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Via email and U.S. Mail

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RE: Celanese Clear Lake Plant –Permit No. PSD-TX-1296-GHG

Dear Ms. Wilson:

These comments are submitted on behalf of Sierra Club and its 600,000 members, including over 21,000 members in Texas. The issues addressed below regarding the proposed *Greenhouse Gas Prevention of Significant Preconstruction Draft Permit* for the Celanese Clear Lake Plant (Clear Lake Plant) are based off of publicly available materials, including the June, 2013 Statement of Basis (SOB) prepared by EPA Region 6 (the Region), the draft permit, the permit application and the applicant's revised permit application.

The EPA has a clear mandate to act on climate change. EPA Administrator Gina McCarthy recently reiterated the responsibility of the agency to EPA staff following direction from President Obama: "We have a clear responsibility to act now on climate change."[1] The methanol plant at issue in this draft permit offers a clear opportunity to act on climate change. The Region must require the most stringent technologically feasible greenhouse gas control technology: carbon capture and sequestration (CCS). It is imperative that the Region acts to ensure that facilities such as the Clear Lake Plant, which is ideally suited to install CCS technology, implements controls that will reduce climate changing greenhouse gases. **Our analysis, which corrects errors in the applicant's analysis, indicates that CCS will cost less than $25/ton even before considering valuable offsets**. This average cost estimate strongly indicates that CCS is economically feasible, and the Region must therefore require a BACT limit for CO_2 based on the implementation of CCS.

[1] http://thehill.com/blogs/e2-wire/e2-wire/312561-new-epa-chief-to-staff-this-is-a-defining-time-for-epa

Texas suffered its driest year ever in 2011, and the three years 2011-2013 have been among the driest on record. Cities are struggling to keep reservoirs full, and the Texas coast is experiencing accelerating sea level rise. Places like Galveston Island are spending substantial sums of money to keep the Gulf of Mexico at bay. Texas is very vulnerable to climate changes and the Region must consider climate change impacts from the increased CO_2 emissions that would result from the Clear Lake Plant.

Lower natural gas prices have spurred a rush of new petrochemical production facilities in the United States, particularly along the Gulf Coast. These new facilities will account for substantial greenhouse gas (GHG) emissions, and it is critical that the Region and other responsible agencies in the area ensure that GHG emissions are controlled to the greatest extent required by law. The prevention of significant deterioration (PSD) permitting process is vital to the development and implementation of technologies and practices that will limit the emissions of CO_2 and other GHGs. The permitting of facilities in Texas and along the Gulf Coast also offers a unique opportunity to pursue the deployment of CCS technologies. A recent study completed by the U.S. Geological Survey concluded that the Gulf Coast, or "Coastal Plains" region, contains 65% of the country's estimated accessible carbon storage resources.[2] New facilities in Texas, such as the Clear Lake Plant, have a unique opportunity to develop these storage resources and substantially lower their GHG emission profiles. In particular, methanol production facilities result in high purity CO_2 streams that are well suited for CCS. These comments address the GHG PSD draft permit for the Clear Lake Plant.

The Clear Lake Plant is subject to GHG PSD regulations. New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a carbon dioxide equivalent (CO_2e) basis, or modifications at existing facilities that are expected to increase total GHG emissions by at least 75,000 tpy CO_2e, are subject to PSD permitting requirements even if they do not significantly increase emissions of any other PSD pollutant. Celanese estimates that the new methanol unit at the Clear Lake Plant will potentially result in a GHG emission increase of 535,218 tons per year (tpy) of carbon dioxide equivalents (CO_2e). (SOB, p. 31) The Clear Lake facility would add a new 1,433,000 tpd Methanol plant consisting of primary and secondary reformers. Finished methanol will be fed to an on-site acetic acid plant or shipped off-site by truck, railcar or pipeline. (SOB, pp. 4-5; Revised Application, pp. 1-2/1-3) The new methanol plant would emit increased GHGs at a rate far greater than 100,000 tpy CO_2e; therefore, the project is subject to PSD review for all pollutants emitted in a significant amount. The Texas Commission on Environmental Quality (TCEQ) has assumed permitting responsibility for all non-GHG pollutants emitted from the proposed addition to the Clear Lake plant. The Region's draft permit and these comments address only GHG related issues.

A. <u>The Cost Analysis for Carbon Capture and Sequestration In The Region's Statement of Basis is Invalid</u>

Carbon capture and sequestration (CCS) is a process that uses adsorption or absorption to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The CO_2 is then transported to an appropriate storage location, most likely underground in a

[2] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41. Available at: http://pubs.usgs.gov/circ/1386/

geological storage reservoir such as a deep saline aquifer or a depleted oil well or coal seam. The Region identified CCS using an amine solvent-based process with monoethanolamine (MEA) as a technologically feasible control technology in step 2 of the BACT analysis. (SOB at p.8) However, the Region rejected CCS in step 4 on the grounds that CCS would result "in an increase of more than 25% in the capital costs" for the project, which the Region claimed would be "prohibitive in relation to the overall cost of the proposed project." (SOB at p.12) As the EPA has regularly asserted, rejection on the basis of a percentage of total costs is not valid in a BACT analysis. Celanese's cost effectiveness analysis, which the Region accepted without change, also contains several errors that result in Celanese dramatically overstating the total average cost effectiveness of CCS. The Region's conclusion that CCS is not feasible due to economic impacts is therefore not supported.

1. The Region Incorrectly Applied the Standard for Eliminating a Technically Feasible Alternative for Adverse Economic Impacts

The Region's determination that CCS is too expensive in relation to the total costs of the entire project is not a valid basis for rejection in step 4 of the BACT analysis. The Region's analysis concluded that CCS "results in an increase of more than 25% in the capital costs for Celanese's project." (SOB at p. 12) The NSR Manual expressly rejects this type of conclusion without more analysis. "[T]he capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading."[3] Cost considerations in determining BACT should be expressed in terms of average cost effectiveness. *NSR Manual* at B.36; *see, also, Inter-Power of New York, Inc.,* 5 E.A.D. 130 at 136 (1994). On its face, the Region's conclusion that CCS would add 25% to the total project cost is an invalid basis for rejecting CCS as BACT in step-4 of the top-down BACT analysis. Further, even if the comparison to total project cost was valid, the Region's decision is incorrect because the asserted costs for CCS are grossly overstated.

a) <u>The Region Must Consider the Average Cost Effectiveness of CCS Compared to the Costs Borne by Other Similar Facilities</u>

The first step in calculating the average cost effectiveness of alternative control options (such as CCS), is for the Region to correctly define the baseline emission rate. Baseline emission rates are "essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions," for the applicant's proposed operation.[4] Once the baseline is calculated, the cost-per-ton of pollutant controlled is calculated for each control option by dividing the control option's annualized cost by the tons of pollution avoided ("Baseline emissions rate – Control option emission rate"). *In re Steel Dynamics*, 9 E.A.D. 165, 202 n.43 (EAB 1999); *In re Masonite Corp.*, 5 E.A.D. 551, 564 (EAB 1994); *NSR Manual* at B.36-.37. The SOB did not include an average cost effectiveness calculation of CCS expressed in terms of cost-per-ton of GHG removed, even though the application included an estimate of $120 per ton of CO_2 avoided. The Region merely concluded that the total capital cost compared to the total project cost was too high, and the Region made this determination without providing any record evidence as to what the total project cost will be. This rationale does not meet BACT requirements to reject a technology for adverse economic impacts.

[3] *NSR Manual*, p. B.45.
[4] See *NSR Manual* at B.37.

When determining if the most effective pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT as a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." *NSR Manual* at B.44; *see also Steel Dynamics*, *Inc.,* 9 E.A.D. 165 at 202 (2000)*; Inter-Power*, 5 E.A.D. at 135 ("In essence, *if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and, therefore, acceptable as BACT*." (quoting *NSR Manual* at B.44) (emphasis original)). This high standard for eliminating a feasible BACT technology exists because the collateral impacts analysis in BACT step 4 is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility. The Region and Celanese inappropriately compare the total cost of CCS to the total cost of the facility. To reject CCS, BACT requires a demonstration that the costs of pollutant removal are disproportionately high for the specific facility compared to the cost of control at other facilities. No such CCS comparison was made here.

Although the BACT requirement to control GHG emissions in a PSD permit is relatively new, there are nevertheless some plants with similar emissions streams that use CCS. Sierra Club is not aware of publicly available data in a BACT analysis for the costs-per-ton of controlling GHGs from this type of facility through the use of CCS. However, the fact that the data are not publicly available in a BACT analysis does not mean they do not exist. The application identifies several similar projects, including the Leucadia Energy methanol plant in Louisiana, that are implementing CCS systems. The Region must consider the cost of CCS at these and other facilities when making a determination about whether CCS at Clear Lake creates an adverse economic impact unique to the facility at issue. Even if Celanese's estimated $120.2 cost per ton of CO_2 removed for CCS at the Clear Lake Plant were valid, which it is not,[5] that average cost does not necessarily constitute an adverse economic impact unless it is disproportionate to the cost-per-ton of CCS at other facilities such as the Leucadia Energy plant. At a minimum, to reject CCS at Clear Lake when other facilities will be using the same technology, the applicant must demonstrate—with actual data—that the cost per ton at Clear Lake is disproportionate to other facilities, including Leucadia Energy facility.

The Region cannot simply reject a technologically feasible alternative to control GHGs because there are no other BACT determinations requiring add-on technology to control GHG. For every pollutant newly subject to a BACT limit and for every new technology developed to control that pollutant, there has to be a first instance where the control is determined to be BACT. The legislative history is clear that Congress intended BACT to perform a technology-forcing function.[6] The Region has made no showing why the Clear Lake Plant PSD permit should not require CCS, especially when other similar facilities employ CCS, even if not pursuant to a BACT determination. The BACT analysis of CCS must at a minimum consider

[5] Sierra Club disputes Celanese's cost-per-ton conclusion. The estimated $120.2/ton of CO2 removed is far too high.
[6] *See* S. Rep. No. 95-252, 95th Cong., 1st Sess. 31 (1977), reprinted in 3 A Legislative History of the CAA Amendments of 1977 at 1405; 123 Cong. Rec. S9171, 3 Legislative History at 729 (remarks of Sen. Edmund G. Muskie, principal author of 1977 Amendments).

costs at facilities that have deployed CCS to determine whether any unusual or unique circumstances at Clear Lake warrant rejection of CCS.[7]

Sierra Club recently commented on a different PSD permit for the Baytown Olefins ethylene production facility where the applicant estimated (incorrectly) that the cost of CCS would be approximately $253.30 per ton removed. The Clear Lake facility's estimated average cost effectiveness is less than half of the Baytown estimate,[8] yet there is no explanation from the Region why the much lower cost per ton of CO_2 removed remains too high. There is no indication whatsoever from the Region what a reasonable cost effectiveness estimate for CCS on this facility would be.

The Region should also consider the costs of failing to control GHG emissions, expressed as the social cost of carbon. There are several sources concluding that carbon has a high social cost. A recent study found that the social cost of carbon estimates range from $28 up to $893 per ton of CO_2.[9] EPA recently revised its estimated social cost of carbon to $40 in 2015 and increasing up to $76 by 2050.[10] These thresholds suggest that the cost of CCS at Clear Lake, as adjusted by Sierra Club to $25 per ton, would be a more economic choice compared to higher estimated social costs of carbon.

b) <u>The Region Improperly Considered Only the Cost of CCS Compared to the Total Project Costs</u>

Celanese determined that the total annualized cost would be ~$120 per ton of CO_2 avoided. (Revised Application, p.3-17) As discussed in more detail below, this estimate is significantly higher than if an appropriate analysis were conducted. However, even if $120 per ton of CO_2 avoided was an appropriate estimate, the Region improperly based its rejection of the cost of CCS on the total cost of CCS compared to the total cost of the Clear Lake Project. Celanese claimed, and the Region accepted, that CCS costs would result in an increase to current project capital costs by more than 25%. Celanese did not provide any support for the claim that this cost would render the project economically infeasible or that CCS would increase project costs by more than 25%. Simply citing to the 25% cost increase does not provide a sufficient basis to reject CCS in the top-down BACT analysis.

Celanese only provided a summary conclusion in its application stating: "CCS is determined to not be cost effective as the annualized costs equate to ~$120 per ton CO_2 avoided and would increase current project capital costs by more than 25%." (Revised Application, p.3-17) The Region drew from this statement only the total cost of CCS relative to the entire project: "The estimated CCS capital needed only for capture and a new pipeline for the current project results in an increase of more than 25% in the capital costs for Celanese's project…thus CCS has been

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[7] *See, e.g., Cost and Performance of Carbon Dioxide Capture from Power Generation, International Energy Agency. Available at: http://www.iea.org/publications/freepublications/publication/costperf_ccs_powergen-1.pdf*

[8] Sierra Club's estimate of the average cost effectiveness of CCS is less than 10% of the Baytown applicant's estimate.

[9] Ackerman, Climate Risks and Carbon Prices: Revising the Social Cost of Carbon, p. 2. Available at: http://www.sei-international.org/mediamanager/documents/Publications/Climate-mitigation-adaptation/Economics_of_climate_policy/sei-climate-risks-carbon-prices-2011-full.pdf

[10] Assuming a 3% discount rate. Available here: http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

eliminated as BACT for this project as economically infeasible." (SOB p.12) This blanket and unsupported assertion is not sufficient to eliminate the most effective feasible control technology. *Alaska Dep't of Envtl. Conservation v. E.P.A.*, 540 U.S. 461, 466 (2004) ("Having acknowledged that it lacked information needed to judge SCR's impact on the mine's operation, profitability, or competitiveness, [the agency] could not simultaneously proffer threats to the mine's operation and competitiveness as reasons for declaring SCR economically infeasible"). The Region's basis for rejecting CCS at the Clear Lake Plant rests solely on the proportional cost of CCS compared to the cost of the total facility. The Region made no attempt to demonstrate that the Clear Lake Plant is particularly unsuitable for CCS compared to other facilities, which is required for rejecting a top-ranked technology based on collateral impacts (including cost). There is no evidence to support Celanese's assertion that an increase to project costs of 25% would eliminate the profitability or competitiveness of the project. The analysis therefore does not comply with the top-down BACT analysis, and the Region must revise its BACT analysis to consider the average cost effectiveness of CCS. Furthermore, the Region must revise the cost effectiveness calculation to reflect a more accurate estimate of cost effectiveness, which we discuss in more detail below.

In summary, to reject CCS based on cost-effectiveness at step 4, the Region must determine that the cost of CCS at the Clear Lake Plant is disproportionate to the cost of the same technology applied to similar sources elsewhere. In addition, the Region should evaluate the costs of CCS at the Clear Lake Plant against the best estimate of the costs of failing to require the same level of control as would result from the use of CCS (i.e. social costs).

2. Celanese's Cost Analysis for CCS Is Faulty

The cost analysis that Celanese provided, and the Region relied upon, contains numerous flaws. The Region must calculate cost effectiveness of a control technology to satisfy BACT according to the EPA *Air Pollution Control Cost Manual* or "Cost Manual" and the NSR Manual.[11] *State of Oklahoma v. EPA,* App. Case 12-9526, p.20 (10th Cir. July 19, 2013). Celanese's cost effectiveness analysis deviates from the Cost Manual's requirements in several instances, which resulted in inflated capital costs and operating expenses.

The revised application's BACT analysis includes a cost effectiveness analysis for CCS from the reformer furnace, which is the major source of CO_2 from the proposed methanol facility. (Revised Application, Sec. 3.3.4.5) This analysis concludes that it would cost about $120.2 per ton of CO_2 "avoided" to capture CO_2 from the reformer flue gas, transport it to a storage reservoir, and store it. However, as we discuss below, this is a gross overestimate of the cost effectiveness of CCS. The Celanese analysis follows the wrong methodology and contains many errors and omissions.

Sierra Club revised the CCS cost analysis to comply with the applicable costing methodology, which corrected some of these problems. Our revised analysis is included in Exhibit 1. Our analysis indicates that CCS will cost less than $25/ton. This cost analysis indicates that CCS is highly cost effective, even without considering potential cost offsets (such

[11] U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B-02-001, 6th Ed., January 2002 ("Cost Manual"), The EPA Air Pollution Control Cost Manual is the current name for what was previously known as the OAQPS Control Cost Manual, the name for the Cost Manual in previous (pre-2002) editions of the Cost Manual.

as sale of CO_2 as a product), and therefore the Region must require a BACT limit based on the reduced CO_2 emissions achievable with CCS.

Sierra Club's revised estimate of $25 /ton of CO_2 avoided does not include income generated from selling the CO_2 for use in enhanced oil recovery or the various tax credits that may be available. At the low end, the market value for CO_2 is at least $6 per ton. This income stream from the sale of CO_2 for enhanced oil recovery would reduce the cost of CO_2 CCS from $25/ton to at most $19/ton and could potentially offset the entire cost at the upper end of the range of market values for CO_2.

a) <u>Celanese Applied the Wrong Methodology in its CCS Cost Analysis</u>

The Celanese CCS analysis uses the wrong method to calculate cost effectiveness for purposes of BACT. Cost effectiveness, measured in dollars per ton of pollutant removed, is calculated according to the EPA *Air Pollution Control Cost Manual* or "Cost Manual", in accordance with the NSR Manual, p. B.35, to assure consistency of BACT decisions made on the basis of cost. A control technology is considered to be "cost effective" if it falls within a reasonable range of cost-effectiveness estimates where other costs are calculated using the same methodology.

Cost effectiveness determinations include several steps. First, the capital cost is estimated and annualized using a capital recovery factor. Second, the annual operating and maintenance (O&M) costs are estimated. Third, these costs are summed and divided by the tons of pollutant removed. Procedures outlined in the Cost Manual must be used to estimate these costs.

Celanese failed to follow standard procedures for each of these steps, as discussed below. The cost estimates in the revised application do not fully explain the procedures that Celanese used to estimate a cost of $120.2 per ton CO_2 avoided. (Revised Application, p. 3-17) However, where we could reproduce or infer Celanese's calculations, it is evident that Celanese failed to follow acceptable procedures or padded the costs to make them look higher than they actually are. Sierra Club's revised analysis, which corrects these errors, is included in Exhibit 1 to these comments.

The CCS cost analysis that the Region relied on sums amortized capital costs and operating and maintenance (O&M) costs for three major component: (1) one lump sum for capture and compression[12] including a boiler, infrastructure modifications, and pollution offset reduction credits; (2) pipeline transfer; and (3) geologic storage. (Revised Application, p. 3-17) Much of this analysis is very poorly documented and leaves much to be inferred.

(i) Boiler

One of the principle reasons that the applicant's CCS cost effectiveness estimate is inflated is that Celanese included a boiler to supply steam to regenerate the MEA, which adds numerous line item estimates in the cost analysis: $19,000,000 to the capital costs; $16,575,000/yr for annual natural gas costs; $358,474/yr for electricity to run various components; and, $5,000,000

[12] This line item in the Revised Application, p. 3-16 states: "30-year amortized capital cost of capture and **storage** including the boiler, infrastructure, and pollution off-set reduction credits." However, the analysis includes "**storage**" costs on the next page, 3-17, and does not separately identify "compression" costs. Thus, we infer that "**storage**" in the quoted material from p. 3-16 is an error and should have been "compression."

to buy offsets for its NOx and VOC emissions. The use of a boiler also impacts the cost effectiveness calculation because Celanese offsets the CO2 captured by the system with an increase in 195,909 ton/yr of CO_2 from burning natural gas in this boiler. In other words, Celanese assumes the CCS system is less effective because the boiler results in additional CO_2 emissions, thereby reducing the relative effectiveness of the CCS system. However, this boiler is not necessary to provide the steam required to regenerate the MEA because the plant already produces excess steam.

The capital costs of the amine system includes $19,000,000 for a boiler, deaerator, condensate receiver, boiler feedwater pumps, condensate return pumps, etc. to produce 317,276 lb/hr of saturated steam to regenerate the MEA. (Revised Application, p. 3-16) In addition, $5,000,000 is included to purchase NOx and VOC offsets as the boiler would be located in the Houston/Galveston/Brazoria ozone nonattainment area. No support is provided for either estimate.

The cost analysis fails to consider integration of steam demand with existing utilities or whether recovery of additional heat from flue gases of the primary and secondary reformers could meet part or all of this demand. The cost analysis by Worley Parsons (WP) in Appendix A to the revised application indicates explicitly that their study scope **excluded** "heat integration with other Celanese plant system." (Revised Application, Appx. A, WP, p. 3 (pdf 54)).

The process flow diagram for the new methanol plant shows excess "HP steam to users" as one of the outputs of the methanol process. (Revised Application, Appx. A, WP, p. 8) Elsewhere, the revised application states: "There will be heat recovered from the flue gases of the primary reformer that will be used to generate steam that is exported to the Celanese Clear Lake Plant's main steam header system. This will not affect any of the other Celanese production units as their steam demand will not be changing. This recovered heat is not used to produce methanol and therefore will not be counted in the heat input when evaluating the reformer's limit for compliance." (Revised Application, p. 4-2.)

In other words, the revised application clearly indicates that there is excess steam in the system generated by the methanol unit itself, and that steam could be used to regenerate the amine. There is no need to build an entire new steam system just to provide steam to regenerate the amine. Although the revised application is silent on the amount of excess steam, it is likely that there is adequate steam available in the existing system, or adequate waste heat available in the huge petrochemical complex at the Clear Lake Plant that could be recovered more economically, without generating additional GHG, NOx, and VOC emissions by building a whole new steam system. Thus, in our revised cost calculations, we have eliminated the capital and O&M costs of the new boiler system and the NOx/VOC offsets. If Celanese chooses to build a CO_2 capture system, for example, to produce a pure CO_2 stream as input to other unit operations at the facility, it could do so far more economically than proposed here. By attributing the entire capital and operating costs of a new boiler to the CCS system here, and failing to integrate steam demand with existing utilities, Celanese has inflated costs in this analysis to avoid installing CCS.

(ii) Electrical Infrastructure Upgrades

The capital costs of the amine/compressor system include $7,000,000 for electrical infrastructure upgrades. Celanese does not provide any support for this estimate. (Revised Application at p. 3-16) It is unclear why the amine system would require significant upgrades that would not have otherwise been included in the new methanol plant cost estimate prepared by Worley Parsons. Absent any express justification, such as identification of the specific equipment that would be upgraded and a demonstration of project-related need other than end of equipment useful life, Sierra Club eliminated these unsupported capital costs from our revised cost estimate.

(iii) Boiler Fuel Costs

The cost analysis includes $16,575,000 per year to purchase natural gas to fire the boiler. (Revised Application, p. 3-16) As noted above, because the existing plant has available excess steam being generated by other processes, a fuel-fired boiler is not required to produce steam to regenerate the amine, and this cost is therefore unwarranted and is removed from our revised cost analysis.

Regardless, we note that the annual natural gas cost estimate assumed a natural gas price of $5.00/MMBtu. (Revised Application, p. 3-16) This price is excessive for a large petrochemical facility that uses a significant amount of natural gas as feed to various unit processes, located in close proximity to many pipelines, the Katy hub, and shale gas fields in Texas. The Celanese facility undoubtedly has long-term natural gas delivery contracts for substantially less than $5.00/MMBtu. The actual cost of delivery of natural gas to the facility based on current conditions should be used in a BACT cost effectiveness analysis and should be supported with contract information. We also note that the proper cost effectiveness methodology does not allow for escalation of costs due to inflation; therefore, the current price of natural gas actually available to the Clear Lake Plant must be used as the basis for any fuel costs.

(iv) Electricity

The cost analysis includes $3,940,000 per year for electricity to operate the MEA system, supporting boiler, and CO_2 compression system, estimated as $50 per MW-hr times the electrical demand (9.0 MW). (Revised Application, p. 3-16) This unit cost for electricity at the Clear Lake Plant is unsupported and is much higher than values commonly used in BACT cost effectiveness analyses. The unit cost of electricity used in cost effectiveness analyses is the cost to the owner to generate the electricity, not the market cost of electricity in the region. Presumably, a large petrochemical facility generates much of its own electricity from steam turbines using recovered heat from various process streams supplemented by on-site gas fired turbines, which would result in a unit cost no higher than about $10-$30/MW-hr.[13] Sierra Club revised the cost of electricity in our cost analysis using a conservative estimate of $30/MW-hr. (See Exhibit 1, Cell C23)

The Worley Parson analysis estimated auxiliary power requirements of 5,309 hp (3.96 MW) to operate various pumps, blowers, and air coolers for the amine capture system only. (Revised Application, Appx. A, WP Analysis, p. 16, Table 6.2) This value is high compared to estimates in the literature, which report 14 to 16 kWh per metric ton of methanol produced.[14] Celanese estimated that the facility would produce 1,433,000 tons of methanol. (SOB, p. 4) This works

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[13] Wholesale Market Data, ERCOT Houston and South Texas trading hub, 2013. Available at: http://www.eia.gov/electricity/wholesale/

[14] M. Aresta, Carbon Dioxide Recovery and Utilization, Kluwer Academic Publishers, Norwell, MA, 2010, Chapter 15: Angeliki A. Lemonidou, Julia Valla and Iacopos A. Vasalos, Methanol Production from Natural Gas: Assessment of CO2 Utilization in Natural Gas Reforming, Chapter 15, Table 15.4.

out to 2.3 MW to 2.6 MW to capture the CO_2 from producing methanol at the Clear Lake Plant. Thus, the Worley Parson analysis overestimated the auxiliary power requirements by nearly a factor of two. This overestimate is likely due to the fact that the Worley Parson analysis used air cooling based on the assumption that makeup water availability is limited at the site, but the analysis failed to support this assumption. About 40% of the electrical demand (2033 hp out of a total of 5309 hp) is used to run the air coolers. (Revised Application, Appx. A, WP Analysis, p. 15, Table 6.2.) Sierra Club did not make any adjustment for this issue, but the Region should require Celanese to justify the use of air coolers and the lack of on-site makeup water in the responses to comments. The Region must also provide Sierra Club and the public the opportunity to respond to any response provided by Celanese on this issue.

(v) Contingency Factor

Worley Parsons estimated the capital costs of the amine/compression system included in Appendix A of the Revised Application. This cost analysis applied a 16.5% contingency factor to the fully loaded capital costs (equipment + material + labor + engineering + construction management + home office + fees). (Revised Application, Appx. A, WP Analysis, pp. 18 (MEA) & 25 (Compression); see Sierra Club calculations in Exhibit 1 from the WP cost spreadsheets, cells C60 and E60) A 16.5% contingency is excessive for an amine system and compressor station, which are widely used in numerous other similar applications.

The construction of a CCS system is not a novel technology that requires an excessively high contingency. Hundreds of plants currently remove CO_2 from natural gas, hydrogen, and other gases with low oxygen content. The amine scrubbing and compression methods costed here to remove CO_2 from methanol plant gases have been used to separate CO_2 from natural gas and hydrogen since they were patented in 1930.[15] These processes are used in many industries including: urea plants, ethanol plants, hydrogen plants, ammonia plants, ethylene oxide plants, natural CO_2 wells, geothermal wells, mineral processing plants, direct iron ore reduction plants, enhanced oil recovery, and methanol production[16] to recover pure CO_2 streams. Notwithstanding the common application of this technology in industrial processes, the revised application states that capture-only technologies have not been commercially demonstrated. (Revised Application, p. 3-11) However, this contention is absolutely false. CO_2 capture systems have been widely used in many related industries, including the methanol industry, to recover and recycle CO_2 to increase methanol production.[17] Therefore, there is no basis to inflate the contingency estimate.

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[15] Gary T. Rochelle, Amine Scrubbing for CO2 Capture, Science, v. 325, no. 5948, 25 September 2009, pp. 1652-1654; Arthur L. Kohl and Richard B. Nielsen, Gas Purification, Gulf Publishing Co., Houston, 5th Ed., 1997, Chapter 2: Alkalnolamines for Hydrogen Sulfide and Carbon Dioxide Removal, pp. 40-186.

[16] See, for example, Witteman, By-Product CO2 Recovery Systems, Industrial Gas Sources. Available at: http://www.pureco2nfidence.com/launch/images/downloads/wittemann_capabilities.pdf; Oatar Methanol Plant Due Carbon Dioxide Recovery Plant, Oil & Gas Journal, March 15, 2012. Available at: http://www.ogj.com/articles/2012/03/qatar-methanol-plant-due-carbon-dioxide-recovery-plant.html.

[17] See, for example, Rochelle 2009 and the QPC Quimica Methanol Plant for a specific recent example. This methanol plant, located in Brazil, has recovered CO2 since 1997 using the Fluor Econamine FGSM process and supplied the captured gas to the food industry. Available at: http://www.zeroco2.no/projects/metanol-plant-prosint and Gulf Petrochemical Industries Company Carbon Dioxide Recovery Plant, Bahrain. Available at: http://www.chemicals-technology.com/projects/gulfpetrochemicalsco/.

There is also no basis to apply an excessively high contingency factor for CCS at the Clear Lake Plant based on unanticipated circumstances. According to the Cost Control Manual, a contingency factor in a cost effectiveness analysis "should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system."[18] An example of such a contingency factor would be a hundred year flood that postpones delivery of materials where the arrival of those materials at the job site is not a problem unique to the retrofit. The standard contingency factor used in a cost effectiveness analysis, when it is included, is 3% of purchased equipment cost.[19] Thus, Sierra Club revised the contingency in our analysis to use 3% of fully loaded capital costs. See Exhibit 1, Cells F60 and H60.

(vi) Labor Rates

The capital costs of the amine/compression system estimated by Worley Parsons assumed a labor rate of $90/hr. (Revised Application,Appx. A, WP Analysis, pp. 18 (MEA) & 25 (Compression); see Sierra Club's calculations in Exhibit 1 based on the WP cost spreadsheets, Cells C57 and E57) No support is provided for this very high labor rate, and many public sources demonstrate that this rate is excessive.

The Bureau of Labor Statistics website indicates the average March 2013 total cost to employer for construction workers was $34.43/hr and $35.09/hr in private industry.[20] This is a national average, including heavily unionized California and the northeastern states. Texas labor rates are below the national average.[21] This same report shows the average nonunion wage within the goods-producing industries, which includes construction workers, is $32.91/hr compared to $41.79/hr, or about $9/hr less than for a union shop. Based on Sierra Club's understanding, this project is expected to be a non-union job and therefore the estimate for CCS should use non-union wages. If Celanese uses union labor rates to estimate CCS costs, then it should also commit publicly to using union labor when it builds the facility. In any case, the labor rates cited by Celanese are too high both for union and non-union rates.

The official Davis-Bacon construction hourly wages that are mandated on federally funded jobs in Harris County, Texas, where the project is located, range from approximately $9/hr to $43/hr depending on skill set: $9.29/hr for a common laborer; $12.35/hr for a pipelayer; $20 for an equipment operator; $27/hr for a pipefitter; $35/hr for an electrician; and $43/hr for a boilermaker.[22] These rates include fringes. The most recent Davis-Bacon[23] prevailing wages for heavy construction work in Harris County, Texas, for on-shore pipeline construction (Wage

[18] Cost Manual, Chapter 2, Cost Estimation: Concepts and Methodology, Sec. 2.5.4, p. 2-30, pdf 44.

[19] See, for example, Cost Manual, Section 5.2, Post-Combustion Controls, Chapter 1: Wet Scrubbers for Acid Gas, Table 1.3 and Section 6, Chapter 1: Baghouses and Filters, Table 1.9.

[20] Bureau of Labor Statistics (BLS), Employer Costs for Employee Compensation - March 2013, Tables 6, 10, 12. Available at: http://www.bls.gov/news.release/pdf/ecec.pdf.

[21] Ibid., Table 15.

[22] Harris County Building Construction Prevailing Wage Rates, Quarter 1 of 2012. Available at: http://www.eng.hctx.net/wage/addurl.aspx?func=1&yr=2012&qtr=1&tb=1.

[23] Davis-Bacon Wage Determinations by State, For Harris County, Texas. Available at: http://www.wdol.gov/dba.aspx.

Determination TX45), which includes the skills similar to those required to build the CCS system, range from about $17/hr for laborers and power equipment operators to $44/hr for pipefitters:

Table 1
Davis-Bacon Prevailing Wages
On-Shore Pipeline Construction
Harris County, Texas

	Rates	Fringes
Laborers:		
Drillers	$ 16.08	2.01
Hot Pay	$ 15.58	2.01
Jackhammermen	$ 15.58	2.01
Loaders	$ 16.08	2.01
Powderman, blasters &		
shooters	$ 16.58	2.01
Unskilled	$ 15.08	2.01
Pipefitter	$ 36.49	7.45
Power equipment operators:		
Group 1	$ 22.95	6.05
Group 2	$ 17.54	4.80
Group 3	$ 12.37	3.55
Truck drivers:		
Group 1	$ 18.82	a
Group 2	$ 18.82	a
Group 3	$ 16.81	a
Group 4	$ 16.04	a
Group 5	$ 15.71	a

FOOTNOTE
a - $2.52 PER HOUR PLUS $41.00 PER WEEK

Finally, a 2008 wage survey[24] summarizes union and nonunion wages by craft within regions. This survey, reproduced in Figure 1, shows that the highest wage plus benefits in Region 6 (AR, LA, NM, OK, TX) for non-union construction workers is about $25/hr to $27/hr for masons, boilermakers, electricians, heavy equipment operators, ironworkers, millwrights, pipefitters, and riggers. None of the skilled craft workers in this survey approach the $90/hr wage rates assumed in the Worley Parsons analysis. Furthermore, wages have generally fallen since the survey presented in Figure 1.

The $90/hr wages used in the Worley Parsons analysis are factors of two to three times higher than those reported in the sources reviewed by Sierra Club. The materials the Region

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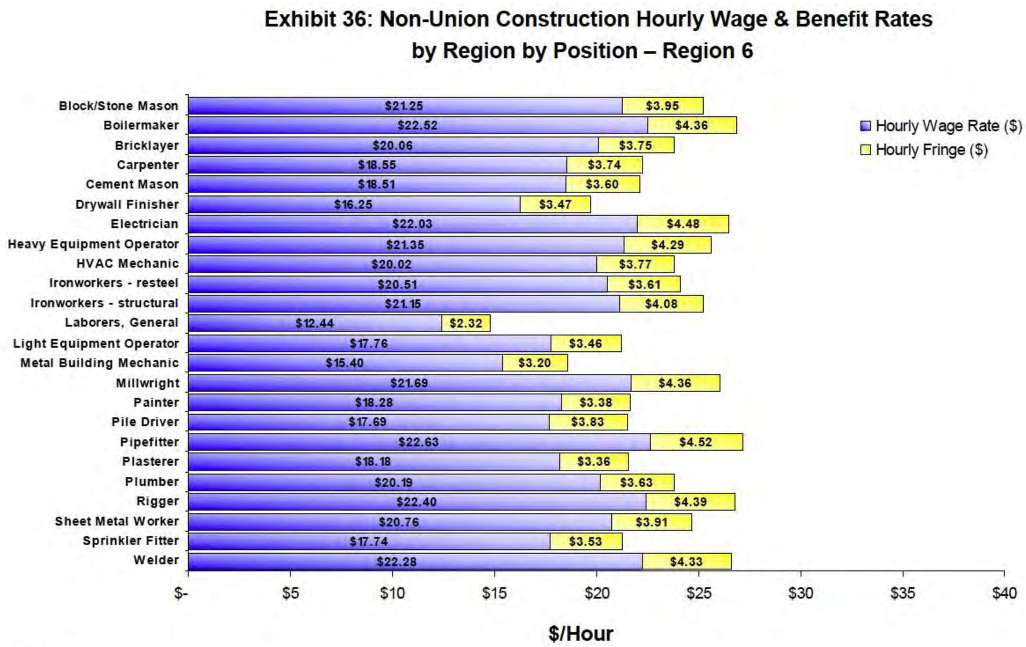
[24] FMI Management Consulting, Craft Worker Compensation Research Report, January 2008, Ex. 36, 41 - 54. Available at: http://www.agc.org/galleries/laborhr/AGC%20Craft%20Worker%20Compensation%20Research%20Report%20-%20Final%201-4-08.pdf.

provided for public review contain no support for high labor rates that are an average of $90/hr for all workers, regardless of skill level.

Sierra Club revised all of the capital equipment costs for the MEA/compression systems, assuming an average fully loaded labor rate of $40/hr for all crafts, which is at the upper end of the range for the most skilled union workers and thus is still very conservative. (See Exhibit 1, Cells F56 and H56).

Figure 1



PAS (2007)

(vii) Pipeline Costs

The revised application at page 3-11 states that the Clear Lake Plant is located about 12 miles from the Denbury Green Pipeline, the destination of the recovered CO_2. However, the cost analysis for the pipeline inexplicably assumes the need for 25 miles of pipeline. (Revised Application, p. 3-16 and Appx. A, pdf 51) As both the capital and O&M costs are directly related to the distance of the pipeline,[25] based on the method Celanese used to calculate pipeline costs (Revised Application, pdf 51), these costs are overestimated by a factor of two. (See Exhibit 1, Cells C18 and C27).

(viii) Capital Cost Reductions

The Worley Parsons cost analysis made a number of simplifying assumptions that overestate capital costs. First, they used a generic MEA system, rather than several available commercially proven processes such as the MHI KS1 and Fluor Econamine systems. Second, they used air

[25] NETL, Estimating Carbon Dioxide Transport and Storage Costs, March 2010, Table 2.

cooling whenever possible rather than water cooling. Third, they failed to incorporate preheating condensate and generating LP steam by economizing the feed gas to preheat condensate. (Revised Application, Appx. A, WP Analysis, pp. 4-5).

Further, capital costs could be significantly reduced by using some of the recovered CO_2 in the methanol plant itself, which would reduce the investment in the plant by about 3.4%. The addition of CO_2 to the reformer feed increases methanol production by about 18% compared to steam reforming. Further, recycle is drastically reduced, 50% less, in the steam-CO_2 reforming option, resulting in a smaller methanol reactor volume and thus lower capital investment.[26] This adjustment would further improve the cost effectiveness of CCS and was not considered. MHI is currently building a CO_2 recovery plant specifically targeted to recover 500 tonnes/day of CO_2 from the methanol process to increase total methanol production.[27] CO_2 capture systems are used at other methanol plants to increase production[28] and the potential increase in production should be considered here.

(ix) CO_2 Emission Reductions

The revised application estimated cost effectiveness using the "avoided" CO_2 emissions, rather than the CO_2 emission reduction by the CCS system. The captured CO_2 emissions are 90% of the reformer flue gas CO_2, removed by the CCS system. However, Celanese reduced the amount of captured CO_2 by subtracting 195,909 ton/yr of CO_2 that would result from burning natural gas in the boiler used to generate steam to regenerate the MEA. As explained elsewhere in these comments, a natural gas fired boiler is not required to produce steam to regenerate the MEA. Therefore, in addition to reducing the capital and O&M costs associated with the boiler, the effectiveness of the CCS increases when the emissions from the boiler are not considered. Just correcting this one methodological error reduces the claimed cost effectiveness from \$120.2/ton to \$73/ton. Making the other corrections to capital and O&M estimates discussed above further reduces the cost effectiveness of CCS to \$25/ton.

b) <u>The Region Failed to Consider Offsets to the Cost of CCS</u>

CO_2 has a market value for use in enhanced oil recovery (EOR) or other uses, such as the food industry and in methanol production. The costs of carbon storage can be offset by EOR revenues where available.[29] Estimates of the market price of CO_2 for EOR are around \$33 per ton.[30] Even without EOR, CO_2 has a market value of between \$5-\$20 per ton.[31] CCS costs can be

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[26] Aresta, Chapter 15 and p. 391.

[27] Mitsubishi Heavy Industries to Build CO2 Recovery Plant for Qafac in Qatar, IHS Chemical Week, March 15, 2012. Available at: http://www.chemweek.com/regions/middle_east/qatar/Mitsubishi-Heavy-Industries-to-Build-CO2-Recovery-Plant-for-Qafac-in-Qatar_42022.html.

[28] Gulf Petrochemical Industries Company Carbon Dioxide Recovery Plant, Bahrain. Available at: http://www.chemicals-technology.com/projects/gulfpetrochemicalsco/.

[29] Massachusetts Institute of Technology, *Future of Coal in a Carbon Constrained* World 2007 at 58-59. Available at: http://web.mit.edu/coal/.

[30] *Carbon Dioxide Enhanced Oil Recovery: A Critical Domestic Energy, Economic, And Environmental Opportunity*, National Enhanced Oil Recovery Initiative, Appendix D, Figure D1. Available at: http://www.neori.org/NEORI_Report.pdf

further offset by tax credits of $10-$20 per ton of CO_2 in accordance with Internal Revenue Code Section 45Q (26 USC § 45 Q). Neither the application nor the SOB attempted to offset the cost of CCS with these potential revenue streams or tax credits. The ability of Celanese to reduce its net cost of installing and operating CCS is a critical component of the cost effectiveness calculations. The Region must consider these issues in its BACT analysis to appropriately consider the cost of CCS as a control technology. The consideration of offsetting the cost of CCS is especially critical because the Region based its rejection of CCS on the cost impact of the technology in step 4 of the top-down BACT analysis.

The CCS system for the Clear Lake Plant was designed specifically to produce CO_2 for use in enhanced oil recovery applications, but the analysis does not include any information on the potential market value that companies would offer for the purchase of the Clear Lake Plant's captured CO_2. (Revised Application, Appendix. A, WP Analysis, p. 4) In fact, the analysis does not make any attempt to assign a value to the captured CO_2. The Clear Lake Plant is only a few miles from the Hastings oil field in Alvin (near Pearland) where Denbury Resources is currently purchasing CO_2 for enhanced oil recovery. Denbury Resources uses CO_2 in enhanced oil recovery and has entered into long-term contracts to purchase CO_2 from six proposed plants or sources in the Gulf Coast region. Two of these six projects are currently under construction with estimated completion dates in 2013 and 2014. These two sources will supply about 165 MMcf/day of CO_2[32] or about 3.4 million tons per year, which is over seven times the amount of CO_2 that would be produced by the Celanese methanol project. It follows, therefore, that Celanese would reasonably find a willing buyer in Denbury for its captured CO_2. Any potential sale value of CO_2 would offset the cost of CCS for the Clear Lake Plant and should be reflected in the cost effectiveness analysis.

The amount that Denbury might pay for this CO_2 is unknown, but according to its operations report, Denbury's cost to produce CO_2 in 2011 was $0.31 per Mcf,[33] which equals about $6/ton.[34] In addition, according to the 2008 Congressional testimony of Denbury Resources Vice President Ronald Evans, it costs about $20/ton to obtain CO_2 from natural sources and transport it moderate distances.[35] Moreover, a recent US DOE report placed $45 per ton as the market price for CO_2 and indicated that the CO_2 market is stable, and CO_2 demand is high at that price.[36] Conservatively assuming the lower end of this range, if all of the CO_2 recovered from the reformer furnace were sold to Denbury for EOR, this income stream would reduce the cost of

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[31] *See,* Rushing, Sam, *Carbon Dioxide Apps Are Key In Ethanol Project Developments*, Ethanol Producer Magazine, April 15, 2011. Available at: www.ethanolproducer.com/articles/7674/carbon-dioxide-apps-are-key-in-ethanol-project-developments

[32] Operations - Gulf Coast Region CO2 Sources. Available at: http://www.denbury.com/operations/co2-sources/gulf-coast-region/default.aspx.

[33] Ibid.

[34] 1 tonne of CO2 occupies 556.2 m^3 x 35.3147 ft^3/m^3 = 19,642 ft^3 = 19.642 Mcf. As there are 1.1023 short tons in a metric tonne, 1 ton of CO2 occupies 17.819 Mcf. Therefore, ($0.31/Mcf)(19.643 Mcf/ton) = $6.1/ton.

[35] *Spinning Straw Into Black Gold: Enhanced Oil Recovery Using Carbon Dioxide*, Subcommittee On Energy And Mineral Resources, Committee On Natural Resources U.S. House Of Representatives, Thursday, June 12, 2008. Available at: http://www.gpo.gov/fdsys/pkg/CHRG-110hhrg42879/html/CHRG-110hhrg42879.htm

[36] See DOE/NETL-2010-1417, "Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology," (April 30, 2010) Table 13 footnote.

CO_2 CCS from \$25/ton to approximately \$19/ton[37] and could potentially offset the entire cost if Celanese received the upper end of the range of CO_2 value.

The revised application also assumed \$10,860,000 in capital costs and \$3,826,000/yr for O&M costs related to geological storage. (Revised Application, p.3-16) These costs would not be incurred if Celanese sold the captured CO_2 to Denbury Resources. Removing the storage costs from Sierra Club's estimate in Exhibit 1 reduces the average cost effectiveness for CO_2 removal by approximately \$8/ton.

Finally, as noted above, Celanese did not include any analysis of tax savings or credits that could be realized under Internal Revenue Code Section 45Q. CCS costs can be further offset by tax credits of \$10-\$20 per ton of CO_2 in accordance with Internal Revenue Code Section 45Q (26 USC § 45 Q).

3. Celanese Did Not Consider Specific CCS Opportunities in the Region

The CCS cost analysis provided by Celanese looked only at a 25 mile pipeline to Denbury and did not consider other potential storage options in the coastal plains region. Texas has a substantial network of pipelines and storage capabilities that could provide additional opportunities, at potentially lower costs, for the storage of CO_2. Celanese appears to have considered only a single destination, the Denbury Pipeline, for the potential storage of CO_2, and even then, Celanese doubled the pipeline distance from 12 miles to 25 miles for no apparent reason. The coastal plains region contains 65% of the country's estimated accessible carbon storage resources, with an estimated 2,000 gigatons of accessible storage resources.[38] The Region's BACT analysis did not even attempt to identify or provide any cost estimates for CCS at any of the region's geologic formations. To the extent the Denbury Resources pipeline is not available or is not the cheapest alternative, the Region must require Celanese to analyze other CCS options in the area.

In addition to revising the cost effectiveness methodology, the Region should require Celanese to provide additional support and documentation for its estimated capital costs and annual operating costs and allow for public comment on those additional materials.

B. The Region Improperly Considered Adverse Energy and Environmental Impacts

The Region asserts that, aside from adverse economic impacts, CCS should be eliminated as BACT based on energy and environmental impacts. (SOB at 12) However, the NSR Manual makes clear that energy and environmental impacts from the Clear Lake Plant are not a valid basis to reject CCS as BACT.

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[37] See also L. D. Carter, An Early Deployment Strategy for Carbon Capture, Utilization, and Storage (CCUS) Technologies, June 4, 2012. Available at: http://www.uscsc.org/Files/Admin/Educational_Papers/20120604_Early%20Deployment%20Strategy%20for%20CCUS%20Technologies_FINAL.pdf

[38] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41. Available at: http://pubs.usgs.gov/circ/1386/

The NSR Manual provides that energy impacts that are "significant or unusual" should be examined in a BACT analysis.[39] In most cases, extra fuel or electricity required to power a control device should simply be factored in to the economic impacts analysis.[40] In this case, there are no significant or unusual energy impacts to install CCS. Celanese considered the energy requirements to power a CCS system and included the costs of a steam boiler in its analysis of cost impacts. Moreover, there are no site-specific or other unique energy issues at the Clear Lake plant such as fuel scarcity or supply constraints that would render CCS infeasible. Therefore, there is no basis to reject CCS for energy impacts.

Similarly, there are no identified adverse environmental impacts from the Clear Lake Plant's installation of CCS. The SOB asserts that the "[i]mplementation of CCS would increase emissions of GHGs, NOx, CO, VOC, PM_{10}, and SO_2 because of the increased energy needed to operate the CCS controls." (SOB at p.12) The Region also notes that the area is in non-attainment for ozone, and additional NOx and VOC could exacerbate ozone formation in the area. Celanese also adjusted its cost calculations to include $5,000,000 in NOx and VOC off-sets. This assessment of a potential increase in criteria pollutants is not a valid basis for rejecting a feasible control technology due to adverse environmental impacts. First, the point made by Celanese (and included in its cost analysis) that any additional ozone precursor emissions require an off-set means that in fact there would be no increases in the non-attainment area. The $5 million payment for offsets would reduce the area's emissions of NOx and VOC by an equal amount. Put another way, the increases are negated by reductions elsewhere. Second, as the NSR Manual expressly states, the "environmental impacts analysis is not to be confused with the air quality impacts (i.e. ambient concentrations)…"[41] In this case, whether CCS at the Clear Lake Plant would increase some criteria pollutants does not constitute an adverse environmental impact because the only impacts the Region points to are ambient air concentrations. There are no other identified significant or unusual impacts from the addition of CCS other than the additional energy requirements to operate CCS. Therefore, there is no basis to reject CCS due to adverse environmental impacts.

Further, as discussed elsewhere in these comments, we note that the new boiler included in the cost analysis that would generate these alleged impacts is not required. The steam required to regenerate the MEA is produced by the methanol synthesis process itself, or it is available from non-fuel-fired heat recovery sources within the Clear Lake complex (e.g., steam turbines, heat recovery). Thus, there would be no increase in GHGs, NOx, CO, VOCs, PM10, and SO2 from burning fuel to supply steam.

C. The Permit Does Not Require the Most Efficient Methanol Production Process

The most effective CO_2 control technology is CCS. However, the draft permit must also require the most energy efficient methanol production process as part of the BACT analysis, which the Region failed to require in this case. For the proposed methanol facility at the Clear Lake Plant, the draft permit sets a limit on specific energy consumption of 30 MMBtu per ton of methanol produced, where the energy consumed is the sum of the energy in the process feed gas plus the energy required to operate the reformer furnace. (Draft Permit, Condition II, Table 1

[39] *NSR Manual*, p. B.29.
[40] *Id.* at p. B.30.
[41] *NSR Manual*, p. B.46.

and III.A.1) Our research indicates that this does not represent the most efficient methanol process. The *Encyclopedia of Chemical Technology* reports that by the mid-1990s, energy consumption of methanol production from natural gas had fallen to 29.0 to 30.3 GJ/tonne (LHV),[42] which equals 28 to 29 MMBtu/ton (HHV). A recent analysis by the International Energy Agency reported specific energy consumption to produce methanol from natural gas using "Best Practice Technology" of 28.5 GJ/tonne (LHV),[43] which equals 27.2 MMBtu/ton (HHV). In contrast, the draft permit based the limit for the Clear Lake Plant on 30 MMBtu per ton of methanol produced. This limit is not the most efficient methanol production process and therefore the draft permit should be revised to require the most efficient process.

Clean Air Act § 165(a)(4) requires the Region to select the Best Available Control Technology (BACT) as the basis for the emissions limit, which is defined as "an emissions limitation … based on the maximum degree of reduction for each pollutant subject to regulation under the Act…" 42 USC 7479(3); 40 CFR 52.21(b)(12). The NSR Manual provides: "The reviewing authority…specifies an emissions limitation for the source that reflects the **maximum degree** of reduction achievable…" (NSR Manual, p.B.2 (emphasis added)). Without a showing that the most efficient pollution control technology is either technically infeasible or that it should be eliminated due to disproportionate site-specific energy, economic or environmental impacts, the Region must set the GHG BACT emission rate limit based on the most efficient controls. Here, that means at a minimum, that BACT should be based on a heat input no greater than 27.2 MMBtu unless the applicant can show site specific reasons why this is not achievable

The draft Permit also excludes periods of start-up, shutdown, and malfunction from the BACT efficiency limit of 30 MMBtu/ton. (Draft Permit, Conditions III.A.1.q.) The Region cannot set a BACT permit limit that completely excludes periods of startup and shutdown. BACT is an emission limitation that applies at all times. 42 U.S.C. §§ 7479(3) (BACT is an "emission limitation"), 7602(k) (an emission limitation must be continuous); *In re RockGen Energy Center*, 8 E.A.D. 536, 553-55 (EAB 1999). Moreover, startup and shutdown are

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[42] Jacqueline I. Kroschwitz and Mary Howe-Grant (Eds.), Kirk-Othmer Encyclopedia of Chemical Technology, 4th Ed., 1995, vol. 16, p. 539.

[43] International Energy Agency, Chemical and Petrochemical Sector, Potential of Best Practice Technology and Other Measures for Improving Energy Efficiency, September 2009, Table 1, http://www.iea.org/publications/freepublications/publication/chemical_petrochemical_sector.pdf

common events and must be addressed through appropriate planning to minimize emissions. *RockGen*, 8 E.A.D. at 553 (citing EPA guidance).

Sierra Club appreciates the opportunity to provide these comments.

Sincerely,

*/s/ Travis Ritchie*____

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