Clean Coal Power Initiative Update: Texas Clean Energy Project, 400 MW Integrated Gasification Combined Cycle Poly-Generation with 90 Percent Carbon Capture

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ABSTRACT

The Texas Clean Energy Project (TCEP) was selected by the U.S. Department of Energy (DOE) for cost-shared co-funded financial assistance under Round 3 of its Clean Coal Power Initiative[2] (CCPI). A federal government and industry collaboration, the goal of the CCPI is to accelerate the readiness of new coal utilization technologies for commercial use, ensuring that abundant domestic coal is a portfolio option for clean, reliable, and affordable power. The CCPI directly supports the national Climate Change Technology Program, a multi-agency research and development (R&D) program to reduce carbon dioxide (CO_2) emissions. The TCEP is intended to be a capstone commercial-scale clean coal demonstration incorporating decades of DOE-sponsored R&D into coal gasification; environmental/pollutant controls; high-hydrogen (H_2)-capable combustion gas turbines; and, carbon capture and storage (CCS). The facility will be among the cleanest commercial, solid-fuel power facilities in the world and will significantly surpass the emissions reduction targets for 2020 established under the Energy Policy Act of 2005 (EPAct 2005, Public Law 109-58). The facility's emissions will be far below any limits previously permitted in Texas for a fossil-fuel plant, and will meet the U.S. Environmental Protection Agency (EPA) 111(b) Rule for CO_2 emissions. At about 90 percent carbon capture efficiency plant-wide and greater than 90 percent from the total coal synthesis gas (syngas) stream, the TCEP CO_2 emissions on a megawatt-hour (MWhr) basis will be about 50 percent of a comparably-sized natural gas combined cycle (NGCC) power plant without CO_2 capture. The TCEP integrates CO_2 capture with integrated gasification combined cycle (IGCC) in a commercial poly-generation setting. The project is being developed by Summit Texas Clean Energy LLC (STCE), a company of Summit Power Group LLC (SPG), and will feature Siemens[3] gasification and combined cycle power; carbon monoxide (CO) shift; and, Linde[4] Rectisol® Wash Unit (RWU) acid gas removal (AGR). The TCEP will generate about 405 megawatts-electric (MW_e), which will support all internal loads while delivering about 200 MW_e of low-carbon power to the electric utility grid. The facility is also designed to produce granulated urea, $(NH_2)_2CO$ and pipeline-quality CO_2 as primary products; and, inert non-leachable slag; argon (Ar); liquid nitrogen (N_2); sulfuric acid (H_2SO_4); and, ammonium sulfate, $(NH_4)_2SO_4$ as minor products. This paper provides background; a status update post plant reconfiguration; and, a government perspective on the TCEP and project financing of first-of-a-kind commercial demonstrations.

KEYWORDS: Carbon Capture and Storage, CCS, Clean Coal Demonstration, Coal Gasification, High-Hydrogen Gas Turbine, Integrated Gasification Combined Cycle, IGCC, Pre-Combustion, Texas Clean Energy Project, TCEP

1. BACKGROUND

STCE is developing the TCEP to be located on a 600-acre former FutureGen-candidate site in Penwell, Texas, about 15-miles southwest of Odessa. The TCEP will be an IGCC plant, with a nameplate capacity of at least 400 MW_e, in combination with an ammonia/urea complex for the production of agricultural fertilizer, and the facilities to capture, concentrate, pressurize and deliver pipeline-quality CO_2 to existing regional pipelines for use in oil fields for deep geologic storage with concomitant enhanced oil recovery (EOR) in the Permian Basin of west Texas. The TCEP will deploy coal gasification technology to convert Powder River Basin (PRB) sub-bituminous coal, delivered by rail from Wyoming, into a syngas that will be cleaned and further treated to a high-H_2 syngas. The clean high-H_2 syngas will be divided into two streams: one will be blended with natural gas and combusted as fuel in an advanced Siemens "H" class turbine for power generation; and, the other will be used as feedstock for reaction with N_2 gas to form ammonia (NH_3). The captured CO_2 will also be divided into two streams: one will be used as feedstock for conversion of the NH_3

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[2] Funding Opportunity Announcement (FOA) DE-PS26-08NT43181, "Clean Coal Power Initiative – Round 3," award number DE-FE0002650
[3] Gasification: Siemens Fuel Gasification Technology GmbH & Co. KG (Germany); Power Generation: Siemens Energy (USA)
[4] Linde Engineering North America Inc., a.k.a. The Linde Group (Germany)

into ammonium carbamate ($NH_2CO_2NH_4$) which will be decomposed into granulated urea fertilizer for commercial sales; and, the other will be compressed for transport by pipeline for offsite use in EOR.

The TCEP received its final air quality permit[1] from the Texas Commission on Environmental Quality (TCEQ) on December 28, 2010. The initial Front-end Engineering and Design (FEED) was completed in July 2011[2]. The National Environmental Policy Act (NEPA) final Environmental Impact Statement (EIS) was issued in July 2011[3] and the Record of Decision (ROD) was issued in September 2011[4]. A contract for the sale of the electricity was completed with CPS Energy in June 2011 and redone in September 2014. Contracts for urea and CO_2 sales were completed by the end of calendar year 2011 and have been updated several times since. The contract for the purchase of coal feedstock from Cloud Peak Energy's Cordero Rojo mine, as well as a memorandum of understanding (MOU) with the Union Pacific Railroad (UPRR) for delivery of the coal to the TCEP site, have also been finalized.

In September 2012, STCE announced a MOU with Sinopec Engineering Group (SEC) to commence negotiations on a new engineering, procurement, and construction (EPC) contract. But in 2014, it was announced that STCE would replace SEC with China Huanqiu Contracting & Engineering Corporation (HQC), a subsidiary of China National Petroleum Corporation (CNPC). This coincided with a July 8, 2014 signing of a Framework Agreement[5] between SPG and the Huaneng Clean Energy Research Institute, a subsidiary of the China Huaneng power company, for the companies to work together on the TCEP and Huaneng's 250 MW IGCC GreenGen project in Tianjin, China that will add carbon capture, utilization and storage (CCUS) for EOR in its upcoming Phase 2. This agreement is part of the U.S.-China Climate Change Working Group CCUS Initiative, launched under the annual U.S. and China Economic Dialogue. STCE engaged HQC to refresh the FEED with an emphasis on adopting the latest Siemens technologies; improving plant efficiencies; increasing product quantities; and, if possible, reduce the capital cost. HQC partnered with Technip USA for construction services and entered into licensing contracts with Process Technology Licensors to develop Process Design Packages (PDPs) for specific plant processes. STCE also revised contracts with Siemens to update the FEED for the Power Block and facility Operations & Maintenance (O&M). The FEED Update was completed in February 2015 and resulted in a reconfigured plant[5]. As necessitated by the plant reconfiguration, a supplemental analysis for the final EIS was issued in May 2015[6].

2. PLANT CONFIGURATION AND CHANGES SINCE FEED UPDATE

TABLE 2-1. TCEP System Changes

System(s)	Plant 12/2013	Plant 12/2014
Coal Storage	45-days	30-days
Gasifier	Two SFG-500	One SFG-850
Slag Handling	2 x 100%	1 x 100%
CO Shift	2 x 50%	1 x 100%
Gas Turbine (60Hz)	SGT6-5000F3	SGT6-8000H
Sour Water Stripper	2 x 100%	1 x 100%
Sulfuric Acid Plant	1 x 100%	2 x 100%
Ammonia Scrubber	N/A	1 x 100%
Duct Burners	Yes (on NG)	N/A

Table 2-1 lists changes to the TCEP plant configuration since December 2013. Attachment 1, Comparison of TCEP Configurations at Normal Operating Conditions, compares key inputs, internal streams, and outputs of the previous and current configurations.

2.1 Chemical Block

The TCEP Chemical Block includes the coal feedstock systems; air separations unit (ASU); gasification island; gas cleanup; sour water treatment; RWU/AGR; liquid N_2 wash unit (NWU); and, the commercial product process units (except power generation).

Coal Feedstock Systems – The TCEP will convert about 5,000 tons per day (tpd), as received, or about 1.55 million tons per year (MMtpy), of PRB sub-bituminous coal delivered to the site by rail from Wyoming. A single system for receiving, storing, and handling coal will feed the Coal Pre-Drying System,[6] and then the Coal Milling & Drying system, to prepare the coal for the gasifier. The coal handling system will consist of a railcar unloading facility, a coal storage system, a reclaim system, a coal crushing system, and a silo fill system. The function of this system will be to unload coal from unit trains, convey it to the storage pile, reclaim it from the storage pile, crush the coal, and convey it to the raw coal bins in the Coal Pre-Drying/Coal Milling & Drying building.

The railcar unloading system will consist of rapid-discharge, bottom-dumping railcars with an automatic continuous dumping system. The rail unloading hopper will be capable of unloading coal at a rate of 4,000 tons/hour. Belt feeders will transfer coal from the unloading hoppers to a conveyor to the coal storage piles. From the pile(s), coal will be fed into the reclaim hoppers. Reclaim belt feeders will transfer coal from the reclaim hoppers at a rate of 1,000 tons/hour to the Coal Pre-Drying System raw coal bins (4 x 33

[5] Texas Clean Energy Project Web site, maintained by Summit Power Group LLC, http://www.texascleanenergyproject.com/
[6] A coal pre-drying step was added upstream of the Coal Milling & Drying system, using low pressure (LP) steam as the heat source.

percent). All conveyors will be enclosed to reduce particulate emissions, and the Coal Pre-Drying/Coal Milling & Drying building will be fully enclosed with dust suppression sprays and collection systems used to control dust and noise.

A traveling trip conveyor will feed each of the 3 x 33.33 percent operating (plus one spare) Coal Pre-Drying Systems. Low pressure (LP) steam will be used in the tube dryers to pre-dry the raw coal to approximately 12 weight-percent moisture before being fed into the Coal Milling & Drying System. In the 2 x 50 percent operating (plus one spare) mills, hot drying gases from the combustion of natural gas and NWU offgas will be used to dry the pulverized coal to an approximate 5 weight-percent moisture. The hot drying gases will carry the dried, crushed coal and gases out of the mills and to rotary classifiers, which will return particles larger than the desired size to the mills. A portion of the spent hot drying gas will be purged through a dust collector (fabric filter) and vented to the atmosphere. Collected dust will be combined with the coal from the classifiers. The dried, pulverized coal will then be pneumatically conveyed, using N_2 gas, to the coal bunker that serves the coal feeding system for the gasifier.

Air Separations Unit – The ASU[7], about 83 percent smaller than in the prior configuration, will consist of a 1 x 100 percent main air compressor, a 1 x 100 percent cold box, and 2 x 100 percent cryogenic liquid oxygen (O_2) pumps. It will provide O_2 gas and N_2 gas for the entire facility. The ASU will produce about 2,704 tpd of 99.5 percent pure O_2 for use as an oxidant in the gasifier, and about 4,142 tpd of 99.9 percent pure N_2 for use as follows: (1) 1,740 tpd for producing ammonia (NH_3) as a precursor to urea fertilizer; (2) 962 tpd as a carrier gas for dry coal feed to the gasifier and for purging purposes in the gasification island; and, (3) 1,440 tpd as a carrier gas for coal milling and drying. The ASU will also produce about 1,200 tpd of 98 percent pure N_2 for use as a diluent to be blended with the syngas feed to the gas turbine. The ASU will produce a high-purity stream of argon gas, about 85 tpd, to be recovered as a commercially marketable product. For startup and shutdown purposes, and to enhance overall plant availability, liquid O_2 and liquid N_2 storage will be provided. Excess liquid N_2, about 75 tpd, would be a commercially marketable product.

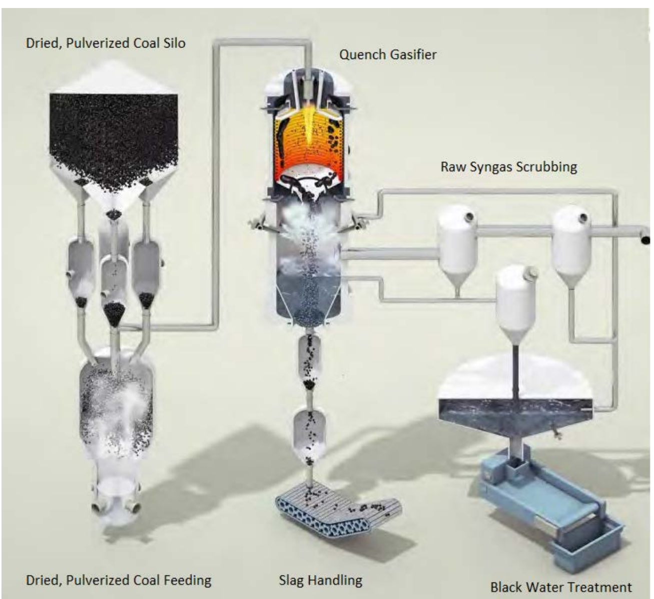

FIGURE 2-1 Siemens Gasification Systems

Gasification Island – The gasification island[8] (illustrated in Figure 2-1) will include: a 1 x 100 percent dense-flow pulverized coal feeding system; a 1 x 100 percent dry feed, oxygen-blown, quench gasifier with three burners and cooling screen; a 1 x 100 percent raw syngas treatment system; a 1 x 100 percent slag discharge unit; a 1 x 100 percent slag loadout system; a 1 x 100 percent flash system; a 1 x 100 percent black water treatment system; and, a 1 x 100 percent black water filter cake transport and storage system.

Pulverized Coal Feeding System – A dense-flow coal feeding system, using N_2 as the carrier gas, will receive the pulverized and dried coal from the Coal Milling and Drying System and feed it through three burners into the gasifier. The system includes a dry coal silo, four pneumatic conveying drums, lock hopper, and three feeder vessels.

Quench Gasifier – The TCEP will feature one SFG-850 (850 MW_{th} coal heat input LHV basis) dry feed, entrained-flow, oxygen-blown gasifier. The reactor/quench vessel is about 9,000 ft^3 and will produce about 229,500 normal cubic meters per hour (Nm^3/hr) of raw syngas. This is a key change from the two SFG-500 (500 MW_{th}) gasifiers used in the prior configuration. Coal will be almost totally gasified in a pressurized (greater than 600 psig), high-temperature (greater than 2,600 ºF) environment to form raw syngas consisting principally of H_2, CO, CO_2, and water. Other constituents that are formed, and which will need to be removed, are NH_3, hydrogen sulfide (H_2S), and carbonyl sulfide (COS). The inorganic materials in the coal will be converted to a hot, molten slag. The hot raw syngas and the molten slag will leave the gasifier and flow downward into the quench section. There, the raw syngas will be cooled by the injection of water, and the molten slag will solidify in the bottom of the quench section.

[7] The Linde Group (Germany) is the ASU process technology licensor.
[8] Siemens Fuel Gasification Technology GmbH & Co. KG (Germany) is the process technology licensor for systems deployed in the gasification island.

Granulated slag, quench water, and some unreacted char forms a mixture referred to as black water that will be removed from the quench chamber and treated in the black water treatment plant. A portion of that stream will be recycled for use as quench water, with the remainder being cleaned further for use in other areas of the plant. The slag removed from the quench sump will be dewatered and conveyed to the slag handling, storage and loadout system. Water carried out of the slag discharge system will be collected and pumped to the black water treatment plant. Water that is needed in the slag discharge system will be recycled from the black water treatment plant.

Raw Syngas Treatment Systems – The raw syngas from the quench section will be sent to a raw syngas treatment system for removal of fine ash, chlorides and char. This system includes a jet scrubber for removal of large particles, two venturi scrubbers for removal of mid-sized and fine particles, a high-pressure nozzle system and a raw syngas knockout drum. A portion of the scrubber water will be sent to the black water treatment plant.

Slag Discharge Unit and Loadout System – The 1 x 100 percent slag discharge unit, a change from the 2 x 100 percent system of the prior configuration, will remove and collect inert gasifier slag and convey it to storage for the loadout system. The unit will consist of a crusher, hopper, and water-cooled discharge conveyor. The inert, non-leachable slag, about 665 tpd,[9] will be collected in the slag trough and conveyed to a covered storage area. The storage area will be periodically emptied by front-end loaders moving the slag to the chain reclaimer. The chain reclaimer will convey the slag onto belt conveyors that transfer the slag to a loadout for rail or truck. The slag from the TCEP will be sold as a commercially marketable product, for example, for use in the manufacture of cement, as a road base, for manufacturing roofing tiles, as asphalt filler, and as a sandblasting agent. Any slag not sold will be trucked or sent by rail to a permitted off-site solid waste landfill.

Flash System – During startup and in emergency situations, the raw syngas will be burned in a flare, with the exhaust gases vented to the atmosphere.

Black Water Treatment System – The black water treatment system will include one flash vessel, chemical dosing for precipitation and flocculation to remove suspended solids, a settling basin, a wastewater vessel, and a sludge filter press. Liquid effluent from the quench chambers, the slag discharge units, and blowdown scrubbing water from the syngas scrubbing system, as well as remaining syngas condensate, will contain fine particulate matter, unreacted carbon (soot), salts, and condensed heavy metal sulfides removed from the syngas stream. The pressurized black water will be sent to the flash vessel to remove dissolved gases and for cooling.

The pretreated black water will then pass through the precipitation and flocculation steps, where flocculants will be added to stimulate coagulation and settlement of soot and fines. Fine slag and precipitants will be removed in a gravity settler, thickened and dewatered using a fabric filter press to separate the solids from the black water stream. Up to 90 percent of the dried filter cake (containing a large fraction of unreacted carbon) will be mixed with the feed coal and recycled in the gasifier to produce more syngas, and the remainder will be sent for appropriate off-site disposal. A portion of the clear overflow from the gravity settler, called grey water (< 0.1 percent dry solids), and the filtrate of the filter unit will be collected and mixed with softened water for recycle to the gasification island for use in the quench and slag discharge systems. The remaining grey water, which contains a high concentration of chloride salts, will be sent to the wastewater treatment system for further treatment.

<u>Gas Cleanup</u> – Gas cleanup for the TCEP will consist of a 1 x 100 percent CO shift unit, a change from the 2 x 50 percent CO shift unit of the prior configuration; a 1 x 100 percent low-temperature gas cooling unit; and, a 1 x 100 percent mercury (Hg) removal unit.

CO Shift Unit – To increase the H_2 content and decrease the CO (and thereby increase the CO_2) content of the syngas for low-CO_2 (after capture) power generation and for production of urea (which requires CO_2 feedstock), a sour[10] CO Shift Unit with three shift stages will be used to alter the syngas composition using the water-gas shift reaction. CO present in the raw syngas from the gasification island will react with steam over a cobalt and molybdenum oxides catalyst bed to form CO_2 and H_2. Once the syngas is shifted to a high concentration of CO_2 (and H_2), the CO_2 can be efficiently removed in the downstream RWU/AGR system, where greater than 90 percent of the CO_2 will be removed from the syngas. The shift unit will also convert COS to H_2S, which will be considerably easier to remove in the AGR system than COS. After H_2S removal in the RWU/AGR, the syngas will have a very low

[9] No filter cake recycle case. The Design Basis notes that up to 90 percent of the filter cake will be recycled to blend with the inlet coal in the Coal Milling & Drying System, so that the unreacted carbon left in the filter cake can be gasified, producing enhancing syngas production and reducing the use of raw coal.
[10] The CO shift unit is a sour shift unit because it will be placed prior to the AGR system, and therefore the syngas will contain large amounts of H_2S and COS. Because the shift reaction will release energy in the form of heat, the reaction equilibrium will favor high CO conversion at lower temperatures, and low CO conversion at higher temperatures. The heat from the shift reaction will be used to generate steam for use in other areas of the TCEP.

concentration of sulfur contaminants, which will minimize sulfur dioxide (SO_2) emissions in the gas turbine exhaust and will reduce sulfur in the feed stream sent to the urea plant.

Low-Temperature Gas Cooling Unit – Condensate from the CO Shift Unit will be cooled further in the low-temperature gas cooling unit. Water will condense from the syngas as it is cooled. The condensate will be collected and stripped of NH_3 and minor dissolved gasses, heated, and returned to the gasification island for use in the syngas scrubbing system. The cooled overhead sour scrubber gases, which will primarily contain sulfur gases, will be sent to the H_2SO_4 plants. The cooled syngas will be sent to the Hg removal unit.

Mercury Removal Unit – Hg removal will be accomplished by passing the syngas through a pre-sulfided activated carbon bed adsorber, where the Hg compounds will be adsorbed and converted to stable mercuric sulfide (HgS). The system is expected to achieve greater than 95 percent Hg removal from the syngas, based on the performance of this technology in other coal gasification plants. At the end of its useful life, the carbon beds will be removed (and replaced) and transported off-site to appropriate facilities for disposal or recovery of the Hg compounds.

<u>Sour Water Treatment</u> – The coal gasification process will generate the following sour (sulfur-bearing) wastewater streams: (a) gray water effluent from the black water clarifiers; (b) black water clarifier sludge from the gasification block; and, syngas condensate from the raw syngas stream in the piping and in the syngas coolers upstream of the AGR system. The TCEP will incorporate a 1 x 100 percent sour water stripper, a change from the 2 x 100 percent system of the prior configuration, to treat those sour wastewater streams from the gasification process. The sour water stripper column will remove both H_2S and NH_3 from the sour water stream and return the treated water back to the gasification island for reuse.

The combined feed, from the sources listed above, will first enter a degassing flash drum, where dissolved gases will be released, and entrained oil and solids will be removed. The overhead from the degassing drum will be combined with the overhead from the downstream sour water stripper and sent to the H_2SO_4 plants. After degassing, the water temperature will be increased by heat exchange with the stripped sour water from the sour water stripper. The heated sour water will be fed to the steam-reboiled sour water stripper. Most of the NH_3 in the sour water feed will be removed in this column. Sodium hydroxide (NaOH) will be injected as needed to facilitate the release of NH_3 from the condensate. Stripped sour water will then be sent to the wastewater treatment system.

<u>Acid Gas Removal</u> – The shifted syngas stream will be sent to a 1 x 100 percent RWU/AGR[11] system. The system will be somewhat smaller than in the prior configuration due to the reduced syngas production in going to the single SFG-850 gasifier from the twin SFG-500 gasifiers of the previous configuration. The RWU operates at about -40 ºF (-40 ºC), unlike other AGR systems that use chemical solvents, and therefore has a substantial chiller system. The Rectisol® process is well-commercialized and uses concentrated and chilled methanol (greater than 99 percent by weight) as a physical solvent in a re-circulating wash column to physically dissolve and remove the acid gas components (H_2S, COS and CO_2).

Concentrated streams of sulfur compounds (H_2S and COS) and CO_2 will be produced for downstream processing. The H_2S and COS will be removed in the lower section of the Rectisol® wash column, and the CO_2 will be removed in the upper section. The sulfur-containing gases that are captured and removed in the RWU/AGR will be sent to the H_2SO_4 plants. The RWU/AGR is designed for greater than 99 percent sulfur removal, or to less than 0.1 parts per million by volume (ppmv); and, for removal of greater than 90 percent of the CO_2 from the syngas, or to less than 1.6 volume-percent.

A total of about 2,800 million Btu per hour (MMBtu/hr) of clean syngas will exit the RWU/AGR system and be divided into two streams of different quality for downstream use. One syngas stream of about 1,450 MMBtu/hr, and approximately 89 mole percent H_2 with a very low content of CO_2 and a total sulfur concentration of less than 0.1 ppmv, will be moisturized and used as a fuel for the advanced Siemens "H" class turbine, blended with N_2 diluent and natural gas at about 56 percent syngas to 44 percent natural gas. The other syngas stream of about 1,280 MMBtu/hr, and approximately 93 mole percent H_2, and will be sent to the NWU for final purification before going to NH_3 synthesis leading to urea production.

A total of about 7,940 tpd or 2.40 MMtpy of CO_2 will be produced in two streams of different purities. A portion of the higher-purity CO_2 stream of about 1,827 tpd or 0.56 MMtpy will be sent to the urea synthesis plant as feedstock for conversion of NH_3 into ammonium carbamate ($NH_2CO_2NH_4$), which will then decompose into granulated urea fertilizer. The lower-purity CO_2 stream and

[11] Linde Engineering North America Inc., a.k.a. The Linde Group (Germany) is the process technology licensor for the RWU/AGR, TSA and NWU.

the remaining part of the high-purity stream that could not be used in the urea production plant will be combined (about 6,113 tpd or 1.84 MMtpy), dried, and compressed for transport via pipeline for off-site deep geologic storage with concomitant EOR.

<u>Liquid Nitrogen Wash Unit</u> – The clean, H_2-rich syngas streams exiting the RWU/AGR system, along with high-pressure N_2 from the ASU, will be fed to the NWU. Traces of water, CO_2, and AGR solvent (methanol) will first be removed in the Temperature Swing Adsorption (TSA) system. Both incoming streams of H_2-rich fuel gas and high-pressure N_2 will be cooled against product gas. The syngas will be fed to the bottom of the N_2 wash column, and high-pressure N_2 will be fed at the top. Trace components (offgas or tail gas at about 49 MMBtu/hr) will be removed and separated at the bottom of the column and routed to the Coal Milling & Drying System, where it will be used as a fuel, along with natural gas, for coal drying. The pure H_2 product gas will exit at the top of the column, then through the heat exchanger (against the incoming H_2-rich fuel gas and high-pressure N_2).

<u>Commercial Product Process Units</u> – The chemical product facilities for the TCEP will include H_2SO_4 plants; CO_2 compression and drying; and, the ammonia/urea facilty.

Sulfuric Acid Plants – Acid gas streams from the RWU/AGR and sour water treatment units, along with flash gas from the gasification island, will be sent to the 2 x 100 percent H_2SO_4 plants.[12] This is a change from the 1 x 100 percent of the prior configuration. Both plants will operate at 50 percent load during normal operations. Should one plant go offline, the other would ramp up to support 100 percent TCEP load.

The sulfur compounds will be recovered using a catalytic process to generate commercial-grade, concentrated H_2SO_4. The feed streams will be combusted with air to convert the sulfur compounds to SO_2. Natural gas will be used in normal operations for startup, support, and burner pilot flames. Flue gas from the burner will be cooled by generating superheated steam in a waste heat boiler. The cooled process gas will be sent to a selective catalytic reduction (SCR) system to reduce nitrogen oxides (NO_x) formed during combustion. After NO_x reduction, the gas will enter a three-pass catalytic SO_2 converter, where SO_2 will be oxidized to sulfur trioxide (SO_3). Between each stage of the converter, the gas will be cooled through inter-bed coolers to maximize the conversion in each reactor. Heat from the gases exiting the SO_2 converter will be used to boil water, thereby cooling the effluent gas. During the cooling, most of the SO_3 will react with water in the process gas to form gaseous H_2SO_4. Cooled process gas will condense in the form of concentrated H_2SO_4, and the remaining cleaned gas will exit as tail gas. Hot acid leaving the condenser will be cooled prior to being sent to storage. The TCEP will produce about 50 tpd of concentrated H_2SO_4. About 92 percent (or 46 tpd) of the sulfuric acid will be sold for commercial use. The remaining portion (about 4 tpd) will be pumped to the urea synthesis plant, where it will be used in an ammonia scrubbing system, to reduce air emissions. The byproduct will be ammonium sulfate, a commercially saleable fertilizer. The H_2SO_4 product for commercial sales will be stored in a carbon steel tank coated with a fluorinated polymer and then pumped from the storage tank to either rail tank cars or trucks for transportation off-site.

The tail gas from the condenser section will be routed to a tail gas scrubbing system that uses a dilute hydrogen peroxide (H_2O_2) stream to remove residual SO_2. The overhead vapor from the tower will pass through an electrostatic mist eliminator to remove entrained acid mist. The cleaned gas will be sent to the acid plant stack.

CO_2 Compression and Drying – The CO_2 captured by the RWU/AGR process will be dried, compressed, and divided into two streams, one at low pressure and one at medium pressure. Part of the high purity CO_2 recovered at medium pressure will be further purified to remove moisture and contaminants in a 1 x 100 percent CO_2 purification system and then compressed to high pressure in a 1 x 100 percent CO_2 compressor and sent to the urea synthesis plant. The remainder of the medium pressure, high purity CO_2 stream, along with the low pressure CO_2 stream from the RWU/AGR system, will be compressed to high pressure (about 2,000 psi) in a second 1 x 100 percent CO_2 compressor and transported off-site via existing regional pipeline for deep geologic storage with concomitant EOR.

Ammonia/Urea Plant – For the manufacture of NH_3, the high-H_2 concentration stream from the NWU will be compressed and cooled, then mixed with N_2 from the ASU in a ratio of approximately 3 to 1 in a 1 x 100 percent Ammonia Synthesis Plant[13] producing 99.9 percent anhydrous ammonia. This combined H_2 and N_2 stream will be sent to a multi-bed catalytic reactor in which the NH_3 concentration will be increased. Liquid NH_3 from the bottom of the separator will be fed to another separator operating at a lower pressure. The liquid recovered from this vessel will be sent directly to a receiver in the refrigeration section of the Ammonia Synthesis Plant. Liquid NH_3 will enter the receiver, where it will be split into two streams. Multiple heat exchangers will be used to

[12] Haldor Topsoe (Denmark) is the process technology licensor for the sulfuric acid plants.
[13] Casale S.A (Switzerland) is the process technology licensor for the ammonia synthesis plant.

cool the liquid streams before routing them to one of two separators. Vapor from these separators will combine with the compressed NH_3 vapor from the storage tank and will be recycled back to the receiver at the front of the refrigeration section. The liquid NH_3 product will be sent to the Urea Synthesis Unit (USU),[14] or to the storage tank if needed.

The USU will consist of a 1 x 100 percent urea synthesis system and a 1 x 100 percent urea granulation system. The synthesis system will take the NH_3 and convert it to urea, $(NH_2)_2CO$. A portion of the CO_2 from the RWU/AGR system will be compressed and sent to a urea reactor where it will combine with liquid NH_3. Ammonium carbamate ($NH_2CO_2NH_4$) will be formed and allowed to decompose into urea. In the granulation system, the concentrated urea solution (about 96 percent purity prior to granulation) will be sprayed by a liquid jet into a granulator bed. The bed of particles will be fluidized with fluidization air. When the particles reach a desired size, they will fall through a bottom grid on the bed. The urea granules will be subsequently cooled. A fraction of the particles leaving the granulation bed will be sent to a crusher. The finer particles will act as seeds for growing urea granules in the granulation bed. The air exiting the granulator will be scrubbed with water to remove traces of urea before being directly vented to the atmosphere. The TCEP will produce about 2,480 tpd or 0.756 MMtpy of granulated urea for use as agricultural fertilizer. The urea handling system will transfer granulated urea from the USU to the storage domes and then to rail loadout. A transfer conveyor will deliver urea from the plant to the tripper conveyor, which will transfer the urea to four storage domes having a total capacity to store about 50 days of urea production. Another conveyor will pick up and transfer the granulated urea from the storage domes to the urea loadout conveyor, which will then carry the urea to the loadout bin. Urea will be loaded into railcars for shipment to market, using a telescoping chute. The conveyors will be fully enclosed for weather protection and to control fugitive dust. All urea handling buildings will be fully enclosed or will have dust collection or control systems.

2.2 Combined Cycle Power Block

The Power Block[15] will consist of an advanced 1 x 100 percent high-H_2 capable gas turbine-generator with inlet air chiller; a 1 x 100 percent triple pressure Heat Recovery Steam Generator (HRSG) with SCR system and CO catalyst; a 1 x 100 percent steam turbine-generator with 20-cell air-cooled condenser; and, flash drums, condensate pumps, and boiler feed water pumps. The TCEP combined cycle power block will generate about 405 MW_e (gross), reduced for site conditions. On a like basis, this is an increase from the approximately 379 MW_e (gross) of the previous configuration.[16] After taking power for plant parasitic loads and commercial product facilities, about 200 MW_e of low-CO_2 power would be available to the electric utility grid, or about 1,532,200 MWhr annually.[17]

Combined Cycle Gas Turbine – The TCEP will feature one 60-Hz SGT6-8000H combustion gas turbine. This is a key change from the smaller 60-Hz SGT6-5000F3 used in the prior configuration. The 8000H machine is rated to generate up to 296 MW_e (gross).[18] For the TCEP, it will be designed to combust H_2-rich coal-derived syngas blended with natural gas at about 56 percent syngas as the primary fuel (and 44 percent natural gas), and 100 percent natural gas as a startup and backup fuel. The syngas will first be moisturized prior to entering the gas turbine and will be diluted with high-pressure N_2 from the ASU. The addition of N_2 to the syngas, along with injection of additional N_2 at certain locations in the combustion zone inside the gas turbine, will cool the combustion flame to reduce the formation of thermal NO_x and increase the mass flow through the gas turbine, boosting the gas turbine power output.

Heat Recovery Steam Generator – The HRSG will convert the heat in the gas turbine exhaust to steam, which will then be used in the steam turbine to generate additional power. The feed water system will move and control water flow through the HRSG to generate steam. The steam system will consist of three sections: high-pressure steam, reheat steam, and low-pressure steam. Some steam will be transferred to other locations in the plant to support functions other than driving the steam turbine. The HRSG will supply superheated high-pressure steam to the high-pressure section of the steam turbine. The exhaust from the high-pressure section of the steam turbine, called cold reheat steam because it is reduced in temperature and pressure, will be returned to the HRSG for reheating and combining with additional intermediate-pressure steam produced in the HRSG, and then sent to the intermediate-pressure section of the steam turbine as hot reheat steam. Exhaust from the intermediate-pressure section of the steam turbine (low-pressure steam) will be combined with low-pressure steam from the HRSG to supply the low-pressure portion of the steam turbine. Exhaust from the low-pressure portion of the steam turbine will be cooled in the air-cooled condenser.

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[14] Saipem S.p.A. (Italy) is the process technology licensor for the USU and urea granulation.
[15] Siemens Energy (USA) is the process technology licensor for Power Block systems.
[16] The 379 MW_e (gross) of the previous configuration would have been increased to 439 MW_e (gross) by the addition of 60 MW_e in duct firing not applicable to the present configuration.
[17] 31-year annual average operational estimate as of July 8, 2015.
[18] Source: Siemens Energy Web site: http://www.energy.siemens.com/hq/en/fossil-power-generation/gas-turbines/sgt6-8000h.htm; nominal gross output will vary due to type of fuel and other considerations.

Combined Cycle Steam Turbine - The TCEP will carry over the SST-900RH steam turbine from the previous plant configuration. 900-class machines are rated to nominally generate up to 250 MW_e (gross).[19] By using air-cooling for the Power Block, it is expected that there will be a 30 percent reduction in water consumption.

2.3 General Facilities and Plant Utility Systems

General facilities and Plant utility systems will include raw water treatment; a demineralized water system; a potable water system; fire protection systems; cooling systems; flare systems; an auxiliary boiler; wastewater treatment; deep well injection of nonhazardous brine water; emergency diesel engines; storm water management; and control systems.

<u>Cooling Systems</u> – Two types of cooling systems will be used: wet and dry cooling. An air-cooled condenser will be used for the combined cycle power block. For the chemical processes portion of the polygen plant, units requiring cooling to temperatures less than 140 °F may use wet cooling if other chilled process fluids are not available for heat transfer cooling. Air cooling may be used for the chemical processes portions of the polygen plant where less cooling is required. Makeup water for the wet cooling tower will be obtained from treated municipal wastewater or, under some options, ground water. Cooling tower blowdown from the wet cooling tower will be directed to the wastewater treatment system. The cooling tower will be equipped with a drift eliminator designed to limit drift losses to 0.001 percent of the circulation rate.

<u>Flare Systems</u> – Flare systems will be provided to allow for the safe venting of gases produced during startup, shutdown, and upset conditions. The TCEP will include two flares, each approximately 200 feet high. The main flare will handle combined relief loads, including vent gases from coal gasification, CO shift, and the AGR system. The second flare will handle NH_3 and acidic gas relief loads. It will ensure complete combustion of relief streams with high-NH_3 concentration. Acid gases will be carried by a dedicated header to be burned in a common burner with the NH_3 relief streams. Cold relief loads will be warmed in a low-pressure/medium pressure (LP/MP) steam warm up system prior to sending this stream to the flare. As part of the design of the flare systems, a natural gas–fueled pilot will remain lit on each flare during normal operation to ensure the flares are available if needed. Peak flaring will occur during planned gasifier startups.

The main flare will be designed to burn: (1) syngas associated with process operations and purges associated with normal gasifier operation; (2) non-specification syngas generated during unit startup; (3) syngas generated during short-term gas turbine outages; and, (4) syngas released from pressure-relief valves used to protect against overpressure of individual pieces of process equipment. Syngas sent to the flare during normal flaring events will be filtered, water-scrubbed, and further treated in the AGR system to remove regulated contaminants prior to flaring. Flaring of untreated syngas or other streams will only occur as an emergency safety measure during unplanned plant upsets or equipment failures.

The primary air contaminants in the raw syngas stream will be CO and H_2S, with trace amounts of COS and NH_3. Estimated CO emissions from the flares are based on 98 percent destruction of the CO (by combustion with air) in the flared stream. NO_x emissions are based on the TCEQ-approved factor for flares plus 50 percent conversion of the NH_3 to NO_x. H_2S and SO_2 emissions are based on 98 percent conversion of the H_2S and COS in the stream being converted (by combustion with air) to SO_2.

<u>Auxilliary Boiler</u> – An auxiliary boiler which can fire natural gas or syngas for fuel will be included. The boiler will have a maximum firing capacity of 250 MMBtu/hr on a higher heating value (HHV) basis. The boiler will be primarily used during startup and shutdown. The auxiliary boiler will be equipped with ultra-low NO_x burners and flue gas recirculation to control NO_x emissions.

<u>Deep Well Injection</u> **–** In lieu of large evaporation ponds and a brine crystallizer included in the prior TCEP design, deep well injection will be used for disposal of the brine waters from the raw water treatment and wastewater treatment systems. For the raw water treatment system, the reverse osmosis reject will be treated in a brine concentrator, and then pumped to the deep well injection system. For the wastewater, the reject from the reverse osmosis system will be pumped directly to the deep well injection system. The injection wells will deliver the brine water from the surface to the underground geologic Queen Formation through piping, in conformance with requirements for Class I injection wells. The injection casing will be perforated in the Queen Formation at intervals selected using the results of geophysical logging.

[19] Source: Siemens Energy Web site: http://www.energy.siemens.com/hq/en/fossil-power-generation/steam-turbines/sst-900.htm; nominal gross output may vary.

Emergency Diesel Engines – One 350-horsepower (hp), diesel-fueled fire-water pump and two 2,205-hp, diesel-fueled emergency generators will be deployed at the TCEP. The pumps and generators will only operate during emergencies and on regularly scheduled intervals for testing. It is estimated that these engines will be operated a maximum of 52 non-emergency hours per year each for testing. The engines will not operate during normal polygen plant operations.

Storm Water Management – Storm water runoff will be directed to on-site retention/settling ponds to control peak discharge. The ponds will be sized based on the area of impervious surface on the polygen site and the maximum design storm-flow volumes. There will be no discharge from the storm water runoff ponds. Any storm water runoff that comes into contact with an area that had the potential for the presence of oil (such as water runoff from parking lots) will be directed to a separate retention pond and then on to an oil/water separator. Wash down water and other miscellaneous sources will also enter the retention/settling ponds.

Control Systems – The TCEP control system will allow monitoring and control of the plant to be accomplished from a central control room. From work stations, operators will monitor the plant processes and manipulate controls as needed to maintain efficient and safe plant operations. Engineering workstations will give the plant engineering workforce the ability to monitor plant operations and update software and control schemes as needed.

3. ENVIRONMENTAL PERFORMANCE

TABLE 3-1 TCEP Emissions

Particulate Matter	0.008	lbs/MMBtu	
SO_2	0.005	lbs/MMBtu	Greater than 99 percent removal
Mercury	0.012	tpy	Greater than 95 percent removal
NO_x	0.0112	lbs/MMBtu	Greater than 90 percent eliminated
CO_2	0.585	MMtpy	Greater than 90 percent removal from the syngas produced; about 90 percent removal on a plant-wide basis

Table 3-1 summarizes TCEP emissions. As part of the FEED Update, the design of the reconfigured plant must also comply with all of the air permit limitations. Total plant emissions per year will not exceed air permit limits due to the reduced size of the Chemical Block (reduced coal feed and resulting size of the ASU and syngas production and cleaning systems), and due to lower capacity factor (83.7 percent). Point source emissions from the 8000H gas turbine will be the same as the prior 5000F3, as the plant configuration maintains an SCR and CO catalyst. Total emissions from the 8000H Power Block will not exceed the air permit limits due to the lower capacity factor.

The TCEP will be among the cleanest commercial, solid-fuel power facilities in the world and will significantly surpass the emissions reduction targets for 2020 established under the EPAct 2005, Public Law 109-58. The facility's emissions will be far below any limits previously permitted in Texas for a fossil-fuel plant, and will meet the U.S. EPA 111(b) Rule for CO_2 emissions. At about 90 percent carbon capture efficiency plant-wide and greater than 90 percent from the total coal syngas produced, the TCEP's CO_2 emissions on a MWhr basis will be about 50 percent of a comparably-sized NGCC power plant without CO_2 capture.

4. PROJECT STATUS

STCE has essentially completed all technical (engineering and design), and environmental (NEPA and permits) work that is typically necessary to support financial closing on construction financing (refer to the Background section of this paper for more information). Off-take agreements are in place for all the TCEP primary products. This has been the case for two years (and more). STCE has proceeded with a portion of the advanced engineering that would normally be done after financial close in order to ensure continuity of work and optimize the construction schedule, while it continues to strive toward bringing the project to financial close; i.e., working to address the needs of potential debt and equity partners.

5. FEDERAL PROJECT MANAGER PERSPECTIVE[20]

The challenges that STCE and the TCEP have faced during the definition and development phase of the project are emblematic of why such projects are of interest to the U.S. Government; reinforcing the need for government involvement through taking on a substantive portion of the financial risks inherent to demonstrating the commercial efficacy of first-of-a-kind commercial-scale demonstration projects. Yet even with Federal financial assistance, the challenges facing TCEP and other such projects, particularly

[20] The contents of this section represent the views of the NETL Federal Project Manager assigned to the TCEP and do not necessarily reflect the views of the NETL, the Office of Fossil Energy, the Department of Energy, or the United States Government.

those that are project financed, can remain daunting and may ultimately prove difficult to overcome. Even so, the prospects without Federal assistance would not be as attractive.

Other observations include:

1) Having substantially completed all technical engineering/design and offtake agreements typically necessary for achieving financial close on project construction financing does not necessarily mean a project will achieve financial close.
2) While there is a good general understanding for accurate scheduling of activities such as engineering and design, it is very difficult to identify an accurate schedule for activities directly related to the securing of project financing, including securing debt and equity commitments, and completing financial due diligence, which can be heavily nuanced. This means that there may be little real utility in attempting to manage all aspects of the front end (definition and development) phase of such projects using a fully loaded resource scheduling tool.
3) While changing contractors and systems and going through cost reduction exercises may all be signs of a project most likely to 'fail' if that project is a 2^{nd} or 3^{rd} or N^{th} of-a-kind, it may simply be a subset of the risks and challenges associated with a first-of-a-kind commercial-scale demonstration project.
4) Each potential debtor and contributor to equity may likely have its own unique thresholds (e.g., for IRR) for committing to a project.
5) International collaboration and partnerships bring additional complications and nuance; this is magnified when government-to-government interactions are also involved or may be helpful.
6) Is a $450 million dollar cost-shared contribution from the government enough to push a multi-billion dollar first-of-a-kind commercial-scale demonstration project over the top? Is there a better approach to federal incentives for such projects? The government may need to re-evaluate its technology and other incentive programs to better ensure successful outcomes and that national objectives/goals are achieved.
7) Patience and hard work are essential for riding out the 'hills and valleys' toward success.

6. ACKNOWLEDGEMENTS

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7. DISCLAIMER

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ATTACHMENT 1, COMPARISON OF TCEP CONFIGURATIONS AT NORMAL OPERATING CONDITIONS

Component	Units	Plant 12/2013	Plant 12/2014	Reason For Change/Comment(s)
Coal Storage Pile(s)	Tons	261,000	147,000	Coal pile reduced from 45-days to 30-days of storage; same height.
Coal Input, as received	Tons/Day	5,789	4,983	Lower coal feed due to replacing two SFG-500 gasifiers with a single SFG-850 gasifier.
Coal Input, dried at 5% moisture	Tons/Day	4,291	3,693	Lower coal feed due to SFG-850; added LP steam Coal Pre-Drying; Coal Milling & Drying System now combusts NG and NWU offgas.
O_2 Consumption	Tons/Day	3,240	2,704	Lower O_2 feed due to SFG-850 gasifier; also reduces size of ASU.
Raw Syngas Production ($CO + H_2$)	Nm^3/hr	275,000	229,486	Switch to SFG-850 results in reduced raw syngas production as compared to operating two SFG-500 gasifiers.
Clean Syngas (HHV)	MMBtu/hr	3,345	2,774	Switch to SFG-850 results in reduced clean syngas exiting RWU.
Clean Syngas to NH_3/Urea (HHV)	MMBtu/hr	1,390	1,281	SFG-850 results in reduced clean syngas production; split to NH_3/urea is about 8% lower than previous configuration.
Clean Syngas to Gas Turbine (GT) (HHV)	MMBtu/hr	1,864	1,444	Syngas to Power Block (gas turbine) is function of total clean syngas exiting RWU and clean syngas required for the NH_3/urea plant.
Natural Gas (NG) to Power Block (HHV)	MMBtu/hr	291	1,150	NG to Power Block is blended with coal-derived syngas and combusted in the GT; percentage of syngas in fuel blend reduced.
Total Heat Input to GT (HHV)	MMBtu/hr	2,155	2,594	8000H GT is larger than prior 5000F3 GT.
NG to Duct Burners (HHV)	MMBtu/hr	689	0	Current configuration does not have duct burners; 8000H GT is larger than prior 5000F3 GT.
Total Heat Input to Power Block (HHV)	MMBtu/hr	2,844	2,594	Sum of inputs above to GT and duct burners (duct firing only applies to previous configuration).
Combined Cycle (CC) Output	MW_e	378.8	405	Shown reduced by site conditions; nameplate of both configurations is >400 MW_e; increased output is a result of using larger 8000H.
CC Heat Rate (HHV)	Btu/kWh	7,508	5,984	8000H CC (w/o duct burners) has higher efficiency than 5000F3 CC.
CO_2 Captured	Tons/Day	9,334	7,940	Switch to SFG-850 results in reduced clean syngas production and consequently decreased total CO_2 production (and captured CO_2).
CO_2 Captured	Tons/Year	3.1 M	2.4 M	Reduced due to SFG-850 and 83.7% capacity factor.
CO_2 to Urea Plant	Tons/Day	2,036	1,827	Reduced urea production requires less CO_2.
CO_2 to Urea Plant	Tons/Year	684,000	558,158	Reduced due to SFG-850 and 83.7% capacity factor.
CO_2 to EOR	Tons/Day	7,298	6,113	CO_2 to EOR is function of CO_2 captured less CO_2 required for urea.
CO_2 to EOR	Tons/Year	2.42 M	1.84 M	Reduced due to SFG-850 and 83.7% capacity factor.
Urea Production	Tons/Day	2,737	2,476	Approximately 9% lower than the previous configuration.
Urea Production	Tons/Year	919,000	756,000	Reduced due to SFG-850 and 83.7% capacity factor.
Slag/filter cake (no recycle case)	Tons/Day	774	665	Reduced due to lower coal feed rate.
H_2SO_4 Production	Tons/Day	56	50	Reduced due to lower coal feed rate and resulting lower levels of sulfur compounds to be removed from syngas.
H_2SO_4 (for sale)	Tons/Day	56	46	Reduced due to lower coal feed rate; further reduced due to about 8% of the produced H_2SO_4 being used to control NH_3 emissions in the urea plant (producing ammonium sulfate).
Ammonium Sulfate	Tons/Year	0	1,619	Estimated based on H_2SO_4 used in ammonia scrubber and converted; 83.7% capacity factor; not included in previous configuration.
Filter Cake	Tons/Year	129,970	98,767	Estimated based on SFG-850 gasifier and 83.7% capacity factor; up to 90% will be recycled and blended with coal so unreacted carbon in filter cake can be gasified in 2nd pass, reducing storage/disposal and reducing the inlet coal feed. Previous configuration value based on prior 92% capacity factor.