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October 14, 2013

Aimee Wilson
Air Permits Section
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202

Re: Supplemental Comments to PSD-TX-612-GHG

Please find enclosed supplemental comments from Air Liquide Large Industries U.S. LP ("Air Liquide") on the draft PSD permit for GHG emissions for the redevelopment of the cogeneration facility in Pasadena, Texas (PSD-TX-612-GHG). Please contact me with any questions.

Very truly yours,

Bracewell & Giuliani LLP

Richard Alonso

Enclosure

SUPPLEMENTAL COMMENTS FROM
AIR LIQUIDE LARGE INDUSTRIES U.S. LP ("AIR LIQUIDE")
ON THE DRAFT PSD PERMIT FOR GHG EMISSIONS
FOR THE REDEVELOPMENT OF THE
COGENERATION FACILITY IN PASADENA, TEXAS
(PSD-TX-612-GHG)
October 14, 2013

Air Liquide is submitting the following information to EPA Region 6 to clarify and address various issues in the statement of basis for the draft permit for the Bayou Cogeneration Plant (PSD-TX-612-GHG). EPA should consider this additional information when evaluating the draft permit.

CCS Cost Analysis

First, Air Liquide would like to address the basis that EPA used for rejecting carbon capture and sequestration ("CCS") in step 4 of the Best Available Control Technology ("BACT") analysis. Part of EPA's rationale for rejecting CCS was based upon a comparison of the cost of installing CCS at the Bayou Cogeneration Plant as compared to the overall project cost. EPA typically uses a dollar per ton ($/ton) basis when evaluating the cost of pollution control devices. Air Liquide believes that in limited circumstances it may be appropriate for EPA to compare the cost to install CCS against the total project cost. *See In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07 (E.A.B. Sept. 17, 2012). However, as the EAB noted in *Palmdale*, cost effectiveness "is typically calculated as the dollars per ton of pollutant emissions reduced." *Id.* at 54 (citing the 1990 Draft NSR Manual). Air Liquide's permit application and these supplemental comments provide a $/ton analysis of the cost effectiveness of CCS as a control technology. In order to remain consistent with the cost effectiveness BACT analysis required by the NSR Manual, Air Liquide recommends that EPA rely on the $/ton analysis, as revised in these supplemental comments and Attachment 1, as the basis for its step 4 BACT analysis.

Air Liquide has made the following revisions to the $/ton cost basis:

Interest rate

Air Liquide used an interest rate of 10% in its permit application for calculating its capital recovery costs. EPA Region 6 has issued final GHG permits for several projects that used a 7% (or higher) interest rate for capital recovery costs. For example, Enterprise Products Operating, Mont Belvieu Complex Eagleford Fractionation and DIB Units used a 7% interest rate and 20 year equipment life.[1] ETC Texas Pipeline - Jackson used an 8% factor over 10 years.[2] Copano

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[1] Application for Prevention of Significant Deterioration Air Permit for Greenhouse Gases, Enterprise Mount Belvieu Complex, Eagleford Fractionation and DIB Units, at 6-12, *available at* http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/enterprise_mont_belvieu_revapp.pdf.

[2] Greenhouse Gas PSD Air Permit Application, ETC Texas Pipeline Ltd., at 36, *available at* http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/etc-jackson-app-revised03-15-12.pdf.

Processing used 7% over 20 years.[3] The Valero McKee crude expansion used 8% over 10 years.[4] To be consistent with EPA Region 6 practice, Air Liquide revised the $/ton analysis using a 7% interest rate for capital recovery.

Retrofit cost

Air Liquide used a factor of 1.5 in its cost analysis to account for onsite demolition and retrofit costs. A study issued by the National Energy Technology Laboratory ("NETL") in August 2013 suggests that in some cases a factor of 1.1 is appropriate. *See* NETL, Estimating Plant Costs Using Retrofit Difficulty Factors (Aug. 2013). This study was not available at the time that Air Liquide conducted its BACT analysis. After reviewing this study and considering site-specific constraints, Air Liquide determined that a revised retrofit cost factor of 1.1 is appropriate for this project.

Air Liquide acknowledges that the retrofit factor of 1.5 that it used in its calculations is at the high end of the range provided in EPA's Cost Manual. EPA, Office of Air Quality Planning and Standards Pollution Control Construction Cost Guidance at 2-28 (the "Cost Manual"). As the Cost Manual acknowledges, "[t]he magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices." *Id.* "The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst." *Id.* The retrofit cost factor is intended to address additional expenses the facility will incur when attempting to "shoe-horn" additional control equipment in to its existing design footprint. *Id.*

Air Liquide believes that site-specific construction constraints at the Bayou Cogeneration site may warrant a higher retrofit factor than generic NETL factor of 1.1. Because the Bayou Cogeneration Plant is landlocked, Air Liquide cannot locate new equipment on land that is immediately adjacent to the facility – in other words, the layout of the new CCS equipment would not be not optimal and Air Liquide would need to make numerous modifications to the site layout to accommodate the installation of this equipment. However, in the absence of a line-by-line analysis by cost account, as recommended by the NETL study, Air Liquide proposes to use the generic retrofit factor of 1.1 for purposes of this analysis.

Overall, the construction costs for retrofitting the existing site with CCS will be higher than the costs of installing CCS at a Greenfield combined heat and power ("CHP") plant. For purposes of this analysis, Air Liquide used a retrofit value of 1.1 based on the generic CCS retrofit factor from the 2013 NETL study. This value has been incorporated in the enclosed revised $/ton calculations.

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[3] Application for Prevention of Significant Deterioration Permit for Greenhouse Gases, Houston Central Gas Plant, at 6-15, *available at* http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/copano-revisedapp120712.pdf.

[4] Letter from Shelly Williamson, Valero McKee Refinery to Ms. Melanie Magee, EPA Region 6, at 106 (June 10, 2013), *available at* http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/diamond_shamrock-mckee-revised-app-jun132013.pdf.

Fuel costs

When analyzing the fuel costs associated with this project, Air Liquide assumed an annual natural gas price of $5/MMBtu. Because natural gas prices fluctuate from day to day, Air Liquide believes that using the Henry Hub spot pricing for a given day does not adequately account for price fluctuations over the course of a year. Therefore, Air Liquide believes it is more appropriate to use an annual average of the Henry Hub spot prices for 2012. This value is $2.77/MMBtu. The enclosed revised $/ton analysis reflects this adjustment.

Offsets to the cost of CCS

Air Liquide's initial cost analysis did not expressly account for tax credits associated with CCS. Since 2008, the IRS has provided a tax credit for two types of CO_2 sequestration. A credit of $20/ton may be taken for CO_2 sequestered in secure geological storage. 26 U.S.C. § 45Q(a)(1). A $10/ton credit is available for CO_2 used as a "tertiary injectant in a qualified enhanced oil or natural gas recovery project," often referred to as "enhanced oil recovery" or EOR. 26 U.S.C. § 45Q(a)(2). This tax credit is capped and ceases to be available once credits have been claimed for sequestering 75,000,000 tons of CO_2. 26 U.S.C. § 45Q(e); *see also* IRS Notice 2009-83 (". . . at such time as the Service certifies, in consultation with the EPA, that 75,000,000 metric tons of qualified CO2 have been taken into account for purposes of § 45Q credit, the Service will publicly announce that the § 45Q credit will cease to be available for the calendar year following such announcement."). As of May 2013, credits have already been claimed for the sequestration of 20,858,926 tons of CO_2. IRS Notice 2013-34 at 4.

Given these limitations on CO_2 tax credits, as explained below, Air Liquide has determined that these tax credits would be available for a limited time after startup of CCS at the Bayou Cogeneration Plant. As noted above, 20,858,926 of the available credits were claimed between 2008 and May 2013. There is not a public register for these credits and because the tax returns for the companies claiming these credits are not publicly available, Air Liquide does not have any way to confirm which projects are claiming these credits. To be conservative, though, we have assumed that the annual rate of consumption of these credits will remain the same going forward. In other words, we have assumed that companies obtained credits of 4,171,785 tons per year between 2008-2013 and we will assume for purposes of this evaluation that those projects would continue to claim credits at that same rate going forward. In addition, we have assumed that the CCS projects that are expected to come online between 2015-2017 would also begin to file claims for these credits. Our attached analysis considered the carbon that is expected to be captured by the following projects: Kemper County (3.5 MMt/yr), Future Gen (1.0 MMt/yr), Texas Clean Energy (2.7 MMt/yr), Hydrogen Energy California (2.6 MMt/yr), and W.A. Parish (1.4 MMt/yr).

Using these assumptions, Air Liquide believes that the 75,000,000 credits would be consumed by the end of 2018 (*see* Attachment 2). Air Liquide anticipates that if it were to install CCS at the Bayou Cogeneration Plant, startup would occur in 2017. Under the best case scenario, Air Liquide might obtain the benefit of those tax credits – at most – for operating years 2017-2018. Furthermore, it is possible that Air Liquide may not be able to claim any of these tax credits if other projects come online at an earlier date or if current projects have a higher annual carbon capture rate than we have estimated.

In addition to tax credits, Air Liquide considered the potential to sell some of its captured CO_2 emissions for enhanced oil recovery ("EOR"). Air Liquide has analyzed the costs associated with two different scenarios for sequestering the CO_2. These scenarios are as follows:

(1) Sequestering 100% of the CO_2 in a geological formation in Texas.
(2) Selling 50% of the CO_2 to Denbury for EOR and sequestering the of the CO_2.

Scenario 1

Under this scenario, Air Liquide has assumed that it would sequester 100% of its CO_2 at a geological formation that is located 200 miles away from the plant. The cost estimate for this scenario includes constructing a 10" pipeline to this site and drilling two wells. The tax treatment for Scenario 1 assumes a $20/ton credit for 100% of the sequestered CO_2 for the years 2017 and 2018. Under this scenario, Air Liquide has determined that the cost basis for CCS would be $47/ton.

Scenario 2

Under Scenario 2, Air Liquide considered the potential revenue that could be generated by selling CO_2 for industrial uses such as EOR. After conducting a review of publicly available information from the Texas Railroad Commission, Air Liquide concluded that the only viable CO_2 pipeline located in the region is the Denbury pipeline.[5] Therefore, under Scenario 2, Air Liquide has assumed the cost to construct a pipeline to connect to the Denbury pipeline. Based upon GPS mapping, the Denbury pipeline is located approximately 12.4 miles from the Bayou Cogeneration Plant. We have assumed a 50% contingency on this length to account for the actual pipeline route using available right-of-ways. Thus, the attached calculations assume that the 10" pipeline to connect to Denbury is 18.6 miles long.

Although the sales price of CO_2 to Denbury is confidential business information, for purposes of this calculation, Air Liquide has assumed that it would be able to sell 50% of its captured CO_2 to Denbury at a price of $10/ton beginning in 2018.[6] According to a 2012 Denbury Analyst Day Presentation, Denbury has sufficient CO_2 from its Jackson Dome reserves and current contracts to meet its needs until 2018.[7] Therefore, Denbury would not begin taking CO_2 from Bayou

[5] Air Liquide obtained information regarding CO_2 pipelines located in Harris and Galveston County from the Texas Railroad Commission ("TRRC") using the instructions available at http://www.rrc.state.tx.us/forms/maps/digital/index.php. *See* Attachment 3. This information from TRRC was current as of 10/8/2013. As shown in Attachment 3, the nearest CO_2 pipelines are the Denbury Pipeline in Galveston County (approximately 12.4 miles from the Air Liquide site) and a short DuPont B pipeline in Harris County that may be restricted to the facility and would not be usable for EOR purposes. Based upon this information, Air Liquide selected the Denbury Pipeline as the closest CO_2 pipeline available for selling CO_2 for EOR.

[6] *See* INEOS USA LLC PSD Permit Application for the La Porte, Texas Ethylene Oxide / Ethylene Glycol Plant, *available at* http://www.epa.gov/region6/6pd/air/pd-r/ghg/ineos-ethylene-app08092013.pdf at 6-13 n.22 (explaining that the sales price of CO_2 to Denbury is confidential business information, but that a 2009 Denbury presentation implies that it might be $10/ton).

[7] Denbury Analyst Day Presentation (Nov. 2012) at 82, 83, http://www.slideshare.net/Denbury/fall-analyst-presentation.

Cogeneration Plant until 2018 at the earliest. Even after this time, we believe it is reasonable to assume that Denbury's ability to take CO_2 will fluctuate and for that reason, we have assumed that Denbury would purchase 50% of the Bayou Cogeneration Plant's CO_2. Thus, Scenario 2 assumes that Air Liquide would also need to incur the cost to construct a 10" pipeline to the geological formation that is located 200 miles away from the plant and drilling two wells. Attachment 1 reflects that the total pipeline length for Scenario 2 is 218.6 miles.

Based upon this information, Scenario 2 assumes that Air Liquide would sequester 100% of the captured CO_2 in 2017. In 2018, Air Liquide could begin selling 50% of the captured CO_2 to Denbury and sequester 50% of the captured CO_2 in geological sequestration. In the cost-effectiveness calculations included for Scenario 2 in Attachment 1, Air Liquide calculated the total CO_2 controlled (i.e. avoided) as the amount of CO_2 sequestered in geological formation. Air Liquide did not include CO_2 used for EOR as avoided CO_2 emissions because it has not been demonstrated that CO_2 for EOR will remain permanently captured.

The tax treatment for Scenario 2 assumes a \$20/ton credit for 100% of the sequestered CO_2 in 2017, a \$20/ton credit for 50% of the sequestered CO_2 in 2018, and a \$10/ton tax credit for CO_2 used for EOR in 2018. Under this scenario, Air Liquide has determined that the cost of CCS would be \$42/ton.

<u>Adverse Energy and Environmental Impacts</u>

As the New Source Review Workshop Manual states, energy and environmental impacts are valid factors the EPA may consider when determining BACT – along with myriad other considerations. *See* EPA Draft New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting (Oct. 1990) ("NSR Manual") at B.29, B.46 (step 4 of the BACT analysis includes consideration of energy impacts and environmental impacts).

To be clear, Air Liquide does not advocate double-counting energy impacts. The proper place for considering these impacts is in the cost analysis. Specifically, as explained in the permit basis, plant efficiency might decrease by 15% if CCS were installed because Air Liquide might need to operate additional equipment to capture the CO_2 and compress it for transportation. In order to offset the amount of power used to support CCS equipment, Air Liquide might need to burn additional fuel to achieve the desired efficiency. However, there are no unique site-specific constraints on energy that would justify EPA eliminating CCS from consideration in step 4 of the BACT analysis based solely on energy issues.

The NSR Manual states that "the environmental impacts portion of the BACT analysis concentrates on impacts other than impacts on air quality (i.e. ambient concentrations)." NSR Manual at B.46. An increase in criteria pollutants is an environmental impact that a "reviewing authority may want to give consideration to" when local air quality concerns are at issue. However, "in most cases…it is not expected that this type of impact would affect the outcome of the [BACT] decision." NSR Manual at B.50. The NSR Manual states that "[t]he applicant should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative." NSR Manual at B.47. Here, the addition of CCS as a control technology would not create any unusual environmental impacts; however, adding CCS to the plant would increase NO_x and VOC emissions – primarily from the amine scrubber in an area that is in nonattainment for ozone. Air Liquide has accounted for this impact by including the purchase of emission reduction credits ("ERCs") to offset these NO_x and VOC emissions in the economic $/ton analysis.[8] EPA should therefore not solely rely on the increase of NO_x and VOC as an adverse environmental impact that would provide a basis for excluding CCS in this instance.

Conclusion

In conclusion, Air Liquide appreciates EPA's willingness to extend the public comment period until October 14, 2013. Air Liquide has added this additional information to the record to ensure that the Bayou Cogeneration Plant's PSD permit is based on an accurate and complete administrative record. We hope that this information has been helpful in explaining the bases for the BACT analysis conducted for this project and suggests that EPA consider this new information when evaluating the Bayport facility's draft PSD permit.

[8] The cost of purchasing ERCs was based upon the prices the City of Houston paid for VOC and NO_x credits in June 2013 ($270,000/ton for VOC ERCs and $151,000/ton for NO_x ERCs).

Attachment 1 - Scenario 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]	0.10	
VOC Emission Credits for CCS System [6]	$300,000/ton of PTE	$1,500,000
NOx Emission Credits for CCS System [6]	$150,000/ton of PTE	$6,750,000
Adjusted Capital Cost		$402,082,297
Annual O&M [1]	$0.00124/kWh	$10,254,106
Annual Fuel [3]	14.7% fuel use at $2.77/MMBtu	$3,381,501

Pipeline Cost Breakdown [4]		
L, Pipeline Length (miles)	Distance to Frio formation	200.0
D, Pipeline Diameter (inches)		10
	Pipeline Costs	
Materials	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D20 + 26,960)	$24,809,122
Labor	$341,627 + $1.85 x L x (343.2 x D^2 + 2074 x D + 170,013)	$83,618,637
Miscellaneous	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$29,033,830
Right of Way	$1,200 (ROW cost in dollars per rod of length) * (5,280/16.5) * L	$76,800,000
	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	$1,726,400

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

Annualized Cost Estimate		
Economic Life, years		20
Interest Rate (%)		7
Tax Credits [5]	$20/ton sequestered for 2 years	($69,856,128)
Total CO_2 Sequestered	100% sequestration	1,746,403
Total CO_2 Sold for Enhanced Oil Recovery	No EOR	-
Capital Costs		$559,749,792
O&M Costs (Annual)		$29,833,273
Capital Recovery		$52,836,420
Revenue from Sale	$10/ton for Enhanced Oil Recovery	$0
Total Annualized Cost		$82,669,693
Total CO_2 Controlled (tpy)		1,746,403
CO_2 Cost Effectiveness ($/ton)		47
CO_2 Cost Effectiveness ($/kWh)		0.030

[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 2013 NETL Study

[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).

[5] Tax credits will be available for 2 years

[6] It is assumed the the CCS system will consume 14.7% of the fuel required to power the turbines, and thus increase project NOX and VOC emissions by 14.7%. Since the project is located in the HGB non-attainment area, emission credits must be aquired for these additional emissions. Prices reflect the cost for the most recent sale of VOC and NOX emission credits in the region.

Attachment 1 - Scenario 2
Air Liquide Bayou Cogeneration Plant
GHG BACT Analysis
Conceptual Cost Estimate for Carbon Capture, Enhanced Oil Recovery and Option for Sequestration

	Post-Combustion CO_2 Capture and Compression	
Base Capital [1]	\$758/kW	\$358,029,361
Demolition and Retrofit Cost Adjustment[2]	0.10	
VOC Emission Credits for CCS System [6]	\$300,000/ton of PTE	\$1,500,000
NOx Emission Credits for CCS System [6]	\$150,000/ton of PTE	\$6,750,000
Adjusted Capital Cost		\$402,082,297
Annual O&M [1]	\$0.00124/kWh	\$10,254,106
Annual Fuel [3]	14.7% fuel use at \$2.77/MMBtu	\$3,381,501

	Pipeline Cost Breakdown [4]	
L, Pipeline Length (miles)	Distance to Frio formation for sequestration, plus distance to Denbury pipeline for sale	218.6
D, Pipeline Diameter (inches)		10
	Pipeline Costs	
Materials	$\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D20 + 26,960)$	\$27,110,360
Labor	$\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2074 \times D + 170,013)$	\$91,363,399
Miscellaneous	$\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$	\$31,720,011
Right of Way	\$1,200 (ROW cost in dollars per rod of length) * (5,280/16.5) * L	\$83,942,400
	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	\$1,886,955

	Geologic Storage Costs [3]	
Number of Injection Wells		2
Well Depth (m)		2,134
CO_2 Captured (tons)		873,202
	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/short ton CO_2	\$291,649
	O&M	
Normal Daily Expenses	\$11,566/Injection Well	\$23,132
Consumables	\$2,995/yr/ton CO_2/day	\$7,165,038
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 (%)		7
Tax Credits [5]	\$20/ton sequestered; \$10/ton sold for EOR	(\$61,124,112)
Total CO_2 Sequestered	50% Sequestration	873,202
Total CO_2 Sold for Enhanced Oil Recovery	50% Enhanced Oil Recovery	873,202
Capital Costs		\$588,064,738
O&M Costs (Annual)		\$22,828,790
Capital Recovery		\$55,509,150
Revenue from Sale	\$10/ton for Enhanced Oil Recovery	(\$4,366,008)
Total Annualized Cost		\$73,971,932
Total CO_2 Controlled (tpy)		873,202
CO_2 Cost Effectiveness (\$/ton)		42
CO_2 Cost Effectiveness (\$/kWh)		0.027

[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 2013 NETL Study

[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).

[5] The \$20/ton tax credit will be available for 2017 at 100% and 50% in 2018. The \$10/ton tax credit will be available at 50% for 2018.

[6] It is assumed the the CCS system will consume 14.7% of the fuel required to power the turbines, and thus increase project NOX and VOC emissions by 14.7%. Since the project is located in the HGB non-attainment area, emission credits must be aquired for these additional emissions. Prices reflect the cost for the most recent sale of VOC and NOX emission credits in the region.

Attachment 2: EOR Tax Credits Analysis

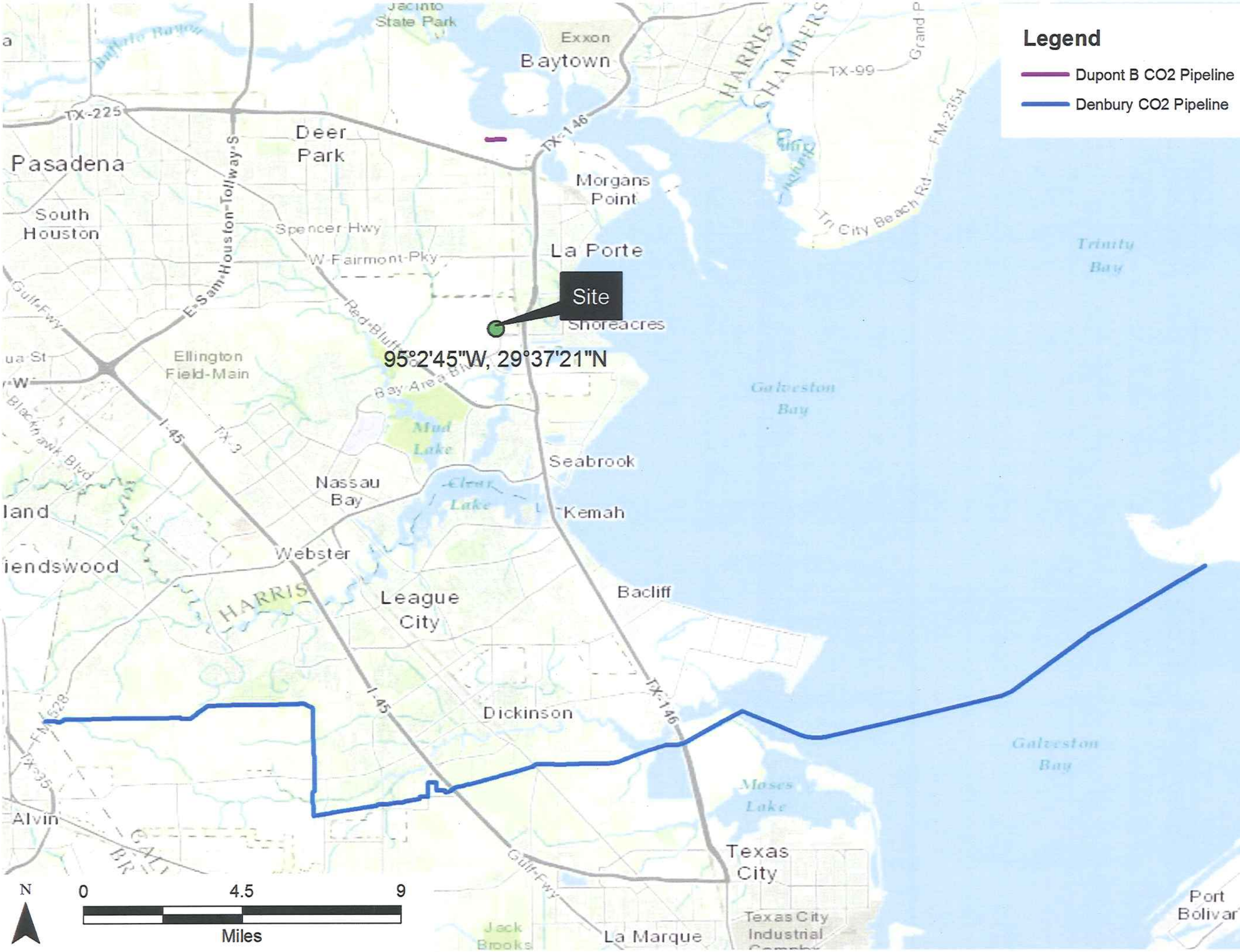
Total Tax Credits Available (tons)	75,000,000
Credits consumed by May 2013 (tons)	20,858,926
Annualized CO2 consumption for companies that claimed credits between 2008- 2013 (tons/year)	4,171,785

Year	Credits Available (tons)	Kemper County (tons)	Future Gen (tons)	TX Clean Energy (tons)	Hydrogen Energy California (tons)	W.A. Parish (tons)	Air Liquide* (tons)
6/1/2013	54,141,074						
1/1/2014	49,969,288.80						
1/1/2015	45,797,503.60	3,500,000		2,700,000		1,400,000	
1/1/2016	34,025,718.40	3,500,000		2,700,000		1,400,000	
1/1/2017	22,253,933.20	3,500,000	1,000,000	2,700,000	2,600,000	1,400,000	2,314,994
1/1/2018	4,567,154.50	3,500,000	1,000,000	2,700,000	2,600,000	1,400,000	2,314,994
1/1/2019	NO CREDITS AVAILABLE						

* Assuming 90% capture of the annual 2,572,215 tons of CO2e

*

Attachment 3


Legend
Dupont B CO2 Pipeline
Denbury CO2 Pipeline
Site
95°2'45"W, 29°37'21"N
Baytown
Exxon
Deer Park
Pasadena
South Houston
Morgans Point
La Porte
Shoreacres
Ellington Field-Main
Seabrook
Nassau Bay
Kemah
Webster
League City
Bacliff
Dickinson
Texas City
La Marque
Texas City Industrial
Alvin
Port Bolivar
Trinity Bay
Galveston Bay
Moses Lake
Mud Lake
Clear Lake
HARRIS
CHAMBERS
TX-225
TX-146
TX-99
TX-3
TX-35
I-45
FM-2354
FM-528
E-Sam-Houston-Tollway-S
Spencer-Hwy
W-Fairmont-Pky
Red-Bluff
Gulf-Fwy
Tri City Beach Rd
N
0
4.5
9
Miles