July 8, 2013

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RE: ExxonMobil Baytown Olefins Plant –Permit No. PSD-TX-102982-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 *Draft Prevention of Significant Deterioration Preconstruction Permit for Greenhouse Gas Emission* for the ExxonMobil Chemical Company Baytown Olefins Plant (Baytown Plant) are based off of publicly available materials, including the May, 2013 Statement of Basis (SOB) prepared by EPA Region 6 (the Region), the draft permit, the permit application and the applicant's response to questions from the Region.

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 Baytown 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 carbon capture and sequestration (CCS)

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technologies. A recent study completed by the U.S. Geological Survey concluded that the Gulf Coast, or "Coastal Plains" region, contains 65 percent of the country's estimated accessible carbon storage resources.[1] New facilities in Texas, such as the Baytown Plant, have a unique opportunity to develop these storage resources and substantially lower their GHG emission profiles. These comments address the GHG PSD draft permit for the Baytown Plant.

The Baytown 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. ExxonMobil estimates that the Baytown Plant will potentially result in GHG emissions increase of 1,479,665 tons per year (tpy) of CO_2e. The proposed Baytown facility would add eight new steam cracking furnaces and recovery equipment at the existing olefins plant in Baytown. The Baytown 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 Baytown Plant. The Region's draft permit and these comments address only GHG related issues.

A. The Permit Should Include an Emission Rate Based on the Production of Ethylene at the Facility

The draft permit should include an emissions rate indicating tons of CO_2e emitted per ton of ethylene produced. Condition II of the draft permit only establishes annual CO_2e emission limits on a 12-month total, rolling monthly, for the Baytown Plant. The total annual plant limit is 1,479,665 tpy CO_2e, and the largest component of the limit is 987,968 tpy CO_2e from the eight new steam cracking furnaces. This annual emission limit does not, by itself, ensure that the plant is operating at the most efficient achievable level. The Region should estimate what an efficient production level should be and include as a permit condition an output-based emission limit that requires efficient production based on the tons of CO_2e generated per ton of ethylene produced. This calculation would provide an emission rate metric similar to the pounds per megawatt hour metric used for power plants, and it would allow for an apples-to-apples comparison between different production facilities to ensure that permitted limits require the best achievable efficiencies at different facilities.

Other similar olefin production facilities use this type of output-rate emission metric. For example, the INEOS Olefins facility cited in the SOB at page 12 includes an emission limit of 0.85 pounds of GHG per pound of ethylene.[2] Similarly, a 2006 review of ethylene production efficiency expressed a "typical" output rate for ethane-based production using a metric with tons

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[1] 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, 41 p., http://pubs.usgs.gov/circ/1386/
[2] INEOS Statement of Basis, Table 1 indicates 0.85 lb CO_2e/lb ethylene. Available at: http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/ineos_sob08232012.pdf

of CO_2 emitted per ton of ethylene produced.[3] In contrast, the draft permit for the Baytown facility does not have a production based emission rate. Based on the annual emission limit, the facility would emit CO_2e at a higher rate per ton of ethylene produced than the INEOS plant. The application and the SOB do not directly address the output rate of the Baytown Plant; however, the applicant's responses to the Region's January 29, 2013 questions, item #4, indicates the project is estimated to produce 1.5 million metric tons of ethylene per year.[4] This equates to 1.65 million short tons.[5] The production efficiency of the Baytown Plant is therefore 1,479,665 tons CO_2e emitted annually per 1,650,000 tons of ethylene produced. This equates to 0.90 tons of CO_2e per ton of ethylene, which is less efficient than the 0.85 rate at the INEOS plant.

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. In this case, at the very least the INEOS plant is more efficient than the Baytown Plant, but there is no analysis or explanation as to why the Baytown Plant cannot meet this lower emission rate that is achievable at a similar facility. The Region should conduct a BACT analysis based on the emission of tons of CO_2e per tons of ethylene produced and require the Baytown Plant to meet a rate of at least 0.85 tons CO_2e/ton ethylene and perhaps lower, depending upon the results of the specific energy consumption evaluation discussed below.

B. The Draft Permit Does not Require the Most Efficient Processes

The draft permit does not require the Baytown Plant to use energy efficient processes. Section 4.2.1.3 of the application asserts that the cracking furnaces, the primary source of GHG emissions, use an energy efficient design. (Application at p. 4-3) However, the application fails to present any information to allow an independent assessment of this claim, and the draft permit does not include any conditions requiring the use of energy efficient design. Based on the information provided, the Baytown Plant appears to be an inefficient production design compared to other facilities.

Vendor literature for cracking furnaces indicates that innovations over the last twenty years have reduced CO2 emissions by 30 percent using furnaces that achieve greater than 95 percent

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[3] Typical output-based emissions in the survey ranged from 1.0-1.2 tons CO_2/ton ethylene. *See*, Ren et al., Olefins from Conventional and Heavy Feedstocks: Energy Use in Steam cracking and Alternative Processes, Energy, v. 31, 2006, Table 2. Available at: http://igitur-archive.library.uu.nl/chem/2007-0621-201429/NWS-E-2006-3.pdf

[4] http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-olefins-resp01312013.pdf

[5] The draft permit and SOB are not consistent with ExxonMobil's response. The draft permit at page 2, states: "the new ethylene unit will increase the production capacity of the plant by approximately 2 million metric tons per year of polymer grade ethylene." Similarly, the SOB states that the modification will add "approximately 2 million metric tons per year of ethylene produced." SOB, p. 4. It appears the Region rounded up the 1.5 million metric tons to 2 million metric tons. These comments assume production of 1.5 million metric tons as indicated by the applicant.

thermal efficiency.[6] Neither the application nor the SOB address the thermal efficiency of the Baytown Plant's furnaces. Based on Sierra Club's calculations, presented below, the Baytown Plant's proposed furnaces as contemplated in the draft permit are less efficient than 20 year old designs and thus do not satisfy BACT.

A common measure of energy consumption for ethane cracking is the specific energy consumption (SEC) per ton of ethylene produced. Modern plant values for SEC are 14 GJ/tonne of ethylene for ethane cracking (13 MMBtu/ton, HHV).[7] The SEC for the Baytown Plant is not reported in the record for this case. However, the data provided allow for an estimate by backing into the calculation.[8] The draft permit allows eight cracking furnaces, each with a maximum design heat input of 515 MMBtu/hr and duct burners with a combined maximum design heat input of 773 MMBtu/hr (HHV). (Draft Permit at p. 2) Thus, the total annual heat input to produce 1.65 million tons of ethylene from ethane is 42,862,680 MMBtu/yr.[9] The corresponding SEC rate is therefore 26 MMBtu/ton. This rate is much higher than the 13 MMBtu/ton SEC that modern plants can achieve.[10]

Energy efficiency is a critical component of the BACT analysis, particularly for GHGs. EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* is clear on this point: "Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews."[11] The energy efficiency of a technology is fundamental to the BACT determination. "Initially, in many instances energy efficient measures may serve as the foundation for a BACT analysis for GHGs, with add-on pollution control technology and other strategies added as they become more available."[12] In this case, in addition to considering add-on technologies such as carbon capture and sequestration (CCS), the Region must first establish the BACT limit foundation by setting the limit based on the most energy efficient production design. "When a permit applicant proposes to construct a facility using a less efficient boiler design…a BACT analysis for this source should include more efficient options."[13] In this case, ExxonMobil is proposing to construct a facility with a less efficient SEC than other modern facilities.

The application does not provide any support for ExxonMobil's assertion that the facility "will use a proprietary furnace design to minimize its carbon footprint."[14] To the contrary, the Baytown Plant's proposed ethylene production project is not nearly as efficient as other modern plants. The Region must therefore revise its BACT analysis to fully disclose the efficiency of the various project components and include a review of more efficient options. The revised BACT

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[6] *See, e.g.,* Technip, Ethylene Productgion, October 20, p. 10, Available at: http://www.technip.com/sites/default/files/technip/publications/attachments/Ethylene_October_2012_9.pdf

[7] See review in: E. Worrell and others, Energy Use and Energy Intensity of the U.S. Chemical Industry, Lawrence Berkeley National Lab Report LBNL-44314, Sec. 3.3, April 2000, Available at: http://www.energystar.gov/ia/business/industry/industrial_LBNL-44314.pdf

[8] The Region should not rely only on this estimate. The Region should require ExxonMobil to produce its own calculations and submit a revised draft permit for public comment and review.

[9] Annual heat input = (8x515 + 773)x8760 = 42,862,680 MMBtu/yr.

[10] *See supra,* note 7.

[11] *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p.29.

[12] *Id*.

[13] *Id*.

[14] Application at p. 4-3.

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analysis should also fully explore other widely recommended efficiency measures disclosed elsewhere that are not even mentioned in the record for this case.[15] Finally, the draft permit should include a limit on specific energy consumption (SEC) rate in order to provide a direct measure of energy efficiency and corresponding GHG emissions.

C. The Cost Analysis for Carbon Capture and Sequestration is Invalid

Carbon capture and sequestration (CCS) is a process that removes CO_2 from flue gas where it is then transported to an appropriate storage location, most likely underground in a geological storage reservoir such as a deep saline aquifer or a depleted oil well or coal seam. The Region identified CCS as a feasible control technology in step 2 of the BACT analysis. (SOB at p.9) However, based on the application and follow-up responses from ExxonMobil, the Region rejected CCS in step 4 on the grounds that CCS would cost $205 million annually, which the Region claimed would be "prohibitive in relation to the overall cost of the proposed project." (SOB at p.10) The Region's CCS conclusions are invalid.

1. The Region Failed to Consider Offsets to the Cost of CCS

CO_2 has a market value for use in enhanced oil recovery (EOR) or other uses. The costs of carbon storage can be offset by EOR revenues where available.[16] Estimates of the market price of CO_2 for EOR are around $33 per ton.[17] Even without EOR, CO_2 has a market value of between $5-$20 per ton.[18] 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 ExxonMobil 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.

ExxonMobil failed to account for the relative advantages and market opportunities that the Baytown Plant has to sell CO_2. The applicant's October 16, 2012 responses to the Region note that the Denbury Green Pipeline is only 30 miles from the Baytown Plant. (October 16, 2012 Responses at p. 22) Denbury Resources uses CO_2 in enhanced oil recovery, but the analysis does not include any information on the potential market value that Denbury Resources would offer for the purchase of the Baytown Plant's captured CO_2. The analysis also does not consider other potential markets for the sale of CO_2 for other industrial applications. Any potential sale value of

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[15] See, e.g., Maarten Neelis, Ernst Worrell, and Eric Masanet, Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry, June 2008, Lawrence Berkeley National Lab Report LBNL-964E. Available at: http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf?28f1-c5cb

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

[17] *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

[18] *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

CO_2 would offset the cost of CCS for the Baytown Plant and should be reflected in the cost effectiveness analysis. Finally, as noted above, ExxonMobil did not include any analysis of tax savings or credits that could be realized under Internal Revenue Code Section 45Q.

2. 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 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."[19] 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).

The ExxonMobil cost effectiveness analysis used an undisclosed and nonstandard cost method and concluded that the result of that calculation renders CCS not cost effective, without making any effort to establish a basis for that determination. ExxonMobil appears to have reached its conclusion by extrapolating from the cost effectiveness value in dollars per ton (which is the proper metric) to total annualized cost and asserting that the annualized cost of $204.6 million is too high. ExxonMobil claimed, and the Region accepted, that this cost would render the proposed project "unviable." (October 16, 2012 Responses, p. 25; SOB at 10) Even if the $204.6 million annual cost estimate were reasonable, which as discussed below it is not, ExxonMobil did not provide any support for the claim that this would render the project "unviable" or that CCS would increase project costs by more than 25%.

ExxonMobil only provided a summary conclusion in a February 13, 2013 email to the Region stating, "[t]he final project costs are not yet determined; however, 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."[20] 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 Baytown 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 Baytown Plant is particularly unsuitable for CCS compared to other facilities, and there is no evidence to support ExxonMobil's assertion that the project would be "unviable." This analysis 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.

The first step in calculating the average cost effectiveness of alternative control options (such as CCS), is for IEPA to correctly define the baseline emission rate. Baseline emission rates are

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[19] NSR Manual, p. B.45.
[20] February 8, 2013 email to Aimee Wilson, Region 6. Available at: http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-baytown-olefins-resp2epa02082013.pdf

"essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions," for the applicant's proposed operation.[21] 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. The SOB merely concluded that the total capital cost compared to the total project cost was too high. This rationale does not meet BACT requirements to reject a technology for adverse economic impacts.

When determining if the most effective pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT on 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 ExxonMobil 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.

In the case of the Baytown Plant, there are few, if any, BACT determinations requiring CCS at a similar facility. The requirement to control GHG emissions in a PSD permit is relatively new, and there is no established threshold for costs-per-ton of GHG controlled that constitutes an adverse economic impact. However, even if ExxonMobil's estimated $253.30 cost per ton of CO_2 removed for CCS at the Baytown Plant was valid, which it is not,[22] that average cost does not necessarily constitute an adverse economic impact. The Region cannot simply reject a feasible technology 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. [23]The Region has made no showing why the Baytown Plant PSD permit should not require CCS. The BACT analysis of CCS must at a

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[21] *See NSR Manual* at B.37.
[22] October 16, 2012 Responses, Table 4-3, p.25. Sierra Club disputes ExxonMobil's cost-per-ton conclusion. The estimated $253.30 /ton of CO2 removed is far too high.
[23] *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).

minimum consider costs at facilities that have deployed CCS to determine whether any unusual or unique circumstances at Baytown warrant rejection of CCS.[24]

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 social cost of carbon estimates range from \$28 up to \$893 per ton of CO_2.[25] These thresholds suggest that CCS at \$253.30 per ton would be a more economic choice compared to higher estimated social costs of carbon. If ExxonMobil properly adjusts its over-inflated cost of CCS, the costs at the Baytown Plant would be even more reasonable compared with the social costs of carbon.

In summary, to reject CCS based on cost-effectiveness at step 4, the Region must determine that the cost of CCS at the Baytown 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 Baytown 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).

3. ExxonMobil's Cost Analysis Is Faulty

The cost analysis that ExxonMobil provided and the Region relied on does not conform to the requirements of a BACT cost effectiveness analysis. The Region must determine cost effectiveness of a control technology to satisfy BACT based on the method set out in the NSR Manual. The analysis provided by ExxonMobil to the Region does not follow the methodology set out in the NSR Manual.

a) Design Basics are Lacking

The ExxonMobil analysis fails to include a description of even the most basic design parameters for CCS. The design basis is fundamental to the BACT analysis. The NSR Manual provides:

> Before costs can be estimated, the control system design parameters must be specified. The most important item here is to ensure that the design parameters used in costing are consistent with emissions estimates used in other portions of the PSD application. In general, the BACT analysis should present vendor-supplied design parameters.

NSR Manual, p. B.33. The NSR Manual goes on to explain that the first step in preparing a BACT cost effectiveness analysis is to determine "the limits of the area or process segment to be costed... This well-defined area or process segment is referred to as the battery limits. The second step is to list and cost each major piece of equipment within the battery limits. The top-down BACT analysis should provide this list of costed equipment. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor…or by a referenced source…" *NSR Manual*, p. B.33; *Steel Dynamics,* 9 E.A.D. at 200 ("where the top

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[24] *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

[25] 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).

pollution control candidate…is found to be inappropriate due to economic impacts, the rationale for the finding should be fully documented for the public record)(internal quotations omitted").

The ExxonMobil cost analysis is missing all of these critical elements. It does not contain the design basis, the battery limits, a list of each piece of equipment and its cost, or the source of the proffered lump-sum cost data for the capture and compression plants, which are the major cost items. The cost estimate, for example, is missing any basis at all, such as process flow diagrams and design drawings; heat, energy and material balances; type and amount of amine; and temperatures, pressures, flows rates, and specific chemical species in the gas streams to be treated.[26]

To thoroughly evaluate the feasibility and the cost of carbon capture on specific emission sources, the applicant must provide the Region and the public with the composition, pressure, and volumetric flow rates of the facility. The cost of capture (normalized to $/ton) is typically driven by the partial pressure of CO_2 in the exhaust stream and the total volumetric flow of gas to determine size of equipment and potential economies of scale. This information can be used to determine the feasibility of capturing a portion of the GHG emissions from the plant. The Region must require a supplemental filing with this information and extend the public comment period to respond to that additional information.

Based on the limited and conclusory information provided by ExxonMobil, it is not possible to evaluate the reasonableness of the CCS cost estimates, nor is it possible to even verify the validity of the design itself. Experience with similar cost estimates, as discussed in more detail below, indicates that ExxonMobil has significantly overestimated the cost of the capture system.

b) Cost Effectiveness Methodology is Incorrect

ExxonMobil used 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",[27] in accordance with the NSR Manual, p. B.35, to assure consistency of BACT decisions made on the basis of cost. The method of determining if a control technology is "cost effective" requires that the cost at all facilities included in the range 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. In the case of the Baytown Plant, the cost estimates in ExxonMobil's October 16, 2012 responses to the Region do not fully explain the procedures that ExxonMobil used in its analysis. However, it is evident from the data that was provided (e.g. costs reported to nearest penny) that ExxonMobil prepared a detailed cost analysis. That analysis was not available for public review. The Region

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[26] See, e.g., typical design basis at
http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/assets/decc/11/ccs/chapter5/5.4-design-basis-for-co2-recovery-plant.pdf
[27] 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.

must require a supplemental filing with this information and extend the public comment period to respond to that additional information. Pending further analysis of that information, Sierra Club makes the following comments based on the information that was available.

(i) Overnight Costs

The Cost Manual procedures specify the use of the overnight costing method, rather than the "all-in" method, which ExxonMobil appears to use. The costs in the application and the pipeline estimates in the supplemental responses to the Region appear to confirm that the "all-in" costing method was used. In the overnight method, the costs quoted by the vendor are used as the overnight capital cost, with no adders for inflation, escalation, allowance for funds used during construction (AFUDC), owners' costs, and other similar adders. The overnight method explicitly excludes adders that have a high degree of uncertainty and generally inflate costs indiscriminately. ExxonMobil's analysis appears to include these types of invalid adders in the CCS estimate.

First, ExxonMobil's costs are presented in 2016 dollars. (October 16, 2012 Responses, p. 23, note 11) These costs therefore include an escalation factor from 2012 to 2016, which is not allowed in the overnight method.

Second, the costs for transport and storage liability are based on the DOE/NETL 2010 Report. (October 16, 2012 Responses, pp. 24-25, notes 12 and 16) The DOE/NETL 2010 Report did not use the BACT cost effectiveness "overnight" method, but rather the LCOE method or Levelized Cost of Electricity.[28] The LCOE method analyzes the cost of generating electricity for a particular system. It is an economic assessment of the cost of the energy-generating system including all of the costs over its lifetime: initial investment, O&M, cost of fuel, cost of capital. It is the antithesis of the BACT overnight method and therefore does not provide a valid foundation for ExxonMobil's cost effectiveness analysis.

The DOE/NETL analysis included costs not allowed in BACT cost effectiveness analyses, including financing costs, owner's costs, royalties, and AFUDC. The DOE/NETL cost analysis also used a 30-year, current-dollar levelized cost estimating method inconsistent with BACT methodology. These costing approaches overestimate costs compared to those calculated using the BACT "overnight method." Cost effectiveness is a relative determination that relies on comparison to costs borne by other similar facilities, calculated using the same method for all facilities in the range considered.

Third, with respect to capture and compression costs, ExxonMobil did not disclose which method it used to estimate those costs, and ExxonMobil did not provide any supporting material for its proposed capital and operating costs. Those capital estimates are discussed in more detail below, but Sierra Club notes that ExxonMobil's cost estimate of $245.7 per ton of CO_2 avoided for capture and compression is substantially higher than the $60-$114 per ton estimate in the DOE/NETL report.[29] The substantially higher ExxonMobil estimates suggest that the Baytown Plant analysis used the same invalid adders that the DOE/NETL report used. Those additions inflate the cost effectiveness value by using an improper, non-compatible costing methodology.

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[28] *See, Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, Appendices p. A-14. Available at: http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[29] *Id.* at p.33.

There is no evidence in the materials provided that ExxonMobil conducted its own cost analysis using the overnight cost method, nor is there any information provided to verify the accuracy of either ExxonMobil's or DOE's broad and unsupported CCS cost estimates. The Region must analyze the cost effectiveness of CCS using the overnight cost method.

(ii) Annualized Capital Costs

Another major flaw in the cost effectiveness analysis is the annualized capital cost factor. ExxonMobil's supplemental responses to the Region are silent on the procedure ExxonMobil used to annualize capital costs. However, back calculation from ExxonMobil's estimates in $/ton in Table 4-1 indicate that the applicant assumed a capital recovery factor (CRF) of 0.2,[30] the same as assumed for flare gas recovery. In other words, ExxonMobil calculated annual costs as 20% of the total capital costs. This is excessive and grossly overestimates cost effectiveness.

The Cost Manual requires the use of a capital recovery factor, calculated from the social rate of interest and the expected equipment lifetime to annualize capital costs.[31] The EPA uses the real treasury interest rate from the Office of Management and Budget (OMB)[32] as the social interest rate. The most recent social interest rate, used by EPA in similar calculations, is 0.8% over a 20 year term. Calculating the annualized capital cost using the Cost Control Manual approach yields a capital recovery factor of 0.0543 (compared to 0.2 used in ExxonMobil's analysis) for the Baytown Plant analysis.[33] This revised capital recovery factor reduces the annual capital cost from $140 million per year claimed by ExxonMobil[34] to $39.9 million. Similarly, the annual unit capital cost is reduced from $173.1/ton to $49.4/ton. This one correction to ExxonMobil's methodology thus reduces the cost effectiveness of carbon capture and compression from $245.7 /ton CO_2 avoided (Table 4-1) to $122/ton CO_2 avoided.[35] This estimate is further reduced by correcting the overstated capital and operating costs for CCS.

c) Capital and Operating Cost Estimates are Overstated

ExxonMobil estimated that annual operating costs for CCS would be $72.6/ton. (October 16, 2012 Responses, p.23) However, that estimate is not supported in the record. For example, the record does not disclose how much amine was assumed, how much power would be required, how much fuel would be required, or the assumed unit cost of any of these utilities. The record is therefore inadequate for meaningful public comment, and the O&M costs cannot be reviewed. The Region must require a supplemental filing with additional information and extend the public comment period to respond to that additional information.

Based on Sierra Club's experience and consultation with others in the field, ExxonMobil's costs appear to be grossly overestimated. For example, the $58.6 million estimated by ExxonMobil for fuel, utilities and amine is far too high. As a comparison, a 2010 report by DOE/NETL on cost and performance baseline for fossil fuel plants estimated total annual O&M

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[30] Capital Recovery Factor (based on 10/16/12 Responses, Table 4-1) = annual capital cost in $/yr ÷ total capital cost in $ = ($173.1/ton CO_2 avoided)(807,163 tons/removed)/(90.6+200.0+127.1+63.8+76.2+177.6) = 0.2

[31] See Cost Control Manual, Chapter 2 at 2-12 to 2-13.

[32] http://www.whitehouse.gov/sites/default/files/omb/assets/a94/dischist-2013.pdf.

[33] Cost Manual, Chapter 2, p. 2-21: CRF = 0.008(1.008)^20/[(1.008)^20-1] = 0.0543.

[34] See October 16, 2012 Responses, Table 4-1: 173.1 $/ton CO_2 * 807,163 tons CO_2 avoided)

[35] 49.2+72.6=$121.8/ton

costs of \$4,599,292 to remove 4.9 million tons CO_2 from a 550 MW coal boiler.[36] This results in a normalized operating expense of \$0.94/ton. After adding compression costs of \$6.33/ton (0.0745 MWh/ton * \$85/MWh) and amine auxiliaries \$2.90/ton (22.4 MW/657 tons per hour * \$85/MWh) and fuel costs of \$18.59/ton, the total cost is approximately \$28.76/ton of CO_2 removed. This example calculation shows that O&M costs should be around \$20/ton to \$30/ton on the high side, including compression costs, which would result in \$16 to \$24 million per year to remove the proposed 807,374 ton/yr from the Baytown Plant.[37] ExxonMobil's costs are much higher without any explanation as to why they are higher.

ExxonMobil assumes that a dedicated utility boiler and cooling tower would be necessary for the CCS process. The analysis does not consider whether integration with existing utilities in place is feasible. The Region should require ExxonMobil to provide support for the assertion that an entire utility plant will be necessary to install CCS.

d) Averaging the Cost Estimates of Separate CO_2 Streams is Misleading

The applicant's cost analysis overstates the operating cost of CCS by lumping together the cost of CCS for the cracking furnaces with the cost of CCS from the additional utility plant that ExxonMobil claims would be necessary. (October 16, 2012 Responses, p.22) Even if a utility plant is necessary, which may not be the case, the utility plant would most likely be simple cycle or combined cycle natural gas fired turbine. This stream would have a lower concentration of CO_2 (4 vol%) than the cracking furnaces (8 - 12 vol%). From both a cost and design perspective, ExxonMobil should not combine these two streams and instead should analyze each process separately.

Capture from the cracking furnaces will have a lower relative cost due to the higher concentration of CO_2 for a given capture rate (shorter absorber column, less fluid circulation per ton of CO_2 captured). By combining the evaluation of a stream with low partial pressure of CO_2 (the utility plant) with the higher partial pressure (cracking furnaces), as ExxonMobil has done in its analysis, the analysis drives up the average cost of capture for the entire facility. Energy requirements, based on second law of thermodynamics analysis, follow a power law. This means that the increase in CO_2 concentration from 4 vol% to 10 vol% represents a significant difference in the costs to capture the different streams.

For purposes of a BACT evaluation, the Region must investigate the feasibility of capturing a portion of the processes if capture of the entire process is disproportionately expensive. In other words, the analysis must consider a tiered evaluation of the cost of capturing CO_2 from each stream. This tiered analysis would allow the Region to consider whether BACT requires CCS on some, but not all, of the Baytown Plant's processes. The Region should require ExxonMobil to

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[36] See Case 10 in *Cost and Performance Baseline for Fossil Energy Power Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*, Nov. 2010. Available at: http://www.netl.doe.gov/energy-analyses/baseline_studies.html Cost estimates in Exhibit 4-30 on page 405:
MEA solvent \$1,105,536 + NaOH \$1,061,704 + H2SO4 \$324,217 + Corrosion Inhibitor \$7,358 + Water \$2,100,477 (conservative estimate assumes allocating all of the water to the capture system) = \$4,599,292.

[37] ExxonMobil does not explain how it calculated 807,374 tons of CO_2 avoided annually in Table 4-3 of its October 16, 2012 Responses. The draft permit indicates that the steam cracking furnaces result in 982,000 tpy CO_2. A removal efficiency of 90%, which ExxonMobil cites, would yield 883,800 tpy CO_2, a 9% difference in removal. By lowering the estimated avoided tons of CO_2, ExxonMobil reduced the overall cost effectiveness estimate for CCS.

separately analyze each CO_2 stream and determine a cost per ton of CO_2 avoided for each successive stream.

e) ExxonMobil Did Not Consider Specific CCS Opportunities in the Region

The cost analysis 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. ExxonMobil appears to have considered only a single destination, the Denbury Pipeline, for the potential storage of CO_2. As noted above, the coastal plains region contains 65 percent 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.

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

4. The Region Improperly Considered Adverse Energy and Environmental Impacts

ExxonMobil asserts that, aside from adverse economic impacts, CCS should be eliminated as BACT based on energy and environmental impacts. (SOB at 10) The Region acknowledges ExxonMobil's position without indicating whether it agrees with ExxonMobil that energy or environmental impacts provide an independent basis to reject CCS as BACT. However, the NSR Manual makes clear that energy and environmental impacts from the Baytown Plant are not a valid basis to reject CCS as BACT.

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. ExxonMobil considered the energy requirements to power a CCS system and included the costs of a utility plant in its analysis of cost impacts. There are no other unique energy issues 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 Baytown Plant's installation of CCS. The SOB asserts that the "[i]mplementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, and SO_2 by as much as 11%..." (SOB at p.10) 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. 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. The NSR Manual expressly states that the "environmental impacts

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[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, 41 p., http://pubs.usgs.gov/circ/1386/

[39] NSR Manual, p. B.29.

[40] *Id*. at p. B.30.

analysis is not to be confused with the air quality impacts (i.e. ambient concentrations)…"[41] In this case, whether CCS at the Baytown Plant would increase some criteria pollutants does not constitute an adverse environmental impact. There are no 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.

D. The Draft Permit Fails to Account for Increased Upstream and Downstream Production (Debottlenecking)

In addition to ethylene production, the modification to the Baytown Plant will also result in an increase in other products, "including fuel gas, propylene, a heavy components (C3+) stream, and other lower-output hydrocarbons." (SOB at p.4.) The application also discloses that Deethanizer bottoms product will be sent to the Baytown olefins plant's Depropanizer in the existing plant facilities. (Application, p. 2-3) This additional production would substantially increase GHG and other emissions from these downstream facilities, essentially "debottlenecking" them. The NSR Manual provides, "[t]he BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emission increase would occur."[42] The BACT analysis for the Baytown Plant must therefore include net increases in emissions that will occur from an expansion in the capacity of ethylene that in turn allows an expansion in the capacity of downstream (or upstream) units.

A bottleneck is a limitation on the operation of an emission unit due to restrictions at upstream or downstream units that prevents it from reaching its full capacity. Any process that will limit or has the potential to limit throughput is a bottleneck. "Debottlenecking" is a physical change in the method of operation, though not necessarily a change in the emission unit itself, that may result in an increase in emissions.[43] Examples include an increase in line capacity by increasing the capacity of a limiting upstream or downstream unit.

An emissions increase under federal NSR is the amount by which the new level of "actual emissions" exceeds the old level of "actual emissions." The "actual emissions" are the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive twenty-four-month period selected by the owner or operator within the ten-year period immediately preceding. The new "actual emissions" level is the lower of the unit's "potential" or "allowable" emissions after the change.[44] The increase in emissions that result from removing bottlenecks must be considered in determining which sources must install BACT for GHG. [45] The addition of eight new ethylene cracking furnaces constitutes a change in the

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[41] NSR Manual, p. B.46.

[42] NSR Manual, p. B.4.

[43] See, e.g., Patrick W. Foley, Debottlenecking, Available at: http://daq.state.nc.us/permits/psd/docs/db1.pdf.

[44] NSR Manual at A.41, A.48.

[45] Letter from Kathleen Henry, Chief, Permits and Technical Assessment Branch, to John M. Daniel, Jr., PE, DEE, Director, Division of Air Program Coordination, Commonwealth of Virginia, November 23, 1998; Letter from R. Douglas Neeley, Chief Air & Radiation Technology Section, to Rhonda Banks Thompson, Manager, Clean Air Act Implementation Section, Bureau of Air Quality, South Carolina Department of Health and Environmental Control, Re: Request for Guidance on PSD Applicability Determinations for Boiler Emissions, March 14, 1997 ("EPA's interpretation of the regulation to date has been that when a particular physical change or change in the method of operation would cause an increase in emissions from other emission units, then those "other" emissions must be included in determining PSD applicability for the particular change.").

method of operation for the entire Baytown facility, including downstream units that receive its byproducts, and therefore GHG BACT should also be required for these downstream units. The Region did not conduct a BACT analysis for any of these upstream or downstream processes.

E. The Analysis of Fugitive Equipment Leaks is Flawed

The Baytown Plant would include a number of new piping components, including connectors, flanges, valves, pumps, and compressors. (October 16, 2012 Responses, Attachment 1, Emission Calculations for Fugitives; Application Sec. 4.6.) All of these components leak unless the facility uses leakless components. Theses leaks are referred to as "fugitive equipment leaks." The emission calculations and BACT analysis for these leaks in the application and the SOB are fundamentally flawed.

First, the BACT analysis in the application (Section 4.6) and SOB (Section XIV) incorrectly dismiss the most effective control technology: leakless technology. Instead, the application asserts that leakless technologies "are used in situations where highly toxic or otherwise hazardous materials are used." (Application, Sec. 4.6.) While leakless technology is used to control leaks of toxic and hazardous gases, this is certainly not their only use. Leakless technologies are widely used in petrochemical facilities. They are not restricted to highly toxic or otherwise hazardous streams. Leakless technologies are used, for example, in every petroleum refinery in California's Bay Area Air Quality Management District (BAAQMD). Preventing leaks saves money and prevents adverse air quality impacts. It is a reasonable and technically feasible control technology.

Second, the application and SOB also incorrectly assert that leakless technologies cannot be repaired without a unit shutdown, which ExxonMobil claims often generates more emissions. (Application at p. 4-15; SOB at p. 26) This is a distinction without meaning. All fugitive components require the same general shutdown procedures to repair. A leaking component that leaks above its acceptable leak rate must be repaired using the same shutdown protocol as its leakless counterpart. The principal difference is that the leakless component does not leak over its lifetime while non-leakless components leak constantly at a design rate greater than zero. Leakless components should be BACT in this application.

Third, the application and SOB conclude that the audio/visual/olfactory (AVO) leak detection method is the most effective method to detect leaks from GHG sources. (Application at p. 4-16; SOB at p. 27) Relying solely on AVO is not reasonable. A large petrochemical plant has a complex mixture of chemicals in the background air that could mask the tiny amounts of mercaptans used as an odorant and thus present in leaking natural gas. It is unreasonable to rely on an individual "sniff-test" during inspection rounds to detect all leaks in such a facility.

Further, Texas guidance on fugitive emissions specifically notes that "[g]enerally, an AVO inspection program may only be applied to inorganic compounds that cannot be monitored by instrument. In limited instances, the AVO inspection program may be applied to extremely odorous organic compounds such as mercaptans."[46] The compound of interest in fugitive emissions is methane, which can be monitored by instrument.

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[46] TCEQ, Emissions Factors for Equipment Leak Fugitive Components, p. 4, Available at: http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf

Fifth, the application asserts without support that alternative fugitive leak detection methods, such as LDAR, the same methods in widespread use throughout the petrochemical and refining industries, are not cost effective to detect natural gas leaks at the subject facility. Similarly, the SOB rejects instrument monitoring and remote sensing: "the economic practicality of [LDAR] cannot be verified." These conclusions about the economic practicality of LDAR are baseless. The BAAQMD, for example, supervises LDAR programs at five refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under its Regulation 8, Rule 18 (Reg 8-18).[47] There is no basis to conclude that conventional LDAR methods, used in many thousands of similar facilities, would not be cost effective here.

The Region does not provide any cost analysis or any analysis showing that installing leakless technology, LDAR, or remote sensing would be disproportionately expensive compared to the many other facilities where it has been used for decades. BACT requires the maximum degree of control from a technically feasible technology unless there is a demonstrated adverse economic, energy or environmental impact. In this case, there is no evidence in the SOB or the application indicating that installing and operating leakless technology, LDAR, or remote sensing would cause uniquely excessive costs at the Baytown Plant compared to other similar facilities. A widely used technology, such as leakless components or LDAR, cannot be eliminated on cost effectiveness grounds unless unique circumstances are demonstrated.[48] The ExxonMobil BACT analysis fails to demonstrate unique circumstances, and it also fails to present any cost analysis whatsoever.

F. BACT Should Include a Flare Gas Recovery System

ExxonMobil provided a supplement BACT analysis in its October 16, 2012 responses to the Region. (Responses at p.12 and Table 1) This analysis evaluated flare gas recovery to control GHG emissions from the flare. However, the Region overlooked this option in its SOB BACT analysis. (SOB at pp. 20-23) The ExxonMobil analysis calculated a cost of $134.2 per ton of CO_2e removed. This conclusion is incorrect for at least two reasons.

First, ExxonMobil calculated the "amortized capital cost" assuming a capital charge rate of 19% and an expected equipment life of 20 years. (Responses, p.12, Note 7) As discussed elsewhere in these comments, costs are annualized for purposes of BACT cost effectiveness using a capital recovery factor, calculated from the social rate of interest and the expected equipment lifetime. The most recent social interest rate, used by EPA in similar calculations is 0.8% over a 20 year term, which yields a capital recovery factor of 0.0543 (compared to 0.195 used in ExxonMobil's analysis). Using this value to annualize capital costs reduces the annual capital cost for flare gas recovery from $3.9 million to $1.09 million (nearly a factor of four). This change reduces the cost effectiveness of control from $134.20 per ton CO_2e to $35.5 per ton CO_2e.

Second, ExxonMobil simply asserts with no justification that $134.20 per ton CO_2e is not cost effective. A control technology is considered to be "cost effective" if it falls within a reasonable range of cost-effectiveness estimates. Cost effectiveness is determined by comparing

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[47] http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/Rules%20and%20Regs/reg%2008/rg0818.ashx?la=en
[48] See NSR Manual, pp. B.44, B.45.

annual cost per ton of pollutant removed for the source of interest to the range of cost effectiveness values for other similar permit decisions. If a given cost effectiveness value falls within the range of costs borne by other similar facilities, it is assumed to be cost effective unless unusual circumstances exist at the source. Thus, cost effectiveness is a relative determination, based on costs borne by other similar facilities. To compare costs among units, a level playing field must be established by following the same cost rules in each determination.

Flare gas recovery is widely used in similar industries. All of the refineries in the BAAQMD, for example, use flare gas recovery to control flaring emissions.[49] California's South Coast Air Quality Management District also regulates flaring emissions.[50] ExxonMobil has not demonstrated any unique or unusual circumstances that would render flare gas recovery at the Baytown Plant unusual or infeasible compared to the many other similar petrochemical facilities that currently use it. The Region must revise the draft permit to require flare gas recovery.

Third, the cost effectiveness analysis only considered the CO_2e emissions that would be avoided by using a flare gas recovery system. This system would also reduce the emissions of NOx, SO2, CO, PM/PM10/PM2.5, and sulfuric acid mist as these are all byproducts of combustion in the flare. The flare gas recovery system would prevent the combustion of the flared gases, avoiding these emissions. The cost effectiveness analysis must consider the total pollutants removed, not just GHGe.[51] This change would significantly reduce the cost effectiveness of flare gas recovery in dollars per ton of "total" pollutant removed, making the costs far more favorable.

G. Operating Conditions

ExxonMobil's supplemental responses to the Region include various commitments to ensure efficient operation. However, the draft permit does not include conditions requiring the implementation of these commitments, and therefore the Baytown Plant could conceivably deviate from those practices. The commitments made by ExxonMobil in its responses to the Region should be incorporated into the draft permit. Several examples are described below:

1. Pyrolysis Furnaces (Steam Cracking Furnaces)

The October 16, 2012 Responses 5.A, 5B and 5.C (pages 13-15) layout the procedures that ExxonMobil would follow to ensure that good combustion efficiency of the burners is maintained. The procedure involves continuous monitoring of CO, a combustion byproduct. ExxonMobil proposes an annual average CO limit of 50 ppmv corrected to 3% oxygen on a 12-month rolling basis and a 100 ppm 1-hr average "alarm." At page 14, the response provides, "ExxonMobil proposes to calculate the CO concentration monthly and record the 12-month rolling average to establish an enforceable BACT limit supported by recordkeeping requirements." The Region should include this monitoring requirement in the draft permit to ensure that burner efficiency is maintained to comply with BACT.

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[49] http://www.baaqmd.gov/Divisions/Compliance-and-Enforcement/Refinery-Flare-Monitoring.aspx
[50] http://www.aqmd.gov/comply/R1118_main.htm
[51] Letter from Brian L. Beals, Chief, Preconstruction/HAP Section, Air & radiation Technology Branch, to Edward A. Cutrer, Jr., Program Manager, Stationary Source Compliance Branch, Environmental Protection Division, Georgia Department of Natural Resources, Re: Calculation of Cost Effectiveness of Emission Control Systems, March 24, 1997.

2. Stack Temperatures

Responses 6.A and 6.B (pages 16-17) and 11 (pages 28-29) assert that the Baytown Plant will operate with an exhaust stack temperature at or below 325 F during on-line operation to assure efficient operation. They also quote a range of 309 to 340 F for other similar projects. The draft permit Conditions II 7 and III.A.1.j limit the furnace gas exhaust temperature to <340 F, for the same reasons asserted by ExxonMobil. However, 340 F is the upper end of the range for other furnaces, which does not satisfy BACT. The permit should at a minimum adopt ExxonMobil's assertion that the Baytown Plant will maintain efficiency based on 325 F. Further, EPA should consider whether a lower temperature, as low at 309 F, would result in greater efficiency and thereby constitute BACT.

3. Maintenance and Washing Practices

Response 6.C (page 18) asserts that the Baytown Plant will perform certain maintenance practices, such as washing, to maintain efficiency. These practices are necessary to ensure efficient operations, which the Region has proposed as BACT for the facility. The Region should therefore include the maintenance practices as permit conditions, including periodic washes of the convection section and maintenance of seal bags to manage air ingress.

4. Work Practice Standards and Operational Limitations

ExxonMobil's October 16, 2012 responses include as Attachment 4, Table 3-2 a list of proposed "Work Practice Standards and Operating Limits." The Region should verify that, at a minimum, all of the proposed work practice standards and operational limits are included in the draft permit.

H. Miscellaneous Draft Permit Issues

During review of the draft permit, Sierra Club noted several areas of ambiguity or inconsistency. Sierra Club therefore makes the following recommendations:

- The GHG limits in Table 1 are set so that there is one limit for all eight cracking furnaces. (See page 8, Note 3) When one or more of the units are down, this would allow the other operating units to operate less efficiently than would otherwise be considered as BACT. The Region should set GHG BACT limits for each emission unit, not for a group of emission units.[52]

- Page 10 of the draft permit provides: "The Permittee shall monitor the furnace for coke buildup and perform a decoke when needed." The permit should be revised to clarify what "when needed" means. Further, ExxonMobil's October 16, 2012 Response 8.A (page 26) lays out decoking design and procedures to assure efficient operation. The Region should require these parameters as permit conditions. Finally, the permit should limit the amount of coke that can form.

- Draft permit section III.A.1 includes two sub-sections "c."

- The draft permit does not contain any monitoring to demonstrate compliance with the flare efficiencies of 98% for the elevated flare and 99% for the ground flare in Condition III.A.3.b (Draft Permit p. 11) The condition is therefore not enforceable as a practical matter. The Region should revise the permit condition to include monitoring to demonstrate compliance.

Sierra Club appreciates the opportunity to provide these comments.

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Sincerely,

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[52] Sierra Club notes that if the Region adopts our recommendation to implement a GHG rate based on the rate of CO_2e per ton of ethylene produced, this issue would be resolved.