Walker, Elizabeth (AIR)

From: Osbourn, Scott [Scott_Osbourn@golder.com]
Sent: Monday, June 02, 2008 12:40 PM
To: Read, David
Cc: Vielhauer, Trina; Angela Morrison Uhland; virginia@wetherellconsulting.com; Glenn Farris
Subject: RE: RAI meeting
Attachments: RAI Response rev1.doc; Startup Schedule.pdf; Gas Cleaning PFD for air permit.pdf

As we discussed, please find attached a DRAFT of our response to the Department's request for additional information. I look forward to our discussions at 2:30 PM today.

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From: Read, David [mailto:David.Read@dep.state.fl.us]
Sent: Monday, June 02, 2008 10:26 AM
To: Osbourn, Scott
Cc: Vielhauer, Trina
Subject: RAI meeting

Scott Trina asked me to contact you to see if you still plan on faxing us the response to the RAI for BG&E today so we can discuss it by phone at 3:00 pm. We will need the response a couple of hours before the meeting so when can give it a quick review. I will also try to contact you by phone on this issue.

Thanks

David Lyle Read
Engineering Specialist II
Special Projects Section
Bureau of Air Regulation (BAR)
Division of Air Resource Management (DARM)
Florida DEP
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June 2, 2007 07389628

Florida Department of Environmental Protection
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Attention: Mr. A. A. Linero

RE: RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
BIOMASS GAS AND ELECTRIC; FACILITY ID NO. 0730109

Dear Mr. Linero:

This letter is in response to your request for additional information regarding the Air Construction Permit application submitted by Golder Associates Inc. on behalf of Biomass Gas and Electric (BG&E) on April 3, 2008.

1. Material Handling. In the application, it is indicated that the wood fuel feedstock will be processed off-site and shipped by train to the facility location. The exact composition of the wood feedstock is not provided. Will the feedstock contain understory materials such as detritus material from the floor of forest areas and leaves and small branches or will it consist solely of chipped to size wood chunks from tree trunks? Detritus materials and leaves may contain mercury from dry and wet deposition which could affect the mercury emission estimates. [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response—The feedstock will consist of woody biomass, which will be processed at a remote fuel preparation area. At this remote area, the feedstock will be sorted, screened and chipped to size. Deleterious material such as nails, glass and metal will be removed for landfill disposal. Although some leaves and small branches may inadvertently find their way into the feedstock, the focus is on producing wood chips from the woody biomass. While mercury should be at very low levels in the biomass feedstock to the gasifier, the disposition and control of any mercury that might be present is discussed in the response to Comment No. 6 in this letter.

2. Startups/Shutdowns. In the application, it is estimated that there will be a total of 6 startups of the gasifier system per year. There is no request of provisions in the permit for additional startups for shakedowns during the initial operation of the facility. Does BG&E actually anticipate that the facility will not require additional startups and shutdowns of the gasifier system during the first year of the facility's operation? [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response-- During initial operations, there will be a larger number of startups and shutdowns than the 6 anticipated after the startup and shakedown period. The 6 is based on annual operations after the shakedown period.

In addition, there is a major difference between a cold startup, which takes at least 18 hours, and a hot startup, which can take from as little as a few minutes to several hours. For definition purposes, hot startups are defined as ones where the gasifier is over 1,000 ^0F when the startup occurs.

At another gasification facility, the Burlington facility, there were approximately 22 cold startups/shutdowns during the first year of operation. By 2001, this number had dropped to 7. Cold startups involve a transition period during the change from air-fired operation to pyrolysis, where smoke can be produced during the change from excess oxygen combustion to sub-stoichiometric oxygen combustion, and finally to pyrolysis. This period of operation at the flare has an expected initial duration of up to 30 minutes for cold startups. One of the operational objectives of the Tallahassee plant is to reduce the length of the cold startup transition to a minimum, with a target of 10 minutes achieved after the first year of operation. Flare design to help minimize sub-stoichiometric conditions during burnoff are a part of the preliminary engineering design effort, with the objective of minimizing smoke production during the sub-stoichiometric transition.

Emissions from hot startups are minimal, since the wood still pyrolyzes at temperature, with low tar formation. During an electrical trip, gas production tapers off over about three minutes to a zero flow. The gas is flared during this period. Since the gas varies in composition rapidly during this three minute period, there will be events of a few seconds duration where the flared gas may transition through a substoichiometric range and produce smoke.

Therefore, in response to the Department's comment, BG&E would like to request the flexibility for as many as 22 startup/shutdowns during initial operation, until an average of no more than 6 startup/shutdowns would be required annually.

3. Volatile Organic Compounds (VOC) and Sulfur Dioxide (SO_2) Emissions during Shutdowns. On pages 12 to 15 of the application, emission estimates are provided for nitrogen oxides (NOx) and particulate matter (PM) during shutdowns, while none are given for VOC and SOx based on the argument that these emissions from the turbines are already low. What are the anticipated emissions of these pollutants during shutdowns? [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response-- As previously stated, emissions during shutdown are anticipated to be low. Emission estimates were provided for NOx (0.05 tons per year or TPY) and PM (0.0005 TPY) based on material balance and AP-42 emission factors. Attached are estimates for VOC and SO2, which also rely on AP-42 emission factors.[These will be provided by BG&E]

4. Startup and Shutdown Procedures. In Section 2.2.1 of the application, the startup and shutdown modes and procedures for the gasifier/power block are briefly described with the caveat that full descriptions of the procedures are not provided due to their proprietary nature. To effectively assess the proposed durations and associated emissions involved during the startup and shutdown of the gasifier/power block of the facility, the Department requires a full description of the procedures. Please indicate which submitted documents are considered proprietary. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response-- The full description of the startup/shutdown procedure, which SilvaGas has currently developed, was included in the air application. SilvaGas has also developed a preliminary gasifier startup schedule (see attached Figure 1), consistent with the cold startup duration described in the response to Comment No. 2 above. A more detailed procedure is anticipated, but only as part of the Operating Manual for the plant. This will not be developed until the detailed design phase of the engineering effort. It is not BG&E's intent to claim these procedures as proprietary, the issue is that these formalized procedures do not yet exist. The proposed project is not a conventional power plant, where an operating manual of this type may be available off the shelf.

5. Refractory Life. If the facility only requires 6 startups per year what is the anticipated life of the gasifier refractory? If additional startups are required, especially during the initial operation of the facility, how is the life of the refractory affected? [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response-- The refractory life varies substantially, depending on the location of the refractory in the vessel. SilvaGas obtained a patent on installing tees instead of elbows at 90 degree flow direction changes, in order to reduce the erosion rate at the ells (i.e., the critical point of circulation between the gasifier and the combustor). Improved materials suggest that the life of the refractory in straight sections of the vessels and ductwork will be approximately 5 years, although there are examples in similar services where the refractory has lasted in excess of 30 years. The worst case found at Burlington was for a vent pipe off a seal pot which had a gas velocity of 400 feet per second. This refractory lasted only two weeks, but was an isolated case compounded by design error.

   Our cyclone vendors suggest an upper limit on gas flow velocity to minimize refractory wear in the cyclone impact zones. Hard facing of exotic materials such as silicon or tungsten carbide plates are planned for the worst impact zones. SilvaGas currently is using advanced computational fluid dynamics software which can predict erosion locations and wear rates. One of the ongoing maintenance programs for the Tallahassee plant is to verify and calibrate the computer prediction of refractory erosion locations and wear rates.

   Startups and shutdown affect refractory life only if the heatup and cooldown rates result in thermal expansion-based stresses. The maximum heatup and cooldown rates for the Tallahassee plant are based on Burlington rates which successfully prevented thermal stress induced cracks. An additional factor is the refractory anchoring spacing and design. BG&E is working closely with our original refractory vendor, based out of Tampa, to provide the correct anchor spacing and design.

6. Syngas Cleanup. In Section 2.1.3 of the application, the syngas cleanup system proposed for the project is discussed. However, very few details of the proposed system are given. In previous meetings between the Department and BG&E, it was indicated by BG&E that the syngas cleanup system will be provided by Dahlman Filter Technology. Based on research done by the Department, the technology provided by Dahlman principally involves the removal of tar compounds from the syngas stream utilizing an oil wash. Details on the removal of other pollutants of concern (particulates, inorganic impurities such as sulfur compounds and volatile metals) were not available from research or in the application. Please provide to the Department a more detailed description of the syngas cleanup system proposed for the facility, including, if

available, process schematics, which will allow the Department to make a comprehensive technical evaluation of the gas cleanup system. If such information is deemed proprietary, please indicate on the submitted documents. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response—A simplified process flow diagram of the product gas cleanup system has been obtained from Dahlman and is attached as Figure 2. As described in the following paragraphs, the gas cleanup system has no direct emissions to the atmosphere. Only condensate water leaves the closed system.

Further background on the gasifier is necessary in order to understand the operation of the gas cleanup system. The gasifier operates as a pyrolysis unit, under reducing conditions. For instance, organic sulfur and nitrogen in the feedstock are converted to H_2S *and* NH_3 *in small amounts. In a similar fashion, it is expected that mercuric salts, methyl mercury organics or mercuric oxides would be reduced to elemental mercury, and be evaporated into the product gas. The wash oil scrubbers remove tars above the dew point of water, so the vapor pressure of the elemental mercury remains high, and at its very low concentration, it should all remain in the vapor phase. The same is true of the* H_2S *and* NH_3.

When the de-tarred product gas goes through the water scrubber at the tail end of gas cleanup, the acid gases and inorganic salts (metallic ions) are cooled down and absorbed to about a 90 percent removal level by the water, according to calculations by Dahlman. The removal level in such a system of mercury is probably quite low, due to the insolubility of mercury in the water, but the elemental mercury probably reacts with the H_2S *present to make mercuric sulfide, and drops out as a particulate in the main recirculating water loop. There is an additional separate section in the water scrubber that has an isolated recirculating loop of caustic soda solution. The primary objective of this section is to remove the remaining* H_2S *by reaction with the caustic, making sodium sulfide.*

This recirculating loop of caustic soda solution with sulfides in it provides an ideal solution for scrubbing mercuric compounds out of the vapor phase, with the dissociation constant for mercuric sulfide at 10^{-35}. *Thus, all of the remaining mercury should come out here, since the* $S^=$ *ion concentration should be much higher here rather than in the main recirculating water loop.*

This is the approach used as the mercury cell caustic chlorine plants for removing any ppt traces of mercury from plant waste water and the food-grade product caustic soda. The water is treated with a ppm concentration or lower of $S^=$ *ions, and the precipitated mercuric sulfide filtered out. Residual concentrations of mercury in the food grade caustic soda are removed in the same manner, down to non-detectable limits.*

The recirculating water at the water scrubber is blown down on a regular basis, where it is used in the cooling tower as part of the cooling tower makeup water. The design has not proceeded far enough yet to determine if this water needs filtration. Should detectable mercury concentrations be obtained in either this blowdown or the blowdown from the separate caustic cuirculating loop, then this could be filtered to remove the mercuric sulfide particulate.

Further, the combustor receives char and olivine from the gasifier at about 1,350 ^0F. *At this temperature, and under the gasifier reducing conditions, mercury compounds would be separated out in the upstream cyclones as part of the product gas, described above. A negligible amount of mercury would enter the combustor, as there would be virtually no* *mercury present in the char. However, if any mercury were present, it would likely remain in the ash bound as a non-volatile inorganic salt rather than be released as a vapor.*

The vast majority of any mercury in the feedstock should end up in the makeup water from the water scrubber going to the cooling tower, and in particular, the blowdown from the separate caustic loop in the water scrubber which contains S ions. Routine sampling of this stream by filtration, and typically, an AA or similar analysis of the filter cake for mercury should determine if there is any need for further monitoring of mercury emissions.

7. Volatile Metal Emissions. As indicated in No. 6 above, no details are provided on how volatile metals, such as mercury, are going to be removed from the syngas. In the application, it is stated that the mercury concentration in the wood fuel is minimal and consequently expected mercury emissions are negligible. However, if this is not the case, does the syngas cleanup system utilize an activated carbon bed or something similar to control volatile metal emissions such as mercury? [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response—This comment is addressed above.

8. Duct Burner Firing. Based on the application, it appears that the duct burners will only fire syngas (product gas). Will natural gas ever be fired in the duct burners? [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response—Only product gas will be fired in the duct burners.

9. Emissions Averaging. In Table 3-2 of the application, emissions in ppm at 15 percent oxygen (O_2) of NO_X, carbon monoxide (CO), volatile organic compounds (VOC), and ammonia (NH3) appear to be given for annual stack testing requirements. Please provide Continuous Emissions Monitoring System (CEMS) 24 hour block average and 12 month rolling average estimates of CO emissions and 24 hour block average and 30 day rolling average estimates of NO_X, emissions when firing the combustion turbine and the combustion turbine in combination with the duct burners for the temperatures and loads cited in the table. [Rule 62-4.070, F.A.C. Reasonable Assurance]

   Response-- BG&E's requested emission limits are provided in the attached table (this is to be provided in a later transmittal).

10. SO_2 Emissions. On page 19 of the application, it is stated that SO_2 emissions will be minimized through the utilization of natural gas during startups and the gas cleanup system on the product gas. Please provide estimates of the SO2 concentration in the product gas before and after cleanup. In addition, provide estimates of SO2 stack emissions when firing product gas for the same conditions described in No. 9 above. [Rule 62-4.070, F.A.C. Reasonable Assurance]

    Response—As stated earlier, the gasifier operates as a pyrolysis unit, under reducing conditions, converting organic sulfur in the feedstock to small amounts of H_2S. The H_2S is then reduced to acceptable levels in the gas cleanup system. SO_2 emissions would result from the residual level of H_2S in the product gas (after the gas cleanup system), which is fired in the combustion turbines and duct burners, or, in the event of a system malfunction, when the product gas is flared. (BG&E will provide a summary table of the H2S in the pre- and post-

gas cleanup scenarios, as well as the amount of SO2 that can be generated by firing in the CT/DB or by flaring).

11. Combustion Turbine and Duct Burner Emissions Estimates. When comparing the upper and lower portions of Table 3-2 of the application, the emissions of NO_X, CO, and VOC appear to be lower when firing the duct burners than when not, please clarify. In addition, pollutants and units given in the table are not defined nor is the basis for the different emission concentrations for the various pollutants. Please redo this table and resubmit to address these issues and generally provide a clear overview of the expected emissions for the project as a function of turbine load, ambient air temperature, and duct burner firing. [Rule 62-4.070, F.A.C. Reasonable Assurance]

    Response— A subsequent discussion between Golder and David Read of the Department has cleared up some of the confusion associated with the emission table. Further, as stated in the response to Comment No. 9 above, BG&E has provided a tabular summary of the requested emission limits, including averaging times and methods of compliance (BG&E will provide in a separate transmittal).

Please do not hesitate to call should you require additional information.

Sincerely,

GOLDER ASSOCIATES INC.

Scott Osbourn, P.E.
Senior Consultant

Enclosures

SO/dcg

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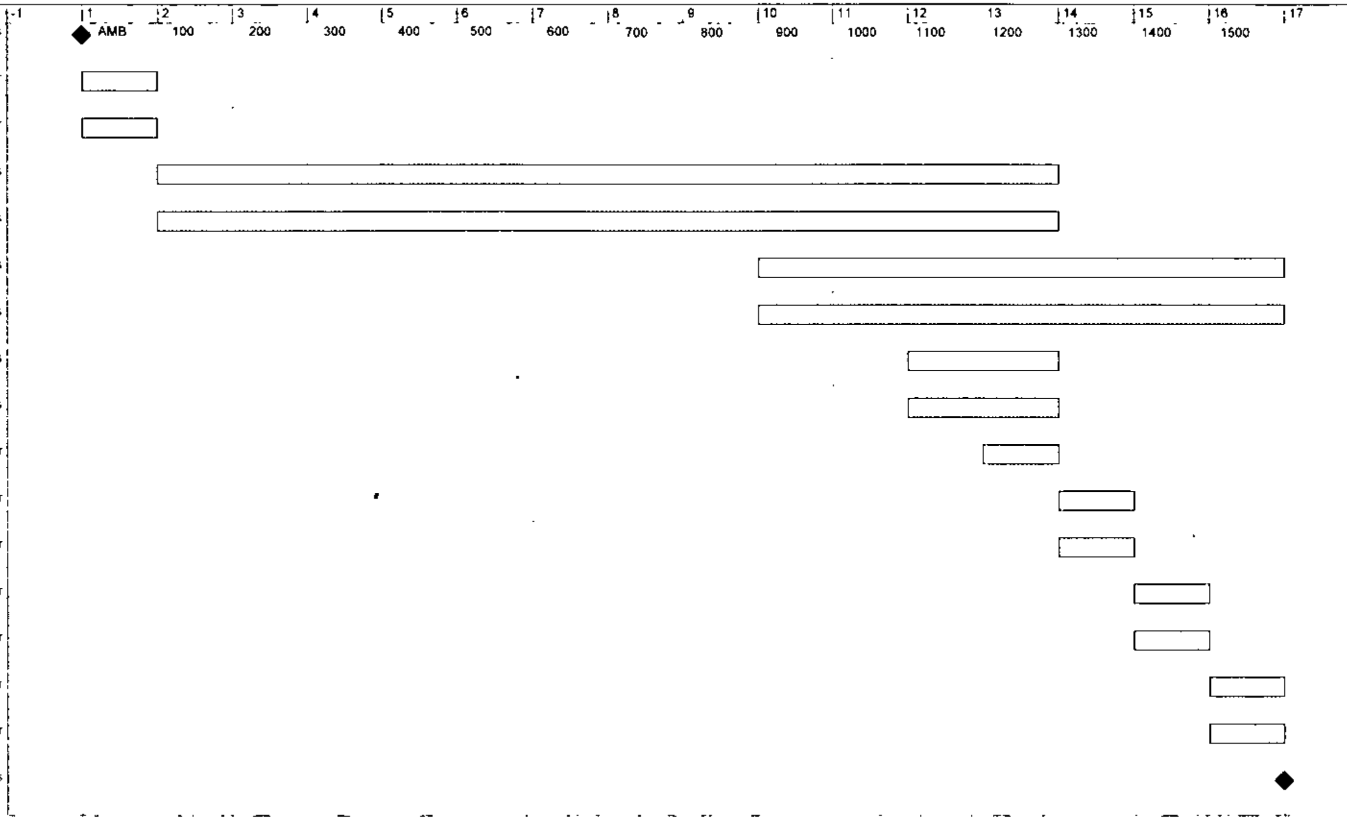
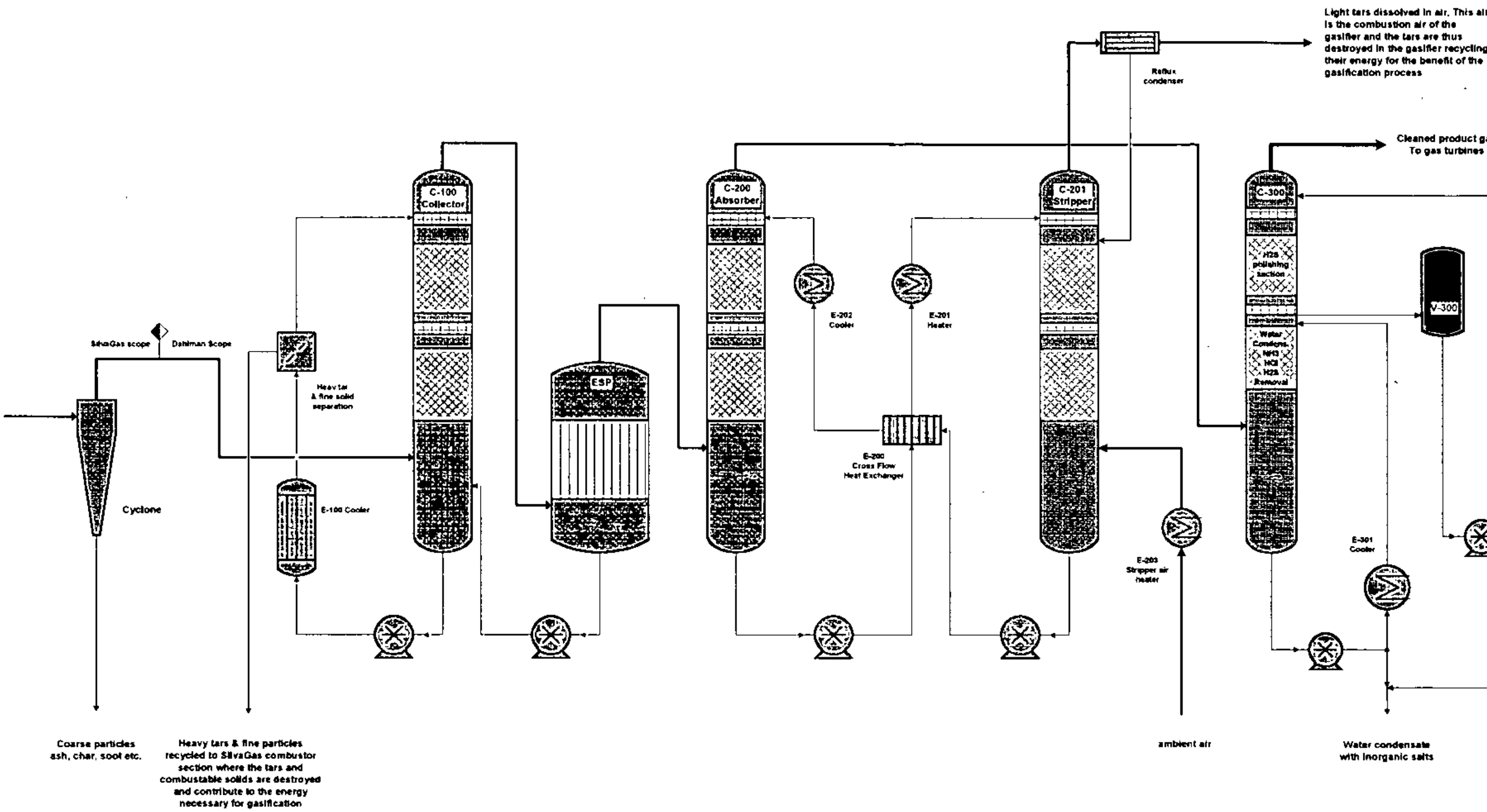
Preliminary
Gasifier Start-Up Schedule

ID	Task Name	Duration
1	**Temperature, deg F**	0 hrs
2	Start Combustion Blower	1 hr
3	Start Gasifier Blower	1 hr
4	Start Combustion Duct Burner	12 hrs
5	Start gasifier duct burner	12 hrs
6	Start combustor seal pot fluidizing flow	7 hrs
7	Start gasifier seal pot fluidizing flow	7 hrs
8	Increase combustor heatup rate	2 hrs
9	Increase gasifier heatup rate	2 hrs
10	Start combustor overbed burner	1 hr
11	Start wood and steam flowrate	1 hr
12	Start combustor overbed burner	1 hr
13	Ramp up wood to full rates	1 hr
14	Reduce / stop gasifier blower	1 hr
15	Stabilize at full rates	1 hr
16	Reduce / stop combustor overbed burner	1 hr
17	Operational	0 hrs



Project: Master BG&E Shell_r
Date: January 8, 2008

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External Milestone | Deadline



drawn by JWK	date 09-05-2008	customer	Biomass Gas & Electric LLC Tallahassee project
checked by -	approved by -		
drawing no -	revision 000 JWK 09-05-08	title	Simplyfied Process Flow Diagram,
am proj.	scale N.A.	DAHLMAN INDUSTRIAL PROJECTS	Dahlman Industrial Projects B.V. P.O. Box 438 NL 3140 AK Maassluis Noordzee 8 NL 3144 DB Maassluis Phone +31-10-5991114 Fax +31-10-5991100 E-mail dahlman@dahlman.nl Internet www.olgatechnology.com
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