October 4, 2013

Mr. John Stanton
Assistant General Manager; Energy Supply
Gainesville Regional Utilities
301 S.E. 4th Avenue
Gainesville, Florida 32614

Re: Gainesville Renewable Energy Center Independent Evaluation of Operational and Environmental Risk

Dear Mr. Stanton:

Burns & McDonnell (BMcD) was retained by Gainesville Regional Utilities (GRU) to provide an independent evaluation of a set of key operating parameters for the 100 MW Gainesville Renewable Energy Center (GREC), in support of GRU's evaluation of a potential acquisition of GREC. As part of this analysis, BMcD provided input on operational and environmental risks associated with these parameters that GRU may be subject to should GRU acquire GREC and become owner relative to the current risks which GRU is subject to under the current Power Purchase Agreement (PPA) in which GRU is the Buyer for all power and environmental attributes of GREC. BMcD also provided input as to the significance of each of these relative changes in risk levels.

<u>Bubbling Fluidized Bed Boiler Technology</u>

The GREC facility uses Bubbling Fluidized Bed (BFB) boilers. BFB boilers utilize an inert material, usually sand, to provide the bed in the boiler. High pressure air is blown into the boiler through the material a fluidized bed. BFB boiler technology is more tolerable of fluctuations in fuel properties than a stoker boiler, making this technology a good choice for application in facilities that will burn woody biomass. BFB boilers are a proven technology with worldwide application burning a wide variety of feedstock, including woody biomass. The boiler at the GREC facility was provided by Metso, who has installed hundreds of boilers worldwide, including over 100 BFB boilers, many of which burn woody biomass.

There is one BFB boiler of this size burning woody biomass currently operating in the United States, which is a similar 100 MW Metso BFB biomass boiler, located in Nacogdoches County, Texas. The Nacogdoches plant began commercial operation in 2011 and is currently owned and operated by Southern Company. However, there are comparably sized BFB boilers operating on biomass throughout the world. Metso has over a dozen woody biomass boilers of a similar size installed worldwide.

Availability Factor

To determine the anticipated outage and availability factors for GREC, publically available data provided by the Generator Availability Data System (GADS) was collected and evaluated. The data analyzed included the Equivalent Forced Outage Rate (EFOR), and Equivalent Availability Factor (EAF) for the operating plants considered in this evaluation. The definitions of each of these terms are presented below.

Equivalent Forced Outage Rate (EFOR): $EFOR = \frac{FOH + EFDH}{FOH + SH + EFDHRS} x100\%$

Where:
FOH – Forced Outage Hours
SH – Scheduled Hours
EFDH – Equivalent Unplanned (Forced) Derated Hours
EFDHRS – Equivalent Unplanned (Forced) Derated Hours during Reserve Shutdowns

Equivalent Availability Factor (EAF): $EAF = \frac{AH - EPDH - EUDH - ESEDH}{PH} x100\%$

Where:
AH – Available Hours
EPDH – Equivalent Planned Derated Hours
EUDH – Equivalent Unplanned Derated Hours
ESEDH – Equivalent Seasonal Derated Hours
PH – Period Hours

GADS data was obtained for all wood-fuel based biomass facilities with outputs less than 200 MW which are operational from 1990 to 2013. The average EAF for plants which meet the criteria stated above was reported at 86.6 percent (%), with an EFOR of 3.53%.

The majority of the biomass facilities included in the GADS data above are stoker boilers constructed in the 1980s. Compared to a modern BFB, stoker boilers include systems such as fly ash reinjection, mechanical dust collectors, and electrostatic precipitators, each of which require a relatively high level of maintenance. It would be anticipated that a BTB boiler plant would have a shorter duration planned outage due to the reduced maintenance requirements. Referencing the EAF equation above, if the equivalent planned derated hours for a new BFB plant were reduced, due to the lower maintenance requirements, such that 2-week long planned outage were necessary as opposed to 4-week outage likely required for a stoker boiler, it is possible that a newly constructed BFB can achieve an EAF of 90% or higher. Additionally, BMcD is aware of another power generating facility utilizing BFB technology that has been assumed to be able to achieve a 90 percent availability factor and owners of the facility have utilized a 90 percent EAF for planning purposes.

Net Plant Heat Rate

BMcD calculated an estimated net heat rate of the plant of 12,600 Btu/kWh, based on a boiler efficiency of 77 percent. Detailed design information for the plant and equipment was not provided for review; therefore, the actual heat rate may be somewhat improved over this estimate. Some of the characteristics that could lead to an improved actual heat rate relative to the estimated heat rate include a higher boiler efficiency, a more favorable steam turbine heat rate, and lower parasitic load relative to the assumptions used in the calculation of heat rate in this evaluation.

Operating and Maintenance Costs

Fixed operating and maintenance (O&M) costs are expenditures that are anticipated to be incurred regardless of relatively minor changes to the capacity factor of the facility and generally consist of items such as payroll, training, plant mobile equipment maintenance, buildings and ground maintenance, and standby power. In addition to these costs major maintenance activities will be required on major equipment, which will be scheduled on a routine basis and are not anticipated to vary in cost and frequency based on relatively minor changes to capacity factor. That being said, these costs would likely decrease if the capacity factor of the plant were to change dramatically, such as a facility changing from baseload operation to intermittent or seasonal operation due to reduced operating hours incurred by the equipment. Major maintenance activities and costs would be incurred at various levels each year; however, for purposes of preparing the O&M budget these costs were normalized to an average annual major maintenance cost. Based on these inputs, a fixed operating and maintenance cost estimate was developed based on a total of 30 full-time employees being required for plant operation plus an additional 3 full-time employees required for managing fuel procurement activities. Under this staffing plan, a fixed O&M estimate was developed and is summarized in Table 1 in 2013 dollars. Corporate overheads are excluded from the fixed O&M costs provided in Table 1.

Table 1: Summary of Fixed O&M Costs

Fixed O&M		
Labor	$	4,400,000
Fuel Procurement	$	430,000
Miscellaneous Materials & Services	$	1,200,000
Other General Maintenance (SCR, Baghouse, Water Treatment)	$	70,000
Service Contracts (Boiler & DCS)	$	600,000
Boiler and Steam Turbine Major Maintenance	$	3,000,000
Insurance	$	1,000,000
Subtotal	**$**	**10,700,000**

Variable O&M costs consist of expenditures that are anticipated to be incurred directly proportional to the capacity factor of the plant. These costs generally consist of consumable items such as aqueous ammonia, sodium bicarbonate, water, water treatment chemicals, and landfill costs for bottom ash. Fly ash is assumed to be hauled off to a fertilizer plant at no cost. A summary of the estimated annual variable O&M costs assuming a 90% capacity factor is presented in Table 2.

Table 2: Summary of Variable O&M Costs

Variable O&M		
Bottom Ash Disposal	$	58,000
Bed Material Cost	$	237,000
Water & Chemicals	$	34,000
Sodium Bicarbonate	$	309,000
Aqueous Ammonia	$	218,000
Subtotal	**$**	**856,000**

In addition to the fixed O&M and variable O&M costs, expenditures for equipment replacement and maintenance are anticipated, that are expected to be capitalized. These costs include capital investments for replacement of the SCR catalyst, replacement of bags in the baghouse and other miscellaneous capital replacements in systems such as fuel handling equipment. Estimated annual capital expenditures for the plant are summarized in Table 3 below.

Table 3: Summary of Fixed O&M Costs

Capital Budget		
SCR Catalyst Replacement	$	250,000
Baghouse Bag Replacement	$	400,000
Other Capital Expenditures (Fuel handling, etc.)	$	2,000,000
Subtotal	**$**	**2,650,000**

Emission Performance

The GREC facility was designed with one of the most advanced air quality control systems for a biomass plant, consisting of a Selective Catalytic Reduction (SCR) system to reduce NO_x emissions, dry sorbent injection (DSI) to reduce SO_2 emissions, and a baghouse to control particulate emissions.

An SCR system is a proven and common technology on both natural gas and coal-fired units, but has limited operating experience on a biomass boiler. SCR systems require ammonia to be injected into flue gas upstream of a catalyst, which causes the ammonia to react with NO_x in the flue gas to reduce NO_x levels prior to exiting the plant stack. The air permit for the facility limits NO_x levels in the stack emissions to 0.07 lb/MMBtu. Assuming that the boiler outlet NOx level is 0.18 lb//MMBtu, the SCR system will be required to achieve a NO_x removal rate of approximately 61 percent. This is well within the range of capability of SCR system technology. There is some concern of presence of alkali in the biomass fuel that could deactivate the catalyst in the SCR system. If catalyst deactivation occurs, the plant would likely be required to replace the catalyst more often than expected, which would increase the O&M cost associated with this portion of the capital expenditures outlined in the previous section of this report. It is not uncommon for vendors to provide guarantees for the operating life of items such as SCR system catalysts, in which case the financial impact of this issue would not be of concern. Additionally, vendor guarantees provide the plant owner with additional reassurance that the equipment will perform as anticipated and provide an indication of the vendor’s confidence in the technology.

Removal of SO_2 from plant exhaust will be achieved through dry sorbent injection (DSI), using sodium bicarbonate as the sorbent material. Depending on sulfur content in the fuel, SO_2 emissions rates could vary; however, sulfur content in biomass fuel is anticipated to be relatively low. The air permit for the plant limits SO_2 emissions from the stack to a level of 0.029 lb/MMBtu. Assuming an uncontrolled SO_2 emission rate of 0.067 lb/MMBtu, a 67 percent SO_2 removal rate will be required. With the plant operating at a 90 percent capacity factor, 887 tons of sodium bicarbonate is estimated to be consumed each year. DSI systems are a proven technology for SO_2 removal in coal burning boilers where the uncontrolled SO_2 emissions are an order of magnitude higher than on this project. When starting from a very low uncontrolled emissions rate, there is a risk that the same normalized stoichiometric ratio may not achieve the same rate of removal. This risk translates to potentially requiring more sodium bicarbonate to be injected to achieve the desired removal rate, which would increase this component of the variable O&M costs.

A baghouse is used at this plant to control particulate matter emissions. It is expected that GREC will have to meet the new Industrial Boiler Maximum Achievable Control Technologies (IB MACT) limit of 0.0098 lb/MMBtu for particulate matter. This new limit is actually much less stringent than the previous IB MACT revision, which was 0.0011 lb/MMBtu. Therefore, it is reasonable to believe that GREC will be able to meet the new limit, especially if the vendor provided an emission level guarantee based on the previous version of IB MACT.

Summary of Operating and Environmental Risks

In addition to preparing the estimates presented in prior sections of this report, BMcD evaluated the changes in risk profile for operating costs and characteristics presented in this report under GRU ownership of the plant, as opposed to continued participation in the PPA. Table 4 below summarizes the results of this evaluation.

Table 4: Summary of Change in Risk under GRU Ownership of GREC

Risks	Under PPA	GRU Ownership	Change to GRU Risk	Confidence	Significance
Plant Fixed O&M Costs	A Fixed O&M payment of $18 million is applicable at a 90% EAF with no escalation with no risk to GRU for cost overruns	Fixed O&M costs are estimated to be $10.7 million and GRU will be directly responsible for these costs	Costs change from a fixed payment to uncertainty in plant fixed O&M costs	Budgets developed for fixed O&M costs are reasonable and GRU has experience operating other plants of similar size and complexity. Therefore, adding GREC to its portfolio of operating assets does not represent a significant change in risks.	Low
Costs of SCR catalyst, baghouse, and other major maintenance exceed forecast	These capital expenditures are covered by the Non-Fuel Energy Charge and Fixed O&M Charge. GRU is not responsible for any increased costs.	GRU will be responsible for all maintenance and replacement costs, therefore, GRU will bear any cost increase.	Costs change from fixed payment to uncertainty in maintenance costs.	If OEM has guarantee on operating life of SCR catalyst and baghouse, the change in risk will be minimal.	Low

Risks	Under PPA	GRU Ownership	Change to GRU Risk	Confidence	Significance
Fly ash has to be sent to a landfill rather than of hauled by fertilizer plant at no cost	GRU pays $3.15/MWhr in variable O&M regardless of disposal method of fly ash.	GRU will be responsible for finding a place to send the fly ash and will incur all associated costs.	From fixed payment to uncertainty in plant variable O&M costs.	GRU has other operating coal plants and is experienced in fly ash disposal, but a change in fly ash disposal methods will increase costs incurred by GRU	Medium
Plant unavailability factor is higher than projected	GRU will receive $150,000 for each 1% difference between Unavailability Factor Requirement and actual Unavailability factor, with this payment capped at $1.5 million per year	GRU will not receive the damage payment from GREC and will incur the full fixed O&M costs of the plant regardless of availability rate	GRU would no longer receive compensation for reduced availability of the plant and would still be required to pay the full fixed O&M cost, resulting in additional cost risk.	In either scenario GRU will be responsible for obtaining replacement energy when GREC is not available. GRU will have full control over the best way to bring the plant back to the desired availability factor to help mitigate this risk.	Medium

Risks	Under PPA	GRU Ownership	Change to GRU Risk	Confidence	Significance
Plant does not meet estimated heat rate	Fuel is a pass through and there is no heat rate guarantee; however, there is an implied heat rate in the fuel costs calculation. Changes to actual heat rate due not affect GRU costs.	GRU will be responsible for plant heat rate and fuel costs; therefore, an increase in heat rate increases the fuel cost applicable to GRU.	Minimal change in risk, since implied heat rate is greater than estimated heat rate. In fact it is possible that fuel costs could be reduced based on the potential to achieve a more favorable heat rate.	GRU will have full control over the best way to improve heat rate if the plant fails to meet expectations. Additionally, there is likely margin within the implied heat rate in the PPA.	Low

Risks	Under PPA	GRU Ownership	Change to GRU Risk	Confidence	Significance
Plant does not meet emissions limits	GRU is not currently responsible for increased costs to meet emissions limits that are triggered by something other than change in law (i.e. additional sodium bicarbonate and ammonia costs to meet existing limits). If plant does not meet Unavailability Factor requirement due to failure to meet emissions, GRU could receive LD payment from GREC.	Increased sodium bicarbonate costs or ammonia injection costs would be GRU responsibility. No penalty payment to GRU from GREC if availability is impacted by failure to achieve emissions rates.	Potential increased variable O&M costs due to increase in sodium bicarbonate and ammonia injection rates.	Necessary removal rates of criteria pollutants are within the expected achievable removal rates of the technology utilized. Potential increases in costs to achieve higher removal rates would likely be relatively minimal. In either scenario GRU will be responsible for obtaining replacement energy when GREC is not available. GRU will have full control over the best way to meet emissions limits.	Low

If you have any questions regarding this information, please feel free contact Jeff Kopp at 816-822-4239 or jkopp@burnsmcd.com.

Sincerely,

Jeffrey T Kopp

Jeff Kopp, PE
Manager of Project Development

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