BACT FOR CARBON CAPTURE AND SEQUESTRATION

FPC TX addresses the potential to capture GHG emissions that are emitted from Carbon Capture and Sequestration (CCS) candidate sources associated with the 2012 Expansion Project listed below (plant names in parenthesis):

- 14 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE)

The EPA five step top down BACT evaluation for this potential control technology options is provided in this Appendix. As shown in that analysis, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as a BACT option for any of the emissions sources associated with the 2012 Expansion Project.

6.1.1 STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The emerging carbon capture and sequestration (CCS) technologies generally consist of processes that separate CO_2 from combustion or process flue gas (capture component), the compression and transport component, and then injection into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations (sequestration component). These three components of CCS are addressed separately below:

Carbon Capture:

Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges. Although the DOE-NETL discussions focus on CCS application at combustion units in electrical generation service, elements of this discussion are applicable when discussing the application of CCS to sources in the chemical manufacturing industry. The following excerpts from DOE-NETL Information Portal illustrate some of the many challenges, but not all, that are present in applying available CO_2 Capture technologies at combustion and process sources located at chemical manufacturing plants.

> *…In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries… Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output…*[1]

In its CCS information portal, the DOE-NETL adds:

> *…Separating CO_2 from flue gas streams is challenging for several reasons:*
>
> - *CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.*
> - *Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.*

It should be noted that the majority of the candidate CCS source vent streams (previously listed in this section) are dilute in CO_2 concentration and contain impurities such as PM, NO_X and SO_2, thus increasing the challenge of CO_2 separation for the Point Comfort expansion project.

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[1] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited July 26, 2012).

Compression and Transport:

The compression aspect of this component of CCS will represent a significant cost and additional environmental impact because of the energy required to provide the amount of compression needed. This is supported by DOE-NETL who states that:

> *Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall plant system…*[2]

If CO_2 capture and compression can be achieved at a process or combustion source, it would need to be routed to a geologic formation capable of long-term storage (sequestration). The long-term storage potential for a formation is a function of the volumetric capacity of a geologic formation and CO_2 trapping mechanisms within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites and their associated technical challenges as follows:

> *Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently…*[3]

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[2] *Id.*

[3] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited July 26, 2012)

Therefore, as can be seen from the DOE-NETL Information Portal, CCS as a whole cannot be considered a commercial available, technically feasible option for the combustion and process vent emissions sources under review in the FPC TX proposed expansion. FPC TX's expansion project generates flue gas streams that contain CO_2 in dilute concentrations and the project is not located in an acceptable geological storage location. Even so, FPC TX provides even further and more detailed evaluation to address all 5 steps of the EPA BACT analysis.

6.1.2 Step 2: Eliminate Technically Infeasible Options

Although, as described above, CCS should not be considered an available control technology, in this section, FPC-TX addresses, in more detail, the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed expansion project GHG emission sources. The feasibility issues are different for each component of CCS technology (i.e., capture; compression and transport; and storage). Therefore, technical feasibility of each component is addressed separately below.

6.1.2.1 CO_2 Capture

Though amine absorption technology for CO_2 capture has routinely been applied to processes in the petroleum refining and natural gas processing industries it has not been applied to process vents at chemical manufacturing plants.

The Obama Administration's Interagency Task Force on Carbon Capture and Storage, in its recently completed report on the current status of development of CCS systems for power plants, states that carbon capture could be used on combustion units. However, the following discussion on carbon capture technology availability for high volume vent streams and large combustion unit shows that carbon capture is not commercially available for application.

Large commercial applications, such as the expansion project sources, present even more difficult application of carbon capture, in part, due to the additional variability in flow volumes as typically experienced in chemical plants. Therefore, the discussion related to power plants also shows that of CO_2 capture for chemical process combustion and process vent stream are not commercially available.

Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.[4]

In its current CCS research program plans (which focus on power plant application), the DOE-NETL confirms that commercial CO_2 capture technology for large-scale combustion units (e.g., power plants) is not yet available and suggests that it may not be available until at least 2020:

> *The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:*
>
> *(1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;*
>
> *(2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;*
>
> *(3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;*
>
> *(4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades.*[5A]

To corroborate that commercial availability of CO_2 capture technology for large-scale combustion (power plant) projects will not occur for several more years, Alstom, one of the major developers of commercial CO_2 capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion, states on its web

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[4] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

[5] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).

site that its CO_2 capture technology will become commercially available in 2015.[6] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be available for CO_2 emissions generated from chemical plant sources, like those included in the Point Comfort expansion project.

6.1.2.2 CO_2 Compression and Transport

Notwithstanding the fact that the above discussion demonstrates that the carbon capture component of CCS is not commercial available for chemical plant combustion and process vents, FPC TX provides the following discussion concerning technical feasibility. This discussion further supports that the compression and transport component of CCS may be technically feasible but, as explained later, the cost evaluation shows that it is not economically reasonable. Therefore, CCS is not BACT for the 2012 Expansion Project.

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated would need to be compressed and transported to a facility capable of storing it. There are potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported if a pipeline was available or constructed to transport to the sequestration sites. The map found at the end of this Appendix identifies potential CO_2 pipelines. Please note that some of these CO_2 pipelines are for the purpose of delivering CO_2 to Enhanced Oil Recovery (EOR) sites .[7]

A pipeline for EOR is not a feasible option for providing CO_2 sequestration because, for the EOR process, the injected CO_2 is purposefully injected into a formation which will allow CO_2 migration through the formation to the surface in order to, at the same time, force oil to the surface. As oil is forced to the surface, CO_2 is also forced to the surface. So in the EOR process, CO_2 is not isolated or sequestered or retained below the surface. In addition, while there may be a market for CO_2 for EOR projects, current demand for EOR pipelines cannot be guaranteed to remain steady for the life of the proposed project. EOR projects are driven by the

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[6] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov.30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/ (last visited July.26, 2012).

[7] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100(last visited July 26, 2012).

recovery of oil and will end when the cost of oil recovery is no longer financially viable. Therefore, in addition to not actually sequestering the CO_2, the long term viability of EOR as a use of the captured CO_2 is not assured. Therefore, EOR pipelines are eliminated as technically feasible sequestration option.

The closest site that is currently being field-tested to demonstrate its capacity for potential large-scale geological storage/sequestration of CO_2 is the Southwest Regional Partnership (SWP) on Carbon Sequestration's Scurry Area Canyon Reef Operators (SACROC) test site, which is located in Scurry County, Texas approximately 439 miles away (distance estimated using shortest feasible pipeline pathway from Point Comfort to SACROC site). See the map at the end of this Appendix for the test site location. There is no pipeline available to deliver the CO_2 associated with this project to the SACROC test site. Therefore, assuming that this site is eventually demonstrated to be capable of indefinitely storing/sequestering a substantial portion of the large volume of CO_2 generated by the proposed project, a 439 mile-long, 20-inch diameter pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the storage facility which is infeasible.

6.1.2.3 CO_2 Sequestration

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable pipeline or sequestration site as addressed in Step 4 of the BACT analysis. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,

- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[8] and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, sites with such recognized potential for some geological storage of CO_2 are located within 15 miles of the proposed project, but such nearby sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the proposed power unit, i.e., SWP's SACROC test site, is located in Scurry County, Texas approximately 439 miles away (via pipeline routing). It should be noted that, based on the suitability factors described above, currently the suitability of the SACROC site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed project has yet to be fully demonstrated.

6.1.3 STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As documented above, implementation of CCS technology for the FPC TX expansion emission sources is not currently commercially available or feasible for both technical and economic reasons. Even so, FPC TX will provide detailed economic and impacts analyses in Step 4 which provides further documentation for eliminating this option as a control Technology to be evaluated for the GHG emission sources associated with the FPC TX expansion.

6.1.4 STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

6.1.4.1 Additional Environmental Impacts and Considerations

There are a number of other environmental and operational issues related to the installation and operation of CCS that must also be considered in this evaluation. First, operation of CCS capture and compression equipment would require substantial additional electric power. For example, operation of carbon capture equipment at a typical natural gas fired combined cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50%

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[8] *Id.*

(based on the fuel higher heating value (HHV)) to approximately 42.7% (based on fuel HHV).[9] To provide the amount of reliable electricity needed to power a capture system, FPC TX would need to significantly expand the scope of the utility plant expansion proposed with this project to install one or more additional electric generating units, which are sources of conventional (non-GHG) and GHG air pollutants themselves. To put these additional power requirements in perspective, gas-fired electric generating units typically emit more than 100,000 tons CO_2e/yr and would themselves, require a PSD permit for GHGs in addition to non-GHG pollutants.

FPC TX would need to construct a pipeline that is estimated to be at least 439 miles in length to transport captured GHGs to the nearest potential sequestration site (SACROC site). Constructing a pipeline of this magnitude would require procurement of right-of-ways which can be a lengthy and potentially difficult undertaking. Pipeline construction would also require extensive planning, environmental studies and possible mitigation of environmental impacts from pipeline construction. Therefore, in addition to being costly, the transportation of GHGs for this project would potentially result in negative impacts and disturbance to the environment in the pipeline right-of-way.

Finally, implementation of CCS for the 2012 Expansion Project poses several operational and business concerns. Not withstanding that EOR is not a feasible sequestration option, any sale of CO_2 material to either a pipeline entity or to a storage facility (EOR) would be made under contractual terms. FPC TX is in the primary business of selling commodity and specialty chemicals; the sale of CO_2 would be a secondary product. The GHG sources that would be tied into a CCS system must be periodically taken out of service for maintenance or other reasons to ensure maximum yield of primary product from the production unit, thereby temporary eliminating or reducing the supply of CO_2 to the buyer. FPC TX has identified contractual issues relating to the sale of CO_2 that conflict directly with existing contracts relating to the sale of primary products. For this reason, FPC TX believes that the sale of CO_2 from the Point Comfort expansion sources poses an unacceptable business conflict.

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[9] US Department of Energy, National Energy Technology Laboratory, “Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy”, Revision 2, November 2010

6.1.4.2 CCS Cost Evaluation

Based on the reasons provided above, FPC TX believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. Furthermore, the Congressional Budget Office's June 2012 document entitled *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* states that "average capital costs for a CCS-equipped plant would be 76 percent higher than those for a conventional plant."[10] Even so, to address possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, FPC TX has estimated such costs on a site-specific basis.

For the cost evaluation, FPC TX considered all plants project (Olefins Expansion, LDPE plant and gas turbines) associated the expansion GHG emission sources for which CCS is considered technically feasible, for purposes of this analysis, even though separate permits are requested for each plant. These GHG emissions sources include the following emission units (respective plant names/permit applications shown in parenthesis):

- 14 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE Plant)

FPC TX's site-specific cost estimate assumed that an amine based scrubbing system and associated compressors would be used. While not fully proven on gas-fired turbine flue gas or process heater exhaust, amine based scrubbing systems are the most mature technology potentially available for CCS. To determine the capital cost of the amine scrubbing system and associated compressors for the FPC TX project, FPC TX used cost information from a DOE-NETL study from 2010 as a benchmark and scaled the cost based on the actual FPC TX capacity and stream characteristics, as described below.

- FPC TX stream will require additional gas conditioning and equipment capacity to meet specifications for final sale because

[10] *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide,* Page 7 (June 2012).

  - FPC TX's combined exhaust streams from CCS candidate sources has an annual average CO_2 concentration of 4.19% by volume versus the DOE-NETL IGCC gas turbine example with a CO_2 concentration of 6.3% by volume
  - FPC TX's proposed annual CO_2 to be recovered from CCS candidate sources is 3,167,981 tons/yr, versus the DOE-NETL example with less than half of this much CO_2
- FPC TX will require thousands of feet of gas in plant gathering system piping to collect vent gas from the variety of CO_2 emission points located in different operating units across the Point Comfort site.
  - FPC TX estimated that over 8,500 linear feet of ductwork would be necessary to route the exhaust streams together to a common capture and compression system
- Additional electricity is required to power the capture and compression system
  - FPC TX's site-specific cost estimate included the cost for extra power assuming that power would be purchased from electric utility providers at a market rate

The following costs were not included in the cost estimated so the actual cost is expected to be much higher than the cost reported here. Costs of obtaining rights of way for construction of a pipeline were not included in the site-specific cost estimate. Also it should be noted also that the liability and property issues related to underground CO_2 storage have not been fully resolved. CCS cost estimates provided by DOE-NETL did not include an escalation factor to account for increasing costs as available sequestration sites begin to fill up or the ongoing monitoring costs associated with a sequestration project.

The CCS system site-specific cost estimate is presented on Tables 6-1 through 6-5 at the end of this Appendix. The total CCS system capital cost is estimated at over 1.5 billion dollars, which is more than 75% of the total Point Comfort expansion project capital cost (total estimated capital cost is 2 billion dollars). Increasing the capital cost of the expansion project by this margin and including all the ongoing operating and maintenance costs would render this project economically unviable.

As discussed above, CCS was determined to be not commercially available and not technically feasible; therefore, a detailed examination of the energy, environmental, and economic impacts of CCS is not required for this application. However, at the request of EPA Region 6, FPC-TX included the estimated costs for implementation of CCS which are presented in Tables 6-1 through 6-5. As discussed above these costs show that CCS is not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as BACT for the FPC TX expansion.

6.1.5 Step 5: Select BACT

As demonstrated in Steps 2 and 4 of the BACT review, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as BACT for the FPC TX expansion.

6.1.5.1 CCS in Other GHG Permits

FPC TX searched GHG permits issued by EPA Region 6 and other states. Only one permit included the use of CCS, the Indiana Gasification, LLC (IG) project, permit no. 147-30464-00060 issued by the Indiana Department of Environmental Management (IDEM). The IG project proposes the construction of a coal gasification power plant that will produce liquefied carbon dioxide which will be compressed and piped several hundred miles to EOR facilities in the Gulf Coast region.

This project differs significantly from the Point Comfort expansion in most technical aspects, but it should also be noted that IG has secured federal loan guarantees and potentially state tax credits to make the project, including application of CCS, economically viable. Furthermore, on page 154 of 181 of the PSD/TV Permit, Step 4 of the GHG BACT evaluation for the acid gas removal units (the primary GHG emission vents) state that:

> *IG will not begin construction of this facility without a fully financed project agreement for the pipeline that provides for the pipeline to be in place and ready to receive liquefied CO_2 at the point when pipeline quality CO_2 is available.*

This statement provides evidence that the project, including application of CCS, hinges on the approval and contracts for a new CO_2 pipeline. It is clear from the following quote from the Indiana permit application that installation of CCS was not justified for this project as BACT. The GHG BACT evaluation for the proposed IG plant concludes that “Based on the technically feasibility analysis in Step 2, there are no viable control technologies for the control of GHG emissions from the acid gas recovery unit vent." This is consistent with the results of FPC TX's BACT analysis of CCS for the Point Comfort Expansion project.

Table 6-1: Reference Capture and Compression Cost Data
from DOE-NETL Combined-Cycle Gas Turbine Cost Example
Formosa Plastics Corporation, Texas
2012 Expansion Project
Point Comfort, Texas

Cost Category	Item Name	Value	Units	Reference in DOE-NETL Report [1]	Notes
Capital Expenses	CO_2 Removal System	216.00	Cost (millions $)	Exhibit 5-25, page 495 (with CCS)	
	CO_2 Compression System	24.63		Exhibit 5-25, page 495 (with CCS)	
	Cooling Water System	8.45		Exhibit 5-25, page 495 (with CCS) and Exhibit 5-14, page 472, (w/o CCS)	
	Accessory Electric Plant	10.02		Exhibit 5-25, page 496 (with CCS) and Exhibit 5-14, page 473, (w/o CCS)	
	Instrumentation and Control	1.28		Exhibit 5-25, page 496 (with CCS) and Exhibit 5-14, page 473, (w/o CCS)	
	Total Direct Capital Costs	***260.38***			
	Owner's Costs	7.61		Exhibit 5-25, page 497 (with CCS) and Exhibit 5-14, page 474, (w/o CCS)	Includes the following costs: prepaid royalties, preproduction (start-up) costs, working capital, inventory capital, land, financing cost,
	Inventory Capital	1.65		Exhibit 5-25, page 497 (with CCS) and Exhibit 5-14, page 474, (w/o CCS)	
	Initial Cost for Chemicals	0.95		Exhibit 5-25, page 497 (with CCS) and Exhibit 5-14, page 474, (w/o CCS)	
	Other Owner's Costs	38.30		Exhibit 5-25, page 497 (with CCS) and Exhibit 5-14, page 474, (w/o CCS)	Includes preliminary feasibility studies, including a front-end engineering design (FEED) study, economic development, construction and/or improvement of roads and/or railroad spurs outside of site boundary, legal fees, permitting costs, owner's engineering, and owner's contingency.
	Financing Costs	6.75		Exhibit 5-25, page 497 (with CCS) and Exhibit 5-14, page 474, (w/o CCS)	Covers the cost of securing financing, including fees and closing costs but not including interest during construction
	Total Direct and Indirect Capital Costs	***315.64***			
Operating Expenses	Annual Power Requirements	606,849	MWh/yr	Reference [1], Exhibit 5-27, page 499	
	Cost of Power	58.90	$/MWh	www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a	
	Annual Power Costs	35.74	$ (million/yr)		
	Annual Fixed Operating Costs	7.69		Exhibit 5-26, page 498 (with CCS) - Exhibit 5-15, page 475 (w/o CCS)	Includes annual operating labor cost, maintenance labor cost, administrative & support labor and property taxes and insurance
	Annual Variable Operating Costs	3.57		Exhibit 5-26, page 498 (with CCS) - Exhibit 5-15, page 475 (w/o CCS)	Includes maintenance material cost and consumables (water, chemicals, supplemental fuel, gases, waste disposal, byproducts, etc.)
	Subtotal	***47.00***			
Capital and Operating Expense Estimation, $/ton CO_2	Annual Tons of CO_2 Sequestered	1,477,986	Short Tons/yr	Exhibit 5-8, page 458 (w/o CCS) -Exhibit 5-19, page 480 (with CCS)	
	Annual Capital Cost [2]	10.52	$ (million)/yr		Calculated by assuming the total direct and indirect costs are distributed equally over the life of the equipment and does not account for interest rate
	Annual Operating Cost	47.00	$ (million)/yr		
	Annual Capital Cost Per Ton CO_2	7.12	$/Ton CO_2 Avoided		
	Annual Operating Cost Per Ton CO_2	31.80	$/Ton CO_2 Avoided		
Total Annual Capture and Compression Cost per Ton CO_2		**38.92**	**$/Ton CO_2 Avoided**		

Notes:
[1] DOE-NETL Report: Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2a, September 2013: Natural Gas Combined Cycle Plants

[2] Based on the following years of operation (project life): **30**

Table 6-2: Site-Specific Capture and Compression Costs
Formosa Plastics Corporation, Texas
2012 Expansion Project
Point Comfort, Texas

Cost Category	Item Name	Value	Units
Capital Expenses [1]	CO_2 Removal System [2]	778.22	Cost (millions $)
	CO_2 Collection Duct Work [3]	20.6	
	CO_2 Compression System	59.02	
	Cooling Water System	20.25	
	Accessory Electric Plant	24.01	
	Instrumentation and Control	3.07	
	Total Direct Capital Costs	***905.13***	
	Owner's Costs	18.24	
	Inventory Capital	3.95	
	Initial Cost for Chemicals	2.28	
	Other Owner's Costs	91.78	
	Financing Costs	16.18	
	Total Direct and Indirect Capital Costs	***1037.55***	
Operating Expenses	Annual Power Requirements [1][2]	2,186,410	MWh/yr
	Cost of Power	58.90	$/MWh
	Annual Power Costs	128.78	$ (million/yr)
	Annual Fixed Operating Costs [1]	18.43	
	Annual Variable Operating Costs [1]	8.56	
	Subtotal	***155.76***	
Capital and Operating Expense Estimation, $/ton CO_2	Annual Tons of CO_2 Sequestered	3,541,796	Short Tons/yr
	Capital Recovery Factor (CRF) [4]	0.07455	
	Annual Capital Cost (CRF x Total Capital Investment)	77.35	$ (million)/yr
	Annual Operating Cost	155.76	$ (million)/yr
	Annual Capital Cost Per Ton CO_2	21.84	$/Ton CO_2 Avoided
	Annual Operating Cost Per Ton CO_2	43.98	$/Ton CO_2 Avoided
Total Annual Capture and Compression Cost per Ton CO_2		**65.82**	

Notes:

[1] These capital and operating costs were estimated to be more expenseive for a unit that is processing a larger stream, as comparied to the DOE-NETL costing example (for a combined cycle exhaust). FPC TX CO_2 removal system costs were estimated by adjusting equipment the removal system cost estimated from DOE-NETL CO_2 CCS equipment cost analysis using the ratio of the annual mass of CO_2 sequestered, as follows:

DOE-NETL CCGT Annual CO_2 Tons Sequestered (short tons/yr):	1,477,986
FPC TX Annual CO_2 Tons Sequestered (short tons/yr):	3,541,796
Proportional Scalar (FPC TX Tons/CCGT Tons) =	**2.40**

[2] Cost for this system is estimated to be more expensive than for a unit receiving purely combined cycle exhaust because the concentration of CO_2 in the FPC TX stream is less. FPC TX CO_2 removal system costs were estimated by adjusting equipment the removal system cost estimated from DOE-NETL CO_2 CCS equipment cost analysis using the ratio of the two CO_2 concentrations as follows:

CO_2 Concentration of CCGT used in DOE-NETL CCS cost analysis:	6.30	(% volume)
CO_2 Concentration of the Combined FPC TX exhaust stream:	4.19	(% volume)
Adjustment Factor based on concentration ratio of FPC TX/DOE-NETL:	**1.50**	

[3] Estimated cost of ductwork and support systems to route the exhausts from the candidate CCS source to a common location. Does not include the costs for control systems and bypass stacks that would be needed in the event of a recovery system shutdc

[4] Capital recovery factor (CRF) is from Appendix A, Table A.2 of EPA Air Pollution Control Cost Manual.
Factor selected from lowest interest rate (5.5%) in Table A.2 and for longest time period (25 years).
Using the lowest interest rate and longest time period conservatively yields the lowest CRF value.

Table 6-3: CO_2 Transport Costs
Formosa Plastics Corporation, Texas
2012 Expansion Project
Point Comfort, Texas

Pipeline Capital Costs

Terrain	Capital Cost ($/inch-Diameter/mile) [1]	No. Miles of Each Terrain	Adjusted Capital Costs
Flat, dry	$50,000	238	$238,000,000
Mountainous	$85,000	147	$249,900,000
Marsh, Wetland	$100,000	52	$104,000,000
River	$300,000	2	$12,000,000
High Population	$100,000	0	$0
Offshore (150'-200' depth)	$700,000	0	$0
	Totals:	**439**	**$603,900,000**

Pipeline Fixed O&M Costs

Item Name	Value	Units
Fixed O&M [2]	8,454	$/mile/year
Distance of Pipeline	439	Miles
Site's Pipeline Fixed O&M	**3.71**	**Million $/year**

Transport Costs from Point Comfort Plant to Scurry County, TX (SACROC)

Item Name	Value	Units
Pipeline Distance	439	miles
CO2 Daily Flow Rate	9,704	short tons/day
Pipeline Diameter	20	inches
CO2 Surge Tank [3]	1.25	Million $
Pipeline Control System [3]	0.11	Million $
Pipeline Capital Cost	603.90	Million $
Total Pipeline Capital Costs	***605.26***	***Million $***
Total Years of Usage	30	Years
Annual Pipeline Capital Costs	20.18	Million $/yr
Annual Pipeline O&M Costs	3.71	Million $/yr
Annual Pipeline Combined Costs	***23.89***	***Million $/yr***
Total $/ton of CO2 Transported	**6.74**	**$/Ton CO2 Transported**

Notes:

[1] From page 8 of DOE-NETL Report 2010/1447, Estimating Carbon Dioxide Transport and Storage Costs, March 2010

[2] From page 5, Table 2 of DOE-NETL Report 2010/1447, Estimating Carbon Dioxide Transport and Storage Costs, March 2010

[3] Costs from DOE-NETL Report 2010/1447, Estimating Carbon Dioxide Transport and Storage Costs, March 2010

Table 6-4: CO_2 Storage Costs
Formosa Plastics Corporation, Texas
2012 Expansion Project
Point Comfort, Texas

Geologic Storage Capital Costs

Item Name	Value [1]	Units
Site Screening and Evaluation	$4,738,488	$
No. of Injection Wells (approx. 1 per 10K daily CO_2 tons)	1	No. of Wells
Injection Well Cost	$647,041	$
Injection Equipment	$483,032	$
Liability Bond	$5,000,000	$
Total Capital Cost:	**$10.87**	***Million $***
Annual Capital Cost of Storage:	**$0.36**	**Million $**
Capital Cost $/ton of CO2 stored:	**$0.10**	**$/Ton CO2 Stored**

Declining Capital Funds

Item Name	Value [1]	Units
Pore Space Acquisition	$0.334	$/short ton CO_2
Annual Cost of Pore Space Acquisition	$1.18	Million $/yr
Total Cost of Pore Space Acquisition	**$35.49**	**Million $**

Storage Operations and Maintenance Costs

Item Name	Value [1]	Units
Normal Annual Expenses (Fixed O&M)	$4.22	Million $/yr
Annual Consumables (Variable O&M)	$29.06	
Annual Surface Maintenance (Fixed O&M)	$0.12	
Annual Subsurface Maintenance (Fixed O&M)	$3.19	
Annual Storage O&M:	**$36.60**	

Storage Cost Summary

Annual Capital and Operational Costs	**$38.14**	**Million $/yr**
$/ton of CO2 stored:	**$10.77**	**$/Ton CO2 Stored**

Note:

[1] Costs were determined based on sequestration metrics stated in DOE-NETL report "Estimating Carbon Dioxide Transport and Storage Costs", no. 2010/1447, page 6.

Table 6-5: Cost Summary for Carbon Capture, Compression, Transportation and Sequestration in Scurry County, Texas

Formosa Plastics Corporation, Texas
2012 Expansion Project
Point Comfort, Texas

Cost Type	$/Ton of CO_2 Sequestered
Carbon Dioxide Capture and Compression System	65.82
Transport	6.74
Storage	10.77
Total $/Ton CO_2:	**83.33**