August 9, 2013

Ms. Aimee Wilson, P.E.
Air Permits Section
United States Environmental Protection Agency (USEPA)
Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733 Project No. 0151579

Subject: Response to Information Request Call - Air Liquide, LP Bayou Cogeneration Plant

Dear Ms. Wilson,

On behalf of our client Air Liquide, LP (Air Liquide), Environmental Resources Management (ERM) submits this letter in response to your phone correspondence with Air Liquide on August 7, 2013, requesting additional information and comments regarding the draft permit for a greenhouse gas (GHG) Prevention of Significant Deterioration (PSD) permit currently under review by USEPA, Region 6. A summary of each request for information (RFI) is provided along with Air Liquide's response.

***RFI #1 Please provide more information on CCS costs and technology used***

For the economic analysis of CCS, Air Liquide assumed that they would be installing an amine based scrubbing system and associated compressors. While not fully proven on gas-fired turbine flue gas, amine based scrubbing systems are the most mature technology potentially available for CCS. To calculate the cost of CCS, Air Liquide used cost information from a DOE-NETL study from 2010 to determine the capital cost of the amine scrubbing system and associated compressors. There is no available space to construct the necessary equipment to capture and compress $CO_2$; therefore, a capital cost adjustment factor was included to account for demolition of existing assets to provide a sufficient footprint. Further, costs were revised per EPA's request assuming a 10-inch diameter, 30-mile long pipe to deliver the compressed $CO_2$ to the Denbury pipeline. A 10-inch pipe is conservatively small and likely underestimates the costs for constructing the pipeline; however, pipeline costs account for only 3% of the total capital costs resulting in minimal impacts to the normalized costs. An updated capital cost estimate is included as Attachment 1 to this submittal.

***RFI #2 Was Enhanced Oil Recovery (EOR) considered for CCS?***

EOR was considered in the economic analysis of CCS, but no value was included in the economic analysis for CCS for the sale of $CO_2$. Currently there is not a significant market in the Texas Gulf Coast region for $CO_2$ for EOR, and in the future if CCS is implemented the market will be saturated, further depressing the value. As such, it is Air Liquide's opinion that EOR in the region has no economic value. Further, it is beyond the scope of the business purpose for this project to become contractually obligated to provide $CO_2$ for commercial purposes, including EOR.

***RFI #3 Please provide information on the increase in criteria pollutants associated with CCS***

For the economic calculations related to CCS, it was taken from the NETL study that the carbon capture and compression equipment would at best require an additional energy input of about 15% of the designed plant output. As such, to provide this additional energy it would require combustion of approximately 15% more fuel. Combustion of 15% more fuel would lead to a 15% increase in the products of combustion ($NO_X$, CO, VOC, PM, etc.). For this facility, a 15% increase would amount to the following annual emission increases in criteria pollutants:

- $NO_X$ – 34.4 tpy
- VOC – 3.36 tpy
- CO – 62.9 tpy
- PM – 8.87 tpy
- $SO_2$ – 1.31 tpy

Given that the facility is in a non-attainment county, it is Air Liquide's opinion that the environmental cost associated with the increase in ozone precursors is too high to justify CCS to control a pollutant for which there is no NAAQS.

***RFI #4 – Please provide justification for the 3% degradation factor claimed on the BACT efficiency provided.***

Air Liquide is requesting a 3% adjustment to new and clean thermal efficiency to represent performance degradation over time. Attachments 2 and 3 show typical performance curves for GE turbines in regards to efficiency losses over time. Pages 45-47 in Attachment 4 show a performance curve for a generic turbine, as well as discussion of what causes that degradation loss. Based on the performance data provided, it is Air Liquide's opinion that a 3% adjustment is fully justified and would allow Air Liquide to operate the turbine according to the maintenance cycle recommended by the manufacturer.

***RFI #5 – Please provide a description of the environmental benefit of the proposed project.***

Air Liquide is installing 4 Gas Turbines and 3 Boilers at Bayou Cogeneration facility. The Gas Turbines are equipped with GE Dry Lox NOx technology (DLN 1+) with CLEC to control the NOx emissions. As a result of this installation, the NOx emissions are reduced from 9 ppm to 5 ppm (excluding Duct Burners). The NOx emissions as well as CO and CO2 are monitored by CEMS.

The NOx emissions from the new Boilers are controlled by a Selective Catalytic Reduction (SCR) unit. This will achieve a reduction from 16 ppm to 9 ppm of NOx. The NOx, CO, $CO_2$ and $NH_3$ emissions from the stacks are monitored by CEMS.

The overall net reduction in $NO_X$ emissions from the project is 99 tpy.  This reduction is significant considering the facility is located in a severe ozone non-attainment area.

If you have any questions, please feel free to contact Mr. Eric Hodek of my staff at (512) 374-2261 or at eric.hodek@erm.com.

Sincerely,

Environmental Resources Management

Peter T. Belmonte, P.E.
Partner

Attachments
1 – Updated CCS Cost Calculations
2 – GE Turbine Performance Degradation Information
3 – GE Turbine Performance Degradation Information
cc: Mr. Aswath Kalappa, Air Liquide

**Attachment 1**
**Air Liquide Bayou Cogeneration Plant**
**GHG BACT Analysis**
**Conceptual Cost Estimate for Carbon Capture and Sequestration**

| **Post-Combustion $CO_2$ Capture and Compression** | | |
|---|---|---|
| Base Capital [1] | $758/kW | $358,029,361 |
| Demolition and Retrofit Cost Adjustment[2] | 0.5 | |
| Adjusted Capital Cost | | $537,044,041 |
| Annual O&M [1] | $0.00124/kWh | $10,254,106 |
| Annual Fuel [3] | 14.7% fuel use at $5/MMBtu | $6,103,793 |

| **Pipeline Cost Breakdown [4]** | | |
|---|---|---|
| L, Pipeline Length (miles) | | 30 |
| D, Pipeline Diameter (inches) | | 10 |
| | Pipeline Costs | |
| Materials | $\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D20 + 26,960)$ | $3,776,306 |
| Labor | $\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2074 \times D + 170,013)$ | $12,833,179 |
| Miscellaneous | $\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$ | $4,482,716 |
| Right of Way | $1,200 (ROW cost in dollars per rod of length) * (5,280/16.5) * L | $11,520,000 |
| | Other Capital | |
| $CO_2$ Surge Tank | Fixed | $1,150,636 |
| Pipeline Control System | Fixed | $110,632 |
| | O&M | |
| Fixed O&M ($/year) | $8,632 x L | $258,960 |

| **Geologic Storage Costs [3]** | | |
|---|---|---|
| Number of Injection Wells | | 2 |
| Well Depth (m) | | 2,134 |
| $CO_2$ Captured (tons) | | 1,746,403 |
| | Capital | |
| Site Screening and Evaluation | Fixed | $4,738,488 |
| Injection Wells | $\$240,714 \times e^{0.0008 \times \text{Well Depth}}$ | $1,327,177 |
| Injection Equipment | $\$94,029 \times (7,839/(280 \times \text{Number of Injection Wells}))^{0.5}$ | $351,802 |
| Liability Bond | Fixed | $5,000,000 |
| | Declining Capital Funds | |
| Pore Space Acquisition | $\$0.334/\text{short ton } CO_2$ | $583,299 |
| | O&M | |
| Normal Daily Expenses | $11,566/Injection Well | $23,132 |
| Consumables | $\$2,995/\text{yr}/\text{ton } CO_2/\text{day}$ | $14,330,076 |
| Surface Maintenance | $\$23,478 \times (7,839/(280 \times \text{Number of Injection Wells}))^{0.5}$ | $87,841 |
| Subsurface Maintenance | $7.08/ft-depth/Injection Well | $30,217 |

| **Annualized Cost Estimate** | |
|---|---|
| Economic Life, years | 20 |
| Interest Rate (%) | 10 |
| Capital Costs | $582,918,274 |
| O&M Costs (Annual) | $31,088,124 |
| Capital Recovery | $68,469,360 |
| Total Annualized Cost | $99,557,484 |
| Total $CO_2$ Controlled (tpy) | 1,746,403 |
| $CO_2$ Cost Effectiveness ($/ton) | 57 |
| $CO_2$ Cost Effectiveness ($/kWh) | 0.036 |

[1] Adapted from Cost and Performance Baseline For Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity, DOE/2010/1397 (Revision 2, November 2010). Plant output converted from CHP to equivalent Frame 7EA combined cycle output to enable use of cost information (www.ge-energy.com/products and services/products/gas turbines heavy duty/7ea heavy duty gas turbine.jsp). Capital costs adjusted using the ENR Construction Cost Index to 2012 dollars. O&M costs not adjusted.

2 Taken from Office of Air Quality Planning and Standards Air Pollution Control construction cost guidance.

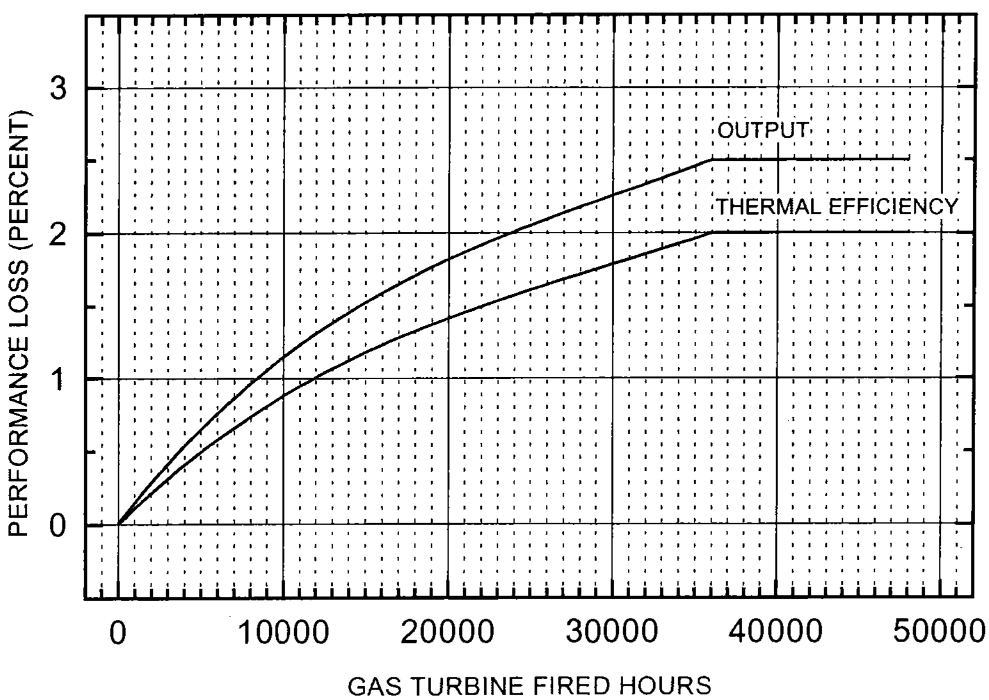
3 Fuel costs represent the additional fuel necessary to compensate for parasitic load caused by the addition of CCS. Based on review of review of the plant heat rates used in Case 13 and 14 presented in Cost and Performance Baseline For Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity, DOE/2010/1397 (Revision 2, November 2010), CCS imposes a 14.7% increase in the plant heat rate; therefore, 14.7% more fuel is necessary to meet plant output. That amount of output need to come from somewhere, and is assumed to be equivalent to the cost of fuel.

4 Pipeline and Geologic Storage cost estimates based on National Energy Technology Laboratory (US DOE) document, *Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-2010/1447 (March 2010).

# EXPECTED GAS TURBINE PLANT NON-RECOVERABLE PERFORMANCE LOSS DURING EXTENDED PERIOD OPERATION

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

* PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
* ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
* ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
* A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
* GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
* THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND MAINTENANCE WITH COMPRESSOR ROTOR AND STATOR SCOURING, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
* DEMONSTRATION OF GAS TURBINE PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.

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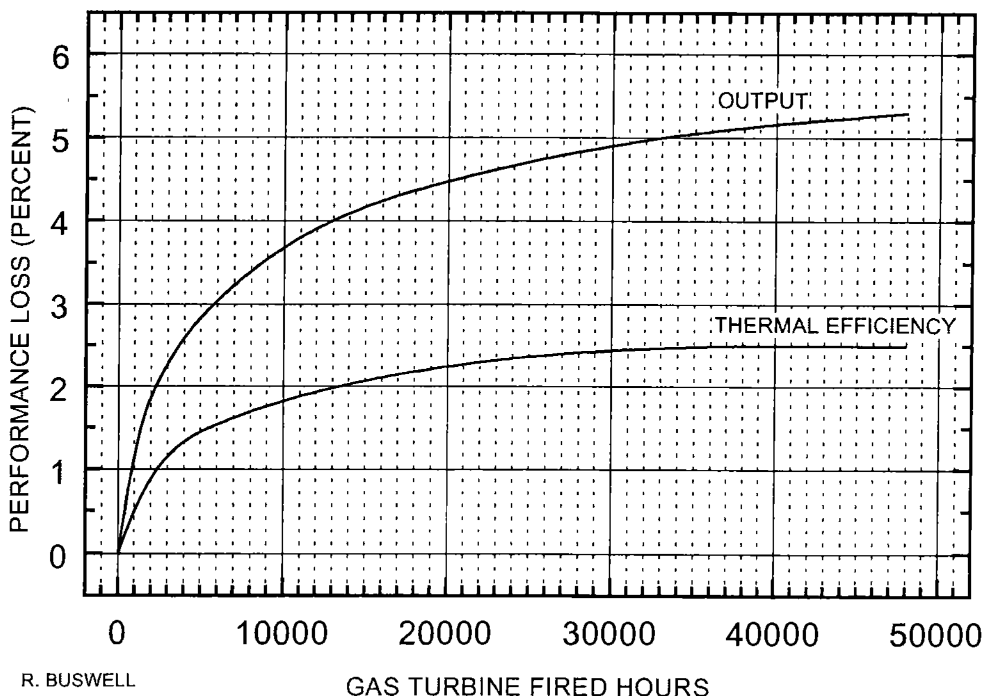
GE Power Systems

# EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

* PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
* ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
* ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
* A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
* GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
* THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
* DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.




R. BUSWELL
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Air Liquide provided a fourth attachment titled “Axial Compressor Performance Maintenance Guide Update,” Technical Update (February 2005), from the Electric Power Research Institute.

Because of apparent licensing and copyright restrictions, we will not post the report online.

However, it may otherwise be available for download to interested parties at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001008325

Please contact Aimee Wilson at (214) 665-7596 or wilson.aimee@epa.gov, with any questions regarding this notice.