

Because the cost of the PPA Amendment exceeds $50,000 (whether characterized as a contract amendment or a settlement agreement) and was not taken to the City Commission for approval, this Office was initially of the opinion that a sufficient basis existed to file a declaratory action seeking to have the PPA Amendment invalidated as an ultra vires act by the former General Manager for Utilities. However, upon researching the matter further, it is our opinion that GREC would very effectively counter any such claim by the City based on the existence of the Purchasing Policy 10% exception, the written notice of the PPA Amendment that was provided to the City Commission, and that the PPA Amendment was approved as to form and legality.

However, it is up to the City Commission whether it desires to direct the City Attorney to initiate a legal challenge. To that end, with the first post-"commercial operations" payment, GRU staff anticipates placing GREC on notice that the portion of payments attributable to the PPA Amendment are being paid under protest, pending City Commission action on this matter.

This Office has identified a number of process improvements that may help prevent a similar situation in the future. They are as follows:

1) Foster a clear understanding that the Utilities Attorney works under the direction of the City Attorney. This recommendation has been fully implemented by the City Attorney and the Utilities Attorney upon the departure of the former General Manager for Utilities and with the cooperation of the Interim General Manager. The Utilities Attorney now has an office within the City Attorney's Office and maintains office hours on location at GRU, similar to the Assistant City Attorneys that serve as the Police Legal Advisor and the CRA Attorney.
2) Amend the City Purchasing Policy (and the City and GRU Purchasing Procedures, if necessary) to clarify that the 10% exception applies only when there are budgeted funds to cover the cost of the increase, and/or specify a monetary cap on the exception.
3) Amend the City Purchasing Policy to clarify that approval of the City Attorney as to form and legality shall be required on all contracts and that such approval is provided only for

the benefit of this City and is not a representation or warranty made for the benefit of any other party and should not be relied upon for any purpose by parties contracting with the City.

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[i] Liberty Counsel v. Florida Bar Board Governors, 12 So3d 183, 191 (Fla. 2009)
[ii] Merriam-Webster online dictionary, http://www.merriam-webster.com/dictionary/implement

EXHIBIT "A"

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MEMORANDUM

To: Bob Hunzinger, Gainesville Regional Utilities
Ed Regan, Gainesville Regional Utilities
John Stanton, Gainesville Regional Utilities

From: Josh Levine, American Renewables
Len Fagan, American Renewables

Date: November 15, 2010

Re: Changes in Regulatory Environment

We appreciate you taking the time to meet with us on October 19, 2010 to discuss the changes in the regulatory and permit requirements that have occurred since last year as we have been working through the permitting process for the Gainesville Renewable Energy Center (GREC). As you know from numerous conversations and meetings over the last 18 months or so, Gainesville Renewable Energy Center, LLC (GREC LLC) was required to make some significant changes to the proposed facility to meet new regulatory requirements. These regulatory and permit changes have resulted in the planned incorporation of an SCR system and related improvements to the bag house design. These improvements resulted in both additional capital costs and additional operating costs for the facility and have, in turn, also increased GREC's actual cost for generating and selling electricity and other attributes to GRU. As such, we believe that these changes appropriately fall under the "Change in Law" provision included in Section 3.2 of the power purchase agreement (PPA) as we discussed last summer. While there are a number of other changes that have occurred over the last 18 months for which we are not seeking a change to the PPA, we are seeking at this time to formalize the verbal agreement we had to make appropriate changes to the Contract Prices at some time in the future in connection with the SCR-related changes.

Pursuant to Ed Regan's request, we have prepared the following memorandum that describes in substantial detail the changes that occurred in the regulatory environment and in terms of permit requirements affecting the project. The memorandum also explains the effect that these changes have had on the GREC facility, both technically and economically, and why we believe that the Contract Prices need to be equitably adjusted to cover the additional costs resulting from these changes as provided for in Section 3.2 of the PPA.

I. Background

The Contract Prices that American Renewables, doing business as Nacogdoches Power LLC at the time, agreed to within the PPA, were based on the project configuration contained in Section 3 of the Revised

Confidential Proposal for Renewable Energy Generation that was submitted in response to Gainesville Regional Utilities RFP 2007-135, Biomass Fueled Generation Facility ("RFP Response") dated April 11, 2008. As stated in the RFP Response, the proposed project design for the Gainesville project was planned to be a duplicate of our Nacogdoches Power project in Texas "in order to maximize cost savings and lessons learned during process design and engineering" (pg. 32). In Section 3 of the RFP Response, we stated that:

> *The Project will utilize a bubbling fluidized bed boiler to produce superheated steam. The boiler will be equipped with a baghouse to control particulate matter. An aqueous ammonia injection Selective Non-Catalytic Reduction ("SNCR") system will be provided for NO_x control. Superheated steam from the boiler will be admitted to a single steam turbine with four extractions for feedwater heating. The steam turbine will generate electricity before exhausting axially into the condenser with cooling water provided from the wet evaporative cooling tower. (pg. 32)*

In addition to the plant configuration described above, we also stated in the RFP Response that we believed that "it will be possible to beneficially reuse the ash as a soil amendment" (pg. 52).

On page 53 of the RFP Response, we reiterated our intention to include "an aqueous ammonia injection Selective Non-Catalytic Reduction system…for NOx control". In addition, on page 55 of the RFP Response, we provided a table that lists the expected air pollution emissions for the Project. GREC LLC believes that this was a reasonable and appropriate approach given the state of regulatory and permit requirements at that time in part because "Nacogdoches Power [had] received all environmental permits required for construction of the Texas Project and recently set the standard for Best Available Control Technology [BACT] in Texas at .10 lb/mmbtu of NOx for biomass-fired generating facilities" with the use of an SNCR (pgs. 52-53).

The Contract Prices we agreed to within the PPA were based on the above-described project configuration as defined in Section 1.2 of Appendix I of the PPA which states:

> *The Facility will utilize a bubbling fluidized bed boiler to produce superheated steam. The boiler will be equipped with a baghouse to control particulate matter. An aqueous ammonia injection Selective Non-Catalytic Reduction ("SNCR") system will be provided for NOx control.*

II. Current Regulatory Requirements in April 2009

In addition to relying upon the statement in the RFP Response that we had recently "set the standard for Best Available Control Technology in Texas at .10 lb/mmbtu of NOx for biomass-fired generating facilities" in order to determine what the current regulatory requirement was with respect to NO_x emissions, American Renewables also looked at similarly-sized biomass-fired generating facilities that were being developed in the region. Unfortunately, there were no existing or proposed facilities in Florida using the same technology in a similar configuration at the time that would have provided insight into how the FL Department of Environmental Protection (FDEP) would interpret what control technology would classify as BACT. [1] In Fort Gaines, GA, a nearly identical biomass project (100 MW net, BFB boiler) to

[1] The closest example would have been the proposed Highland Ethanol LLC project which filed an air application in February 2009 and received a draft permit on March 22, 2009. In their draft permit, FDEP determined that the use of

GREC being developed by Yellow Pine Energy Company (Yellow Pine), filed an air permit application with the Georgia Environmental Protection Division (EPD) in September 2007.[2] In that application, to address NO_x emissions, Yellow Pine proposed utilizing an SNCR with an allowable limit of 0.10 lb/mmBtu on 100% biomass and 0.11 lb/mmBtu on biomass/tire derived fuel, each on a 30-day average. In a December 3, 2008 response to a letter from the GA EPD requesting additional information, the developer of Yellow Pine, Summit Energy Partners, asserted that its proposed NO_x limits "are suitable limits for a [bubbling fluidized bed] BFB with SNCR and is BACT".[3] In the final air construction permit issued to Yellow Pine on May 15, 2009 (the same time in which the GREC PPA was executed and approved), the GA EPD established a NO_x emission limit of 0.10 lb/mmBtu, 30-day rolling average and Yellow Pine was required to install an SNCR (pgs. 7 and 11).[4]

For the reasons stated above, at the time the PPA was executed (see Attachment 1 for GREC Project Development Timeline), American Renewables reasonably believed that the current regulatory requirement was such that a BFB boiler using an SNCR with an emissions limit of 0.10 lbs/mmBtu was, in fact, BACT.

III. Changing Regulatory Requirements in Spring/Summer 2010

As soon as the PPA between GRU and GREC LLC was executed, GREC LLC scheduled a meeting with FDEP. On May 12, 2009, GREC LLC met with FDEP to begin discussing the SCA and PSD permit applications that GREC LLC was planning to file in the fall of 2009. This meeting was attended by Al Linero (FDEP Division of Air Resource Management (DARM)), David Read (FDEP DARM), Jeff Koerner (FDEP DARM) and Mike Halpin (FDEP Siting Office). During this meeting, Mr. Linero suggested for the first time that GREC LLC would need to make a very strong argument if it wished to persuade FDEP that the utilization of SNCR is BACT. Regardless of the history of using SNCR for biomass projects in Florida and in other states, Mr. Linero stated that SCR technology has been widely used in other industries and he believed that SCR would be economically and technically feasible in this case.

On June 24, 2009, GREC LLC held a pre-application scoping meeting with FDEP (numerous staff from multiple divisions/offices within FDEP participated). At this meeting, GREC LLC presented an overview of the GREC project which highlighted the proposed technology, types of fuel that will be utilized and the anticipated project schedule. Mr. Linero again raised the issue that, in his opinion, SNCR with a 0.10 lb/mmBtu NO_x emission limit is not BACT and that GREC LLC would need to strongly consider using SCR and significantly reducing the project's NO_x limit. He highlighted that there were a number of low-temperature, back-end SCR units that could be considered, such as Babcock Power's RSCR technology. We

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SNCR to control NO_x emissions was BACT. Even though this project was utilizing a bubbling fluidized boiler, it is not a good comparison to GREC as the Highland Ethanol project will utilize stillage cake and biogas from the ethanol production process as fuel instead of clean, woody biomass material. The two Florida biomass energy projects which are better comparisons to GREC (and are described in the following section) both filed their air permit applications after the GREC PPA was executed in May 2009.

[2] http://www.gaepd.org/air/airpermit/html/permits/psd/dockets/yellowpine/facilitydocs.htm

[3] http://www.gaepd.org/air/airpermit/downloads/permits/psd/dockets/yellowpine/facilitydocs/120308responseto111208.pdf

[4] http://www.gaepd.org/air/airpermit/downloads/permits/psd/dockets/yellowpine/epddocs/0610001final.pdf

were also made aware that in the period since our last meeting with FDEP in May 2009 (that is, after we first started discussing with FDEP the Project but before GREC filed its own permit), an air construction permit had been filed for a proposed biomass energy facility in Hamilton County, Florida that proposed the use of an SCR system.

This summary was confirmed at the Site Certification hearing in August 2010 where Mr. Linero testified that during our pre-application meetings he had told GREC LLC that it ought to consider using an SCR system instead of an SNCR (GREC Site Certification Hearing - Transcript Volume VII, pg. 958, lines 11-15).

New Air Construction Permit Applications in Florida

At the same time that American Renewables was preparing its SCA and PSD permit applications, two other proposed biomass energy projects in Florida, utilizing similar technology, were preparing, or had filed, air construction permits with FDEP. Both of these applications were filed before GREC's PSD application and both of these projects proposed to utilize an SCR which would result in lower NO_x emission limits. The following paragraphs briefly describe these other projects, and their proposed limits. GREC LLC submits that this information is critical because it directly influenced how FDEP viewed what is and what is not considered BACT.

ADAGE Hamilton

On May 20, 2009, ADAGE LLC filed an air construction permit application for a 50 MW biomass energy facility called the ADAGE Hamilton project located in Hamilton County, FL.[5] ADAGE proposed two alternative, technical configurations: a BFB boiler with an SCR or a CFB boiler with an SNCR (pgs. 2-8 and 2-9). In both technical configurations, ADAGE stated that it could accept a NO_x emissions limit of 0.07 lb/mmBtu (Table 2-3). On January 12, 2010, ADAGE received a final air construction permit from FDEP which required the use of an SCR with the proposed BFB boiler.[6] The FDEP-issued permit set a NO_x emission limit between 0.064 and 0.070 lb/mmBtu (pgs. 3 and 13).[7]

FBenergy Manatee Facility

On October 9, 2009, FBenergy submitted an air permit application for the proposed 60 MW Manatee biomass facility.[8] FBenergy's facility is based on the use of a grate-type suspension (stoker) boiler with an SCR, oxidation catalyst, in-duct sorbent injection and an electrostatic precipitator (pg. 2). The proposed NO_x

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[5] http://www.dep.state.fl.us/Air/emission/bioenergy/adage/adage_hamilton_co.pdf

[6] http://www.dep.state.fl.us/Air/emission/bioenergy/adage/FADAGEPermit.pdf

[7] The ADAGE permit has a 12-month rolling average NO_x emission limit of 53.1 lb/hr enforceable by CEMS. This limit does not directly relate to a lb/mmBtu limit since the actual heat input may be less than the permit maximum limit of 834 mmBtu/hr on a 12-month rolling average basis. If the boiler is operated at the maximum 834 mmBtu/hr level 100% of the time, the hourly NO_x emission limit equates to 0.064 lb/mmBtu. If operated at the nominal heat input of 758 mmBtu/hr, the hourly NO_x emission limit equates to 0.070 lb/mmBtu. The ADAGE permit also has a short-term hourly NOx emission limit of 53.1 lb/hr enforceable by periodic stack testing. Under FDEP compliance testing policy, testing must be conducted at no less than 90% of the design capacity. ADAGE could therefore test at 750.6 mmBtu/hr to demonstrate compliance with the 53.1 lb/hr limit (which equates to a NO_x emission rate of 0.070 lb/mmBtu). Accordingly, the ADAGE NO_x emission limit on a lb/mmBtu/hr basis can range from 0.064 to 0.070 lb/mmBtu. In their Technical Analysis, FDEP indicates that the 53.1 lb/hr limit equates to a nominal 0.070 lb/mmBtu limit.

[8] http://www.dep.state.fl.us/Air/emission/bioenergy/port_manatee/report.pdf

emission limit for the facility is 0.02 lb/mmBtu (Table 3-2). Importantly, Mr. Linero had advised GREC LLC of the FBenergy plans during our pre-application meetings. On June 18, 2010, FBenergy received a final air construction permit for the Manatee biomass facility which required the use of an SCR.[9] The FDEP-issued permit set a NO_x emission limit between 0.018 and 0.020 lb/mmBtu (pgs. 3 and 14).[10]

Decision to Reconfigure GREC

After the second formal meeting with FDEP in June 2009, American Renewables spent July and August 2009 evaluating its options, particularly in light of the ADAGE application and its understanding of FBenergy's plans.. GREC LLC determined that it could (i) propose an SNCR with a NO_x emission limit of 0.10 lb/mmBtu or (ii) it could reconfigure the facility to achieve a lower NO_x emission. The first course of action, which would have included proposing the SNCR as BACT, entailed considerable risk that FDEP would decline to accept SNCR as BACT because two other proposed biomass energy facilities in Florida utilizing similar technology would have a significantly lower NO_x emission limit. If the FDEP did take this view, then any effort to argue in favor of SNCR as BACT would only result in delay of this important project for GRU as the plant would ultimately need to be reconfigured to SCR to comply with the FDEP's regulatory requirement. GRU has been clear in terms of its strong desire to begin construction as soon as possible to be able to take advantage of federal stimulus funds. Therefore, for these reasons, we rejected the first option and focused on reconfiguring the facility.[11]

We next worked with Metso to reconfigure the facility to achieve a NO_x emission limit lower than 0.10 lb/mmBtu, evaluating two options. The first option was to reconfigure the BFB boiler to a CFB boiler while still utilizing an SNCR. The second option was to stick with the BFB boiler but shift from an SNCR to an SCR. The first option was rejected because it posed numerous problems. First, we would lose the cost savings and benefits associated with "lessons learned" from the Nacogdoches Power facility. Second, utilizing a CFB boiler with an SNCR could achieve a NOx emission limit of 0.07 lb/mmBtu, but no lower. As a consequence, if FDEP required an even lower emission rate than 0.07 lb/mmBtu, the unit would not be able to meet it. Finally, FDEP could conclude that in spite of the use of a CFB boiler and a resulting lower

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[9] http://www.dep.state.fl.us/Air/emission/bioenergy/port_manatee/Final_FBEFPermit.pdf

[10] The FBenergy permit has a 12-month rolling average NO_x emission limit of 15.1 lb/hr enforceable by CEMS. This limit does not directly relate to a lb/mmBtu limit since the actual heat input may be less than the permit maximum limit of 833 mmBtu/hr on a 12-month rolling average basis. If the boiler is operated at the maximum 833 mmBtu/hr level 100% of the time, the hourly NO_x emission limit equates to 0.018 lb/mmBtu. If operated at the nominal heat input of 757 mmBtu/hr, the hourly NO_x emission limit equates to 0.020 lb/mmBtu. The FBenergy permit also has a short-term hourly NOx emission limit of 15.1 lb/hr enforceable by periodic stack testing. Under FDEP compliance testing policy, testing must be conducted at no less than 90% of the design capacity. FBenergy could therefore test at 749.76 mmBtu/hr to demonstrate compliance with the 15.1 lb/hr limit (which equates to a NO_x emission rate of 0.020 lb/mmBtu). Accordingly, the FBenergy NO_x emission limit on a lb/mmBtu/hr basis can range from 0.018 to 0.020 lb/mmBtu. In their Technical Analysis, FDEP indicates that the 15.1 lb/hr limit equates to a nominal 0.020 lb/mmBtu limit.

[11] As a related aside, having recently completed eight days of regulatory hearings in front of an administrative law judge (four days for the site certification hearing and four days for the PSD hearing) in August and September 2010, it is clearly obvious that a proposal of using SNCR to control NOx emissions would have been highly criticized by the Petitioners in those hearings and would not have been accepted or allowed by FDEP.

NO_x emission limit, it would still try to require the use of an SCR.[12] For these reasons, we settled on continuing to utilize a BFB boiler, but we would change from an SNCR to an SCR.

Subsequent to this decision, Metso estimated that this change would cost approximately $10 million extra in capital costs and would also result in additional operating costs. On or around August 31, 2009, Josh Levine raised this issue with Ed Regan with respect to the requirement to make this change from an SNCR to an SCR due to the changing regulatory or permit requirements as overseen by FDEP, and that the necessary project changes would entail additional costs not anticipated in the original configuration. The approximate cost impacts were discussed, as well as the fact that this change constituted a "change in law" as intended between the Parties to the PPA and as described in Section 3.2 of the PPA. Ed Regan reported back to American Renewables that the GRU team discussed the situation and agreed that this change from an SNCR to an SCR was appropriate and necessary, would constitute a "change in law" under the terms of the PPA, and that some re-evaluation and adjustment of the Contract Prices between the Parties would need to occur at some appropriate point in the future.

During this same time period, GRU and GREC LLC were working together to finalize our joint Need Determination application. To account for the recent reconfiguration of the GREC facility, GRU and GREC LLC agreed to state in Section 9 of the Need Determination application that:

> *An aqueous ammonia injection selective non-catalytic reduction (SNCR) or a selective catalytic reduction (SCR) system will be provided for NO_x control. The slightly more expensive SCR system was considered for purposes of evaluating the economics of the GREC LLC PPA throughout this Application.* (pgs. 9-2 to 9-3)

In addition, within the Need Determination application, the non-fuel energy charge was increased by $2/MWh to account for the change from an SNCR to an SCR for purposes of evaluating the economics of the Project. The joint Need Determination application was filed on September 18, 2009.

As you know, subsequent to this filing, GREC LLC continued working on the SCA and PSD permit applications and ultimately filed them both on November 30, 2009. Within the PSD permit application, GREC LLC proposed utilizing an SCR with a NO_x emission limit of 0.07 lb/mmBtu.

Further Discussions with Regulatory Agencies

During the Winter/Spring 2010, coordinating discussions between many of the local, regional and state regulatory agencies were held with respect to requests for additional information for the SCA and PSD permit applications and then with respect to the specific Conditions of Certification. In addition, consultation

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[12] This possibility was confirmed by FDEP in their permitting review of the proposed Hendry County Southeast Renewable Fuels project. In recent (August 16,2010) correspondence to the applicant, FDEP stated "*You have indicated that the applicant has not yet decided on a boiler design [stoker or bubbling fluidized bed] for this project but have noted that the "spreader stoker technology results in inherently higher uncontrolled NOX emissions compared to the bubbling bed boiler". While we continue to evaluate both boiler designs, please note that pursuant to the BACT definition and process, the Department has the authority to determine one process or technique is more consistent with BACT and to require its implementation. In addition, we may determine that, regardless of boiler design, the same limit is appropriate as BACT based upon other facilities and determinations.*"

with the Suwannee River Water Management District over this time period resulted in GREC LLC and GRU agreeing to utilize reclaimed water from Alachua for a portion of the plant's process water needs.

As it became clear in May 2010 that GREC LLC was getting close to receiving the Project Analysis Report from FDEP under the Power Plant Siting Act, we reached out to FDEP DARM, and Mr. Linero in particular, to review the status of the PSD application. On June 8, 2010, in a conversation with Tom Davis of ECT, Mr. Linero mentioned that if he were to conduct a BACT analysis for NO_x emissions for GREC, as he was required to do since our application indicated the facility would be a major source of NO_x, it would delay the issuance of our draft air construction permit. Mr. Linero then suggested that if GREC LLC were able to work with GRU to agree to a cap on GRU's NO_x and SO_2 emissions from Deerhaven 2 (DH2) as a result of GRU's recently installed pollution control equipment (which had significantly reduced DH2's actual emissions), such an agreement could ensure that there will be no net increase in NO_x and SO_2 emissions when also considering impacts from GREC. If there were no net increases in NO_x and SO_2 emissions, then, Mr. Linero explained, the FDEP would not need to conduct a BACT analysis for NO_x and SO_2 for GREC and they would accept GREC LLC's proposed limits for NO_x and SO_2 emissions as "BACT-like."

In an email dated June 17, 2010 from Josh Levine to Ed Regan, American Renewables explained that we recognized that in agreeing to this netting proposal, GRU would potentially be exposing themselves to operating constraints in the future and that in recognition of this potential downside to GRU, American Renewables was willing to agree to the following:

a. *In any situation in the future where GREC needs to purchase environmental allowances (such as NO_x and SO_2 allowances) to comply with the environmental regulations, we will give GRU the first right to sell these allowances to GREC at a market rate.*

b. *At the current time, we anticipate that the only "change in law" situation that we will present to GRU under the terms of the PPA before we begin construction later this year, will be with respect to the change from an SNCR to an SCR as we discussed back in August 2009. However, if GRU elects to have GREC LLC finance the proposed reclaimed water pipeline to Alachua, this would be another situation under the "change in law" provision, that we would need to discuss. We will not be seeking an additional change in the PPA Contract Prices due to any situation involving traffic or due to the cost of purchasing reclaimed water from Alachua or for any fee associated with receiving reclaimed water from Alachua.*

Even though American Renewables had based its PPA negotiations on the premise that it would be able to utilize groundwater for all of our process water needs, and GREC LLC was now being required, due to a change in the regulatory requirement, to purchase some reclaimed water from Alachua, GREC LLC had indicated that it was willing to agree to not seek any increase in the PPA Contract Prices related to the reclaimed water issue if, in turn, GRU agreed to finance the reclaimed water pipeline from GREC to Alachua's reclaimed water system. As you will see further down in this memorandum, we are not seeking any change in the Contract Prices related to reclaimed water.

After internal discussions, GRU agreed on June 18, 2010 to FDEP's netting proposal and filed the necessary forms with FDEP to modify the DH2 air permit. On June 23, 2010, Rob Klemens and Josh Levine met with

Mr. Linero and Mr. Read to discuss any outstanding issues related to the GREC PSD permit. At this meeting, Mr. Linero stated that since we were able to reach agreement on the netting proposal, he did not foresee any "additional issues" with the GREC PSD permit.

However, subsequent to the June 23rd meeting, Mr. Linero came back to us twice more (on or about June 30, 2010 and July 7, 2010) to raise issues with GREC LLC's proposed CO, VOC and HAPs emission limits. GREC LLC ultimately was also required to accept lower emissions limits for these constituents. During the course of the GREC permitting efforts, there have been substantial modifications to the air emissions limits imposed on the project since it was first proposed. In Attachment 2 is a table that illustrates the original emissions requirements contained in the RFP Response (pg. 55), the proposed emissions requirements in the PSD permit application and the current emissions requirements in the draft PSD permit. On July 14, 2010, FDEP issued GREC a draft air construction permit.

As further confirmation that the regulatory and permit requirements have changed over the past year, not just in Florida, but also in the rest of the region, the Yellow Pines biomass energy project, discussed above, in Fort Gaines, GA was issued on September 8, 2010 an amendment to its air construction permit by the GA EPD.[13] In this amendment, Yellow Pines agreed to change from using a BFB boiler to using a CFB boiler and to lower their NO_x emission limit to 0.07 lb/mmBtu, 30-day rolling average (pgs. 4 and 5). This amendment came about since the developer needed to propose minor changes to the facility design as its project development had advanced since May 2009 when their air construction permit was initially issued. The developer filed its permit modification letter on March 4, 2010.[14]

IV. Technical Reconfiguration of GREC

To meet the changing regulatory requirements, it was necessary to reconfigure GREC. The GREC Boiler, as now proposed, differs significantly from the original configuration described in the PPA in the back-end design, primarily the NO_x control design concept as well as acid gas reduction.[15] The original configuration utilized an SNCR system based on aqueous ammonia injection into the furnace through strategically spaced nozzles which are able to obtain 0.10 lb/mmBtu NO_x emission rates. The CO emission rate was 0.15 lb/mmBtu which allowed for the boiler to be optimized for controlling NO_x emissions. There was no dry sorbent injection (DSI) system in the original configuration because the calcium in the fuel was assumed to be adequate enough to reduce the HCl and SO_2 emissions to the design limits. A baghouse operating at 320°F for PM control also was included. The back-end design flue gas flow path went through the economizer and then through a two-stage air heater with 320 °F flue gas exit temperature entering the baghouse to the induced draft (ID) fan and into the stack.

Due to the final emission requirements, the GREC boiler differed in the back-end from the economizer outlet as compared to the original configuration. The furnace temperatures and flow rates are very similar up

[13] http://www.gaepd.org/air/airpermit/html/permits/psd/dockets/yellowpine/specialpsddocs.htm
[14] http://www.gaepd.org/air/airpermit/downloads/permits/06100001/psd19518/application19518.pdf
[15] The original configuration of the GREC facility described in the PPA was very similar to the configuration of the Nacogdoches Power (NP) facility. Included as Attachment 3 is the general arrangement (sectional side view) of the boiler of the NP facility.

to this point with an economizer inlet temperature of 802°F and an exit temperature approximately 500°F. Due to the requirement to meet the lower than 0.10 lb/mmBtu NO_x emission rate, as described above, the SNCR was no longer suitable and an SCR was required.

The design concepts for the SCR looked at a high-dust and low-dust design and considered various factors which could cause the catalyst to deactivate. The primary concern in deactivation is poisoning of the catalyst with blockage being a second concern. Several mechanisms can result in these problems which need to be considered in the boiler design. These include:

- SO_3, which is formed in combustion and by catalytic oxidation which then reacts with residual ammonia to form ammonia bisulphate which is a sticky particle that causes major clogging problems; and
- Alkaline metals which chemically attach to active catalyst pore sites and cause binding (sodium and potassium are the prime concern).

The result of the design changes to minimize these impacts was (i) a vertical, low-dust design where the SCR is placed downstream of the baghouse and (ii) to add a DSI system to reduce sulfur (minimizing the SO_2 to SO_3 conversion) as well as HCl and HF emissions. The SCR will be designed to meet the required 0.07 lb/mmBtu NO_x emission limit and a maximum of 10 ppmvd ammonia slip, corrected to 7% O_2, with an expected 16,000 hour operational life at boiler maximum continuous rating (MCR). Since the SCR needs to have a minimum temperature of 440°F to be effective, the design required that the baghouse be located after the economizer with the air heater downstream of the SCR.

In the final, revised design, the air heater uses a split arrangement to maintain suitable gas temperatures entering the baghouse. The flue gas leaves the economizer at 500°F and goes through the first stage of the air heater exiting at approximately 452°F. The cooled gas is then directed to a bag house filter with a pulse jet-type, on-line cleaning system, which strips the flue gas of a high percentage of contaminates. From here, the clean gas flows through a vanadium pentoxide-based catalyst bed (SCR) primarily used for NO_x reduction, to the final section of air heater, and on to the ID fan and stack where the exit temperature is 315°F.

A DSI system is used to inject sorbent for control of SO_2, HF and HCl emissions. Injection is done in the flue duct prior to the baghouse. The reactive time of the sorbent with the flue gas is enhanced by the cake accumulating on the baghouse filter media to achieve the necessary reduction rates. When we first contemplated using a DSI system, the plan was to use hydrated lime for the sorbent (calcium-based). When it was required to utilize the higher temperature baghouse, it was determined that the reaction in this temperature range would be extremely low and would require a sodium-based sorbent. The sodium-based sorbent (trona) is injected into the flue gas duct downstream of the economizer before the air heater. The flue gas then goes through the second stage air heater exiting to the stack at 315°F. The general arrangement (sectional side view) of the boiler of the reconfigured GREC facility is shown in Attachment 4. The same general arrangement of the reconfigured GREC facility with temperatures shown at different points throughout the boiler is presented in Attachment 5.

The two major critical components that are different from the original configuration and add capital and operating cost to the project are the SCR and related changes to the baghouse. Details are as follows:

- The baghouse design of the current configuration, being at a higher temperature and using higher air cloth ratio than the original configuration, is approximately thirty percent larger. The design utilizes special bags which are designed for 500°F continuous temperature and up to a 550°F excursion temperature. The expected operating temperature will be around 452°F and peak (excursion) temperature will not exceed 490°F versus the original configuration of 320°F. To meet this temperature requirement, the bags are of 22 oz. woven fiberglass construction with acid resistant finish and polytetrafluoroethylene (PTFE) membrane and have an air-to-cloth ratio of 4:1 at MCR conditions.

- The SCR is a vanadium-based catalyst installed in the duct work downstream of the baghouse. In the SCR process, 19% aqueous ammonia is injected into the exhaust gas and reacts with NO_x and O_2 emissions to form nitrogen and water. The system includes the catalyst reactor designed for multiple layers of catalyst with the inlet and exhaust duct work, aqueous ammonia vaporization and distribution system (multiple-zone ammonia injection grid (AIG) upstream of the static mixers and flow straightening devices), various structural steel sections, platforms and lifting hoists/monorails to accommodate the catalyst loading and unloading. The SCR process is subject to catalyst deactivation over time resulting in the ongoing replacement of layers. It is estimated that each layer will be replaced once every three years.

  The catalyst design of the SCR is based on a low oxidation, vanadium pentoxide honeycomb design. It consists of 80.2 m^3 with a pitch of 4.9 mm (30 x 30 cells) in two layers. Each layer will utilize a 14 x 3 module arrangement (3.14 by 6.24 feet with a depth of 4.97 feet) using a duct cross-section of 46 x 20 feet. There are six (6) elements per module. The catalyst modules will have a 12 x 6 element arrangement with overall dimensions of 59.69" H x 75.24" L x 37.68" W. The catalyst cleaning system will utilize air as the sootblowing medium.

The impact of adding the SCR and larger baghouse resulted in a higher pressure drop through the boiler and a resulting increase in ID fan power that impacted the auxiliary load. The other impact on the auxiliary load resulted from the lower CO emission rate of 0.08 lbs/mmBtu that required increased air flow through the boiler to optimize combustion resulting in lower CO and VOC emission levels to meet the permit requirements.

V. Change in Law Provision in PPA

Section 3.2 of the PPA between GRU and GREC LLC contains the following "change in law" provision:

> *The Parties recognize and agree that the Contract Prices are based on the current regulatory requirements for generating and selling the Products. A "Change in Law" shall be a change in any applicable law, regulation, permit, ordinance, market rule, or order of any governmental or regulating authority, market regulator, court or arbitration tribunal enacted after the Effective Date where such change in law specifically increases or decreases the actual cost of generating and selling the Products, but it shall not include any such change in law that is not specifically directed toward generating facilities or which just has general economic effects that indirectly increase or decrease Seller's costs, nor shall it include any change in law with respect to Production Tax Credits, Renewable Energy Grant*

> *or Investment Tax Credits. If there is a Change in Law, then the Contract Prices shall be equitably adjusted to cover the additional costs, or pass on the additional savings, associated with generating and selling the Products. No claim for extra compensation based on a change in law that results in an increase in Seller's costs shall be presented by Seller or considered by Purchaser unless Seller shall first have provided written notice of such claim to Purchaser. No claim for a reduction in payments shall be presented by Purchaser or considered by Seller unless Purchaser shall first have provided written notice of such claim to Seller. Receipt of such notice shall in no event constitute acceptance by either Party of the validity of such claim for extra compensation. In the event of a dispute over a claim for extra compensation, Seller represents and agrees that it shall promptly and without interruption proceed with the generation of Products while any claim for a change in Contract Prices is being resolved. Seller shall comply with any Change in Law in the most effective commercially reasonable manner.* (underlining added)

As detailed in the sections above, the "current regulatory requirements" in effect at the time the PPA was executed in April 2009 were consistent with the original technical configuration of GREC that was described in Section 1.2 of Appendix I of the PPA and they were consistent with the emissions limits proposed in the RFP Response. After we executed the PPA and began the permitting process for GREC, the regulatory requirements, as interpreted and imposed by FDEP, were changed. To successfully permit GREC, it became necessary to reconfigure the facility as described above, and achieve lower emissions rates. American Renewables believes that FDEP's interpretation of BACT clearly constitutes a "change in [a] regulation or permit by a governmental or regulating authority...enacted after the Effective Date" and is therefore a "change in law" as intended by the Parties when the PPA was executed. Furthermore, as explained in more detail below, this change "specifically increases or decreases the actual cost of generating and selling the Products". Moreover, we believe that the reconfiguration of GREC was done so in the "most effective commercially reasonable manner". For these reasons (and in light of GREC's willingness to assume the added costs of being required to employ reclaimed water), we believe that it is appropriate for the Contract Prices "be equitably adjusted to cover the additional costs" of the SCR and baghouse changes. We look forward to working with GRU on appropriate revisions to the PPA.

VI. Capital and Operating Cost Impacts of Technical Reconfiguration

The following section describes the modifications necessary to comply with changes to regulatory and permit requirements and the estimated costs associated with these modifications. There are four primary technological and operational changes involved with reconfiguring the GREC facility to comply with the changing regulatory requirements.

1. Replacement of SNCR with SCR

Earlier this fall, GREC LLC executed an equipment supply contract with Metso to supply the boiler for the GREC project. As part of this process, Metso needed to price out exactly what the change from an SNCR to SCR would be. As described in the letter from Metso dated October 14, 2010 attached as Attachment 3, the shift from utilizing an SNCR to an SCR requires lengthening the boiler "footprint" by approximately fifty (50) feet to allow re-arranging the boiler heat transfer surface, installation of an SCR reactor with an ammonia injection grid (AIG), and upgrading the baghouse filter to operate at elevated gas temperatures.

A summary of the boiler modifications on an installed basis are as follows:

- Eliminate SNCR ammonia injection nozzles and metering in the upper furnace
- Addition of a new bay, platforms, and structural support steel between columns 6 and 7
- Redesign the tubular air heater to a "split" arrangement
- Redesign all flue gas ductwork and supports from the tubular air heater to ID fan inlet
- Upgraded "hot" baghouse filter with high temperature bags
- Addition of ammonia injection grid (AIG) and SCR inlet ductwork including mixers and flow straighteners
- Redesign ammonia forwarding skid with vaporizer for AIG
- Addition of a one-plus-one SCR reactor including instruments and analyzers
    - One level of standard modules of 4.9 mm pitch vanadium-based catalyst (~80 m^3)
- Catalyst lifting device
- Larger ID fan to accommodate increased flue gas pressure drop
- SCR Training and Startup Advisors
- Addition of sodium-based dry sorbent injection system (DSI) at the economizer outlet
- Addition of lime-based DSI at the baghouse inlet duct

The present-day installed price for Metso to modify the originally proposed BFB boiler island to the requirements for the GREC project to incorporate the above noted modification is $15,300,000.

In addition to the Metso costs, there are additional capital costs for the engineer, procure, construct (EPC) contractor due to the increased boiler footprint, increased piping and electrical and instrumentation run lengths, and additional insulation. In October 2010, GREC LLC executed a "full-wrap" EPC contract with Fagen, Inc.

Based on the information from Metso, Fagen estimates in its letter dated October 14, 2010, attached as Attachment 4 that the larger footprint translates to a change in foundation sizing by an increased length of approximately 50 linear feet. This affects balance of plant construction by increasing concrete quantity for the boiler, as well as an increase in deep piling to support it. All of the appurtenant items to concrete such as rebar and steel embedments would increase proportionately as well.

Fagen further estimates that piping is slightly affected by the increase in the amounts for sorbent injection and ammonia injection. Ammonia forwarding pumps would also be slightly upsized to handle increased flow requirements. The ammonia tank also needs to be larger.

Fagen also estimates that electrical and instrumentation costs are also increased due to added run lengths due to increased boiler length and increased boiler auxiliary loads which will necessitate additional wiring and size to accommodate the added horsepower. These changes will affect tray, conduit, wire and cable, terminations, and instrumentation.

Finally, Fagen estimates that there would be additional insulation required for the SCR.

The following is a breakdown from Fagen of the additional costs caused by the shift from the SNCR to the SCR:

• Concrete, rebar, embeds	$386,000
• Piling	$162,500
• Piping	$53,500
• Electrical & Instrumentation	$323,050
• Insulation	$225,000
Total	**$1,150,050**

The total additional capital costs required to shift from an SNCR to an SCR, as estimated by Metso and Fagen is therefore $16,450,050.

As described above, the SCR is designed to accommodate two catalyst layers. The initial layer will be installed and is expected to operate for 16,000 hours after which time the second layer will be installed. The catalyst management plan is to replace a given layer of catalyst every third year. It is estimated that the cost to remove and replace catalyst will average out to approximately $1,500,000 every third year ($500,000 per year); including disposal cost of the old catalyst, which can be classified as a hazardous waste. For each year, a maintenance cost provision to clean and inspect, analyze catalyst samples and make routine repairs is predicted to be $150,000. The total operational cost impact is estimated to be $650,000 per year.

2. *Change from calcium-based DSI system to sodium-based DSI system*

As noted in the air emissions table in Attachment 2, the former emission requirements for SO_2 and HCl are achievable through the chemical reactions in the boiler combustion process based on the fuels to be fired, but in order to meet the former emission requirement for H_2SO_4, a calcium base (hydrated lime) dry sorbent injection (DSI) system was needed. The use of hydrated lime is not sufficient to comply with the new emission limits imposed by FDEP under its changing regulatory requirements. The new, lower emission limits required a more aggressive control of HAPS (namely HF and HCl), as well as H_2SO_4 and SO_2, with the use of a DSI system. The GREC project is located very close to a low-cost hydrated lime supply source, which would be ideal for a hydrated lime injection system. However, with the inclusion of the SCR into the flue gas cleaning requirements, the need to significantly reduce or nearly eliminate all SO_2/SO_3 going to the SCR is required. This is to remove the potential for formation of ammonia bisulfate, a reaction between ammonia and SO_2/SO_3, which at lower temperatures causes high fouling in the catalyst beds and is extremely difficult to remove. Further, as oxidation occurs through the catalyst some SO_3 is reformed, which then has an impact on the H_2SO_4 guarantee level. In designing the system, Metso needed to be cognizant of these issues and essentially needed to reduce the given levels of SO_2 and SO_3 to a point low enough such that they can still meet the SO_2 and H_2SO_4 emission levels leaving the flue gas stack. Given the fuels to be fired, the required amount of sulfur reduction required beyond the self-reduction that is accomplished within the boiler exceeds the capability of a calcium-based system. A sodium-based injection system is therefore required.

For the sodium-based DSI, the GREC project will utilize trona as the sodium carbonate. Unfortunately, trona is not widely available and comes from a greater distance than hydrated lime. Based on estimates from potential suppliers, American Renewables estimates that the hydrated lime for a calcium-based DSI would have cost $250,000 per year (approximately 2,130 tons/yr (540 lbs/hr) at $117/ton) while the trona will cost $525,000 (approximately 2,130 tons/yr (540 lbs/hr) at $247/ton). So the operational cost impact for using a sodium-based DSI system is estimated to be $275,000 per year.

3. *Fly ash can no longer be beneficially re-used*

American Renewables stated in the RFP Response that we believe that "it will be possible to beneficially reuse the ash as a soil amendment". This is standard practice for many biomass energy facilities. Unfortunately, the use of trona in the DSI system will contaminate the fly ash and make it unusable as a soil amendment. GREC LLC will now need to properly dispose of the fly ash as a low-level hazardous waste at a certified landfill. American Renewables assumes that approximately 12,500 tons per year of contaminated fly ash will need to be disposed of at a cost of $50 per ton (includes hauling and tipping fee). The operational cost impact due to the contaminated fly ash will be $625,000 per year. If, in the future, an alternative use/process is discovered which would reduce, or eliminate, the disposal cost of the contaminated fly ash, American Renewables agrees that it would be appropriate for the Parties to re-evaluate and adjust the Contract Prices to reflect this change.

4. *Facility heat rate increases*

As stated above, the impact of adding the SCR resulted in a higher pressure drop through the boiler and a resulting increase in ID fan power (5,950 kW to 6,878 kW) that impacted the auxiliary load. The other impact on the auxiliary load resulted from the lower CO emission rate of 0.08 lbs/mmBtu that required increased air flow through the boiler to optimize combustion resulting in lower CO and VOC emission levels to meet the changing regulatory requirements. American Renewables estimates that the facility heat rate will increase by 928 kW which results in 106 Btu per kWh, or about 1.1 tons per hour of additional biomass fuel. American Renewables estimates that the extra biomass fuel will cost $225,000 per year.

Summary of capital and operating cost impacts of technical reconfiguration

Due to the four primary technological and operational changes involved with reconfiguring the GREC facility to comply with the changing regulatory requirements, there is a total increase of $16,450,050 in capital costs and $1,775,000 in annual operational costs.

Technological/Operational Change	Capital Cost Impact	Operational Cost Impact
1. Replacement of SNCR with SCR	$16,450,050	$650,000
2. Change from calcium-based DSI system to sodium-based DSI system	N/A	$275,000
3. Fly ash can no longer be beneficially re-used	N/A	$625,000
4. Facility heat rate increases	N/A	$225,000
Total	**$16,450,050**	**$1,775,000**

VII. Notice of Request for Changes to Contract Prices

To cover these additional costs as provided for in Section 3.2 of the PPA, American Renewables submits that the following proposal to equitably adjust the Contract Prices within the PPA is appropriate. First, assuming a 13% weighted-average cost of capital (WACC), the cost per year over the 30 year PPA of the $16,450,050 capital cost increase is $2,195,000. American Renewables proposes to recover this amount through an increase in the non-escalating Non-Fuel Energy Charge of $2.784 per MWh. Second, to account for the $1,775,000 annual operational cost increase, American Renewables proposes to increase the escalating Variable O&M Charge by $2.251 per MWh.

Alternative Proposal

During our meeting on October 19, 2010, GRU asked American Renewables to consider accounting for the facility heat increase through an adjustment in the conversion factor in the "Base Fuel Charge" definition within the PPA. American Renewables has considered this request and is willing to adjust the "Base Fuel Charge" definition to read:

> *"Base Fuel Charge" means, for each calendar year, the Target Fuel Price x 1.36 (tons/MWh).*

The conversion rate has been increased from 1.35 tons/MWh to 1.36 tons/MWh.

If this alternative proposal is chosen, the operational cost increase would be reduced to $1,550,000 and the Variable O&M Charge would only need to be increased by $1.966 per MWh. The increase to the Non-Fuel Energy Charge would remain at $2.784 per MWh.

Attachment 1

GREC Project Development Timeline

Date	Action
October 8, 2007	GRU initiated two-step request for proposal (RFP) process to solicit biomass-fueled electric generation
December 14, 2007	GREC LLC (d/b/a Nacogdoches Power, LLC) submitted initial RFP response
April 11, 2008	GREC LLC submitted revised RFP Response ("RFP Response")
May 12, 2008	Gainesville City Commission voted unanimously to authorize GRU to negotiate a PPA with GREC LLC
April 29, 2009	PPA was executed between GRU and GREC LLC
May 7, 2009	PPA was unanimously approved by Gainesville City Commission
May 12, 2009	GREC LLC conducted initial meeting with FL Department of Environmental Protection (FDEP) Siting Office and Division of Air Resource Management
June 24, 2009	GREC LLC conducted pre-application scoping meeting with FDEP
August 31, 2009	GREC LLC discussed with GRU the change in regulatory requirements that necessitated making a change from SNCR to Selective Catalytic Reduction (SCR)
September 18, 2009	GRU and GREC LLC jointly filed the Need Determination Application with FL PSC
November 30, 2009	GREC LLC filed the Site Certification Application (SCA) and PSD permit application with FDEP
June 8, 2010	Al Linero (FDEP DARM) spoke to Tom Davis (ECT) about the proposed "netting solution" with respect to GREC's NO_x and SO_2 emissions
June 18, 2010	GRU agreed to FDEP's netting proposal
June 23, 2010	GREC LLC and GRU met with Al Linero and David Read (FDEP DARM) to discuss the netting proposal and other PSD issues
June 30, 2010	Al Linero raised questions about GREC's proposed CO/VOC emissions rates
July 7, 2010	Al Linero raised questions about GREC's proposed HAPs emissions
July 13, 2010	GREC LLC conducted a conference call with Al Linero and Trina Vielhauer (FDEP) to discuss outstanding PSD issues
July 14, 2010	FDEP issued draft PSD permit to GREC

Attachment 2

GREC Air Emissions

Emissions	Emission Requirements in RFP Response (lb/mmBtu, HHV)	Proposed Emissions Requirements in PSD Permit Application (lb/mmBtu, HHV)	Current Emissions Requirements In Draft PSD Permit (lb/mmBtu, HHV) [(a)]
SO_2	0.046	0.041	0.029 [(b)]
NOx	0.100	0.070	0.070
CO	0.150	0.120	0.080 [(c)]
VOC	0.020	0.013	0.009 [(d)]
PM_{10} (front half catch)	Not Addressed	0.015	0.015
PM_{10} Total	0.032	0.042	Not Addressed
HCl	0.020	0.0060	2.22 lb/hr[(b)(e)]
HF	Not Required	0.0120	2.22 lb/hr[(b)(e)]
∑ HCl, HF, Organic HAP, Metal HAP	Not Required	Not Required	5.63 lb/hr[(f)]
H_2SO_4	0.003	0.0010 [(b)]	1.4 lb/hr[(b)(g)]
Opacity	Not Addressed	Not to exceed 20% (6-minute average) except for one 6-minute period per hour of not more than 27%	Not to exceed 10% (6-minute average) except for one 6-minute period per hour of not more than 20% [(h)]
Ammonia Slip	Not Addressed	10 ppmvd dry corrected to 7% O2	10 ppmvd dry corrected to 7% O2

(a) Emission level for Lead (Pb) on a weight basis shall be equivalent to the weight of such element in the incoming fuel. Owner shall be responsible for procurement of biomass fuel that complies with the Design Fuel and air permit requirements with respect to Lead (Pb).

(b) Requires use of dry sorbent injection system

(c) CO emissions must meet at least 0.12 lb/MMBtu during Year 1; thereafter 0.08 lb/MMBtu.

(d) VOC emissions must meet at least 0.010 lb/MMBtu during Year 1: thereafter 0.009 lb/MMBtu

(e) Equates to 0.00163 lb/MMBtu at boiler design conditions

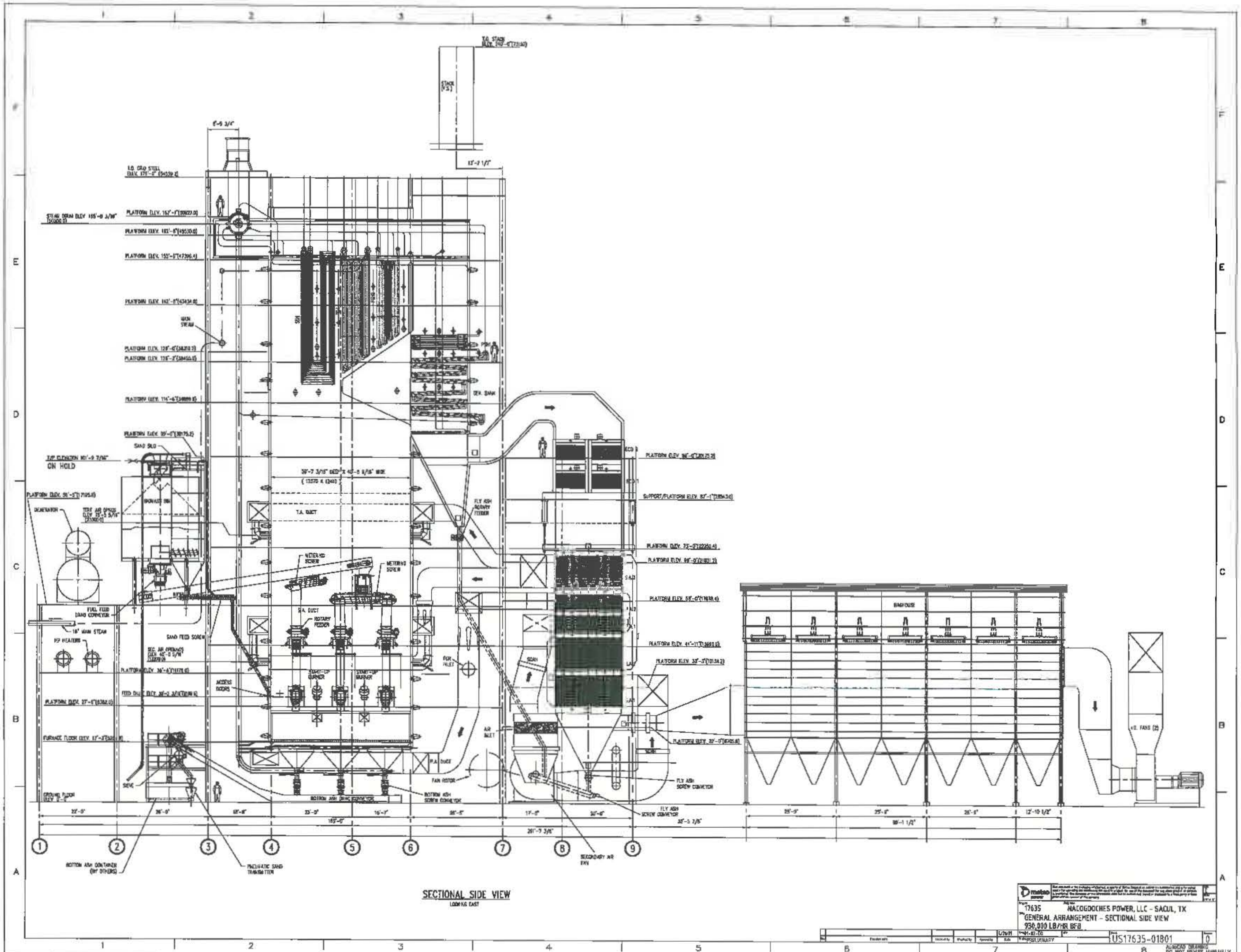
(f) Sum (∑) of the following hazardous air pollutants (HAP): HCl, HF, organic HAP = [C_3H_4O (acrolein), C_6H_6 (benzene), CH_2O (formaldehyde), C_8H_{10} (xylene isomers plus ethyl benzene), CH_3Cl (methyl chloride), CH_3CCl_3 (methyl chloroform), C_2H_4O (acetaldehyde), C_7H_8 (toluene), PAH/POM (polycyclic aromatic hydrocarbon/polycyclic organic matter)] and metal HAP = [Cr (chromium), Pb (lead), Mn (manganese), P (phosphorus)].

(g) Equates to 0.001 lb/MMBtu at boiler design conditions

(h) Limit to apply during startups, shutdowns, and periods of malfunction.

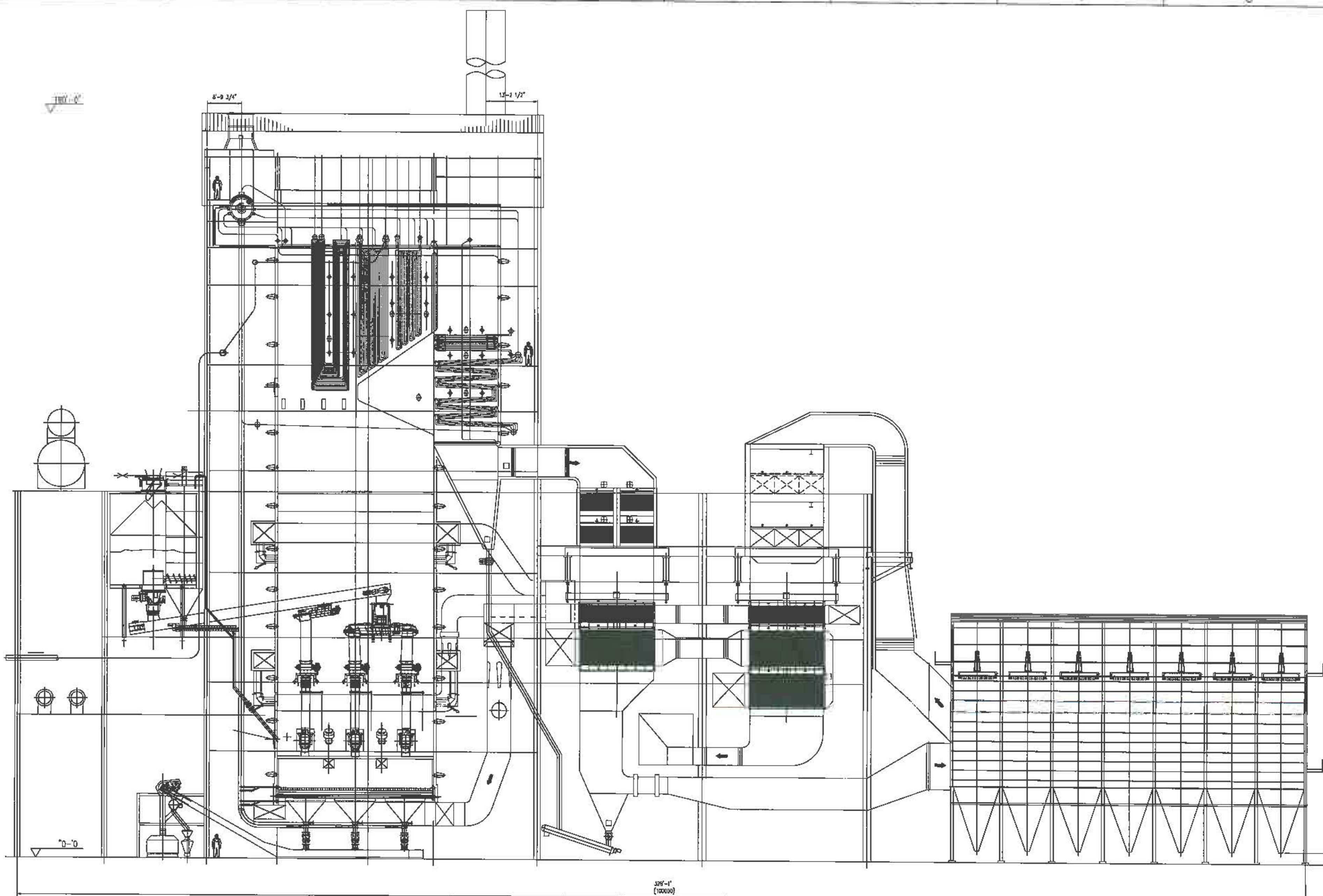
Attachment 3

NP General Arrangement – Sectional Side View (April 2009)


SECTIONAL SIDE VIEW
LOOKING EAST
BAGHOUSE
I.D. STACK
STACK
MAIN STEAM
DEAERATOR
BP HEATERS
T.A. DUCT
S.A. DUCT
METERING SCREW
ROTARY FEEDER
START-UP BURNER
ACCESS DOORS
SAND FEED SCREW
FUEL FEED DRAG CONVEYOR
SAND SILO
ON HOLD
FAN ROTOR
AIR INLET
P.A. DUCT
FLY ASH SCREW CONVEYOR
FLY ASH ROTARY FEEDER
BOTTOM ASH SCREW CONVEYOR
SECONDARY AIR FAN
BOTTOM ASH CONTAINER (BY OTHERS)
PNEUMATIC SAND TRANSMITTER
SIEVE
GROUND FLOOR
17635
NACOGDOCHES POWER, LLC - SACUL, TX
GENERAL ARRANGEMENT - SECTIONAL SIDE VIEW
930,000 LB/HR BFB
PRELIMINARY
US17635-01801
0
AUTOCAD DRAWING
DO NOT REVISE MANUALLY

Attachment 4

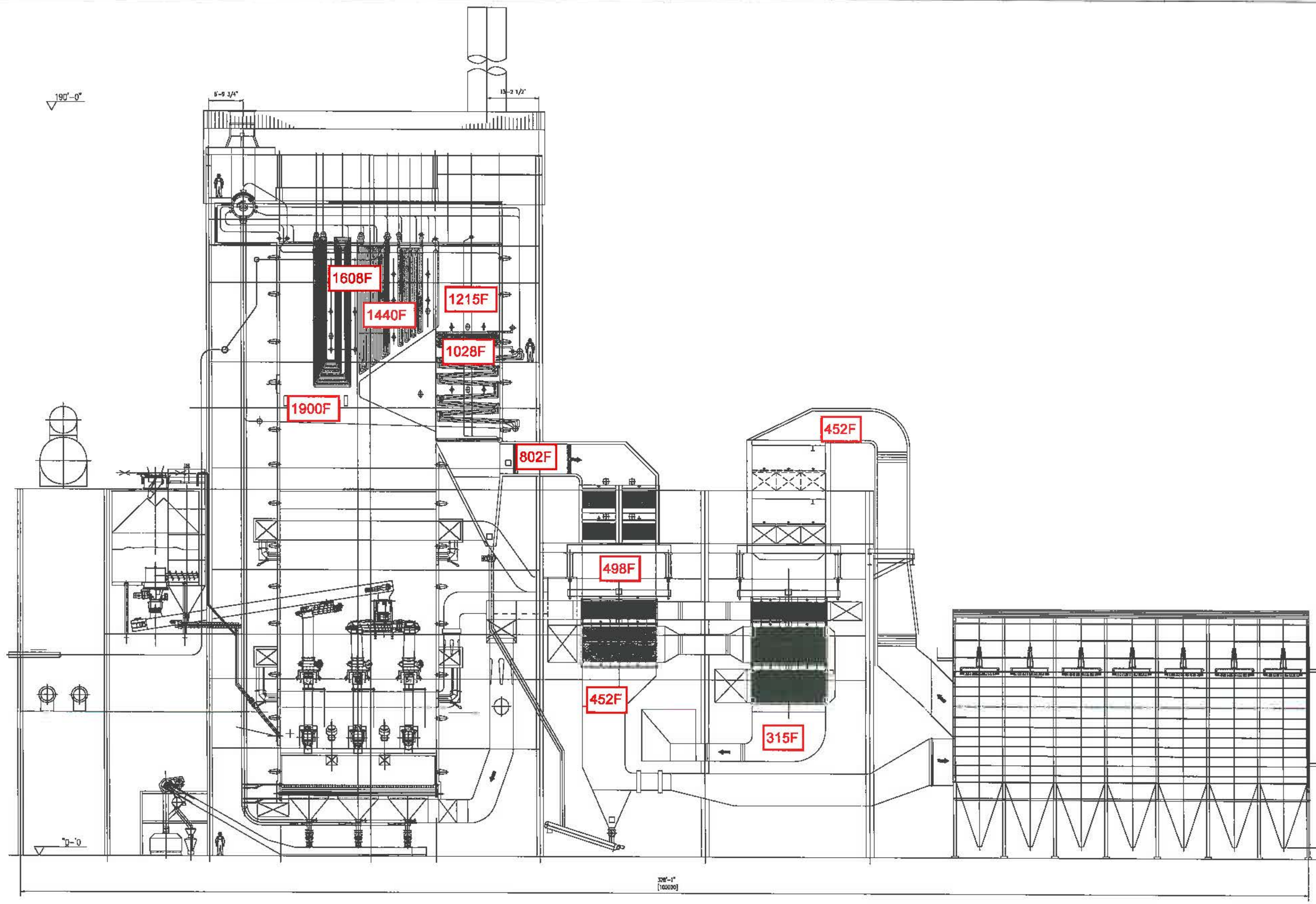
GRFC General Arrangement – Sectional Side View (January 2010)



metso
N00013
GAINESVILLE RENEWABLE ENERGY CENTER, LLC
100MWe BFB BOILER LAYOUT
SECTIONAL SIDE ELEVATION (TYPICAL)
PRELIMINARY
USN00013-00001
0
AutoCAD DRAWING
DO NOT REVISE MANUALLY

Attachment 5

GREC General Arrangement – Sectional Side View with Temperatures (January 2010)



Temperatures per Predicted Performance,
45% fuel moisture case

N00013 GAINESVILLE RENEWABLE ENERGY CENTER, LLC
100MWe BFB BOILER LAYOUT
SECTIONAL SIDE ELEVATION (TYPICAL)
PRELIMINARY
USN00013-00001
0
AutoCAD DRAWING DO NOT REVISE MANUALLY

Attachment 6

Metso Power Letter – October 14, 2010

October 14, 2010

Ari Mervis
American Renewables, LLC
75 Arlington Street, 5th Floor
Boston, MA 02116

Reference: American Renewables - GREC Project
Metso Power Reference No. N00013
EPC Boiler Island – Environmental Impact

Dear Ari,

Metso Power is pleased to be supplying a bubbling fluid bed (BFB) boiler island for the proposed Gainesville Renewable Energy Center project. You have asked Metso to quantify impacts to the design, installation and operation of the boiler island as a result of changes in the air emissions requirements for the project.

There have been substantial modifications to the air emissions limits imposed on Metso. The project will achieve lower levels of NOx, SO_2 and Hazardous Air Pollutants (HAPs) than were previously anticipated to be required by environmental regulators for fluidized bed renewable energy projects. The following table illustrates the baseline (former) and current emissions requirements:

Emissions [h]	Current Emission Requirements (lb/MMBtu, HHV)	Former Emissions Requirements (lb/MMBtu, HHV)
SO_2	0.029 [e]	0.046
NOx	0.070	0.100
CO	0.080 [a]	0.150
VOC	0.009 [b]	0.013
PM_{10} (front half catch)	0.015	0.015
PM_{10} Total	0.042	0.032
HCl	2.22 lb/hr [e][f]	0.020
HF	2.22 lb/hr [e][f]	Not required
Σ HCl, HF, Organic HAP, Metal HAP	5.63 lb/hr [c]	Not required
H_2SO_4	1.40 lb/hr [e][g]	0.001 [e]
Opacity	Not to exceed 10% (6-minute average) except for one 6-minute period per hour of not more than 20% [d]	Not to exceed 20% (6-minute average) except for one 6-minute period per hour of not more than 27%
Ammonia Slip	10 ppmvd dry corrected to 7% O2	15 ppmvd dry corrected to 7% O2

(a) CO emissions must meet at least 0.12 lb/MMBtu during Year 1; thereafter 0.08 lb/MMBtu.
(b) VOC emissions must meet at least 0.010 lb/MMBtu during Year 1; thereafter 0.009 lb/MMBtu
(c) Sum (Σ) of the following hazardous air pollutants (HAP): HCl, HF, organic HAP = [C_3H_4O (acrolein), C_6H_6 (benzene), CH_2O (formaldehyde), C_8H_{10} (xylene isomers plus ethyl benzene), CH_3Cl (methyl chloride), CH_3CCl_3 (methyl chloroform), C_2H_4O (acetaldehyde), C_7H_8 (toluene), PAH/POM (polycyclic aromatic hydrocarbon/polycyclic organic matter)] and metal HAP = [Cr (chromium), Pb (lead), Mn (manganese), P (phosphorus)].
(d) Limit to apply during startups, shutdowns, and periods of malfunction.
(e) Requires use of dry sorbent injection system
(f) Equates to 0.00163 lb/MMBtu at boiler design conditions
(g) Equates to 0.001 lb/MMBtu at boiler design conditions
(h) Emission level for Lead (Pb) on a weight basis shall be equivalent to the weight of such element in the incoming fuel. Owner shall be responsible for procurement of biomass fuel that complies with the Design Fuel and air permit requirements with respect to Lead (Pb).

Metso Power, 3430 Toringdon Way, Ste.201, Charlotte, NC 28277 USA
Telephone: 704-541-1453 Fax 704-541-1128 www.metso.com

To reduce NOx emissions to the new requirement will exceed the control efficiency of Selective Non-Catalytic Reduction (SNCR) technology such that it will be insufficient alone when applied to the BFB boiler. SNCR technology, combined with in-furnace staged-combustion, is considered sufficient to sustain NOx emissions down to 0.10 lb/MMBtu on a 30-day rolling average basis with the fuels anticipated for this base-loaded project. The use of SNCR technology has in the very recent past been considered BACT for fluidized bed boiler applications.

To meet the new NOx emission level, the use of Selective Catalytic Reduction (SCR) technology is now required. In integrating this technology Metso Power proposes to locate the SCR downstream of a baghouse filter (BHF), which works to significantly reduce the fouling and poisoning elements contained in the biomass flue gas; thus, yielding predictable NOx reduction and long catalyst life. To maximize the SCR deNOx efficiency using vanadium-based catalyst, the SCR will need to be placed in the boiler backpass at a flue gas temperature well above normal stack temperature. This will require lengthening the boiler "footprint" by approximately fifty (50) feet to allow re-arranging the boiler heat transfer surface, installation of an SCR reactor with an ammonia injection grid (AIG), and upgrading the BHF to operate at elevated gas temperatures.

However, while the need to reduce NOx emissions requires an SCR, the use of this technology poses additional complications when considering the need to also meet the new emission levels for SO_2, H_2SO_4, and the various identified HAPs. As noted in the table above, the former emission requirements for SO_2 and HCl are achievable through the chemical reactions in the boiler combustion process based on the fuels to be fired, but in order to meet the former emission requirement for H_2SO_4, a calcium base (hydrated lime) dry sorbent injection system was needed. This is not the case when considering the new emission requirements. The lower required levels demand the aggressive control of HAPS (namely HF and HCl), as well as H_2SO_4 and SO_2, with the use of a dry sorbent injection (DSI) system. The GREC project is located very close to a low cost hydrated lime supply source, which would be ideal for a hydrated lime injection system; however, with the inclusion of the SCR into the flue gas cleaning requirements, the need to significantly reduce or nearly eliminate all SO_2/SO_3 going to the SCR is required. This is to remove the potential for formation of ammonia bisulfate, a reaction between ammonia and SO_2/SO_3, which at lower temperatures causes high fouling in the catalyst beds and is extremely difficult to remove. Further, as oxidation occurs through the catalyst some SO_3 is reformed, which then has an impact on the H_2SO_4 guarantee level. In designing the system we need to be quite cognizant of these issues and essentially need to reduce the given levels of SO_2 and SO_3 to a point low enough such that we can still meet the SO_2 and H_2SO_4 emission levels leaving the flue gas stack. Given the fuels to be fired, the required amount of sulfur reduction required beyond the self reduction that is accomplished within the boiler exceeds the capability of a calcium based system. A sodium based injection system is therefore required.

The dry injection system proposed is designed for two systems, each capable of injecting sorbent at different locations in the back pass of the unit. It is anticipated that the first stage will utilize a sodium-based reagent (to reduce SO_2 and SO_3 primarily) and will be located in the ductwork after the economizer. The second stage will be located to inject sorbent after the air heater in the BHF inlet duct. This provides alternative locations to determine which area is most effective in achieving the needed emission results. As the experience on SCR technology for biomass applications is quite limited, American Renewables felt that the latter stage of injection could be utilized to test the use of hydrated lime which would result in a lower consumption cost for sorbent usage. However, for Metso Power to extend the required emissions guarantees at this time, the use of a sodium based system is required.

A summary of the boiler modifications on an installed basis are as follows:

- Eliminate SNCR ammonia injection nozzles and metering in the upper furnace
- Addition of a new bay, platforms, and structural support steel between columns 6 and 7
- Redesign the tubular air heater to a "split" arrangement
- Redesign all flue gas ductwork and supports from the tubular air heater to ID fan inlet
- Upgraded "hot" baghouse filter with high temperature bags
- Addition of ammonia injection grid (AIG) and SCR inlet ductwork including mixers and flow straighteners
- Redesign ammonia forwarding skid with vaporizer for AIG
- Addition of a one-plus-one SCR reactor including instruments and analyzers
  - One level of standard modules of 4.9 mm pitch vanadium-based catalyst (~80 m^3)
- Catalyst lifting device
- Larger ID fan to accommodate increased flue gas pressure drop
- SCR Training and Startup Advisors
- Addition of sodium-based dry sorbent injection system (DSI) at the economizer outlet
- Addition of lime-based DSI at the baghouse inlet duct

With the new emissions requirements, the present-day installed price to modify the former BFB boiler island to the requirements for the GREC project to incorporate the above noted scope, is ....$15,300,000 USD.

In addition to the initial capital cost, the ongoing reagent usage at MCR is predicted to be as follows: (Note: comparison is provided to show the differing consumption rates for the given emission requirements)

	SCR / DSI	SNCR
	Current Emission Requirements	Former Emission Requirements
Ammonia flow, lb/hr	400	600
Lime usage, lb/hr	NA	<100
Sodium bicarbonate usage, lb/hr	540	NA

The SCR is designed to accommodate two catalyst layers. The initial layer will be installed and is expected to operate for 16000 hours after which time the second layer will be installed. The catalyst management plan is to replace a given layer of catalyst every third year. It is estimated that the cost to remove and replace catalyst will average out to approximately $1,500,000 USD every third year; including disposal cost of the old catalyst, which in some States can be classified as a hazardous waste. For each year, a maintenance cost provision to clean and inspect, analyze catalyst samples and make routine repairs is predicted to be $150,000 USD.

We trust this information provides you with sufficient input from your boiler island supplier's perspective to meet the new emissions requirements. Should you have any questions, please let us know.

Sincerely,

METSO POWER

Kerry R. Flick

Kerry R. Flick
General Manager – Technology

Attachment 7

Fagen, Inc. Letter – October 14, 2010

FAGEN INC.
Civil - Mechanical - Electrical Contactors
www.fageninc.com
3001 South Lincoln Ave.
Steamboat Springs, CO 80487
Phone: 970.879.8310
Fax: 970.871.1769

October 14, 2010

Mr. Len Fagan
American Renewables
75 Arlington Street, 5th Floor
Boston, MA 02116

RE: Gainesville Renewable Energy Center 100 MW Biomass Power Plant - Environmental Impact to EPC Contract Cost

Dear Len,

In response to the more stringent emissions requirements required for this specific project, we have determined impact in several areas of construction-related work due to the replacement of the selective non-catalytic reduction (SNCR) with a selective catalytic reduction (SCR) system. This replacement has basically changed the configuration of the boiler into a larger footprint.

The larger footprint translates to a change in foundation sizing by an increased length of approximately 50 lineal feet. This affects balance of plant construction by increasing concrete quantity for the boiler, as well as an increase in deep piling to support it. All of the appurtenant items to concrete such as rebar and steel embedments would increase proportionately as well.

Piping is slightly affected by the increase in the amounts for sorbent injection and ammonia injection. Ammonia forwarding pumps would also be slightly upsized to handle increased flow requirements. The ammonia tank also needs to be larger.

Electrical & Instrumentation costs are also increased due to added run lengths due to increased boiler length and increased boiler auxiliary loads which will necessitate additional wiring and size to accommodate the added horsepower. These changes will affect tray, conduit, wire and cable, terminations, and instrumentation.

The last construction discipline affected would be the additional insulation required for the SCR.

The following is a breakdown of the additional costs caused by the SCR replacement:

• Concrete, rebar, embeds	$386,000
• Piling	$162,500
• Piping	$53,500
• Electrical & Instrumentation	$323,050
• Insulation	$225,000
Total	**$1,150,050**

The above costs reasonably depict the affect of the SCR replacement of the original SNCR concept. If you should have any questions or require further clarification please don't hesitate to give me a call at (970) 879-8310, ext 4202.

Thank you,

R.Scott MacFarland,
Vice President

EXHIBIT "B"

ORRICK

MEMORANDUM

To	Gainesville Regional Utilities
From	Orrick, Herrington & Sutcliffe LLP
Date	December 20, 2010
Re	Power Purchase Agreement with Gainesville Renewable Energy Center, LLC

Gainesville Regional Utilities ("GRU") and Gainesville Renewable Energy Center, LLC ("GREC LLC") entered into a Power Purchase Agreement ("PPA") on April 29, 2009. The PPA calls for GREC LLC to construct a power plant that contemplated the use of a Selective Non-Catalytic Reduction ("SNCR") system to limit emissions of oxides of nitrogen ("NOx"). Thereafter, the Florida Department of Environmental Protection ("FDEP") required GREC LLC to install a more costly Selective Catalytic Reduction ("SCR") system. GREC LLC did not challenge that decision.

You received a memorandum from GREC LLC dated November 15, 2010. The memorandum claims that GRU employee Ed Regan ("Regan") told GREC LLC that the FDEP's decision to require the use of a SCR system falls within the PPA's change-in-law provision and that GRU would, as required by the change-in-law provision, equitably adjust the rates it agreed to pay under the PPA. You inform us that Regan was not authorized to make this concession, and in an email dated January 9, 2010, you set forth the limits of Regan's authority and facts relevant to whether it was reasonable for GREC LLC to believe that he had the authority to bind GRU.

We have considered whether the FDEP's decision to require GREC LLC to install a SCR system constitutes change in law under the PPA; whether Regan had apparent authority to provide a binding interpretation of the PPA; whether GREC LLC will be able to rely on parol evidence to show that the FDEP's decision falls within the PPA's change in law provision; and whether reformation of the PPA is available to GREC LLC as a remedy.

Summary Answer

The FDEP's decision to require the use of a SCR system does not fall within the change-in-law provision because there was, quite simply, no change in law. Instead, the FDEP's decision – although not necessarily expected – was based on the long-standing Best Available Control Technology ("BACT") regulatory standard that was in effect at the time the parties entered into the PPA. Regan did not have apparent authority to bind GRU because GRU did nothing to lead GREC LLC to believe that he was authorized to provide a binding interpretation of the PPA. Since the

PPA's change-in-law provision is not ambiguous, GREC LLC will be unable to submit parol evidence to show that the parties intended the change-in-law provision to encompass the FDEP's refusal to permit the use of a SNCR system. Finally, GREC LLC does not have grounds to seek reformation of the PPA.

Background Facts

By entering into the PPA, GREC LLC agreed to construct and operate a 100 MW(net) biomass-fired electricity generating facility ("Facility") in Alachua County, Florida and GRU agreed to purchase all power produced by the Facility at a rate specified in the PPA. The PPA contemplates that the Facility will utilize a SNCR system to limit emissions of NOx, and when the PPA was executed, GRU and GREC LLC both believed that the use of a SNCR system would meet the air emissions control requirements imposed by the FDEP.

In May, 2009, GREC LLC met with the FDEP to discuss the Prevention of Significant Deterioration ("PSD") air permit application it planned to file for the Facility later that year. In determining whether to issue a PSD permit, the FDEP applies the long-standing and discretionary BACT standard. At the meeting, the FDEP expressed its belief that it would be both economically and technically feasible for the Facility to use a SCR system, and that a SCR system – rather than the SNCR system GREC LLC proposed – would accordingly constitute BACT. Although SCR systems result in lower NOx emissions than SNCR systems, they are significantly more expensive.

After the FDEP reiterated its position that a SCR system would likely be required, GREC LLC decided to reconfigure the Facility's design plan to incorporate a SCR system. This decision was made in order to avoid permitting delays, and notwithstanding the additional $10 million in capital costs and increased operating expenses that GREC LLC claims it will incur as a result of the reconfiguration. GREC LLC believes, however, that it is entitled to have those additional costs shared by GRU pursuant to the PPA's change-in-law provision.[1] The change-in-law provision

[1] Section 3.2 of the PPA states:

> Change in Law. The Parties recognize and agree that the Contract Prices are based on the current regulatory requirements for generating and selling the Products. A "Change in Law" shall mean a change in any applicable law, regulation, permit, ordinance, market rule, or other of any governmental or regulatory authority, market regulator, court or arbitration tribunal enacted after the Effective Date where such change in law specifically increases or decreases the actual cost of generating and selling the Products, but it shall not include any such change in law that is not specifically directed toward generating facilities or which just has general economic effects that indirectly increase or decrease Seller's costs, nor shall it include any change in law with respect to the Production Tax credits, Renewable Energy Grant or Investment Tax Credits. If there is a Change in Law, then the Contract Prices shall be equitably adjusted to cover the additional costs, or pass on the additional savings, associated with generating and selling the Products. No claim for extra compensation based on a change in law that results in an increase in Seller's costs shall be presented by Seller or considered by Purchaser unless Seller shall first have provided written notice of such claim to Purchaser. No claim for a reduction in payments shall be presented by Purchaser or considered by Seller unless Purchaser shall first have provided written notice of such claim to Seller. Receipt of such notice shall in no event constitute acceptance

provides that if there is a change in law, the price GRU pays for energy under the PPA "shall be equitably adjusted" to cover additional costs, or to pass on additional savings. As used in the PPA, "Change in Law" is defined as "a change in any applicable law, regulation, permit, ordinance, market rule or order of any governmental or regulatory authority, market regulator, court or arbitration tribunal **enacted after the Effective Date** where such change in law specifically increases or decreases the actual cost of generating and selling the Products." (emphasis added)

Shortly after the decision was made to reconfigure the Facility to include a SCR system, GREC LLC employee Josh Levine ("Levine") spoke with Regan, who is GRU's Assistant General Manager, Strategic Planning. According to GREC LLC, Levine told Regan about the FDEP's stance regarding the use of a SNCR system and that using a SCR system would result in additional costs. GREC LLC claims that Levine and Regan discussed the added costs, "as well as the fact that this change constituted a 'change in law' as intended between the Parties to the PPA." Although the timing is not clear, GREC LLC further claims that after his discussion with Levine, Regan informed GREC LLC that the "GRU team discussed the situation and agreed that th[e] change from an SNCR to an SCR was appropriate and would constitute a 'change in law' under the terms of the PPA, and that some re-evaluation and adjustment of the Contract Prices between the Parties would need to occur at some appropriate point in the future."

Regan, as Assistant General Manager, has been GRU's "principal negotiator" with respect to the PPA's business terms. He reports directly to Bob Hunzinger ("Hunzinger"), GRU's General Manager for Utilities, who is expressly authorized by the Gainesville City Commission ("City Commission") to negotiate the PPA. Although the day-to-day contacts between GRU and GREC LLC are generally between Regan and members of the GREC LLC team, you explain that it should have been obvious to GREC LLC, and its CEO Jim Gordan ("Gordan"), that Hunzinger's approval is required for all substantive terms, and that Hunzinger is required to submit all such terms to the City Commission for approval. Hunzinger and Gordon both participated in and personally concluded negotiating the PPA, and Hunzinger executed the PPA on behalf of GRU. After it was signed, the PPA was presented to the City Commission for approval at a public meeting. Gordon and his team attended the meeting, where they addressed the City Commission.

Analysis

A. Change in Law Provision

Under the federal Clean Air Act ("CAA"), proposed facilities that will emit more than a threshold amount of certain air pollutants, including NOx, are subject to the PSD permit program.

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by either party of the validity of such claim for extra compensation. In the event of a dispute over a claim for extra compensation, Seller represents and agrees that it shall promptly and without interruption proceed with the generation of Products while any claim for a change in Contract Prices is being resolved. Seller shall comply with any Change in Law in the most commercially reasonable manner.

The PSD permit program requires use of the best available control technology (i.e., "BACT") to control and limit the emission of the enumerated air pollutants. 42 U.S.C. § 7475(a)(4). The CAA defines BACT as,

> an emissions imitation based on the maximum degree of reduction of each pollutant . . . emitted from . . . any major emitting facility, which the permitting authority, **on a case-by-case basis**, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such facility though the application of production processes and available methods, systems, and techniques . . . for control of each such pollutant.

42 U.S.C. § 7479(3) (emphasis added); 40 C.F.R. § 52.21(b)(12) (setting forth statutory definition). The FDEP implements the CAA's permitting requirements, and in doing so, it operates under Florida regulations based on standards set forth in the CAA. Florida's definition of BACT is the functional equivalent of its federal analogue in the CAA. See Fla. Admin Code Ann. r. 62-210.200(40)(a).

BACT is not a set numerical, technological or otherwise exact standard. Instead, BACT is the maximum degree of emissions reductions achievable at each individual facility, taking into account economic, energy and environmental factors. What constitutes BACT for each individual facility is determined by the relevant state's air permitting agency on a case-by-case basis. And in evaluating alternative emission control technologies for a specific facility, the state agency exercises discretion in balancing the relevant factors. GREC LLC explains that it proposed to limit the Facility's NOx emissions to 0.10 lb/mmBtu by using a SNCR system because two comparable facilities in Texas and Georgia received permits setting the same NOx limit and authorizing the use of SNCR systems. But while it is appropriate to look to comparable facilities for guidance on what might constitute BACT for a proposed facility, the permit requirements imposed on comparable facilities do not amount to established legal standards.

GREC LLC's memorandum does not refer to any changes made to laws, regulations, orders or legal requirements enacted after the PPA effective date, and a "change in law" – as the term is defined in the PPA – did not cause the FDEP to deny GREC LLC request to outfit the Facility with a SNCR system. The FDEP was by no means bound to impose the same NOx emission standards applied to the Texas and Georgia facilities GREC LLC looked to in proposing to use a SNCR system. The difference between the emissions standards applied to the Texas and Georgia facilities and the facility GREC LLC contracted with GRU to build is a function of the existing BACT standard – which, by its terms, mandates a "case-by-case analysis." Moreover, a change in BACT is not a change in law. BACT is designed to evolve over time in order to give permitting agencies, such as the FDEP, the authority to require new sources of air pollution to use the newest, most effective emissions controls as new technologies or techniques are developed and become technologically and economically feasible. No change or amendment to any law, statute, regulation, rule, or order is necessary for the FDEP to require a stricter or more expensive emission control technology – such as a SCR system – under the BACT standard.

The air emission control requirements imposed by the FDEP were based upon the discretionary BACT standard – a standard that has remained unchanged since before GRU and GREC LLC entered into the PPA. By exercising its discretion under the BACT standard, the FDEP did not "enact" a change in any "law, regulation, permit, ordinance, market rule or order." Instead, the FDEP's decision to require GREC LLC to install a SCR system was an exercise of its discretion within the parameters of the law as it existed on the day the PPA was signed. As such, there was no "change in law" under the PPA, and GRU is not contractually obligated to adjust the prices set in the PPA to account for the increased costs associated with installing and utilizing a SCR system.

B. Apparent Authority

GREC LLC, however, seeks to avoid the limitations of Section 3.2 by claiming that Mr. Regan has conceded on behalf of GRU that a change of law event has occurred. Mr. Regan did not have actual authority to make that binding concession, but a principal may be bound by an unauthorized agent's concession if the agent's apparent authority can be demonstrated. In Florida it is "well settled" that "apparent agency exists only if each of three elements are present: (a) a representation by the . . . principal; (b) reliance on that representation by a third party; and (c) change in position by the third party in reliance on the representation." Mobile Oil Corp. v. Bransford, 648 So. 2d 119, 121 (Fla. 1995). For apparent authority to arise, the principal's representation does not need to be express. See Overseas Private Invs. Corp. v. Dade County, 47 F.3d 1111, 1114 (11th Cir. 1995). Rather, "[a] principal can create the appearance of an agent's authority by knowingly permitting an agent to act in a certain manner as if he were authorized, by failing to correct a known misrepresentation by an agent that he or she has certain authority, or by silently acting in a manner which creates a reasonable appearance of an agent's authority." Ja Dan, Inc. v. L-J, Inc., 898 F. Supp. 894, 900 (S.D. Fla. 1995) (internal quotations, quotation marks and brackets omitted).

A third party's "subjective" reliance on the purported principal's representation of authority is insufficient. Quesada v. Mercy Hosp., 41 So. 3d 930, 931 (Fla. Dist. Ct. App. 2010). Instead, objectively reasonable reliance is required. Nat'l Auto Lenders, Inv. v. Syslocate, Inc., 686 F. Supp. 2d 1318, 1322 (S.D. Fla. 2010) ("[t]he reliance of a third party on the apparent authority of the principal's agent must be reasonable."). Moreover, the third party's reliance must "rest in the actions of or appearances created by the principal, and 'not by agents who often ingeniously create an appearance of authority by their own acts.'" Lensa Corp. v. Poinciana Gardens Ass'n, 765 So. 2d 296, 298 (Fla. Dist. Ct. App. 2000) (internal citation omitted) (quoting Taco Bell of Cal. v. Zappone, 324 So. 2d 121, 124 (Fla. Dist. Ct. App. 1975)).

GREC LLC cannot show that Regan had apparent authority to bind GRU because GRU did not allow or cause GREC LLC to believe that Regan was authorized to concede that the FDEP's refusal to permit the use of a SNCR system constitutes a change in law under the PPA. GREC LLC will point out that Regan was involved in negotiating the terms of the PPA, and that he represented GRU in its day-to-day dealings with GREC LLC. Negotiating terms and daily communications are not, however, the same thing as agreeing, in effect, to a substantial increase in the price term of a contract. GREC LLC was aware, based on its experience negotiating the PPA, that Hunzinger alone had the power to bind GRU with respect to the PPA. Indeed, it is Hunzinger's signature, not Regan's, found at the end of the PPA. Furthermore, the fact Gordon and others from GREC LLC attended the City Commission meeting where the PPA was presented for approval cuts sharply against any argument that GRU made it seem as if Regan could bind GRU. If City Commission approval was required for the PPA to take effect, and it was Hunzinger who concluded the PPA negotiations and signed the agreement, GREC LLC will be hard pressed to argue that GRU made it appear as if Regan – an assistant general manager, who dealt with the nitty-gritty of day-to-day relations – was somehow possessed of the authority to bind GRU to an interpretation of the PPA.

GREC LLC may attempt to rely on the fact that Regan purportedly said that he had "discussed" the issue with "the GRU team," and that the team agreed that the FDEP's decision not to allow use of a SNRC system constitutes a "change in law." But standing alone, Regan's statement that he checked with the "GRU team" and that the team agreed with his interpretation of the PPA is irrelevant; GREC LLC's reliance must "rest in the actions of or appearances created by the principal, and 'not by agents who often ingeniously create an appearance of authority by their own acts.'" Lensa Corp., 765 So. 2d at 298.

Based on the facts provided, GRU in no way allowed or caused GREC LLC to believe that Regan was authorized to provide a binding interpretation of the PPA's change-in-law provision. Moreover, since GREC LLC was fully aware – prior to Regan's representations regarding the change-in-law provision – that Hunzinger had concluded the negations over and signed the PPA, and that the PPA required City Commission approval, any reliance on GRU's purported representations of authority would not be reasonable. Regan did not, therefore, have apparent authority to bind GRU to an interpretation of the PPA.

In addition to apparent authority, Florida law recognizes a nominally distinct doctrine of "agency by estoppel." Whetstone Candy Co. v. Kraft Foods, Inc., 351 F.3d 1067, 1078 n.15 (11th Cir. 2003). But the doctrines of apparent agency and agency by estoppel are substantively identical, State of Florida, Dep't of Transp. v. Heckman, 644 So. 2d 527, 529 (Fla. Dist. Ct. App. 1994) (explaining that there are "no significant differences" between apparent agency and agency by estoppel), and therefore GRU will not be estopped from denying Regan's authority to provide a binding interpretation of the PPA. An agency relationship may also be established by ratification, which "occurs when the principal is *fully informed* of the agent's act and *affirmatively* manifests an intent to approve that act." Stalley v. Transitional Hosp. Corp of Tampa, 44 So. 3d 627, 631 (Fla. Dist. Ct. App. 2010). GRU has not, however, even intimated that it agrees with Regan's interpretation of the PPA, let alone "clearly show[n] an intention to be bound." Id. Since neither agency by estoppel nor ratification will prevent GRU from denying Regan's authority, it seems clear that GRU will not be bound by his unauthorized statements concerning the scope of the change-in-law provision.

C. Parol Evidence Rule

GREC LLC also cannot bring the FDEP's decision to require the use of a SCR system within the PPA's change-in-law provision by arguing that the provision is ambiguous. Florida law distinguishes between two forms of ambiguity, latent and patent. See Landis v. Mears, 329 So. 2d 323, 325 (Fla. Dist. Ct. App. 1976). A latent ambiguity exists, "if a contract fails to specify the rights or duties of the parties under certain conditions or in certain situations, and the occurrence of such condition or situation reveals an insufficiency in the contract not apparent from the face of the document." Handi-Van, Inc. v. Broward Cnty., No. 08-62080, 2010 WL 1223776, at *2 (S.D. Fla. Mar. 29, 2010). "A patent ambiguity is that which appears on the face of the instrument and arises from the use of defective, obscure, or insensible language." Johnson Enters. of Jacksonville, Inc. FPL Group, Inc., 162 F.3d 1290, 1310 (11th Cir. 1998) (brackets omitted) (quoting Crown Mgmt. Corp. v. Goodman, 452 So. 2d 49, 52 (Fla Dist. Ct. App. 1984)). Parol evidence is only admissible to resolve a latent ambiguity; it "may not be introduced to explain a patent ambiguity." Mitchell v. Thomas, 467 So. 2d 326, 329 (Fla. Dist. Ct. App. 1985).

The language of a contract is ambiguous if "it is reasonably susceptible to more than one interpretation." Warfield v. Stewart, No. 2:07-cv-332-Ftm-33SPC, 2009 WL 2421625, at *1 (M.D. Fla. 2009). Ambiguity is "not invariably present when a contract requires interpretation, and failing to define a term does not create ambiguity per se." Dahl-Eimers v. Mut. of Omaha Life Ins. Co., 986 F.2d 1379, 1381 (11th Cir. 1993) (internal citation omitted). For a contract term to be deemed ambiguous as a matter of law, "there must be a genuine inconsistency, uncertainty, or ambiguity in meaning that remains after resort to the ordinary rules of construction." Future Tech Int'l, Inc. v. Tae Il Media, Ltd. 944 F. Supp. 1538, 1565 (S.D. Fla. 1996). Although courts may consider parol evidence when confronted with a latently ambiguous contract provision, "they are barred from using [such] evidence to create an ambiguity to rewrite a contractual provision, or to vary a party's obligation under a contract." Vencor Hosp. v. Blue Cross Blue Shield of Rhode Island, 284 F.3d 1174, 1179 (11th Cir. 2002).

For the reasons discussed above, there is a strong argument that the change-in-law provision is not ambiguous. The PPA clearly defines "change in law" as "a change in any applicable law, regulation, permit, ordinance, market rule, or order . . . enacted after the Effective Date." As explained, the FDEP's decision to impose more rigorous air emission requirements than GREC LLC had expected was made under the BACT standard existing at the time the contract was executed. By exercising its discretion under the existing BACT standard the FDEP did not "enact" a change in any "law, regulation, permit, ordinance, market rule or order." Thus, inasmuch as he change-in-law provision is not "reasonably susceptible to more than one interpretation," Warfield, 2009 WL 2421625, at *1, parol evidence will not be admissible.[2]

D. Reformation

Florida law recognizes that "[a] court of equity has the power to reform a written instrument where, due to a mutual mistake, the instrument as drawn does not accurately express the true intentions or agreement of the parties to the instrument." Providence square Ass'n, Inc. v. Biancardi, 507 So. 2d 1366, 1369 (1987). GREC LLC may attempt to argue that the PPA should be reformed to reflect what the parties would have agreed to had they realized that a SCR system, rather than a SNCR system, would need to be installed in the Facility. The argument will fail, however, because that alleged misperception does not constitute a "mutual mistake" under Florida law, and even if it did, reformation is not the appropriate remedy.

"[B]y definition," a mutual mistake of fact "must be of a fact existing at the time of the contract and not as to a future event." Barnacle Bill's Seafood Galley, Inc. v. Ford , 453 So. 2d 165, 167 (Fla. Dist. Ct. App. 1984). As the court in Ashraf v. Squire Pacific Holdings explained:

> An erroneous perception is not a mistake unless it relates to the facts as they exist at the time the contract is made. A misprediction – a poor prediction of events that are expected to occur or circumstances that are expected to exist after the contract is made – is not a mistake. The law of mistake deals only with the risk of error relating to the factual basis of agreement – the state of affairs at the time of the agreement. It does not deal with the risk of error as to future matters.

No. 08-23104, 2009 U.S. Dist. LEXIS 12985, at *11 (S.D.N.Y. 2009) (quoting E. Allan Farnsworth, Contracts § 9.2, at 602 (4th ed. 2004). GREC LLC and GRU were not mistaken as to a fact in existence at the time they entered into the PPA. They knew that permitting would be done in accord with BACT, and they expected that the FDEP would permit the Facility to utilize a SNCR system. Or said otherwise, they made "a poor prediction of events that [were] expected to occur or circumstances that [were] expected to exist after the contract [was] made." Id. As such, GRU and GREC LLC's mistake does not constitute a "mutual mistake" for purposes of Florida contract law, and the equitable remedy of reformation is unavailable.

Even if GRU and GREC LLC's mistaken belief that the FDEP would permit the use of a SNCR system constituted a mutual mistake, the appropriate remedy would be recision, not reformation. Although Florida law on reformation is anything but neatly defined, the Florida

[2] It is worth noting that Section 29.11 of the PPA provides that "[t]his Agreement may be amended or modified only by a written agreement." Since the change-in-law provision is unambiguous, binding GRU to Regan's unfounded interpretation of the provision would effectively work an oral modification of the contract, contrary to the express language of Section 29.11.

Supreme Court has explained that "in reforming a written instrument, an equity court in no way alters the agreement of the parties. Instead, the reformation only corrects the defective written instrument so that it accurately reflects the true terms of the agreement actually reached." Ayers v. Thompson, 536 So. 2d 1151, 1154 (Fla. 1988). This presupposes that the writing sought to be reformed differs from the parties' actual agreement, such that by reforming the writing the parties' true intent is expressed; the court does not alter or create the agreement, it simply gives the agreement effect. See Brown v. Brown, 501 So. 2d 24, 26-27 (Fla. Dist. Ct. App. 1986). As succinctly put by the Restatement of Contracts, "if . . . the parties make a written agreement that they would not otherwise have made because of a mistake other than one as to expression, the court will not reform a writing to reflect the agreement that it thinks they would have made." Restatement (Second) of Contacts § 155 cmt. b (2010); see Rawson v. UMLIC VP, L.L.C., 933 So. 2d 1206, 1209-10 (Fla. Dist. Ct. App. 2006) (relying on § 151 of Restatement in interpreting Florida law).

To reform the PPA based on GRU and GREC LLC's mistake, a court would have to divine what GRU and GREC LLC would have agreed had they realized that the FDEP would not permit the use of a SNCR system – a task that is beyond the scope of equity's power to reform a contract. See Mills v. Mills, 339 So. 2d 681, 684 (Fla. Dist. Ct. App. 1976) (reformation unavailable despite mutual mistake because there was "no way that the court could rewrite the agreement to . . . [make it conform to what the parties would] have agreed upon had the true facts been known."). Since reformation is not a viable remedy, GREC LLC's remedy, if any, will be to have the PPA rescinded. See generally Pendleton, 836 So. 1025 (granting recision of real estate contract based on mutual mistake where parties were unaware of recent zoning change when they entered into the contract).

Conclusion

The FDEP's decision to require GREC LLC to install a SCR system in the Facility does not fall within the PPA's change-in-law provision and therefore GRU is not required to equitably adjust the prices set in the PPA. Since Regan did not have apparent authority to provide a binding interpretation of the PPA, GRU will not be bound by the statements he made concerning the scope of the change-in-law provision. GREC LLC will not be able to introduce parol evidence in an attempt to show that the FDEP's decision triggers GRU's obligations under the change-in-law provision. Finally, GREC LLC will not be able to have the PPA reformed.

EXHIBIT "C"

American Renewables

75 Arlington Street
5th Floor
Boston, MA 02116
(617) 482-6150
Fax (617) 482-6159
www.amrenewables.com

MEMORANDUM

To: Robert Hunzinger, Gainesville Regional Utilities
Ed Regan, Gainesville Regional Utilities
Raymond Manasco, Gainesville Regional Utilities

From: Josh Levine, American Renewables

Date: March 15, 2011

Re: Equitable Adjustment of GREC PPA per Section 3.2

Per Section 3.2 ("Change in Law") of the Power Purchase Agreement (PPA) between GREC LLC and the City of Gainesville d/b/a Gainesville Regional Utilities dated April 29, 2009, GREC LLC is required to provide a written notice of a claim for extra compensation due to a change in the regulatory requirements for generating and selling the Products, as defined in the PPA. This memo, along with the memo sent on November 15, 2010 and the email to Ed Regan sent on March 15, 2011, constitute GREC LLC's written notice of a claim under Section 3.2.

EXHIBIT "D"

EQUITABLE ADJUSTMENT FOR CHANGE OF LAW

of the

POWER PURCHASE AGREEMENT FOR THE SUPPLY OF DEPENDABLE CAPACITY, ENERGY AND ENVIRONMENTAL ATTRIBUTES FROM A BIOMASS-FIRED POWER PRODUCTION FACILITY

by and between

GAINESVILLE RENEWABLE ENERGY CENTER, LLC

and

THE CITY OF GAINESVILLE, FLORIDA

d/b/a

GAINESVILLE REGIONAL UTILITIES

dated as of March 16, 2011

1. **Equitable Adjustments**. Pursuant to Section 3.2 of the Agreement: (i) the Non-Fuel Energy Charge Contract Price of "$50.00/MWh x Construction Cost Adjuster" set forth at Appendix III is hereby adjusted to hereafter be "54.40/MWh x Construction Cost Adjuster;" (ii) the Non-Fuel Energy Charge Contract Price of "58.10/MWh x Construction Cost Adjuster" set forth at Appendix III is hereby adjusted to hereafter be "$62.50/MWh x Construction Cost Adjuster"; and (iii) Purchaser shall, to the extent not funded by grants received, fund the costs of connecting the Facility to the reclaimed water system of the City of Alachua.

2. **Replacement of Appendix III**. In accordance with the foregoing Equitable Adjustments, Appendix III of the Agreement is hereby replaced and superseded in all respects by the Appendix III attached hereto.

3. **Full Satisfaction of Change of Law Claims**. Seller acknowledges that the foregoing provisions fully address and satisfy any and all claims of Seller arising under Section 3.2 as of the date hereof, including any claims arising out of the EPA Final Rule, the Facility's PSD construction air permit, the Facility's Site Certification Order, or any other order or governmental action or condition as of the date hereof, including, without limitation any cost relating to the following items: replacing the SNCR with SCR; changes to the sorbent injection system, including storage and injection, to control hazardous air pollutant emissions; changes to the ash characteristics due to operational modifications; changes to the baghouse to control particulate matter emissions; changes to the facility water system due to the required use of reclaimed water; and, changes to the auxiliary power which affect the facility heat rate; and the usage of reclaimed water.

4. **Agreement Remains in Full Force and Effect**. Except with respect to the Equitable Adjustments set forth above, all terms and provisions of the Agreement remain in full force and effect, and each of the Parties ratifies and confirms all such provisions. Without limiting the foregoing, this Equitable Adjustment for Change of Law and the terms hereof shall bind and inure to the benefit of the Parties and any successor or assignee acquiring an interest in the Agreement pursuant to Sections 21.1 and 21.2 thereof.

IN WITNESS WHEREOF, Seller and Purchaser have caused this Equitable Adjustment for Change of Law to be duly executed and delivered by persons duly authorized to do so on their behalf as of the date first above written.

GAINESVILLE RENEWABLE ENERGY CENTER, LLC ("Seller")

By: James S. Gordon

Name: James S. Gordon
Title: President

THE CITY OF GAINESVILLE, FLORIDA d/b/a GAINESVILLE REGIONAL UTILITIES ("Purchaser")

Jennifer L. Hunt
By: Chief Financial Officer
For Name: Robert E. Hunzinger
Title: General Manager

APPROVED AS TO FORM AND LEGALITY:

By: Raymond O. Manasco

Name: Raymond O. Manasco, Jr.
Title: Utilities Attorney

Appendix III
Contract Prices

Billing Charge	Facility Status	Measurement (for Billing Period)	Contract Prices	Escalation
Non-Fuel Energy Charge	Facility Receives ITC or Renewable Energy Grant	Available Energy	\$54.40/MWh x Construction Cost Adjuster	None
	Facility Does Not Receive ITC or Renewable Energy Grant	Available Energy	\$62.50/MWh x Construction Cost Adjuster	None
Fixed O&M Charge	N/A	Available Energy	\$23.00/MWh	None
Variable O&M Charge	N/A	Delivered Energy	\$3.15/MWh	Annually on the anniversary of the Effective Date, the Variable O&M Charge shall be escalated by the percentage change in the CPI from the CPI value 12 months before the current anniversary date
Fuel Charge	N/A	Delivered Energy	Base Fuel Charge + Fuel Price Adjuster	None
Shutdown Charge	N/A	Purchaser Shutdown	Startup Fuel Cost + Startup O&M Cost	Annually on the anniversary of the Commercial Operation Date, the Startup O&M Cost shall be escalated by the percentage change in the CPI from the CPI value 12 months before the current anniversary date
Ad Valorem	N/A	Actual monthly (or a lump-sum) ad valorem taxes paid by Seller	Actual monthly (or a lump-sum) ad valorem taxes paid by Seller, subject to adjustment pursuant to Section 3.4.2.	None

EXHIBIT "E"

Mayor and Commissioners,

This packet contains documents you may find helpful in answering questions when the GREC Purchased Power Agreement (PPA) is released publicly this *Wednesday, April 6*. The PPA will be posted that day on www.gru.com in a version that highlights the redacted portions and includes the Equitable Adjustment Agreement along with a letter from GREC to GRU removing the confidentiality requirement.

I would like to stress that the PPA should not be made available publicly until it is posted on www.gru.com on April 6th.

We will be posting the documents on www.gru.com mid morning on Wednesday, issue a press release and then invite media for a Q&A session with Mr. Hunzinger that afternoon.

The packet contains the following items:

- A letter to the editor from General Manager Bob Hunzinger that should be published Tuesday, April 5 in the Gainesville Sun
- Key Messages we would like to convey in discussing the PPA release with the media
- A list of supporters for the GREC facility
- The letter releasing GRU from the confidential terms of the agreement, specifying April 6
- The unredacted PPA with highlighted sections of the agreement that were redacted along with notes in red that explain the context of some sections
- The Equitable Adjustment Agreement to accommodate new state and federal regulations

Please feel free to call me if you have any questions.

Sincerely,

Lewis Walton
Marketing & Communications Manager
GRU
Office: 352-393-1039
Cell: 352-442-5193

CALL : • Lauren
• Thomas
• Jeanna

EXHIBIT "F"

Shalley, Nicolle M.

From:	McNeill, Shayla L
Sent:	Monday, November 18, 2013 4:02 PM
To:	Shalley, Nicolle M.
Subject:	FW: e-LINE: American Renewables Removes Confidentiality Requirement for Biomass Contract
Follow Up Flag:	Follow up
Flag Status:	Flagged
TimeMattersID:	M2F42A295C6C6702
TM Contact:	GRU
TM Contact No:	1000
TM Matter No:	1000.00115
TM Matter Reference:	GREC Arbitration

As discussed

Shayla L. McNeill
Utilities Attorney
Gainesville Regional Utilities
P.O. Box 147117 Sta. A-138
Gainesville, FL 32614-7117
Telephone: (352) 393-1010
FAX: (352) 334-2277

From: Jamerson, Kimberly
Sent: Wednesday, April 06, 2011 10:09 AM
To: EveryoneGRU
Cc: citycomm; Blackburn, Russ D.; Godshalk, Brent L.; Radson, Marion J.; Lannon, Kurt M.; Howard, Cecil E.; gainesvillepio; Rawson, Laura E.
Subject: e-LINE: American Renewables Removes Confidentiality Requirement for Biomass Contract

GRU More than Energy

eLINE

April 6, 2011

The following news release will be distributed to media this morning:

American Renewables Removes Confidentiality Requirement for Biomass Contract

Gainesville, FL – GRU posted on its website this morning a full, unredacted version of the power purchase agreement to buy biomass energy from American Renewables.

In a letter to GRU, American Renewables stated that effective today it was withdrawing confidentiality requirements previously placed on portions of the contract to prevent trade secrets from being released to competitors. Redacting trade secrets is common practice in the business world, and Florida's public records law allows for that information to be protected. American Renewables agreed to release the full contract now as part of a negotiated settlement with individuals who were involved in appeals challenging permits for the biomass plant.

GRU General Manger Bob Hunzinger said he is pleased that the entire power purchase agreement is now public.

"We would have preferred to make the full contract available all along, but complied with American Renewables' confidentiality requirements," said GRU General Manager Bob Hunzinger. "Unfortunately, that has allowed critics to speculate on the contents of the contract and spread misinformation. The contract details will confirm the accuracy of the information we have been sharing throughout this process."

The newly unredacted portions of the contract primarily deal with operational standards for the Gainesville Renewable Energy Center (GREC) and the various components that go into calculating the price GRU will pay for power produced.

With American Renewables removing its confidentiality requirement, GRU was also able to release today an adjustment to the power purchase agreement that addresses negotiated costs associated with recent changes in federal environmental regulations and state permitting requirements. Hunzinger said the changes will have a minimal impact on customers.

"Despite the change in environmental requirements and the economic downturn the country has been dealing with during the past few years, we are pleased that the original bill estimates that we presented to the public and the City Commission two years ago still hold true," Hunzinger said.

The biomass project will have no effect on customer bills until the plant begins producing electricity in late 2013. The cost to the average customer will be about $10 per month initially. Over time, this cost is expected to become less than fossil fuel alternatives, such as coal and natural gas, and customers will see overall savings. Current projections show that will be in about 10 years.

Factors that could affect price include whether construction is completed in time to secure federal tax credits that will save customers about $192 million over the life of the contract, the price GRU is able to sell 50 megawatts of the biomass power during the first 10 years of the plant's operation, and changes to state or federal regulations.

Last month, American Renewables began site clearing for GREC, which will be fueled by clean, leftover wood waste. The project will offer three main benefits to GRU and its customers. It will provide fuel diversity to GRU's generation mix, two-thirds of which is currently fueled by coal. It will also improve reliability of the utility's aging generation fleet, which has an average age of 28 years, and provide long-term cost savings for customers.

"This project offers us a unique opportunity to gain some energy independence and become less reliant on fossil fuels imported from other states," Hunzinger said. "We will be able to rely on a locally supplied fuel source, wood waste, which now typically ends up in the landfill or is burned in the field."

GREC is expected to create more than 700 new jobs and provide an estimated annual economic benefit to the region of more than $31-million per year from ongoing operations.

Visit www.gru.com to get additional information about the biomass plant or download a copy of the power purchase agreement.

Additional information about the project is available on the Biomass Employee Information Center on GRUPerNet

TIMEKEEPERS: PLEASE POST

EXECUTION VERSION

This CONSENT AND AGREEMENT (this "Agreement") dated as of June 30, 2011, is entered into among THE CITY OF GAINESVILLE, FLORIDA d/b/a GAINESVILLE REGIONAL UTILITIES, a municipal corporation duly organized and validly existing under the laws of the State of Florida ("Purchaser"), GAINESVILLE RENEWABLE ENERGY CENTER, LLC, a limited liability company duly organized and validly existing under the laws of the State of Delaware ("Seller") and UNION BANK, N.A., as collateral agent for the Lenders (as defined below) and the other Secured Parties referred to in the Credit Agreement defined below (the "Secured Parties") (in such capacity, together with its successors in such capacity, the "Collateral Agent").

WHEREAS, Seller seeks to construct, own and operate a biomass-fired power production facility anticipated to produce approximately 101.52 MWs to be located in Alachua County, Florida (the "Project");

WHEREAS, Purchaser and Seller have entered into that certain Power Purchase Agreement for the Supply of Dependable Capacity, Energy and Environmental Attributes from a Biomass-Fired Power Production Facility, dated as of April 29, 2009, as supplemented by the Equitable Adjustment for Change of Law dated as of March 16, 2011 (as the same may be amended, supplemented, restated or otherwise modified from time to time in accordance with the terms thereof, the "Assigned Agreement");

WHEREAS, Seller, the Collateral Agent, the lenders from time to time party thereto (the "Lenders") and certain other Secured Parties are parties to that certain Credit Agreement, dated as of the date hereof (as amended, supplemented, restated or otherwise modified from time to time, the "Credit Agreement"), pursuant to which certain funds will be extended to Seller for the development, ownership, construction and operation of the Project and certain related expenses (the "Loans");

WHEREAS, as collateral security for Seller's obligations under the Credit Agreement, Seller has agreed to assign all of its right, title and interest in, to and under the Assigned Agreement to the Collateral Agent for the benefit of the Secured Parties;

NOW, THEREFORE, Purchaser, Seller and the Collateral Agent agree as follows:

1. Definitions. Unless otherwise specified, any capitalized term used but not defined herein shall have the meaning specified for such term as set forth in the Assigned Agreement. In addition, the following capitalized terms shall have the following meanings:

"Agreement" has the meaning set forth in the preamble.

"Assigned Agreement" has the meaning set forth in the recitals.

"Authorization" means any consent, waiver, registration, filing, agreement, notarization, certificate, license, tariff, approval, permit, authorization, exception or exemption from, by or with any Governmental Authority, whether given by express action or deemed given by failure to act within any specified period, and all corporate, creditors', shareholders' and partners' approvals or consents.

"Collateral Agent" has the meaning set forth in the preamble.

"Credit Agreement" has the meaning set forth in the recitals.

"Event of Default" means any event constituting an event of default by Seller under the Financing Documents.

"Financing Documents" means the Credit Agreement and each financing agreement ancillary thereto.

"Governmental Authority" means any United States federal, state, municipal, local, territorial, or other governmental department, commission, board, bureau, agency, regulatory authority, instrumentality, judicial or administrative body.

"Ground Lease" means that certain lease agreement, dated as of September 28, 2009, between Seller and Purchaser.

"Lenders" has the meaning set forth in the recitals.

"Loans" has the meaning set forth in the recitals.

"Project" has the meaning set forth in the recitals.

"Purchaser" has the meaning set forth in the preamble.

"Revenue Account" means the account designated as such to be established and maintained in accordance with the Financing Documents.

"Secured Parties" has the meaning set forth in the preamble.

2. Purchaser Representations and Warranties. Purchaser hereby represents and warrants that:

(a) Purchaser is duly organized and validly existing under the laws of the State of Florida. Purchaser is duly qualified to do business and is in good standing in all jurisdictions where necessary in light of the business it conducts and the property it owns and intends to conduct and own and in light of the transactions contemplated by Assigned Agreement. No filing, recording, publishing or other act that has not been made or done is necessary or desirable in connection with the existence or good standing of Purchaser or the conduct of its business.

(b) Purchaser has the full power, authority and legal right to execute, deliver and perform its obligations hereunder and under the Assigned Agreement. The execution, delivery and performance by Purchaser of this Agreement and the Assigned Agreement and the consummation of the transactions contemplated hereby and thereby have been duly authorized by all necessary action by the City Commission of the City of Gainesville, Florida and no further authorization is necessary. This Agreement and the Assigned Agreement have been duly executed and delivered by Purchaser and (assuming the due authorization, execution and delivery by and binding effect on the other parties thereto) constitute the legal, valid and binding obligations of Purchaser enforceable against Purchaser in accordance with their respective terms, except as the enforceability thereof may be limited by (i) applicable bankruptcy, insolvency, moratorium or other similar laws affecting the enforcement of creditor's rights generally and (ii) the application of general principles of equity (regardless of whether such enforceability is considered in a proceeding at law or in equity).

(c) The execution, delivery and performance by Purchaser of this Agreement and the Assigned Agreement do not and will not (i) require any consent or approval of the City Commission of the City of Gainesville, Florida or of any other Person which has not been obtained and each such consent or approval that has been obtained is in full force and effect, (ii) violate any provision of any law, rule, regulation, order, writ, judgment, decree, determination or award having applicability to Purchaser or any provision of Purchaser's charter, (iii) conflict with, result in a breach of or constitute a default under any bond resolution or loan or credit agreement or any other material agreement, lease or instrument to which Purchaser is a party or by which Purchaser or its properties and assets are bound or affected or (iv) result in, or require the creation or imposition of, any lien upon or with respect to any of the assets or properties of Purchaser now owned or hereafter acquired.

(d) No Authorization that has not already been received is required for the execution, delivery or performance of this Agreement and the Assigned Agreement by Purchaser, or, to the actual knowledge of Purchaser, for the exercise by the Collateral Agent of its rights and remedies with respect to this Agreement.

(e) Assuming the due authorization, execution and delivery by, and binding effect on, Seller and the Collateral Agent, as applicable, this Agreement and the Assigned Agreement are in full force and effect.

(f) There is no action, suit or proceeding at law or in equity by or before any Governmental Authority, arbitral tribunal or other body now pending or to the actual knowledge of Purchaser, threatened against or affecting Purchaser or any of its properties, rights or assets which (i) is likely to have a material adverse effect, individually or in the aggregate, on its ability to perform its obligations hereunder or under the Assigned Agreement or (ii) question the validity, binding effect or enforceability hereof or of the Assigned Agreement or any action taken or to be taken pursuant hereto or thereto or any of the transactions contemplated hereby or thereby.

(g) Purchaser is not in default under any material covenant or obligation hereunder or under the Assigned Agreement and no such default has occurred prior to the date hereof. To the actual knowledge of Purchaser, Seller is not in default under any material covenant or obligation of the Assigned Agreement and no such default has occurred prior to the date hereof. After giving effect to the assignment by Seller to the Collateral Agent of the Assigned Agreement pursuant to the Financing Documents, and after giving effect to the acknowledgment of and consent to such assignment by Purchaser, to the actual knowledge of Purchaser, there exists no event or condition which would constitute a default, or which would, with the giving of notice or lapse of time or both, constitute a default under the Assigned Agreement. Purchaser and, to the actual knowledge of Purchaser, Seller have complied with all conditions precedent to the respective obligations of such party to perform under the Assigned Agreement applicable to date.

(h) This Agreement, the Assigned Agreement, the Large Generation Interconnection Agreement, effective as of November 16, 2010, between Purchaser and Seller, the Ground Lease and related real property documents, and such fuel source agreements that Purchaser may enter into from time to time constitute and include all agreements entered into by Purchaser relating to, and required from Purchaser for the consummation of, the transactions contemplated by this Agreement and the Assigned Agreement.

3. <u>Seller Representations and Warranties</u>. Seller hereby represents and warrants that:

(a) Seller is duly organized and validly existing under the laws of the State of Delaware. Seller is duly qualified to do business and is in good standing in all jurisdictions where necessary in light of the business it conducts and the property it owns and intends to conduct and own and in light of the transactions contemplated by Assigned Agreement. No filing, recording, publishing or other act that has not been made or done is necessary or desirable in connection with the existence or good standing of Seller or the conduct of its business.

(b) Seller has the full power, authority and legal right to execute, deliver and perform its obligations hereunder and under the Assigned Agreement. This Agreement and the Assigned Agreement have been duly executed and delivered by Seller and (assuming the due authorization, execution and delivery by and binding effect on the other parties thereto) constitute the legal, valid and binding obligations of Seller enforceable against Seller in accordance with their respective terms, except as the enforceability thereof may be limited by (i) applicable bankruptcy, insolvency, moratorium or other similar laws affecting the enforcement of creditor's rights generally and (ii) the application of general principles of equity (regardless of whether such enforceability is considered in a proceeding at law or in equity).

(c) The execution, delivery and performance by Seller of this Agreement and the Assigned Agreement do not and will not (i) require any consent or approval of any Person which has not been obtained and each such consent or approval that has been obtained is in full force and effect, (ii) violate any provision of any law, rule, regulation, order, writ, judgment, decree, determination or award having applicability to Seller or any provision of Seller's articles of incorporation or by-laws, (iii) conflict with, result in a breach of or constitute a default under any indenture or loan or credit agreement or any other material agreement, lease or instrument to which Seller is a party or by which Seller or its properties and assets are bound or affected or (iv) result in, or require the creation or imposition of, any lien upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(d) No Authorization that has not already been received is required for the execution, delivery or performance of this Agreement and the Assigned Agreement by Seller, or, to the actual knowledge of Seller, for the exercise by the Collateral Agent of its rights and remedies with respect to this Agreement.

(e) Assuming the due authorization, execution and delivery by, and binding effect on, Purchaser and the Collateral Agent, as applicable, this Agreement and the Assigned Agreement are in full force and effect.

(f) There is no action, suit or proceeding at law or in equity by or before any Governmental Authority, arbitral tribunal or other body now pending or to the actual knowledge of Seller, threatened against or affecting Seller or any of its properties, rights or assets which (i) is likely to have a material adverse effect, individually or in the aggregate, on its ability to perform its obligations hereunder or under the Assigned Agreement or (ii) question the validity, binding effect or enforceability hereof or of the Assigned Agreement or any action taken or to be taken pursuant hereto or thereto or any of the transactions contemplated hereby or thereby.

(g) Seller is not in default under any material covenant or obligation hereunder or under the Assigned Agreement and no such default has occurred prior to the date hereof. To the actual knowledge of Seller, Purchaser is not in default under any material covenant or obligation of the Assigned Agreement and no such default has occurred prior to the date hereof. Seller and, to the actual knowledge of Seller, Purchaser have complied with all conditions precedent to the respective obligations of such party to perform under the Assigned Agreement applicable to date.

(h) This Agreement, the Assigned Agreement, the Large Generation Interconnection Agreement, effective as of November 16, 2010, between Purchaser and Seller, the Ground Lease and related real property documents, and such fuel source agreements that Seller may enter into from time to time constitute and include all agreements entered into by Seller relating to, and required from Seller for the consummation of, the transactions contemplated by this Agreement and the Assigned Agreement.

4. <u>Consent and Agreement</u>. Purchaser hereby consents in all respects to the pledge and assignment to the Collateral Agent of all of Seller's right, title and interest in, to and under the Assigned Agreement and acknowledges and agrees that:

(a) If the Collateral Agent shall provide written notice to Purchaser that an Event of Default has occurred and is continuing and the Collateral Agent desires to exercise its rights and remedies pursuant to the Financing Documents, the Collateral Agent and any designee thereof shall be entitled to exercise any and all rights of Seller under the Assigned Agreement in accordance with its terms; provided that (i) the Financing Documents provide a grant from Seller to the Collateral Agent to exercise such rights and (ii) to the extent such exercise involves directions to Purchaser involving the physical operation of the Project, the Collateral Agent shall have provided written notice to Purchaser that the Collateral Agent intends to take control of the Project. Without limiting the generality of the foregoing, upon the occurrence and continuation of an Event of Default and the delivery of such written notice to Purchaser that the Collateral Agent desires to exercise its rights and remedies pursuant to the Financing Documents, the Collateral Agent and any designee thereof shall, subject to the terms of the Financing Documents, have the full right and power to enforce directly against Purchaser all obligations of Purchaser under the Assigned Agreement and otherwise to exercise all remedies under the Assigned Agreement and to make all demands and give all notices and make all requests required or permitted to be made by Seller under the Assigned Agreement.

(b) Upon the occurrence of a Seller Event of Default, Purchaser shall not exercise any of its rights set forth in the Assigned Agreement to cancel, terminate or suspend performance under, the Assigned Agreement unless it has first afforded the Collateral Agent or its designee a cure period for a duration of (i) in the case of monetary defaults, 30 days from the expiration of Seller's right to cure such default under the Assigned Agreement; and (ii) in the case of nonmonetary defaults, 60 days from the expiration of Seller's right to cure such default under the Assigned Agreement; provided, in the case of this clause (ii) that the Collateral Agent (or its designee) has commenced in good faith to cure any such Seller Event of Default within 30 days from the expiration of Seller's right to cure such default under the Assigned Agreement.

(c) Purchaser shall deliver to the Collateral Agent at the address set forth in Section 6(b) below, or at such other address as the Collateral Agent may designate in writing from time to time to Purchaser, concurrently with the delivery thereof to Seller, a copy of each notice of material breach by Seller or a Seller Event of Default given by Purchaser pursuant to the Assigned Agreement.

(d) In the event that the Collateral Agent or its designee in accordance with paragraph (e) below succeeds to Seller's interest under the Assigned Agreement, whether by foreclosure or otherwise, the Collateral Agent or its designee shall (i) assume in writing liability for all of Seller's obligations under the Assigned Agreement; provided, that such liability shall not include any liability for claims of Purchaser against Seller arising from Seller's failure to perform during the period ending on the earlier of (x) the date of the Collateral Agent's or such designee's succession to Seller's interest in and under the Assigned Agreement and (y) the date Purchaser could have exercised its right to cancel, terminate, or suspend the Assigned Agreement due to a Seller Event of Default, but such cancellation, termination or suspension was prevented due to the Collateral Agent exercising its right to cure under clause (b) above (for the avoidance of doubt, this proviso shall not affect the measurement of performance standards under the Assigned Agreement which are measured over time periods that span both pre and post-succession periods), (ii) cure any and all defaults of Seller under the Assigned Agreement which are capable of being cured and which are not personal to Seller, and (iii) provide Completion Performance Security or PPA Performance Security, as applicable, under the terms of the Assigned Agreement. Except as otherwise set forth in the immediately preceding sentence, none of the Secured Parties shall be liable for the performance or observance of any of the obligations or duties of Seller under the Assigned Agreement and the assignment of the Assigned Agreement by Seller to the Collateral Agent pursuant to the Financing Documents shall not give rise to any duties or obligations whatsoever on the part of any of the Secured Parties owing to Purchaser.

(e) Upon the exercise by the Collateral Agent of any of its remedies under the Financing Documents granting the Collateral Agent the right to assign its rights and interests under the Assigned Agreement or the rights and interests of Seller under the Assigned Agreement, Purchaser consents to the Collateral Agent's assignment of such rights and interests to any purchaser or transferee of the Project, if such purchaser or transferee (i) certifies in writing to Purchaser that it intends to perform the obligations of Seller as and to the extent required under the Assigned Agreement, (ii) cures any and all defaults of Seller under the Assigned Agreement which are capable of being cured and which are not personal to Seller, (iii) provides Completion Performance Security or PPA Performance Security, as applicable, under the terms of the Assigned Agreement, (iv) provides satisfactory written evidence that it is financially capable of performing Seller's obligations under the Assigned Agreement (provided that a tangible net worth by the entity assuming the Assigned Agreement or its direct or indirect parent entity of at least $100 million shall be presumed to meet this requirement), and (v) is reasonably capable of so performing. Upon such assignment and assumption, to the extent the Collateral Agent has previously assumed any obligations thereunder, the Collateral Agent shall be relieved of all obligations under the Assigned Agreement arising after such assignment and assumption.

(f) In the event that (i) the Assigned Agreement is rejected by a trustee or debtor-in-possession in any bankruptcy or insolvency proceeding involving Seller or (ii) the Assigned Agreement is terminated as a result of any bankruptcy or insolvency proceeding involving Seller, if within 45 days after such rejection or termination the Collateral Agent or its designee shall have taken ownership of the Project and certified in writing to Purchaser that it intends to perform the obligations of Seller as and to the extent required under the Assigned Agreement, upon the request of the Collateral Agent or its designee, Purchaser will execute and deliver to the Collateral Agent or such designee a new Assigned Agreement which shall be for the balance of the remaining term under the original Assigned Agreement before giving effect to such rejection or termination and shall contain the same conditions, agreements, terms, provisions and limitations as the original Assigned Agreement (except for any requirements which have been fulfilled by Seller and Purchaser prior to such rejection or termination). References in this Agreement to the "Assigned Agreement" shall be deemed also to refer to the new Assigned Agreement.

(g) In the event that the Collateral Agent or its designee, or any purchaser or other transferee of the interests of the Collateral Agent or its designee in the Project assume or become liable under the Assigned Agreement (as contemplated in subsection (d), (e) or (f) above or otherwise), liability in respect of any and all obligations of any such party under the Assigned Agreement shall not extend to any officer, director, employee, shareholder or agent thereof.

5. Special Agreements. Each of Purchaser and Seller hereby further acknowledges and agrees that:

(a) Purchaser shall notify the Collateral Agent no less than 30 days in advance of its intention to exercise its fuel procurement option pursuant to Section 4.1 of the Assigned Agreement;

(b) the words "PTC Adder" in Section 8.2.11 of the Assigned Agreement are hereby deleted and replaced with the words "PTC Adjustment";

(c) Section 25.1.2 of the Assigned Agreement is hereby deleted in its entirety;

(d) the following is inserted at the end of Section 25.4 of the Assigned Agreement: "The legal remedies available to Seller upon the occurrence of a Purchaser Event of Default or by Purchaser upon the occurrence of a Seller Event of Default, shall include, without limitation, direct damages to Seller or Purchaser, as applicable. To the extent such direct damages are sought by Seller or Purchaser, as applicable, such direct damages shall be calculated on the basis of a methodology to be determined by the appropriate arbitrator selected under Section 24.2 or the relevant court of competent jurisdiction; *provided* that the Parties agree that the estimated net present value of the economic loss to the non-defaulting Party due to the termination of this Agreement may be considered in determination of those damages based on, without limitation, factors such as: the estimated future net revenue under this Agreement and then relevant rates, prices, yields, forward yield curves, volatilities, spreads or other market data as applicable for renewable energy and baseload capacity as determined or estimated over the remaining Delivery Term.";

(e) Section 27.2.5 of the Assigned Agreement is amended to insert the following at the end thereof: "Each Qualified Appraiser shall make its determination of the summation of the above components. Notwithstanding the foregoing, if the Qualified Appraiser believes that the summation of the above components produces a Fair Market Value of the Facility that differs materially from the fair market value using another approach it thinks more appropriate for determining the value of the Facility, then the Qualified Appraiser shall use the fair market value derived under the other approach as the Fair Market Value of the Facility, and provide Seller and Purchaser with an explanation thereof.";

(f) a new Section 29.16 is inserted as follows: "Seller and Purchaser intend that this Agreement will be treated as a "service contract" within the meaning of 26 U.S.C. § 7701(e)(3)."

(g) the words "existing substation" in the definition of "Delivery Point" are hereby replaced with the words "the new substation that is to be built by Seller and conveyed to Purchaser upon completion thereof";

(h) Purchaser and Seller shall work in good faith to produce a mutually agreeable template of operating procedures to be inserted into Appendix VI within a reasonable time period in advance of the Commercial Operation Date and the failure to so produce such template by May 15, 2009 shall not be deemed to be a breach by Purchaser or Seller of the Assigned Agreement;

(i) the penultimate sentence of Section 1.6 of Appendix IX to the Assigned Agreement reading "Alternatively, the Seller may establish a new contracted capacity, if agreeable to the Purchaser." is hereby deleted and replaced with: "Alternatively, Seller may propose a new contracted capacity based on the results from the failed Initial Capacity Tests and Seller and Purchaser will discuss and establish an alternative initial Dependable Capacity consistent with the results of the failed Initial Capacity Tests, such establishment not to be unreasonably withheld or delayed."; and

(j) the definition of "Commercial Operation Date" shall be replaced with the following: "Commercial Operation Date" means the first day following the date Seller successfully completes the Initial Capacity Test (as defined in Appendix IX of this Agreement) or the date Parties agree to an initial Dependable Capacity pursuant to Section 1.6 of Appendix IX of this Agreement.

6. Arrangements Regarding Payments. All payments to be made by Purchaser to Seller under the Assigned Agreement shall be made in lawful money of the United States, directly to the Collateral Agent, for deposit into the Revenue Account (Account No. 6711944708), at Union Bank, N.A., 1251 Avenue of the Americas, 19th Floor, New York, New York, 10020, or to such other Person and/or at such other address as the Collateral Agent may from time to time specify in writing to Purchaser.

7. Miscellaneous.

(a) No failure on the part of the Collateral Agent or any of its agents to exercise and no delay in exercising, and no course of dealing with respect to, any right, power or privilege hereunder shall operate as a waiver thereof, and no single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege. The remedies provided herein are cumulative and not exclusive of any remedies provided by law.

(b) Notices. All notices hereunder shall be in writing and shall be deemed received (i) at the close of business of the date of receipt, if delivered by hand or by facsimile with proof of receipt, or (ii) when signed for by recipient, if sent registered or certified mail, postage prepaid, provided such notice was properly addressed to the appropriate address indicated on the signature page hereof or to such other address as a party may designate by prior written notice to the other parties, at the address set forth below:

if to the Collateral Agent, addressed to;

Union Bank, N.A.
Address: 1251 Avenue of the Americas, 19th Fl.
New York, New York 10020
Telecopy: (646) 452-2000
Attention: Hugo Gindraux
Email: hugo.gindraux@unionbank.com

If to Purchaser, addressed to:

Gainesville Regional Utilities
301 S.E. 4th Avenue
Gainesville, FL 32614-7117
Attention: General Manager
Telephone: (352) 393-1007
Telecopy: (352) 334-2277

If to Seller, addressed to:

Gainesville Renewable Energy Center, LLC
75 Arlington St., 5th Floor
Boston, MA 02116
Attention: James Gordon
Telephone: (617) 482-6150
Telecopy: (617) 904-3109

(c) This Agreement may be amended or otherwise modified only by an instrument in writing signed by the party to be bound by the modification. Any waiver shall be effective only for the specified purpose for which it was given.

(d) This Agreement shall be binding upon and inure to the benefit of the respective successors and assigns of each of Purchaser, Seller, and the Collateral Agent (and the Secured Parties). Purchaser shall not assign or transfer its rights hereunder without the prior written consent of the Collateral Agent.

(e) This Agreement may be executed in any number of counterparts, all of which when taken together shall constitute one and the same instrument and any of the parties hereto may execute this Agreement by signing any such counterpart. This Agreement shall become effective at such time as the Collateral Agent shall have received counterparts hereof signed by all of the intended parties hereto.

(f) If any provision hereof is invalid and unenforceable in any jurisdiction, then, to the fullest extent permitted by law, (i) the other provisions hereof shall remain in full force and effect in such jurisdiction and shall be liberally construed in favor of the Collateral Agent in order to carry out the intentions of the parties hereto as nearly as may be possible and (ii) the invalidity or unenforceability of any provision hereof in any jurisdiction shall not affect the validity or enforceability of such provision in any other jurisdiction.

(g) Headings appearing herein are used solely for convenience and are not intended to affect the interpretation of any provision of this Agreement.

(h) **ALL JUDICIAL PROCEEDINGS BROUGHT AGAINST ANY PARTY ARISING OUT OF OR RELATING TO THIS AGREEMENT SHALL BE BROUGHT EXCLUSIVELY IN THE COURTS OF THE STATE OF FLORIDA OR THE UNITED STATES OF AMERICA, IN EITHER CASE, LOCATED IN ALACHUA COUNTY FLORIDA. BY EXECUTING AND DELIVERING THIS AGREEMENT, EACH PARTY, FOR ITSELF AND IN CONNECTION WITH ITS PROPERTIES, IRREVOCABLY ACCEPTS GENERALLY AND UNCONDITIONALLY THE EXCLUSIVE JURISDICTION AND VENUE OF SUCH COURTS, AND WAIVES ANY DEFENSE OF FORUM NON CONVENIENS.**

(i) **THE AGREEMENTS OF THE PARTIES HERETO ARE SOLELY FOR THE BENEFIT OF PURCHASER, SELLER, THE COLLATERAL AGENT AND THE SECURED PARTIES, AND NO PERSON SHALL HAVE ANY RIGHTS HEREUNDER.**

(j) **THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA.**

(k) **EACH OF PURCHASER, SELLER AND THE COLLATERAL AGENT HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE ASSIGNED AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY OR THEREBY.**

(*Signature pages follow*)

IN WITNESS WHEREOF, the undersigned by its officer duly authorized has caused this Agreement to be duly executed and delivered as of the date first above written.

THE CITY OF GAINESVILLE d/b/a
GAINESVILLE REGIONAL UTILITIES,
as Purchaser

By
Name: Robert E. Hunzinger
Title: General Manager

Approved as to form and legality:

Utilities Attorney

GAINESVILLE RENEWABLE ENERGY
CENTER, LLC,
as Seller

By ______________________
Name:
Title:

UNION BANK, N.A.,
as Collateral Agent

By ______________________
Name: **Hugo Gindraux**
Title: **Vice President**