Celanese Ltd.
Clear Lake Plant
Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions
PSD-TX-1296-GHG

Responses to Public Comments

U.S. Environmental Protection Agency
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I. Summary of the Formal Public Participation Process

The U.S. Environmental Protection Agency, Region 6 (EPA) proposed to issue a Prevention of Significant Deterioration (PSD) permit to the Celanese Clear Lake Plant on June 23, 2013. The public comment period on the draft permit began June 23, 2013 and closed on July 23, 2013. EPA announced the public comment period through a public notice published in the *Pasadena Citizen* on June 23, 2013 and on Region 6's website. EPA also notified agencies and municipalities on June 19, 2013 in accordance with 40 CFR Part 124.

The Administrative Record for the draft permit was made available at EPA Region 6's office. EPA also made the draft permit, Statement of Basis and other supporting documentation available on Region 6's website, and available for viewing at the Harris County Library – La Porte Branch in La Porte, TX.

EPA's public notice for the draft permit also provided the public with notice of the public hearing. The public notice stated that "Any request for a public hearing must be received by the EPA either by email or mail by July 17, 2013, and must state the nature of the issues proposed to be raised in the hearing…EPA maintains the right to cancel a public hearing if no request for a public hearing is received by July 17, 2013, or the EPA determines that there is not a significant interest. If the public hearing is cancelled, notification of the cancellation will be posted by July 19, 2013 on the EPA's Website http://yosemite.epa.gov/r6/Apermit.nsf/AirP. Individuals may also call the EPA at the contact number listed above to determine if the public hearing has been cancelled." During the comment period, EPA did not receive any written requests for a public hearing. EPA posted its announcement that there would not be a hearing on July 19, 2013. EPA received one comment letter from Sierra Club on July 23, 2013.

II. EPA's Response to Public Comments

This section summarizes the public comments received by EPA and provides our responses to the comments. EPA received one comment letter from Sierra Club on July 23, 2013.

Response to Sierra Club's Comments

Sierra Club submitted detailed comments on the draft permit and statement of basis that we have summarized below (in their order of appearance in the comment letter) and to which we have provided responses.

Comment 1: There is no basis to reject Carbon Capture and Storage (CCS) due to economic impact unless the costs for the proposed facility have been compared to the costs of control at other facilities (e.g., Leucadia Energy methanol plant in Louisiana) and found to be disproportionately high. The "NSR Manual" states that "applicants generally should not propose elimination of the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source." The Region must instead determine that the cost-per-ton of emissions reduced and the incremental costs are beyond the cost borne by other sources of the same type in applying the control alternative. It is invalid to reject CCS on the basis of its excessive costs in relation to the overall costs of the project. The Region cannot simply reject CCS because there are not other BACT determinations requiring it. There has to be a first instance where a control is determined to be BACT, since BACT has a "technology-forcing function." The Region's determination that CCS is too expensive in relation to total project costs is not a valid basis for rejection in Step 4 of the BACT analysis. Celanese states "the addition of CCS is expected to increase the total capital project costs by more than 25%. That cost likely exceeds the threshold that would make the project economically viable," which the commenter characterizes as a "blanket and unsupported assertion." The commenter cites Alaska Dep't of Envtl. Conservation v. EPA, 540 US 461, 466 (2004) on the issue of declaring a technology economically infeasible without needed financial information. The Region made no attempt to demonstrate that the Clear Lake Plant was unsuitable for CCS compared to other facilities, and the Region must consider the "average cost effectiveness of CCS."

Response:

We do not agree that our evaluation of economic impacts should be based solely on a cost per ton of CO_2 control metric. The NSR Workshop Manual is not a binding regulation that dictates how the economic impacts analysis must be conducted in all cases. *See*, NSR Workshop Manual, at 1 (October 1990) (first paragraph of Preface); *In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07, Slip. Op. 54 n. 39 (EAB Sept. 17, 2012). While the NSR Manual does caution against eliminating a potential control technology from consideration as BACT by looking only at affordability relative to the source, our GHG Guidance recognizes that "there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT."[1] Given the lack of GHG cost per ton information available at this time for specific types of facilities, as well as other cost variables that are commonly inherent in estimating cost effectiveness for CCS systems (e.g., uncertainty of CO_2 contract price from pipeline operator, uncertainty of price for land acquisition for building pipeline to facility, etc.), we believe that it is reasonable at this time to evaluate the economic impacts of CCS as a percentage of the overall project cost. Furthermore, the EAB recently found that this cost comparison approach to be acceptable, explaining that elimination of CCS where it is found to be cost-prohibitive in comparison to the entire project "was neither inappropriate nor impermissible." *See In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07, slip op. at 54-55 (EAB September 17, 2012). We therefore disagree with the commenter and continue to believe that rejection of CCS as GHG BACT in Step 4, based on its high cost in comparison to the overall project cost, is appropriate and in accordance with EPA guidance and with EAB precedent.

A comparison of the costs of Celanese's project to projects at other facilities does not change our conclusion. Celanese identified three industrial CCS projects currently being pursued under the Interagency Task Force (ITF) Industrial Carbon Capture and Storage (ICCS) program: Air Products,

[1] GHG Guidance at 43.

Leucadia Energy, and Archer Daniels Midland. We have examined each of these projects, and determined that they do not provide a meaningful basis for a comparison of cost-effectiveness.

- The Department of Energy (DOE) funded project with Air Products at the Valero Port Arthur Refinery is utilizing a higher CO_2 concentration process stream (up to 20 % by volume) when compared to Celanese's flue gas (approximately 8% by volume). The Air Products CCS project will capture 90% of the CO_2 from 2 steam-methane reformers yielding 1 million tons per year (TPY) of CO_2. The CO_2 will be used in an enhanced oil recovery (EOR) application. Air Products is receiving $284 million, or 66% of the total project cost of $431 million, from the DOE for their CCS demonstration project.
- The Leucadia Energy (Leucadia Energy, LLC is an affiliate of Lake Charles Cogeneration) methanol plant in Louisiana was selected for funding in July 2010 in the ICCS program. The Leucadia Energy facility will capture 4 million metric TPY of CO_2 from a petroleum coke-to-chemical (methanol, hydrogen, and other by products) plant in Lake Charles, LA. This project will be recovering CO_2 from the syngas cleanup process after gasification of petroleum coke. The project will also be using a higher CO_2 concentration flue gas stream of 30-40 percent by volume. The CO_2 will be used in an EOR application. Leucadia is receiving $261 million in funding from the DOE for this project, which is about 60% of the total project cost of $436 million.
- The Archer Daniels Midland (ADM) Company was selected by the DOE in 2009 to capture CO_2 from biofuels (ethanol from corn) production. ADM will capture approximately 1 million metric tons per day from a very high concentration stream (99% CO_2 on a moisture free basis). ADM will send the CO_2 into storage at the Mount (Mt.) Simon Sandstone Formation (saline reservoir). ADM is receiving $141 million in funding from DOE, or about 67% of the total project costs of $208 million.

EPA does not view the above three projects as comparable to Celanese's proposed methanol production project for the purpose of evaluating economic viability of the CCS technology. This is because these three projects will be recovering CO_2 from streams that are significantly higher in CO_2 concentration than the flue gas stream at Celanese, which would likely lead to different and more expensive technology to capture the carbon from Celanese's more dilute CO_2 stream. Also, these three projects are receiving significant funding from the DOE in order to test new techniques for capturing carbon from flue gas streams at these specific source types. This government funding is not present for the Celanese project and would need to be factored into any economic comparison.

While EPA decided to base the decision to eliminate CCS for the Celanese Clear Lake proposed methanol production project, we note that Celanese calculated an average cost effectiveness of $121/ton CO_2e for installing and operating CCS. The cost study included capital and operating costs for the capture, drying, and compression technologies that would be needed for CCS at the Celanese Clear Lake Plant. We generally accept Celanese's cost estimation of over $121 per ton of CO_2 avoided, or $34.4 million annually, to achieve 90 percent CO_2 emissions capture. Celanese estimated the total capital expenses of constructing a carbon capture system as approximately $125 million (does not include pipeline costs). These costs were developed under the assumption that the source could contract with the pipeline operator to deliver CO_2 gas to geologic storage. Region 6 issued a GHG PSD permit to Equistar for a methanol manufacturing unit, in the SOB for that permitting action we found carbon capture alone to cost $130 million.[2] Based on our review of their submitted cost study and our experience in reviewing CCS cost studies for other types of projects, we find these estimates to be credible. Thus, the CCS capital project costs would increase the cost of the project by more than 25 percent, and we reasonably believe that such increases would make the project economically unviable. In addition, we recognize the potential for environmental impacts of operating a CCS system (e.g., increased criteria pollutant emissions as a result of increased energy use to operate the capture and compression system). These projected environmental impacts, coupled with the project cost increase resulting from the additiona of CCS, have led to the elimination of the CCS technology under Step 4 of the top down BACT analysis.

EPA continues to believe this cost comparison approach is consistent with the definition of BACT under Clean Air Act 169(3), and is a reasonable, objective means to demonstrate that the costs of the control technology are disproportionately high[3]. Additionally, EPA has used a similar approach in other recent PSD permits for methanol production units (e.g., the Equistar Chemicals facility in Channelview, Texas).

Comment 2: The Region should have compared the CCS cost per ton of the proposed Clear Lake facility to the cost of CCS at the Leucadia Energy Methanol plant in Louisiana.

Response:

It is unclear why the commenter believes the Celanese facility should be compared to the Leucadia Energy plant in Louisiana other than they both will produce methanol. At present, the Department of Energy (DOE) – National Energy Technology Laboratory (NETL) is collaborating with industry through the Industrial Carbon Capture and Storage (ICSS) program in cost sharing arrangements to demonstrate CO_2 emission capture technology from industrial sources and to either sequester or beneficially reuse them. We understand that DOE selected Air Products and Chemicals, Inc. (Air Products) and Leucadia Energy to receive DOE funding under the American Recovery and Reinvestment Act (ARRA) for a "large scale" CO_2 capture and sequestration project at Valero's Port Arthur Refinery in Port Arthur, Texas and Lake Charles Cogeneration in Lake Charles, Louisiana respectively. Celanese does not have the benefit of such an arrangement for its project.

The DOE funded project at Leucadia Energy (Leucadia Energy, LLC is an affiliate of Lake Charles Cogeneration) will recover CO_2 from a petroleum coke-to-chemical (methanol, hydrogen, and other by products) plant in Lake Charles, LA. This project will be recovering CO_2 from the syngas cleanup process after gasification of petroleum coke. The process will concentrate the initial process gas stream containing 30-40 percent CO_2 to greater than 99 percent CO_2 purity. The technology will be designed to

[2] Equistar Chemicals, Channelview Plant, PSD-TX-1280-GHG Statement of Basis available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/equistar_methanol_sob122112.pdf
[3] See Draft NSR Manual at B.31-32.

remove more than 90 percent of the CO_2 from the process gas stream. The project is expected to recover 4.5 million metric tons per year of CO_2. The compressed CO_2 will be delivered to the Denbury Green Pipeline for transport to Texas Enhanced Oil Recovery (EOR) projects in the West Hastings oil field. Another aspect of the project is that Leucadia will be responsible for the capture portion of the project while Denbury is responsible for transport and sequestration through EOR. The DOE clearly indicates that the Leucadia project goal is to advance CCS technologies from the demonstration stage to commercial viability.

The approximate cost of the project is $436 million of which $261 million is funded by the DOE, which means that the DOE is providing over 60 percent of the funding for the project. Leucadia was also awarded $1 billion in tax-exempt Gulf Opportunity-Zone Bonds ("GO Zone Bonds") that were issued into escrow in April 2008. The Leucadia project cost per ton to capture CO_2 is approximately $108/ton and is partially funded by DOE, while the cost per ton to capture CO_2 for Celanese is $121/ton CO_2.

Further, the methanol production by Celanese will be done through a combined reformer process which is an entirely different manufacturing process than that being used at Leucadia Energy. The CO_2 in the flue gas stream from the Celanese plant is also estimated to be approximately 8 percent, which is significantly less than the 30-40 percent CO_2 expected in the Leucadia Energy project. The potential cost to recover CO_2 from lower concentration flue gases is generally expected to be higher due to the increased cost for capture. In addition, it is reasonable to expect that Celanese might also be responsible for transport of the CO_2 in addition to the capture costs for CO_2. It is clear that a direct comparison of the prospective costs that Leucadia might incur from an entirely different process design are not the same as those that might be incurred using Celanese's project design. In addition, the responsibilities, capital investment, and annual operating costs for capture, transport, and sequestration of CO_2 might not always have the same business model from one project to the next. The same design and project model are not in place to allow for a direct comparison of the CCS costs of the Leucadia Energy project and the Celanese project.

Comment 3: The Clear Lake facility's estimated average cost effectiveness is less than half of the ExxonMobil Baytown Olefins Plant estimate, 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.

Response:

As discussed in response to Comment 1, we do not agree that our evaluation of economic impacts should be based solely on this cost per ton of CO_2 control metric. Consistent with EPA's permitting guidance for GHGs and the EAB's reasoning in the Palmdale decision that relied upon it, it is not impermissible to rely on a comparison of CCS control costs to overall project costs that clearly shows CCS is cost prohibitive. GHG Permitting Guidance at 42; *City of Palmdale* at 54-55.

EPA clearly indicated in its statement of basis supporting the draft permit that the estimated CCS capital needed only for capture and a new pipeline for the current project would result in an increase of more than 25% in the capital costs for Celanese's project. Looking at operations and maintenance (O&M) costs only, the addition of CCS increases the annual O&M costs by 37 – 57%.[4] We reviewed Celanese's BACT analysis, which was supported by a CCS cost estimate. As we indicated in our BACT analysis we believe Celanese adequately calculated the cost of CCS control for this project, and those prospective costs are prohibitive in relation to the overall cost of the proposed project. In addition, as noted in the Statement of Basis, "[t]he recovery and purification of CO_2 from the stack gases would necessitate significant additional processing and also create environmental/air quality penalties…" (SOB, pg. 11). These environmental impacts, coupled with the increases in costs for the project for installing, operating and maintaining a CCS system, support EPA's rejection of CCS under Step 4 of the BACT analysis.

Comment 4: The region should also consider the costs of failing to control GHG emissions, expressed as the social cost of carbon. The commenter cites a range of $28 to $893 per ton of CO_2. If the cost per ton of CO_2 controlled with CCS at Baytown is lower than the social cost of carbon, the CCS would be a more economic choice and the costs are even more reasonable.

Response:

The economic concept of a "social cost of carbon" has recognized regulatory uses, but we are aware of no instance where it has been applied to individual permitting actions involving determinations of technology-based permit limits. EPA and other federal agencies have used the social cost of carbon (SCC) in rulemakings where a regulatory impact analysis is conducted in accordance with Executive Orders 12866 and 13563. The SCC monetizes damages associated with an incremental increase in carbon emissions in a given year. It includes (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services to climate change. See e.g., 77 FR at 62927 (Oct. 15, 2012 (use of SCC in final rules establishing controls on GHG emissions from new model year 2017-2025 light duty motor vehicles)). Thus, the social cost of carbon can be a useful measure to monetize the benefits of CO_2 reductions from regulatory actions that impact cumulative global emissions.[5]

However, in determining BACT, we consider the "economic impacts" of the technologies under consideration for control of a pollutant subject to PSD. See CAA Section 169(3) (defining BACT). In contrast, the social cost of carbon is a monetized measure of environmental effects – in other words, a monetized assessment of potential risk from the pollutant emissions. But BACT determinations are not risk-based. (Similarly, in determining BACT for criteria pollutants, permitting authorities do not

[4] Email from Celanese (Ashley Duffie) to EPA (Aimee Wilson): CE GHG Permit – Additional Information; December 6, 2013. Email indictaed the O&M costs for the methanol project was estimated at $44.5 million per year.
[5] Further background and details on the social costs of carbon estimations that are presently being used by EPA are provided in other EPA documents. See, e.g., Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 5-36 to 5-39, available at http://www.epa.gov/ttnecas1/regdata/RIAs/EGUGHGNewSourceStandardsRIA.pdf. It appears that the upper end of the commenter- cited-range (i.e., $893 per ton) far exceeds the estimates being used in current economic analyses by the federal government.

directly assess monetized potential benefits of controlling (for example) particulate matter and ozone precursors; these are not economic costs of the control.) Thus, the social cost of a pollutant should not be mistaken for "compliance cost," which includes the cost of control, monitoring, testing, and other considerations, which is more typically calculated when assessing BACT costs**.**

In this regard, the EPA Administrator recognized the harm of GHG emissions in finding that greenhouse gas concentrations in the atmosphere may reasonably be anticipated to endanger public health and welfare (the so-called endangerment finding for GHGs),[6] which (in combination with the substantive regulation of GHG emissions from new light duty motor vehicles) has resulted in application of the statutory BACT requirement to GHGs from major emitting facilities. EPA has noted in the context of evaluating environmental impacts that "it is generally unnecessary to explicitly consider or justify the environmental benefits of reducing the pollutant subject to the BACT analysis, since these benefits are presumed under the CAA's mandate to reduce emissions of each regulated pollutant to the maximum degree achievable." GHG Permitting Guidance 39. The avoidance of economic harm and danger of GHG emissions is accordingly already recognized when a permitting authority applies the "maximum degree of reduction" to the pollutant in consideration of the statutory factors.

Although it is unclear if the commenter proposes a weighing of costs and benefits in this BACT determination, we note that EPA has never interpreted BACT as requiring such a cost-benefit analysis. Rather, EPA has long interpreted BACT as requiring use of the most stringent control technology that is available unless the applicant demonstrates that this is not achievable, considering economic, environmental, or energy impacts. See, e.g. Background Statement on the EPA's Top-Down Policy (June 13, 1989), transmitted by memorandum of John Calcagni (June 13, 1989). We note further that Congress indicated explicitly where it intended EPA to include cost-benefit considerations in the Act (see CAA section 173 (a)(5) (issuance of permits where the permitting authority determines, among other things, that "an analysis of alternative sites, sizes, production processes, and environmental control techniques … demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed …..)).

We have explained at our response to Comment 1, and in other areas of this response, our basis for determining the cost considerations which have led us to reject CCS as a control option for this project. We note further that even were we to accept the commenter's premise as to the relevancy of social cost of carbon in determining economic impacts (for example, as a potential measure for evaluating whether CCS is reasonably cost effective for this project), the economic impacts of CCS here (expressed as dollars per ton of GHG removed) would far exceed the measures of social cost of carbon accepted by the federal government. However, even considered this way, the comparison the commenter urges would involve a type of cost-benefit analysis, comparing the cost of control with the (monetized) benefits of pollutant removal (expressed as SCC). As stated above, EPA has never interpreted BACT as requiring cost-benefit analysis and is not doing so here.

[6] 74 FR 66496 (Dec. 15, 2009).

Comment 5: Costs of CCS should have been calculated according to the Control Cost Manual to assure consistency of BACT decisions.

Response:

We acknowledge that consistency in decision making is a primary objective of the top-down BACT approach, and further acknowledge that the OAQPS Control Cost Manual has been a recommended and utilized resource in the development of cost projections made for the control of criteria pollutants. However, the Cost Manual states that "new and emerging technologies are not generally in the scope of [the] Manual. The control devices included in [the] Manual are generally well established devices with a long track record of performance." Control Cost Manual, 6th Ed., at 1-3. In addition (and perhaps even more so), the Control Cost Manual predates the era of GHGs becoming newly subject to regulation and did not anticipate the considerations that might apply to its permitting. Since cost development for CCS is not contemplated by the Control Cost Manual, many applicants addressing PSD for GHGs have sensibly utilized the best available information on costs for CCS technology, with many of them drawing on resources provided by the U.S. Department of Energy and using methodologies consistent with that literature, including, for example, the DOE/NETL Report cited by the commenter.

In this context, we would consider application of the Control Cost Manual or its methodology to CCS to potentially run counter to the stated consistency objective; moreover, the commenter has not pointed to any permitting case where CCS costs were strictly developed under the Control Cost Manual, much less one where utilizing that methodology was material to an overall determination regarding CCS as BACT. We note that the costs of CCS may be more sensitive to location and other unique factors than conventional add-on controls, so the considerations (i.e., that costs appear excessive or unreasonable) that ordinarily warrant the provision of more detailed and comprehensive cost data do not apply in the same way. We generally agree, however, that any BACT determination finding CCS to be cost effective under one costing methodology makes it important for subsequent cost studies prepared by other permit applicants to provide data and calculations sufficient to make comparisons and take proper account of relevant differences in costing approaches.

Here, we note that the overnight capital cost does not take into account financing costs or escalation, and hence is not an actual estimate of construction cost. Investors in the energy industry typically look to the Levelized Cost of Energy (LCOE) for comparing generation technologies (e.g. solar, natural gas) in the long term, as it includes ongoing fuel, maintenance, and operation costs. The U.S. Department of Energy tracks and makes publicly available levelized cost of energy figures for competing technologies. In addition, there are no specific regulatory provisions that prohibit EPA from utilizing estimated capital costs with future escalation in its BACT determination when under these specific circumstances large scale carbon capture sequestration add-on controls have never been attempted at an ethylene production plant. We believe the projected capital and operating costs relied upon for this BACT determination still make CCS for this project economically unviable.

Comment 6: 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. It is evident Celanese failed to follow acceptable procedures or padded the costs to make them look higher than they actually are.

Response:

Although the draft NSR Workshop Manual provides guidance on performing cost calculations for control options, cost analyses often vary in complexity and specificity. EPA has acknowledged that a less detailed analysis may be more appropriate in certain instances. See GHG Permitting Guidance at 42. Celanese's permit application and supplemental responses to EPA clearly reflected the design basis and equipment that would be needed to install a CCS system. This information was available in the public record at the time the draft permit was at public notice. Celanese identified in its application the specific plants and functional process equipment that would be needed for CCS and the process diagrams for the capture process. For example, the Carbon Capture Plant would include CO_2 compressors and intercoolers, an amine absorber system, a CO_2 regeneration/purification system, blowers, piping, and duct work. It also identified the need for a boiler and plant electrical upgrades.

Celanese further noted that a dedicated boiler would be required to meet the steam requirements for the monoethanolamine (MEA) regeneration in the CO_2 capture plant, indicating that this new boiler would generate its own GHG emissions. The boiler would generate emissions of 195,909 TPY CO_2. Celanese's design did not include capture of this additional CO_2 stream.

Celanese provided the carbon capture and compression cost estimates in the aggregate including both their capital and operating expenses associated with the site-specific carbon capture plant. While a CCS system has been designed and proposed for construction at another methanol production plant based on different methanol production process, Celanese clearly prepared an evaluation for CCS that provided and highlighted the equipment needs and plants that would be required for CCS on this project. In addition, they provided an analysis of their pipeline construction costs to transport CO_2. We thus disagree with the commenter that the validity of the design could not be verified and that the reasonableness of the costs could not be evaluated based on the permit application and supplemental responses provided to EPA that were included in the permitting record. It is also unclear what the commenter specifically believes is an unacceptable procedure or what costs are padded, The application information submitted by Celanese, which was available at public notice, included material balance sheets, CCS equipment lists outlining the design condition assumptions, space and utility requirements, and capital cost estimates. While the original cost effectiveness was estimated to be approximately $121.20 per ton, Celanese submitted revised costs on November 8, 2013 for the cost effectiveness of CCS and the estimated cost effectiveness was revised downward slightly.

Comment 7: The use of a boiler also impacts the cost effectiveness because Celanese offsets the CO_2 captured by the system with an increase in 195,909 tons/yr of CO_2 from burning natural gas in the boiler. However, this boiler is not necessary to provide the steam required to regenerate the MEA because the plant already produces excess steam.

Response:

Celanese identified one method of CO_2 capture for the reformer flue gases – separation by amine absorption. The estimated capital costs included the $19 million for a new steam system to regenerate the monoethanolamine (MEA). Celanese also estimated that it would require approximately 317,000 lbs/hr of steam in order to regenerate MEA and that part of this steam could be potentially sourced from the new methanol unit. But the facility still could not produce enough steam to meet the full demand for amine regeneration. Most of the steam that is required to operate the methanol plant is produced by heat recovery from the synthesis gas leaving the secondary reformer; the remainder is produced by heat recovery from the methanol converters. There are no additional opportunities to produce steam at the proposed methanol plant. Celanese has indicated that they would be approximately 100,000 lbs/hr short and would therefore need to build a new steam system since the existing plant's steam capacity is sized for its current operations and thus do not have enough excess steam, at least on a continual basis, to support a CCS system. It is apparent based on the potential steam needs that Celanese would need to install a new steam boiler to operate CCS technology at the proposed methanol unit. Since the new boiler would be needed to support the use of CCS, it is acceptable for its costs (capital and operational) to be considered in the cost analysis for CCS. Further, the addition of the new boiler will generate increased emissions of GHG and non-GHG pollutants. These additional emissions of NOx and VOC would occur in a nonattainment area, which would require Celanese to purchase the appropriate offsets for those pollutants. The additional CO_2 generated by the new boiler would also offset the amount of CO_2 that would be captured. We have elected to treat the entire CCS system from carbon capture, energy needs, compression, and storage in the overall economic or cost consideration for BACT. Doing otherwise in this case would not fully account for the prospective economic, energy, and environmental impacts of applying CCS as a control option for this project.

Comment 8: 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.

Response:

Worley Parson's used Aspen Tech IPM (in plant cost estimator), budget quotes, and in-house pricing to estimate costs for major process equipment. Both cost estimates are well-documented. Celanese's Worley Parsons study provided an estimate for a 350,000 lb/hr low pressure steam system to meet the amine treating system demand for 317,000 lb/hr of steam and associated equipment. An original estimate of $19,000,000 was provided in the June 14, 2013 application update. This cost was based on in-house pricing for an existing high pressure steam boiler that was estimated to be adequate to supply steam in the CCS system. The Worley Parsons study submitted as part of the permit application clearly identified the equipment and space requirements needed for the utility plant at 6.1 – PLOT SPACE REQUIREMENTS and the capital cost estimates for the equipment identified at 6.1 was clearly estimated at over $19 million at 7. CAPITAL COST ESTIMATE table of the Worley Parson study. However, a "Revised Cost Effectiveness Analysis for Carbon Capture and Storage based on EOR" table was attached to the November 8, 2013 submittal Celanese provided to EPA which provided their updated cost estimates for the boiler and associated equipment, the amine treating system, and NOx and VOC offsets. The revised cost estimate for the new boiler system for amine regeneration was estimated to be approximately $11.6 million along with an additional approximately $5 million for NOx and VOC offsets in this submittal. The revised boiler cost was based on a lower pressure steam boiler than in the original cost estimate. As stated in EPA's statement of basis for the proposed permit, Celanese identified one method of CO_2 capture for the reformer flue gases – separation by amine absorption. The estimated capital costs referenced in EPA's statement of basis included the $19 million for a new steam system to regenerate the monoethanolamine (MEA). As noted in the permit application, Celanese indicated that it might be possible to obtain some of the steam from the new methanol unit, but even in a best case scenario, Celanese would be approximately 100,000 lbs/hr short and would therefore need to build a new steam, system since the existing plant's steam capacity is sized for its current operations and excess steam is not available to support a CCS system. However, based on the permit application which identified the equipment needed for a new steam system to meet the facility's needs and which itemized the estimated cost for each piece of equipment in the steam system, we had no basis to dispute that a new steam system could cost as much as $19 million in our analysis for the draft permit.

In response to the comments claiming that the estimated costs for NOx and VOC offsets of $5 million were too high, Celanese is located in an ozone non-attainment area where it would be required to obtain offsets at a 1.3:1 ratio. Current estimates for the new boiler (steam system) indicate emissions of approximately 14 tons/year of NOx and over 7 tons/year of VOCs. VOC and NOx credits have recently traded in the Houston non-attainment area for as much as $230,000 per ton of NOx and $300,000 per ton of VOCs. The two-year average cost for NOx is $162,141 and $171,634 for VOCs. Either way, the costs are significant. Assuming Celanese had to purchase offsets for 14 tons/year of NOx (19 tons of offsets) and 7 tons of VOCs (9 tons of offsets) at the recently traded price above could actually cost more than $7 million.[7]

Comment 9: 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)).

Response:

Heat integration with other Celanese plant systems was excluded because of the distance between the proposed methanol unit and other Celanese production units that would potentially make heat integration inefficient due to heat loss in transport to other production units. This would have also required additional construction costs and possibly additional energy demands to transfer the heat.

[7] Email from TCEQ (Brandon Greulich) to EPA (Jeff Robinson): RE: Most Recent EC Trade Prices; November 20, 2013.

Therefore, Celanese only considered the viability of heat integration in the CCS system. As explained in the response to comment 8, Celanese would need to install a new steam boiler to operate CCS technology at the proposed methanol unit because the facility would not generate enough excess steam to support CCS.

Comment 10: 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.

Response:

As explained in the Response to Comment 8, Celanese has shown that the new steam facility is needed for CCS. As noted in EPA's statement of basis for the proposed permit, Celanese identified one method of CO_2 capture for the reformer flue gases – separation by amine absorption. The estimated capital costs included the $19 million for a new steam system to regenerate the monoethanolamine (MEA). Celanese also estimated that this would require approximately 317,000 lbs/hr of steam. It is possible that part of the steam could be sourced from the new methanol unit, but even in a best case scenario, Celanese has indicated that they would be approximately 100,000 lbs/hr short of the necessary steam to operate the CCS system. In addition, they have indicated the existing plant's steam capacity is sized for its current operations and excess steam is not available to support a CCS system. In addition, because of the physical distance between the proposed methanol unit and other Celanese production units, heat integration would result in inefficiencies due to heat loss in the transport to other production units. This would require additional construction costs for new piping and possibly additional energy demands to transfer the heat. Finally, we are aware that other methanol production facilities recover CO_2 using the single reformer design. A single reformer design produces excess hydrogen and waste gases which are reintroduction into the process to create more methanol. In response to the comment on recovering CO_2 to input into other operations at the facility, the combined reforming process that Celanese has proposed does not produce excess hydrogen in sufficient quantities (as does a single reformer) to allow for the recovery of CO_2 to produce more methanol.

Celanese's project utilizing a combined reformer will produce approximately 0.37 tons of CO_2 per ton of methanol produced. Recently issued permits for single reformer projects range from approximately 0.83 – 0.92 tons of CO_2 per ton of methanol produced. Celanese's proposed manufacturing process will result in an efficient methanol production operation on a CO_2 per ton of methanol produced basis.

Comment 11: 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.

Response:

Celanese indicated that installation of the CCS system for the proposed project would require that the existing main electrical substation at the plant be upgraded. Celanese's current available electrical capacity is 16 Mega Volt Ampere (MVA). The new methanol unit is estimated to require 9-10 MVA of the available 16 MVA. The applicant has also estimated that a CCS system would require an additional 9 MVA. In addition, Celanese needs to maintain available MVA for emergencies such as transformers going down (potentially as much as 6 MVA). Therefore, the existing available 16 MVA capacity at the Celanese Clear Lake site is insufficient to accommodate the 18-19 MVA need for both the methanol unit and CCS system without an upgrade to the station. In addition, the plant would lose the necessary MVA to accommodate emergencies as well and the upgrade would be necessary to create MVA for emergencies. Celanese also provided an updated cost on November 8, 2013 for upgrading the electrical substation based on more recent cost estimates, and now the estimated costs increased from $7 million to $10 million.

Comment 12: 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.

Response:

For the reasons explained above, we agree with Celanese that a boiler would need to be utilized to supply steam if CCS was implemented. The project will not use the estimated natural gas price of $5.00/MMBtu that the commenter believes is are too high. Celanese provided revised costs for natural gas based on current natural gas prices in a November 8, 2013 submittal. The revised analysis uses a 12-month average from Henry Hub spot natural gas pricing[8]; the 12-month average for 2012 is approximately $2.77/MMBtu. This pricing does not include the transportation charges, so the cost of delivered natural gas would be higher. Based on Celanese's revised cost estimate in its November 8, 2013 submittal, using a natural gas price of $2.77/MMBtu would reduce the projected cost of CCS from $121/ton of CO_2 slightly downward. Even with this revised natural gas price, the addition of CCS would still increase the capital cost of the project by at least 25% since the capital costs would remain essentially the same for the amine treating, compression, boiler, electrical upgrades, and offsets needed to implement CCS. As stated above in response to Comment 3, EPA has additional concerns regarding the environmental impacts associated with implementation of CCS. These environmental impacts, coupled with the increases in costs for the project for installing, operating and maintaining a CCS system, contribute to EPA's rejection of CCS under Step 4 of the BACT analysis.

Comment 13: 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. 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. Celanese estimated that the facility would produce 1,433,000 tons of methanol. (SOB, p. 4) This works 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 (2,033 hp out of a total of 5,309 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.

[8] Historical Henry Hub Gulf Coast Natural Gas Spot Price available from the U.S. Energy Information Administration (EIA) online at http://www.eia.gov/dnav/ng/hist/rngwhhdM.htm

Response:

The Worley Parsons auxiliary power estimate for CCS, as provided in the June 2013 application update, reflects the high auxiliary power required to compress CO_2 for EOR or storage. A higher amount of auxiliary power is required to compress CO_2 than to recover CO_2 for additional methanol production, which is not an option for the combined reformer process at the Celanese methanol unit. The MEA system would require approximately 3.959 MW of electricity for operation of pumps and air coolers. An additional 4.218 MW would be required for CO_2 compression. These values are estimated based on the equipment that was determined to be required to implement CCS by Worley Parsons. Therefore the estimated auxiliary power needed to operate the CCS is roughly 8.177 MW per hour, not 9 MW per hour as the commenter has stated. The Region has no reason to doubt the electrical demand that was estimated by Worley Parsons to be accurate. Celanese has indicated that the most cost effective cooling method is air cooling if CCS was implemented.

For the majority of Texas, ERCOT manages the electricity market. The price of electricity per megawatt can vary significantly between seasons, weather, fuel costs, and peak demand periods in the ERCOT grid. Data derived from the Federal Energy Regulatory Commission which cited Platts data indicates that the 5-year average (2007-2011) day ahead energy price was slightly greater than $50 per MWh.[9] This is consistent with U.S. Energy Information Administration and ERCOT Houston (a major electricity trading hub) data showing 2013 prices spiked to $48.85/MW-hr in May.[10]

The Worley Parsons study was available during public notice and estimated the electrical requirements for an air cooling system instead of a water cooling system. The commenter assumes that an air cooling system is less energy efficient than a water cooling system, which can be true depending upon the industrial process, location, and cooling needs. However, the commenter should not assume that a water cooling system would be less expensive for this specific site. The electrical demands for water cooling system equipment, including cooling tower fans and pumps, would be similar to the electrical demand of air cooling system equipment Installation of a water cooling system at the site would require upgrades to the current facility's water system such as additional piping and water clarification systems which would result in additional costs if a water cooling system were considered. A water cooling system would require the construction of a cooling tower, a new clarifier, sand filter, and other associated equipment. The addition of this equipment would be approximately $3 – 5 million dollars more than the cost of air cooling.[11] Although these additional costs were not included in the Worley Parsons study supporting the permit application, the commenter had an opportunity to comment during the public comment period as both our Statement of Basis (pg. 11) and the Worley Parsons study in the permitting record identified the air cooling system as part of the need for additional electrical supply for the MEA system. We have provided a response to the comment responding directly to the basis for use of an air cooling system instead of a water cooling system for this specific project.

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[9] http://www.ferc.gov/market-oversight/mkt-electric/texas/2012/11-2012-elec-tx-archive.pdf
[10] http://www.eia.gov/electricity/wholesale/
[11] Phone call between Aimee Wilson and Ashley Duffie on December 3, 2013. Ms. Duffie indicated that water cooling would add $3-5 million to the cost of CCS over air cooling.

Comment 14: 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 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. Therefore, there is no basis to inflate the contingency estimate. The standard contingency factor used in a cost effectiveness analysis, when it is included, is 3% of purchased equipment cost. Thus, Sierra Club revised the contingency in our analysis to use 3% of fully loaded capital costs. See Exhibit 1, Cells F60 and H60.

Response:

The contingency factor is reasonable in this case where CCS technology has not been demonstrated for a methanol production process utilizing a combined reformer (which would make it experimental) and the potential unknown additional costs that might have to be absorbed to make CCS viable in this type of methanol reforming process. It is not unusual for experimental construction projects to have higher estimated contingency costs when compared to known demonstrated processes that have been previously constructed.[12] We do agree that CO_2 is being captured in some single stage reformer processes where it can be reintroduced into the production process to increase methanol production. As noted earlier in response to comment 11, the creation of the excess hydrogen in the single reformer design does allow for the potential recovery of CO_2 and reintroduction into the process to create more methanol. The combined reforming process that Celanese has proposed does not produce excess hydrogen in sufficient quantities to allow for the recovery of CO_2 to produce more methanol.

Additionally, although the commenter states that CO_2 capture systems may be "widely used in many applications", typical applications for amine system and compressor stations are for vents with higher pressure and lower nitrogen concentrations than the proposed Celanese methanol plant. The Celanese cost estimate does not include any additional equipment required to meet the CO_2 specifications required by Denbury (or another EOR CO_2 receiver). In addition, the estimate for the boiler did not include infrastructure upgrades that would require further evaluation including the demineralizer and other miscellaneous utility systems. Therefore, a 16.5% contingency is not excessive for estimating the potential construction costs of a CCS system for Celanese's proposed project

Comment 15: 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

[12] https://www.directives.doe.gov/directives/0430.1-EGuide-1-Chp11/view

and E57) No support is provided for this very high labor rate, and many public sources demonstrate that this rate is excessive.

Response:

Celanese submitted additional information on September 24, 2013 and November 8, 2013, and clarified the Worley Parsons technical study submitted with the revised Celanese (June 2013) permit application which used a $90 per hour labor rate. In addition to the contractor hourly wages (i.e., $27.10/hr), Celanese produced a comprehensive hourly labor cost estimate that included contractor benefits and burdens, small tools and consumables, temporary construction facilities, third party rental equipment, travel per diem, overtime premium, overhead project, and overhead for purchased materials.

Comment 16: 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, 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).

Response:

Requiring CCS for this facility would require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and prospective business development of a customer(s) who is willing to purchase the CO_2. It is not reasonable to assume that the right-of-way to construct a CO_2 pipeline from Celanese's Clear Lake facility will be a direct straight line to the Denbury tie in. Celanese used a factor of 2 to account for uncertainty in the right of way, path of pipeline, or tie in points. Additionally, the costs associated with the pipeline account for only 5 percent of the total annualized costs associated with CCS. Therefore the pipeline costs do not significantly impact the cost effectiveness.

Comment 17: The Worley Parsons cost analysis made a number of simplifying assumptions that overstate 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 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. 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. CO_2 capture systems are used at other methanol plants to increase production and the potential increase in production should be considered here.

Response:

The cost analysis for the MEA system evaluation was to determine if CCS would be viable economically. It was not to provide detailed design cost analyses. It is not reasonable to require Celanese to commit to a specific amine system design or manufacturer's technology as part of a BACT cost estimate as an add-on control. We would expect that if CCS were selected as BACT that the Permittee would then determine the most appropriate technological design and vendor to satisfy the terms/conditions of the permit. The CCS boiler was provided with an economizer. In addition, Celanese did include an extensive process-to-process heat exchange system design within the MEA system. Celanese did not evaluate preheating or economizing the feed gas because there was not enough heat value in the stream to make it economically viable. The costs of a generic MEA process provided in the application was reasonable for the BACT analysis. As mentioned previously in our response to Comment 13, the electrical demands for water cooling system equipment, including cooling tower fans and pumps, would be similar to the electrical demand of air cooling system equipment. Additionally, water cooling would require upgrades to the site's water system (such as additional piping and upgrades to water clarifying systems), resulting in additional costs that were not included in the CCS cost estimate..

We are aware that other methanol production facilities recover CO_2 from the single reformer design which allows for the creation of excess hydrogen and waste gases. The creation of the excess hydrogen in the single reformer design does allow for the potential recovery of CO_2 and reintroduction into the process to create more methanol. The primary reformer in a combined reforming plant requires significantly less heat input than does the reformer in a single reforming process. Another effect of using the combined reforming process is that excess hydrogen is not produced, at least not in sufficient quantities to allow for the recovering of CO_2 to produce more methanol. In addition, the combined reforming manufacturing process is more efficient than the single reformer manufacturing process in that it produces a synthesis gas that has a more optimum composition for methanol production. As noted earlier, Celanese's proposed process will still emit less tons of CO_2 on a tons per methanol produced basis than the recently permitted single reformer facilities, even less than those facilities that are partially recovering CO_2 and reintroducing it into their process to produce additional methanol. In conclusion, Celanese's project utilizing a combined reformer will produce approximately 0.37 tons of CO_2 per ton of methanol produced. Recently issued permits for single reformer projects range from approximately 0.83 – 0.92 tons of CO_2 per ton of methanol produced. Celanese's proposed manufacturing process will result in a more efficient methanol production operation on a CO_2 per ton of methanol produced basis.

Comment 18: 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 regenerate the MEA. 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.

Response:

As noted in other portions of our response, the new steam system is necessary to operate a functional CCS system capturing 90% of the combined reformer flue gas. The only way to increase the amount of CO_2 captured from the proposed project is to capture CO_2 from the new steam system used to operate the amine regenerator which in turn would create additional costs not factored into the application's analysis. We disagree that if CCS is being evaluated as an add-on control for the project that the total economic costs, energy needs, and environmental impacts of potentially recovering this CO_2 stream should not be considered as part of the economic considerations for this project which would include the cost to construct and operate the boiler. We've elected to treat the entire CCS system from carbon capture, MEA regeneration, energy needs, compression, and storage in the overall economic or cost consideration for BACT. Doing otherwise, would not fully account for the prospective economic, energy, and environmental impacts of applying CCS as a control option for this project. Our analysis indicates that Celanese in its application was simply trying to depict the trade-off emission impacts if CCS were selected as an add-on control for BACT for the project.

The comments regarding the need for a boiler appear to relate primarily to capital expenditures (e.g., the need for a dedicated boiler) and the operation and maintenance (O&M) costs. We find the need for the additional boiler to be unremarkable and adequately supported by the fact that significant steam requirements apply to the regeneration of MEA solvent that would be utilized in CO_2 capture. Sufficient and reliable quantities of steam and power are particularly important for the contemplated continuous use of CCS (which is energy intensive). In sum, we do not agree the cost estimation for a boiler requires additional record justification, and Celanese's representations regarding the need for the boiler are not lacking in credibility. In any event, we note as a final matter that the capital expenditures for the boiler are little more than 9 percent of total estimated costs, and we see no potential that additional documentation on the boiler would change our overall conclusions regarding the selection of BACT without application of CCS.

Comment 19: The CCS costs do not include estimated revenue from the sale of CO_2 for EOR or tax credits that may be available. At the low end market price of CO_2 is "$6/ton." The Region must correct the CCS cost analysis to include a reasonable projection of revenues from CO_2. 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. Estimates of the market price of CO_2 for EOR are around \$33 per ton. Even without EOR, CO_2 has a market value of between \$5-\$20 per ton. 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). 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.

Response:

We acknowledge the commenter's suggestion that this administrative record may benefit from a discussion of whether revenues from sales of captured CO_2 may be possible, and if so, whether those revenues could be appropriately applied in the BACT cost analysis to partially offset the estimated cost of GHG controls. We acknowledge, as stated in the GHG Guidance, that there may be cases where the economics of CCS may be more favorable, an example being where "the captured CO_2 could be readily sold for enhanced oil recovery." GHG Guidance at 43. In developing cost estimates for CCS, it would have been prudent for Celanese to have addressed whether captured CO_2 may be sold. However, even assuming market demand exists for Celanese's CO_2 stream, we do not necessarily agree with the commenter that "\$33/ton" is a conservative estimate or that revenues from sales for enhanced oil recovery could be maintained for the life of the project. Various published reports or studies cite the prospective purchase price of CO_2 for enhanced oil recovery to range from as low as \$15 to as much as \$45 per metric ton. The price may vary widely depending upon the price of oil per barrel and the availability of CO_2 in or near the particular oil production field. Ultimately a price would have to be negotiated between Celanese and a prospective contractual partner and the price could be less than the assumed estimates above on a cost per metric ton basis. In addition, EPA's proposed NSPS for EGUs for emissions of CO_2 (signed on September 20, 2013) projected costs for supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) units with no CCS (i.e., units that would not meet the proposed emission standard) and for those units with partial capture CCS installed such that their emissions would meet the proposed 1,100 lb CO_2/MWh standard. EPA also included costs for those same EGU units when EOR opportunities are available in the proposed NSPS. EPA included a "low EOR" case assuming a low EOR price of \$20 per ton of CO_2, and a "high EOR" of \$40/ton. These EOR price estimates are net of the costs of transportation, storage, and monitoring (TSM).

Assuming Celanese had a client or partner willing to purchase CO_2 for enhanced oil recovery, and further assuming Celanese could recover approximately 90 percent of its CO_2 emissions from the reformer furnace (435,003 metric tons/479,508 short tons),[13] the potential revenue at \$15 per metric ton would be approximately \$6.5 million per year. Assuming a low EOR price of \$20 per ton and a high

[13] Note that in the NSPS proposal referenced above, EPA proposed a standard based on partial CCS – i.e. less than a 90% capture rate.

EOR purchase price of $40 per ton as projected in EPA's proposed NSPS, these projected purchase prices would only generate approximately $9.6 million and $19.2 million respectively. Celanese estimated that its annual operating costs for CCS including capture, transport (and/or storage) would be $34.4 million for full-scale CO_2 capture, transportation, and geologic sequestration. Even if Celanese could generate $9.6 million in revenue from CO_2 sales, this revenue would only cover approximately 28 percent of the estimated annual operating costs for add-on CCS controls. Assuming the high EOR price of $40 per ton would yield potential revenues of approximately 56 percent of the annual operating costs, this still would not appear to make CCS economically viable for this project.

In addition, just because a company can recover CO_2 does not mean they have a contractual customer or partner willing to purchase the CO_2. The commenter first assumes that Denbury Resources would purchase Celanese's captured CO_2 emissions, but there is no evidence that this is the case. Furthermore, requiring CCS for this facility would require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and prospective business development of a customer(s) who is willing to purchase the CO_2.

The commenter also raises the issue of tax credits for conducting CCS. The Internal Revenue Service program for *Credit for Carbon Dioxide Sequestration Under Section Q45* allows qualified facilities to claim the credit where at least 500,000 metric tons of qualified CO_2 is captured during the taxable year. As an initial matter, without guidance to the contrary, we do not agree that these discussed tax credits are "critical," or even necessarily relevant, to calculated cost effectiveness. The inclusion of a subsidy would not likely be appropriate for a cost analysis, unless income taxes were included in the analysis. Income tax cost considerations were not used in the cost study submitted by Celanese, and we think the long-term uncertainty, speculativeness, and over-complexity of these considerations would make it advisable to exclude them from consideration in the BACT analysis.[14]

In any event, the available credit is $20 per metric ton of qualified CO_2 that is captured and disposed of in secure geological storage; and $10 per metric ton of qualified CO_2 that is captured and used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project (EOR project). Celanese's Clear Lake project permitted potential to emit in short tons would be equivalent to approximately 435,003 metric tons of CO_2 (reformer furnace only). Celanese would not recover enough CO_2 from the reformer furnace at a 90% capture rate to be hypothetically eligible for the tax credit. Even if Celanese could recover 500,000 metric tons of CO_2 per year, it would arguably represent approximately $15 million in value (assuming $20 per ton revenues for CO_2 sale and $10 metric ton business tax credit reductions in tax liability = $30 X 500,000 metric tons). There is no guarantee that Celanese could recover enough CO_2 to qualify for either tax credit since they do not generate the required volume of CO_2 from the reformer furnace. Even assuming it were appropriate to consider these speculative offsets

[14] This judgment is consistent with that reflected in the New Source Review Workshop Manual (Draft 1990) and the EPA Pollution Control Cost Manual (2002), which the commenter has otherwise cited as support (see, e.g., comment 9 and 10 of this RTC). From the NSR Workshop Manual, p. b.11: "Income taxes…are not properly part of economic costs." From the Control Cost Manual: "…subsidies…distort how the direct application of a tax works. Therefore, this Manual methodology does not consider income taxes.")

in the cost analysis, we do not think they would be sizeable enough to make the cost of CCS economically feasible for this project (taking a total annualized cost of more than $34 million dollars per year into account).

Comment 20: 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 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, which equals about $6/ton. 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. 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. 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 CCS from $25/ton to approximately $19/ton and could potentially offset the entire cost if Celanese received the upper end of the range of CO_2 value.

Response:

It cannot be assumed that if Celanese constructed a CCS system to recover CO_2 they will have a contractual customer or partner willing to purchase the CO_2. The commenter first assumes that Denbury Resources would purchase Celanese's captured CO_2 emissions, but there is no evidence that this is the case or that Denbury's current business plans would require additional CO_2 purchases in the Gulf Coast region. Regarding the comment that a recent US DOE report placed a $45 per ton as the market price for CO_2, it should be noted that the price of CO_2 may vary from one oil production area to the next based on demand, and differences in EOR geological/basin production characteristics. In other words, the price paid in one EOR production area may not be the same as the price paid in another. As an example, the price could vary on a per ton basis between the Gulf Coast region and the Permian Basin region of Texas simply due to demand and production basin/production formation characteristic differences. Furthermore, requiring CCS for this facility would require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and prospective business development of a customer(s) who is willing to purchase the CO_2. This price may vary significantly if the construction is occurring in metropolitan areas versus rural areas. In conclusion, as noted in our response to Comment 19, assuming the high EOR price of $40 per ton in EPA's proposed EGU NSPS would yield potential revenues of approximately 56 percent of the annual operating costs; this still would not appear to make CCS economically viable for this project.

Comment 21: 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.

Response:

If the CO_2 captured was sold, then the cost of geological storage would not need to be included in the cost analysis for CCS. Celanese provided an updated CCS cost analysis on November 8, 2013 that eliminated the geological storage costs assuming that the CO_2 could be sold for EOR. The elimination of geological storage reduced Celanese's annual cost estimate for CCS from $34,371,913 to $25,439,489. Geological storage accounted for $362,011 a year in capital costs. Even without the cost of geological storage, the addition of CCS would still increase the capital cost of the project by more than 25% since the capital costs would remain essentially the same for the amine treating, compression, boiler, electrical upgrades, and offsets needed to implement CCS. This would not change our conclusion that CCS is economically infeasible for this project.

Comment 22: 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, such as those from the Clear Lake Plant, are not a valid basis to reject CCS as BACT.

Response:

EPA has stated that the costs associated with direct energy impacts should be calculated and included in the economic impacts analysis (see GHG Guidance at 39), and Celanese's cost study for CCS (citing fuel costs in operating expenses and including the capital costs for a boiler) is consistent with this guidance. However, this does not mean applicants and permitting authorities should not continue to examine whether the energy requirements for each control option result in any significant or unusual energy penalties or benefits. Where such energy impacts are identified, they should be discussed in the record. In this case, the Statement of Basis accurately noted the added energy and fuel requirements of CCS, which is well substantiated in the underlying record. The energy intensity of the process to purify and compress a CO_2 stream is widely known and not questioned, in any case, and may be particularly high for larger streams with comparatively low CO_2 concentrations, as is the case here. However, since energy impacts are not the basis for EPA's elimination of the CCS option in this case, we need not, and do not, reach a judgment here as to whether the energy consumption demands from applying CCS to Celanese's project would be significant or unusual in the context of this permit or as a general matter.

On the issue of environmental impacts and the noted ozone precursor increases, we first note the commenter did not provide the full quotation from the Draft NSR Workshop Manual. Read in its entirety, the statement only clarifies that the environmental impacts analysis and air quality impacts analysis are separately required and that neither of them should be overlooked when they are applicable: "The environmental impacts analysis is not to be confused with the air quality impact analysis (i.e., ambient concentrations), which is an independent statutory and regulatory requirement and is conducted separately from the BACT analysis." NSR Workshop Manual at B.49. This does not mean, as the comment suggests, that other air pollutant emissions may not be studied or referenced when considering environmental impacts in Step 4 of a top-down BACT analysis. In fact, such an assertion is contradicted by language in the same paragraph: "…[T]he environmental impacts portion of the BACT analysis concentrates on impacts other than air quality (i.e. ambient concentrations) due to emissions of the regulated pollutant in question…." Id (emphasis added); See also GHG Guidance at 39-41[15] and NSR Workshop Manual at B.49. The GHG Guidance (with specific reference to the scenario where a control technology for one regulated NSR pollutant would lead to increases of other regulated NSR pollutants) states that permitting authorities have flexibility in deciding how to weigh the trade-offs associated with emissions control options. See GHG Guidance at 41**.** Thus, we disagree that any additional emissions of air pollutants that may be attributed to the use of a control option cannot be validly considered as part of the statutory requirement to consider "environmental…impacts." CAA section 169(3). The collateral increases of other air pollutants (other than the one that is "in question" for a BACT limit) are certainly a type of "environmental impact." It therefore is reasonable for EPA to consider potential increases in ambient levels of ozone attributable to CCS, were the project to include such GHG control.

In conducting the energy, environmental and economic impacts analysis, permitting authorities have "a great deal of discretion" in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration.[16] As earlier noted, this includes weighing trade-offs of increases in other non-GHG pollutants. When weighing any trade-offs between emissions of GHGs and emissions of other regulated NSR pollutants, EPA focuses on the relative levels of GHG emissions rather than the endpoint impacts of GHGs. We believe it is appropriate to focus on the amount of GHG emission reductions that may be gained or lost by employing a particular control strategy and how that compares to the environmental or other impacts resulting from the collateral emissions increase of other regulated NSR pollutants. EPA did so in this case by evaluating the collateral increases of non-GHG pollutants that would occur if CCS were employed at the site. We indicated in our Statement of Basis that implementation of CCS would result in an increase in NOx, CO, VOC, PM_{10}, and SO_2 emissions. In addition, we believe that because the facility is located in an existing ozone non-attainment area [Houston, Galveston, and Brazoria (HGB) non-attainment area], the generation of additional NOx and VOCs (that is not otherwise offset) would potentially exacerbate ozone formation in the area. The State of Texas has made significant progress in reducing ozone levels in the Houston area. If given the option of selecting energy efficiency measures as part of our BACT determination in this specific case or

[15] For example: "…[I]n selecting the BACT limit for carbon monoxide (CO) for a facility in an area that is nonattainment for ozone, a permitting authority may need to assess whether it is more important to select a less stringent control for CO emissions to avoid an unacceptable increase in NOx emissions associated with the CO control technology." p. 40.
[16] *In re Hillman Power*, 10 E.A.D. at 684.

potentially increasing non-GHG pollution from the project by as much as 11 percent by requiring add-on CO_2 controls, we determined that in this case requiring add on controls for CO_2 would not be a beneficial outcome for the Houston, Galveston, and Brazoria (HGB) non-attainment area. Although this factor, by itself, is not decisive, nonetheless it supports the decision that there are adverse cost and environmental implications of requiring a BACT limit based on use of CCS, such that EPA is not requiring that level of control.

Comment 23: 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, PM_{10}, and SO_2 from burning fuel to supply steam.

Response:

We disagree and have provided our analysis on the need of a new boiler in support of CCS in response to Comments 8, 9, and 10 above.

Comment 24: 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 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), 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), 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. 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.

Response:

We consider the value of 27.2 MMBtu/ton proffered by Sierra Club as reflecting the SEC of "the most efficient methanol process" to be of problematic utility to this permitting action. This figure does not represent an actual SEC value for an actual operating plant for which the configuration and reformer design can be compared to the proposed project to assure a meaningful comparison. Because the large variation in plant configurations, output capacity, and reformer design greatly influences the SEC value, we do not believe this measurement allows for useful comparisons among otherwise dissimilar projects or promotes a firm understanding of an individual project's efficiency.

Celanese's proposed process for methanol production at the Clear Lake Plant is more efficient and will emit less CO_2e both on total emissions and on a ton of CO_2e/ton MeOH produced, than three methanol facilities recently permitted in EPA Region 6. Estimated emissions for the facilities are shown in the table below.

Facility	MeOH Production (tpy)	CO_2e Emissions (tpy)[a]	Ton CO_2e/ton MeOH
Celanese – Clear Lake Plant	1,433,000	535,218	0.37
Equistar – Channelview Plant	903,156[b]	831,675	0.92
Methanex – Geismar Plant	1,206,690[c]	999,613	0.83
Lake Charles Clean Energy - Leucadia	2,930,000	5,840,387	1.99

[a] Based on permitted CO_2e emissions

[b] Based on 273 million gallons/yr and 0.7918 g/cm^3

[c] Based on 3,000 metric tons/day

Comment 25: 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 common events and must be addressed through appropriate planning to minimize emissions. *RockGen*, 8 E.A.D. at 553 (citing EPA guidance).

Response:

The exclusion of startup, shutdown, and maintenance related emissions from the BACT limit for the reformer furnaces was in error. The BACT limit will be met during all operations, and does not permit malfunctions. Emissions from malfunctions and upset events must be reported as excess emissions as stated in the permit at Special Condition I.D.1. through I.D.3. and IV.A.4.

The permit has been revised as follows:

> The Permittee shall maintain a minimum overall efficiency of 30 MMBtu (HHV)/ton methanol produced on a 12-month rolling average basis, calculated monthly, for the furnace (REFORM) ~~ex~~including periods of start-up, shutdown, and ~~malfunction~~ maintenance.

III. Revisions in Final Permit

The following is a list of changes for the *Celanese Clear Lake Plant (PSD-TX-1296-GHG) Prevention of Significant Deterioration Permit, Final Permit Conditions*.

1. Section III.A.1.q. Special Permit Conditions for Reformer Furnace
   Special Permit Condition III.A.1.q. was revised as follows:

   The Permittee shall maintain a minimum overall efficiency of 30 MMBtu (HHV)/ton methanol produced on a 12-month rolling average basis, calculated monthly, for the furnace (REFORM) ~~ex~~including periods of start-up, shutdown, and ~~malfunction~~ maintenance.

This change was made to correct an error. The BACT limit of 30 MMBtu/ton of methanol produced applies at all times.

IV. Endangered Species Act (ESA)

EPA determined that issuance of the proposed permit will have no effect on twelve (12) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area. Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS was needed.

V. National Historic Preservation Act (NHPA)

EPA determined that because no historic properties are located within the area of potential effect (APE) and that a potential for the location of archaeological resources is low within the construction footprint itself, issuance of the permit to Celanese will not affect properties on or potentially eligible for listing on the National Register. On June 26, 2013, EPA sent a letter to the State Historic Preservation Officer (SHPO) requesting concurrence on EPA findings for Celanese's cultural survey. The SHPO sent a letter with concurrence to the EPA on July 31, 2013.