PRELIMINARY PUBLIC DESIGN REPORT FOR THE TEXAS CLEAN ENERGY PROJECT

TOPICAL REPORT

PHASE 1
JUNE 2010-JULY 2011

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DOE COOPERATIVE AGREEMENT
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Abstract

Summit Texas Clean Energy, LLC (Summit) is developing the Texas Clean Energy Project (TCEP or the project) to be located near Penwell, Texas. The TCEP will include an Integrated Gasification Combined Cycle (IGCC) plant with a nameplate capacity of 400 megawatts electric (MWe), combined with the production of urea fertilizer and the capture, utilization and storage of carbon dioxide (CO_2) sold commercially for regional use in enhanced oil recovery (EOR) in the Permian Basin of west Texas.

The TCEP will utilize coal gasification technology to convert Powder River Basin sub-bituminous coal delivered by rail from Wyoming into a synthetic gas (syngas) which will be cleaned and further treated so that at least 90 percent of the overall carbon entering the facility will be captured. The clean syngas will then be divided into two high-hydrogen (H_2) concentration streams, one of which will be combusted as a fuel in a combined cycle power block for power generation and the other converted into urea fertilizer for commercial sale. The captured CO_2 will be divided into two streams: one will be used in producing the urea fertilizer and the other will be compressed for transport by pipeline for offsite use in EOR.

The TCEP was selected by the U.S. Department of Energy (DOE) Office of Fossil Energy (FE) for cost-shared co-funded financial assistance under Round 3 of its Clean Coal Power Initiative (CCPI). A portion of this financial assistance was budgeted and provided for initial development, permitting and design activities. Front-end Engineering and Design (FEED) commenced in June 2010 and was completed in July 2011, setting the design basis for entering into the detailed engineering phase of the project.

During Phase 1, TCEP conducted and completed the FEED, applied for and received its air construction permit, provided engineering and other technical information required for development of the draft Environmental Impact Statement, and completed contracts for the sale of all of the urea and most of the CO_2. Significant progress was made on the contracts for the purchase of coal feedstock from Cloud Peak Energy's Cordero Rojo mine and the sale of electricity to CPS Energy, as well as a memorandum of understanding with the Union Pacific Railroad (UPRR) for delivery of the coal to the TCEP site.

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List of Acronyms and Abbreviations

AGR	Acid Gas Removal
ARRA	American Recovery and Reinvestment Act
ASU	Air Separation Unit
BACT	Best Available Control Technology
BEDD	Basic Engineering Design Document
BOP	Balance of Plant
Btu	British thermal unit
C	Carbon
CCPI	Clean Coal Power Initiative
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COS	Carbonyl Sulfide
CRT	Cost Reduction Team
CT	Combustion Turbine
DOE	U.S. Department of Energy
dscf	dry standard cubic foot
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
ERCOT	Electric Reliability Council of Texas
˚F	degrees Fahrenheit
ft^3	cubic foot
FE	Fossil Energy
FEED	Front-end Engineering and Design
ft/s	feet per second
FSH	Fort Stockton Holdings
gal	gallon (U.S.)
GCA	Gulf Coast Waste Disposal Authority
H_2	Hydrogen
HHV	Higher Heating Value
H&MB	Heat and Material Balance
H_2O	water
Hp	Horsepower
H_2S	Hydrogen Sulfide
hr	hour
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
kV	kilovolts
kW	kilowatts
lb	pound
lbs/hr	pounds per hour
LHV	Lower Heating Value
MMBtu	Million Btu
MMSCFD	Million Standard Cubic Feet per Day
mol %	mole percent
MW	Megawatt
MWe	Megawatt electric
NEPA	National Environmental Policy Act
NH_3	ammonia
NOx	nitrogen oxide
O_2	Oxygen
OEPPP	Odessa-Ector Power Partners
PFD	Process Flow Diagram
P&ID	Piping and Instrument Diagram
ppb	parts per billion
ppm	parts per million
ppmv	parts per million, volume basis
psi	pounds per square inch
psia	pounds per square inch, absolute
RAM	Reliability, Availability and Maintainability
ROW	Right-of-Way
SCF	Standard Cubic Foot
SFGT	Siemens Fuel Gasification Technology
SKEC	SK Engineering and Construction
SO_2	Sulfur Dioxide
TCEP	Texas Clean Energy Project
TCEQ	Texas Commission on Environmental Quality
ton	short ton
tons/day	short tons per day
tons/hour	short tons per hour
TPD	tons per day
TPH	tons per hour
V	volt
WWTP	Waste Water Treatment Plant

Executive Summary

Summit Texas Clean Energy, LLC (Summit) is developing the Texas Clean Energy Project (TCEP or the project) to be located near Penwell, Texas. The TCEP will include an Integrated Gasification Combined Cycle (IGCC) plant with a nameplate capacity of 400 megawatts electric (MWe gross), combined with the production of urea fertilizer and the capture, utilization and storage of carbon dioxide (CO_2) which will be sold commercially for regional use in enhanced oil recovery (EOR) in the Permian Basin of west Texas.

The TCEP will utilize coal gasification technology to convert Powder River Basin sub-bituminous coal delivered by rail from Wyoming into a synthetic gas (syngas) which will be cleaned and further treated so that at least 90 percent of the overall carbon entering the facility will be captured. The clean syngas will then be divided into two high-hydrogen (H_2) concentration streams, one of which will be combusted as a fuel in an "F" class gas turbine-based combined cycle power block for power generation and the other converted into urea fertilizer for commercial sale. The captured CO_2 will be divided into two streams: about 21% of the total amount of CO_2 will be used in producing approximately 2,156 tons/day of urea fertilizer and the balance of the CO_2 will be compressed for transport by pipeline for offsite use in EOR.

The TCEP was selected by the U.S. Department of Energy (DOE) Office of Fossil Energy (FE) for cost-shared co-funded financial assistance under Round 3 of its Clean Coal Power Initiative (CCPI). A portion of this financial assistance was budgeted and provided for initial development, permitting and design activities. Front-end Engineering and Design (FEED) commenced in June 2010 and completed in July 2011.

Summit contracted with several engineering and technology companies for specific portions of the TCEP FEED, as follows:

- Gasification Block – Siemens Energy, Inc., through its subsidiary Siemens Fuel Gasification Technology GmbH & Co. KG
- Syngas Block – Linde AG, through its subsidiary Selas Fluid Processing Corporation
- Power Block – Siemens Energy, Inc., through its subsidiary Siemens Power Generation
- Balance of Plant and FEED Coordination – Fluor Corporation
- Operation & Maintenance Support – Siemens Energy, Inc., through its subsidiary Siemens Power Generation

In addition, Summit contracted with the following engineering companies to provide specific engineering and technical consulting services as follows:

- CH2M HILL, Inc. – IGCC and process plant technical consulting and support services; permitting and environmental documentation; engineering and cost estimates for plant laterals (i.e. pipelines and transmission line)

- RW Beck – owner's engineering services

One of the first project requirements at the beginning of FEED was to develop a Project Design Basis, which set the codes, standards, plant configuration, inputs and desired products and by-products for moving forward with the engineering and design work. Each of the FEED contractors began its FEED work, developing preliminary engineering data, process descriptions, process flow diagrams, and preliminary heat and material balances needed for integrating with the other FEED contractors' scopes of work. Once that preliminary information was completed, the project participants (FEED contractors and engineering and technical service providers) met in Fluor's offices for 16 weeks to conduct process simulations, developing overall TCEP facility configurations and heat and material balances for a range of operating conditions (i.e. maximum power generation, maximum urea production, one gasifier out of service. This FEED information was then disseminated to all of the project participants for use in their more detailed FEED work.

Preliminary engineering data developed prior to the FEED was used to prepare the initial air permit application. As more detailed information became available during the FEED, it was used to update the emission sources, locations, and inventories as part of an amendment to the air permit application. This same information was used in the development of the draft Environmental Impact Statement.

In February, 2011, cost estimates were prepared by the individual FEED contractors using their most recent FEED information. Upon review of the combined TCEP cost estimate, Summit initiated a comprehensive Cost Reduction Team. This team worked for 2 months to identify a wide range of design changes that could result in capital cost reductions for the TCEP facility. Representatives from all of the project participants worked on the team, and identified over $150 million in cost savings that could be achieved from key changes in design. Some of the largest cost savings came from changing some materials of construction, changing the water shift reactor configuration, deleting a methanol storage tank, combining two of the CO_2 compressors into one, reducing product storage tank sizes, eliminating the coal crushing system, modifying the coal feeding system to the gasifiers, and eliminating some of the buildings and associated cranes.

Reliability, Availability and Maintainability (RAM) modeling of the entire TCEP facility was performed by Siemens, using inputs from all of the FEED contractors. The results of the RAM analyses were used to make design changes that would enhance plant availability. For example, the RAM analyses showed that adding a second 100%-sized sulfuric acid plant would be a cost-effective change that would provide a significant increase in overall TCEP availability.

FEED work continued as these changes were incorporated into the design. In late June and early July, the FEED contractors completed their work and developed their individual FEED cost estimates to provide an overall cost estimate for moving forward into the Engineering, Procurement and Construction (EPC) phase of the project.

Engineering work continued to incorporate the approved Cost Reduction Team measures and the reliability enhancement measures as part of the transition from FEED into the EPC phase of the project. Summit then began its negotiations for two major EPC contracts, with Linde AG for the Chemical Block (with the gasification area provided by Siemens Fuel Gasification Technology and the utilities and offsites provided by SK Engineering and Construction) and Siemens Energy for the Power Block.

1 Project Introduction & Site Description

DOE selected Summit's TCEP through an open and competitive process under the third round of its CCPI program. The goal of the CCPI, a collaboration between the federal government and industry, is to accelerate the readiness of new coal utilization technologies for commercial use, ensuring future access to clean, reliable, and affordable power in the U.S. The CCPI is consistent with the Energy Policy Act of 2005 (Public Law 109-58) and directly supports the national Climate Change Technology Program, a multi-agency research and development program, in its efforts to reduce CO_2 emissions.

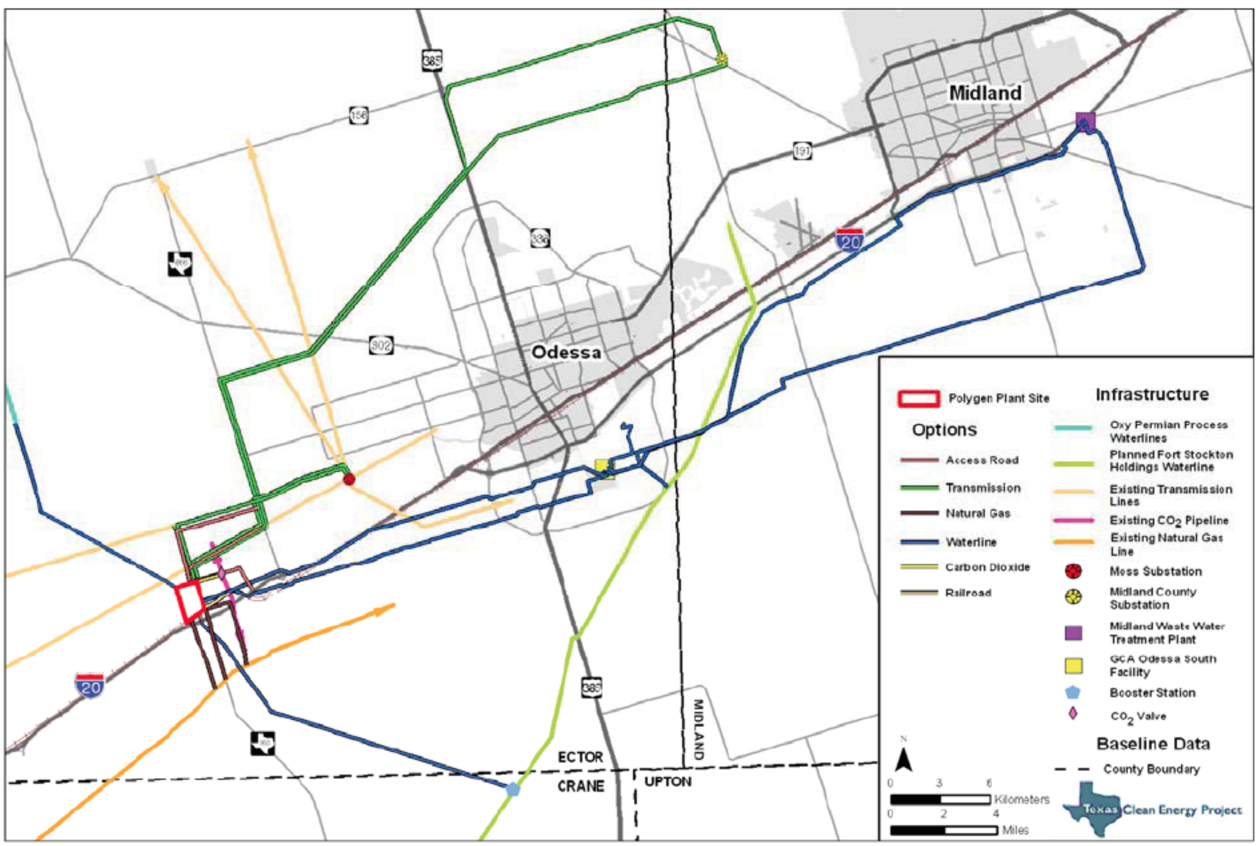
Summit will plan, design, construct, and operate the TCEP, a coal-based electric power generation and chemicals production plant (referred to as a poly-generation or polygen plant). The DOE is providing cost-shared co-funded financial assistance to the project to support project definition, engineering, construction, and a three-year demonstration period at the beginning of plant operations for the purpose of verifying the commercial efficacy of integrating CO_2 capture, utilization and geologic storage with a pre-combustion polygen facility including IGCC electric power generation and the production of other high-value commercial products such as urea, CO_2, sulfuric acid (H_2SO_4) and additional minor products. Captured CO_2 will be sold on the regional market for EOR, resulting in permanent geologic sequestration. The plant is expected to operate for at least 30 years.

The project will be located approximately 15 miles southwest of the city of Odessa in Ector County, Texas on a site adjacent to the community of Penwell and north of Interstate 20 (I-20). The site was previously proposed for DOE's FutureGen project. Summit chose this site primarily because of its proximity to an existing CO_2 pipeline and multiple EOR sites in the Permian Basin. Furthermore, it provides many of the resources needed for development and operation of a large industrial project. This includes access to major roadways, water, rail lines, and the electric transmission network.

Figure 1-1 shows the general location of the site in the State of Texas, and Figure 1-2 shows a more detailed layout of the site with respect to lateral connections.

FIGURE 1-1
TCEP Site Location in Texas

FIGURE 1-2
TCEP Site and Associated Laterals



The TCEP polygen plant site is a nearly rectangular, 600-acre parcel of land. Site elevation ranges from 2,920 to 2,969 feet above mean sea level, with a ground slope of less than 0.5 percent. The site is located in a rural setting that historically has been occupied by ranching and oil and gas industry activities; it is dominated by Mesquite Shrub-Grassland vegetation, which is not rare or unique in this region.

The site was donated to Summit by the Odessa Chamber of Commerce in April 2010. However, several utility, oil, and gas companies continue to lease easements for access to subsurface oil and gas resources. Only one oil well and one gas well remain active. Crude oil pipeline, natural gas pipeline, and condensate pipeline systems are also present on the site. Other existing structures on the site include gravel roads, abandoned oil- and gas-related structures, and overhead electricity distribution lines. No other structures or improvements are known to have historically occurred at the site. No prime or unique farmland soils exist in the plant site, and the site is free from hazardous or radioactive materials, chemicals, or wastes that would be subject to regulation.

The plant site's southern boundary borders CR 1216 and is less than 0.5 mile from I-20. A Union Pacific Railroad (UPRR) line also runs along the site's southern border. Oil and gas development and ranching activities are the predominant land uses in the area. Remnant oil well pad sites and associated industrial structures are present in the area around the polygen plant site, with concentrations occurring mainly west and south of the site. Neighboring properties include undeveloped industrial space and facilities that support the oil and gas industry. The community of Penwell, Texas, is located immediately south of the proposed polygen plant site. The community has a very small population. There are seven occupied residences in Penwell, the closest of which is approximately 0.25 mile from the polygen plant site. The community has four to five businesses, including a post office and operating oil and gas industrial entities.

As part of the Environmental Impact Statement (EIS) prepared for the FutureGen project, a significant amount of site-related and local environmental information was collected and documented (available at http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/FG%20Summary%20-%20FINAL.pdf . Additional site-related and local environmental information can be found in the EIS prepared for the TCEP (available at http://www.netl.doe.gov/technologies/coalpower/cctc/EIS/final_eis_texas_clean_energy.html).

The TCEP will include the construction and operation of a polygen plant and associated linear facilities consisting of an electrical transmission line, one or more water supply pipelines, a natural gas pipeline, a CO_2 pipeline connector, access roads, and a rail spur. These linear facilities will connect the plant to existing utilities, a regional CO_2 pipeline network, roadways, and a rail line.

The TCEP polygen plant was designed to use low-sulfur, Powder River Basin sub-bituminous coal from Wyoming as the feedstock for the gasification island, which will use two Siemens gasifiers to convert that feedstock into syngas for downstream use. After further cleaning, chemical conversion, and processing of the syngas, followed by capture and removal of CO_2, the majority of the hydrogen (H_2)-rich syngas will be used in the power island to generate up to 400 MWe (gross) of electrical power. The balance of the H_2-rich syngas will be used to produce ammonia (NH_3), which will be converted into urea fertilizer and sold into markets in the U.S. Depending on operational conditions, the TCEP will deliver approximately 200 MWe (or 1.6 billion kilowatt-hours) of generated power to the electrical grid system and sold under a long-term Power Purchase Agreement (PPA) to CPS Energy of San Antonio, Texas. The remainder will be used to power the polygen plant operations, including in the urea plant to produce urea fertilizer.

In addition, the polygen plant is being designed to capture, as CO_2, 90 percent or more of the total carbon in the coal fuel used in the plant under almost all operating conditions. The preponderance of the captured CO_2 would be sold under binding commercial contracts. It will be further cleaned and compressed, and then be transported through a short connecting pipeline to an existing, regional CO_2 pipeline for ultimate use in EOR and storage deep underground in oil fields in the Permian Basin. Sulfur compounds captured from the coal-derived syngas will be converted into 93% purity sulfuric acid, which will be sold commercially. Argon gas will be captured by the air separation process and sold commercially. The other product of the gasification process will be inert, non-leachable slag, which will be sold commercially as raw material to manufacturing and construction industry buyers.

2 FEED Goals and Objectives

Following are the key goals and objectives that were developed for the FEED:

- Complete the level of engineering necessary to support an investment-grade engineering, procurement and construction (EPC) cost estimate for a nominal nameplate 400 MWe (gross) IGCC power plant that includes the production of urea, sulfuric acid and CO_2 as commercial products, and targets the capture of 90 percent of the carbon entering the plant.
- Target >60% firm price contracts
- Develop and refine the performance of the plant
- Design for high availability without compromising cost objectives
- Minimize optimization studies and changes
- Target a 10% cost savings on the total EPC cost from Summit's economic model
- Obtain firm price quotes on 70% of the plant equipment

Specific targets for the FEED were set by Summit as follows:

- Target the EPC cost as indicated in economic model
- Develop an investment-grade cost estimate as defined by commercial contracts
- Cost estimate accuracy for Fluor's scope of work at -10%/+15%
- Firm price from Siemens for the Gasification and Power Blocks
- Cost estimate accuracy for Siemens Power Block bulk items at -10%/+20%
- Cost estimate accuracy for Linde's scope of work at -5%/+5% for the engineering and procurement, -20/+20% for construction, and -5/+5% for the Air Separation Unit and for CO_2
- Maintain performance and emissions to comply with the values in the air permit application and with the requirements of the State of Texas law HB469 (which provides incentives for "clean energy projects" that capture and sequester at least 70% of the CO_2 produced from the electricity generation portion of those projects)
- TCEP overall availability of 92%
- Meet or beat a one-year FEED schedule
- Minimize changes to <2% of FEED cost

3 FEED Organization

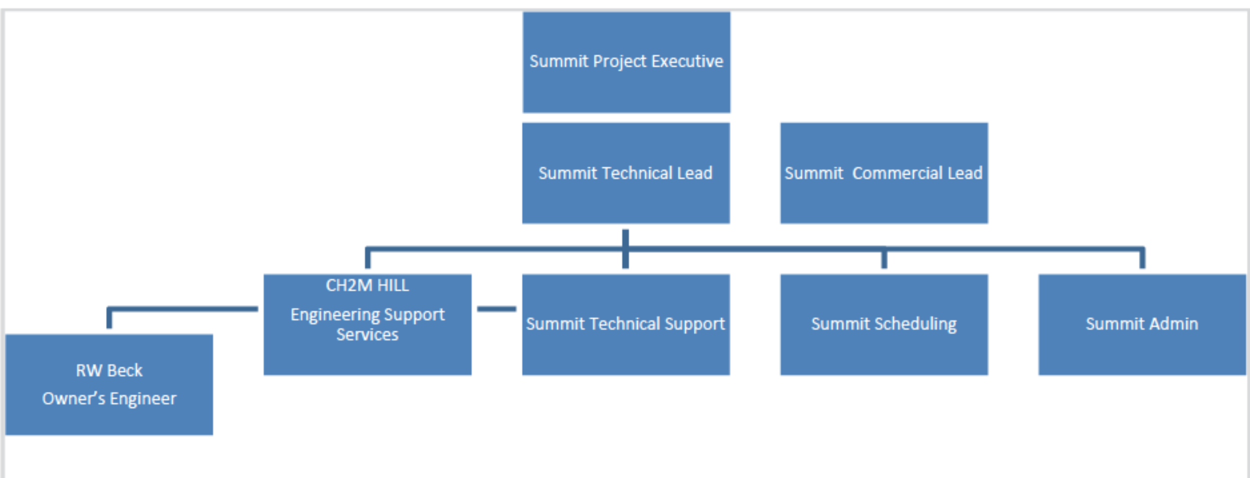
3.1 Owner's Engineering Organization

In order to implement the TCEP, Summit developed an owner's organization comprised of Summit's own staff, with support from the following companies with which it contracted to provide specific engineering services as follows:

- RW Beck: owner's engineering services
- CH2M HILL, Inc.: engineering support services for the IGCC and process plant portions of the TCEP; environmental permitting and documentation services; water supply system engineering; transmission line, natural gas pipeline and CO_2 pipeline preliminary engineering and cost estimates

The owner's engineering organization is shown in Figure 3-1.

FIGURE 3-1
Owner's Engineering Organization



The project assignments, and general duties and responsibilities of the companies and individuals assigned to the TCEP owner's organization were as follows:

3.2 Summit

- Eric Redman: Project Executive
- Ann Banks: Commercial Lead
- Karl Mattes: Technical Lead and Project Director
- Chris Kirksey: Technical Support; Permitting
- Barry Cunningham: Technical Support; Plant Performance
- Rob Kubiaczyk: Scheduling

- Rick Burkhardt: Administration; DOE reporting; American Recovery and Reinvestment Act (ARRA) reporting

3.2.1 RW Beck

Key staff

- Herb Kosstrin
- Clare Behrens

Assignments

- Set Design Basis
- Set configuration
- Set optimizations
- Review major design information after completion
  - Heat and material balances (H&MBs)
  - Optimizations
  - Process Flow Diagrams (PFDs)
  - Piping and Instrumentation Diagrams (P&IDs)
  - Cost estimates
  - Major equipment specifications

3.2.2 CH2M HILL

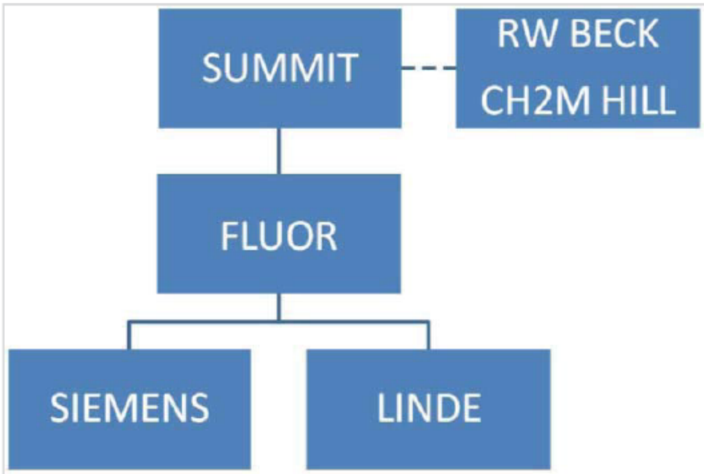
Key Staff and Assignments

- Doug Hall: Project Manager
- Mark Grant: FEED Technology Manager
- Steve Jenkins: Senior IGCC Technology Leader; permitting support
- Valerie Francuz: Gasification Block FEED
- Cecil Gibson: Syngas cleaning, acid gas removal/sulfuric acid, ammonia/urea FEED
- Alan Johnston: Power Block FEED
- Randy Schulze: permitting, National Environmental Policy Act (NEPA) environmental documentation; routing and cost estimates for laterals (transmission line, and natural gas, CO_2 and water supply pipelines)

3.3 FEED Contractors

Summit contracted directly with several large engineering and technology companies to implement the FEED. Figure 3-2 below presents the overall organization and reporting relationships.

FIGURE 3-2
FEED Reporting Relationships

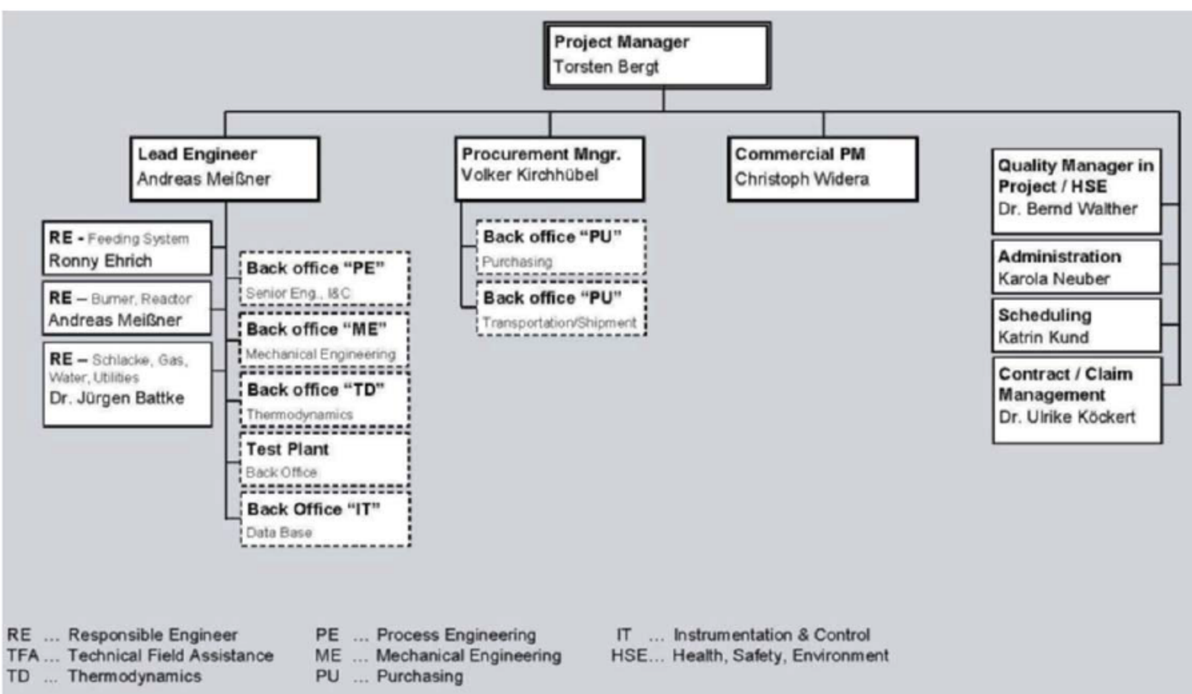


The project organizations and scope of work for Fluor, Linde and Siemens are discussed in more detail below.

3.3.1 Siemens Fuel Gasification

Figure 3-3 shows the project organization for Siemens Fuel Gasification for the Gasification Block FEED. Mr. Torsten Bergt, located in Freiberg, Germany, served as the Project Manager.

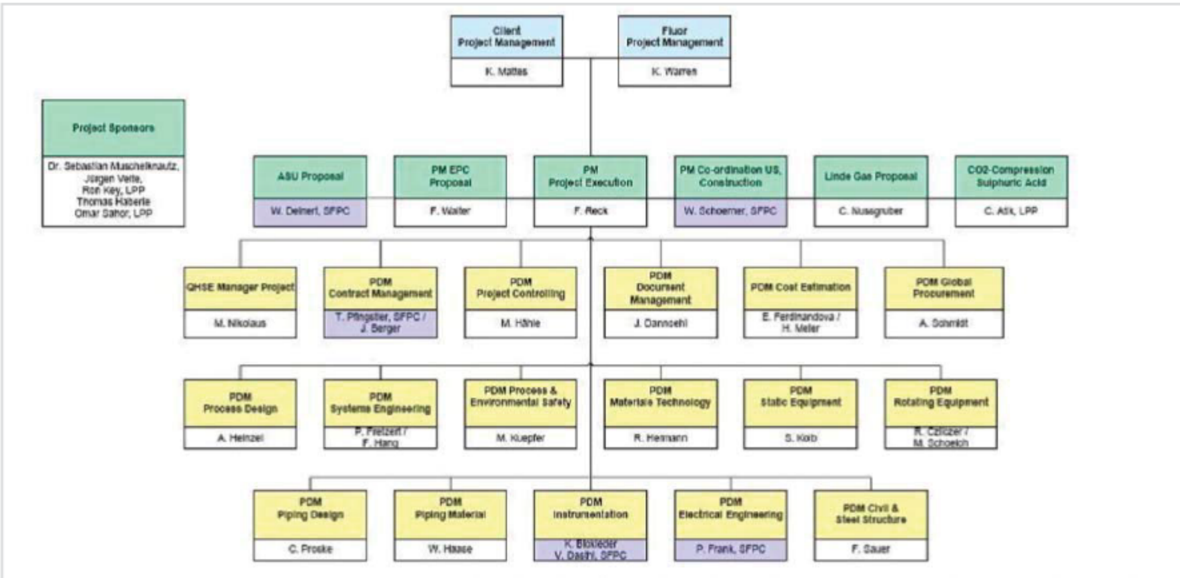
FIGURE 3-3
Siemens Fuel Gasification Project Organization



3.3.2 Linde AG

Figure 3-4 shows the engineering organization that Linde (through its subsidiary Selas Fluid Processing Corporation) assigned to implement the Syngas Block FEED. Mr. Florian Reck, located in Munich, Germany, served as the Project Manager.

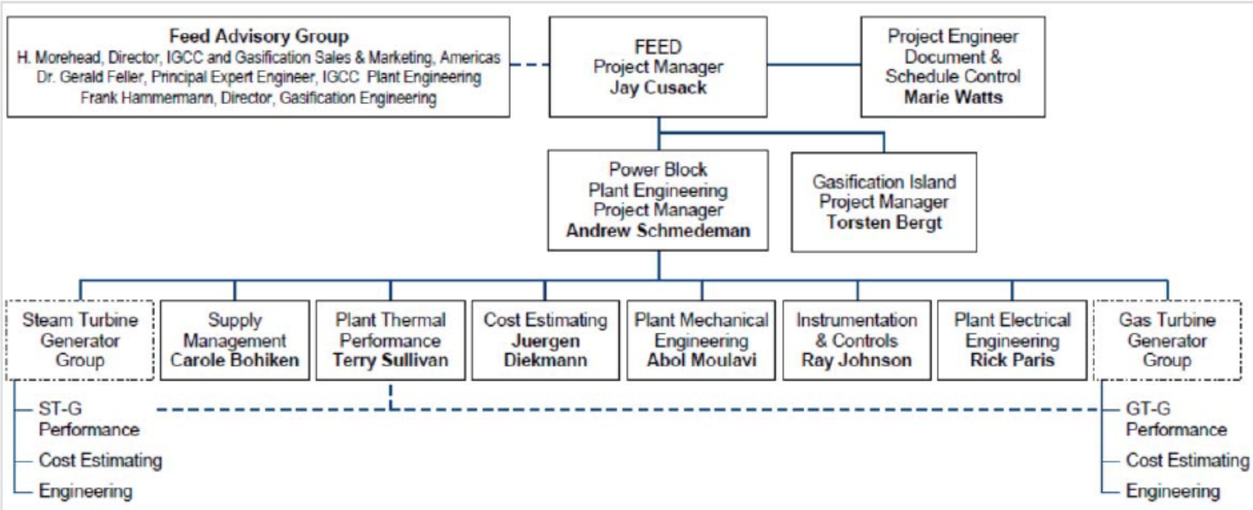
FIGURE 3-4
Linde Project Organization



3.3.3 Siemens Power Generation

Figure 3-5 shows Siemens' organization for implementing the Power Block FEED. Jay Cusack, located in Orlando, Florida, served as the Project Manager. The figure also shows the Siemens internal reporting relationship for the Gasification Island FEED.

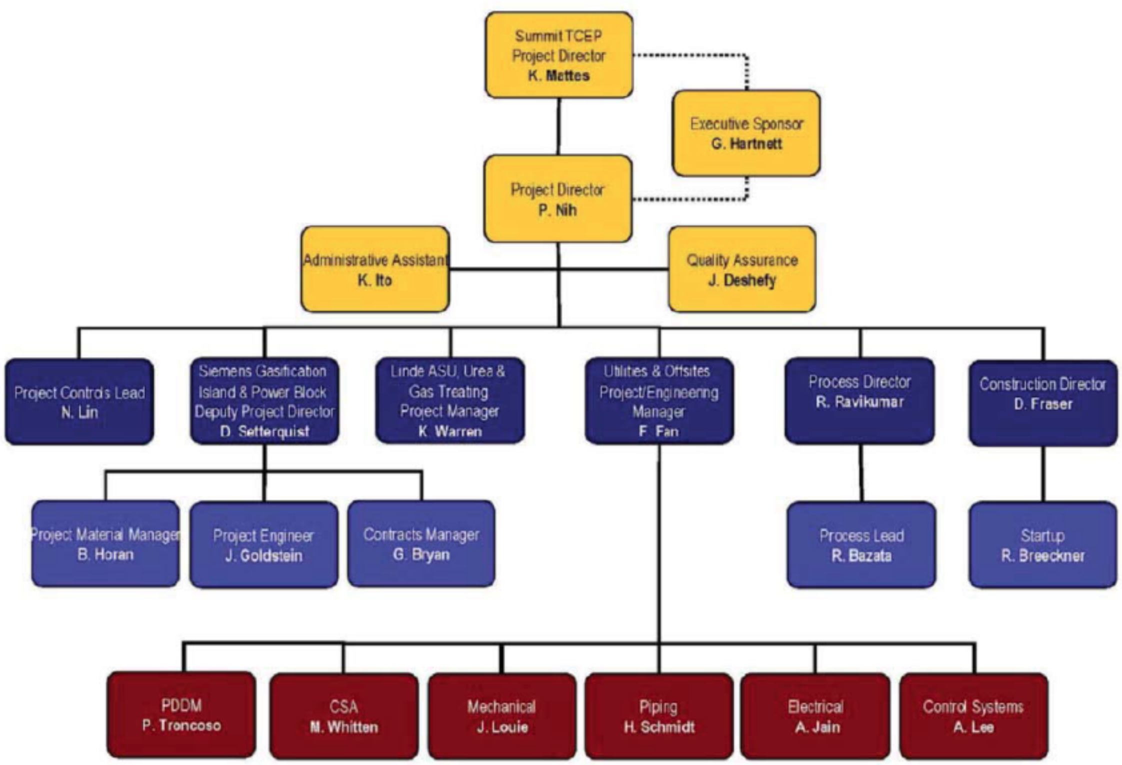
FIGURE 3-5
Siemens Energy Project Organization



3.3.4 Fluor

Figure 3-6 shows Fluor's organization for implementing the Balance of Plant FEED and for coordinating the overall TCEP FEED contractors' work. Paul Nih, located in Irvine, California, served as the Project Director.

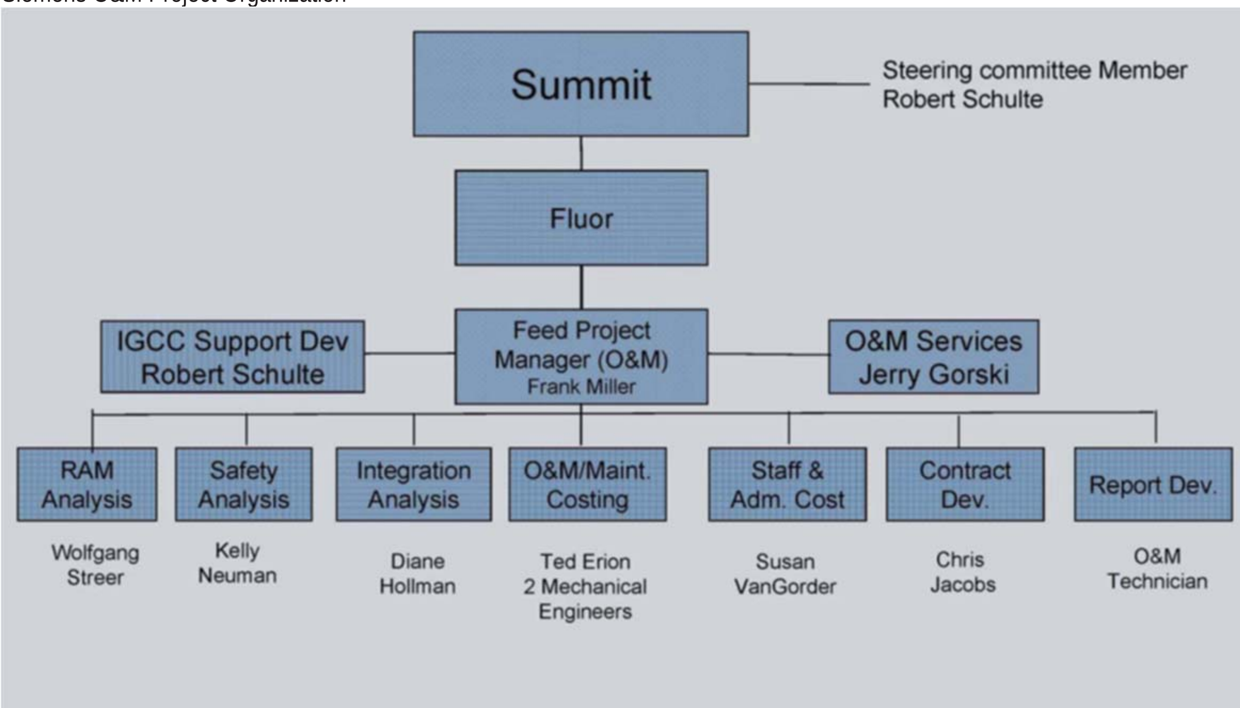
FIGURE 3-6
Fluor Project Organization



3.3.5 Siemens O&M

Figure 3-7 shows the organization that Siemens developed for providing the O&M services portion of the TCEP FEED. This contract was put in place so that Siemens would be responsible for complete operations and maintenance of the TCEP facility and to provide guarantees/warranties for performance, availability and O&M cost. Frank Miller, located in Orlando, Florida, served as the Project Manager. He was later replaced by Robert Schulte.

FIGURE 3-7
Siemens O&M Project Organization



3.4 Coordination and Oversight

In addition to Summit's owner's engineering organization and the individual FEED contractors' project implementation organizations, two key groups were formed to provide high-level TCEP oversight and decision-making.

3.4.1 Executive Sponsors

The FEED contractors assigned key individuals as Executive Sponsors assigned to Summit's Steering Committee. The Executive Sponsors were as follows:

- Summit Power: Ann Banks – Chief Commercial Officer
- Fluor: Greg Harnett - VP of Engineering and Operations
- Linde: Samir Serhan - Director of Engineering
- Siemens: Mark Confer – Director of O&M
- Siemens: George Lamonettin - Director of Sales

The Executive Sponsors' responsibilities were to:

- Provide executive sponsorship and visibility to their project team members and companies
- Resolve disputes
- Offer advice on technical and commercial issues
- Make decisions on high-level FEED issues

The Executive Sponsors met at least on a quarterly basis to review TCEP status, schedule, and cost, and to make high-level decisions on TCEP design, configuration and cost reduction recommendations.

3.4.2 FEED Management Committee

The FEED Management Committee was formed to provide direct management and coordination of the overall engineering work during the year-long FEED process. Project Managers from each of the FEED contractors' organizations were assigned to the FEED Management Committee, as follows:

- Summit Power: Karl Mattes, Vice President of Projects
- Siemens: Jay Cusak – Project Manager
- Siemens: Robert Schulte, Manager of O&M
- Fluor: Paul Nih, Project Director
- Linde: Florian Reck, Project Manager

The FEED Management Committee members' responsibilities were to:

- Direct and manage the year-long FEED process
- Set goals and objectives
- Monitor progress
- Make decisions on value enhancements submitted to them by the FEED contractors, RW Beck, and CH2M HILL

4 FEED Scope

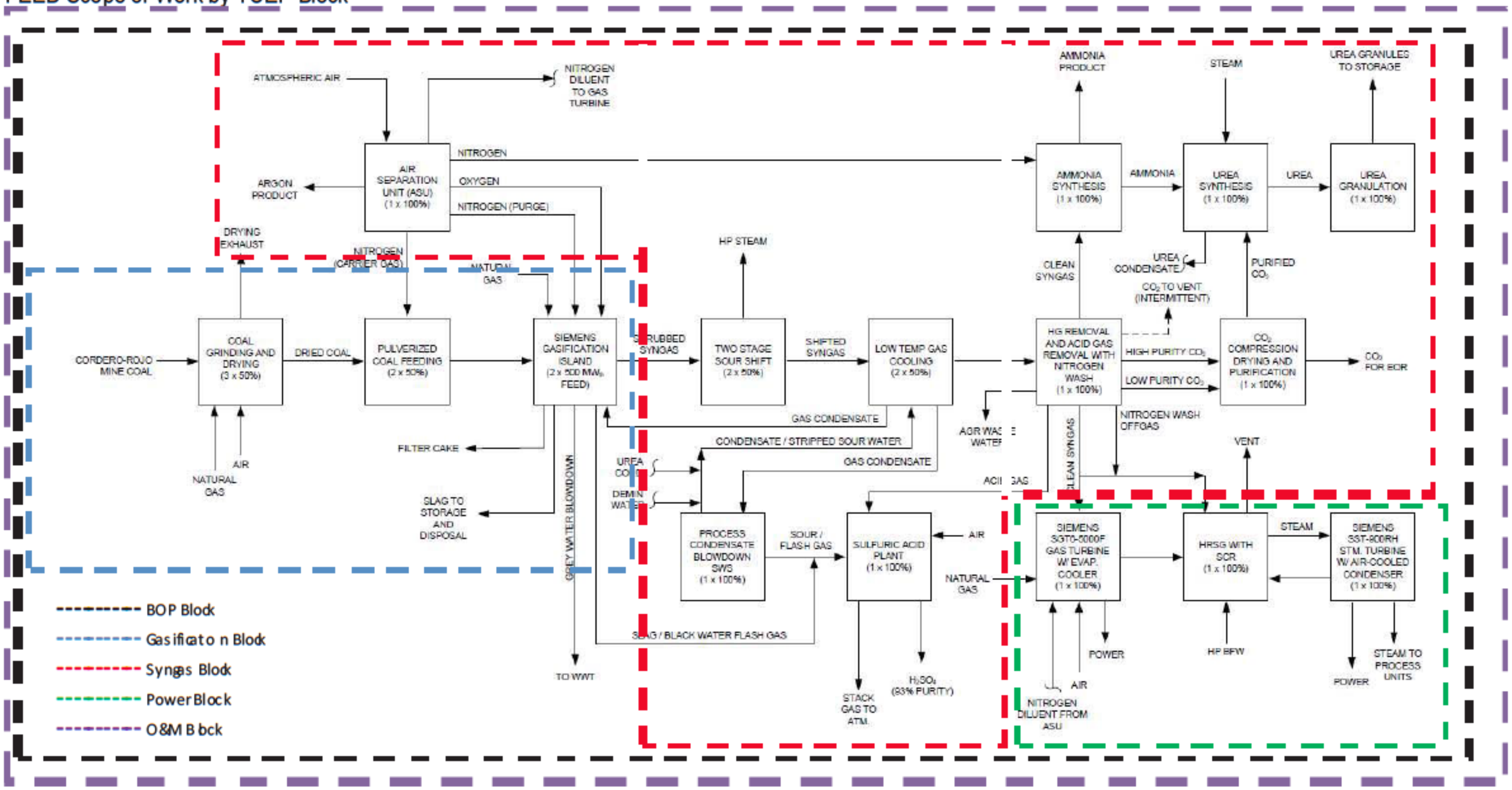
In order to implement the FEED, Summit divided the TCEP facility into distinct "blocks" to be used for determining the scope of work for each FEED contractor. These blocks are shown in Figure 4-1 using the TCEP block flow diagram.

Summit then contracted separately with several engineering and technology firms to provide engineering and design services for the specific blocks as follows:

- Gasification Block – Siemens Energy, Inc. (Orlando, FL) using gasification technology provided by Siemens Fuel Gasification of Freiberg, Germany
- Syngas Block – Selas Fluid Processing Corporation (Blue Bell, PA), as subsidiary of Linde AG (Munich, Germany)
- Power Block – Siemens Energy, Inc. (Orlando, FL), using combined cycle power generation technology provided by Siemens Power Generation of Orlando, FL
- Operating & Maintenance (O&M) – Siemens Energy, Inc. through the O&M services group within Siemens Power Generation
- Balance of Plant (BOP) and FEED Coordination – Fluor Corporation (Irvine, CA)

Fluor Corporation was responsible for coordinating the FEED and exchanging engineering information among the FEED companies. Fluor also developed the Balance of Plant FEED, prepared engineering information that represented overall plant performance, such as heat and material balances and emissions estimates, and compiled the overall plant cost estimate using information developed and submitted by each of the FEED contractors.

FIGURE 4-1
FEED Scope of Work by TCEP Block



5 FEED Schedule

At the beginning of the FEED, an overall project schedule was developed. This is shown in Figure 5-1 below. On a high level, the major milestones were as follows:

- Start of FEED: June 2010
- Siemens Fuel Gasification FEED completed: March 2011
- Siemens Power Generation FEED completed: May 2011
- Linde FEED completed: March 2011
- Fluor FEED completed: June 2011

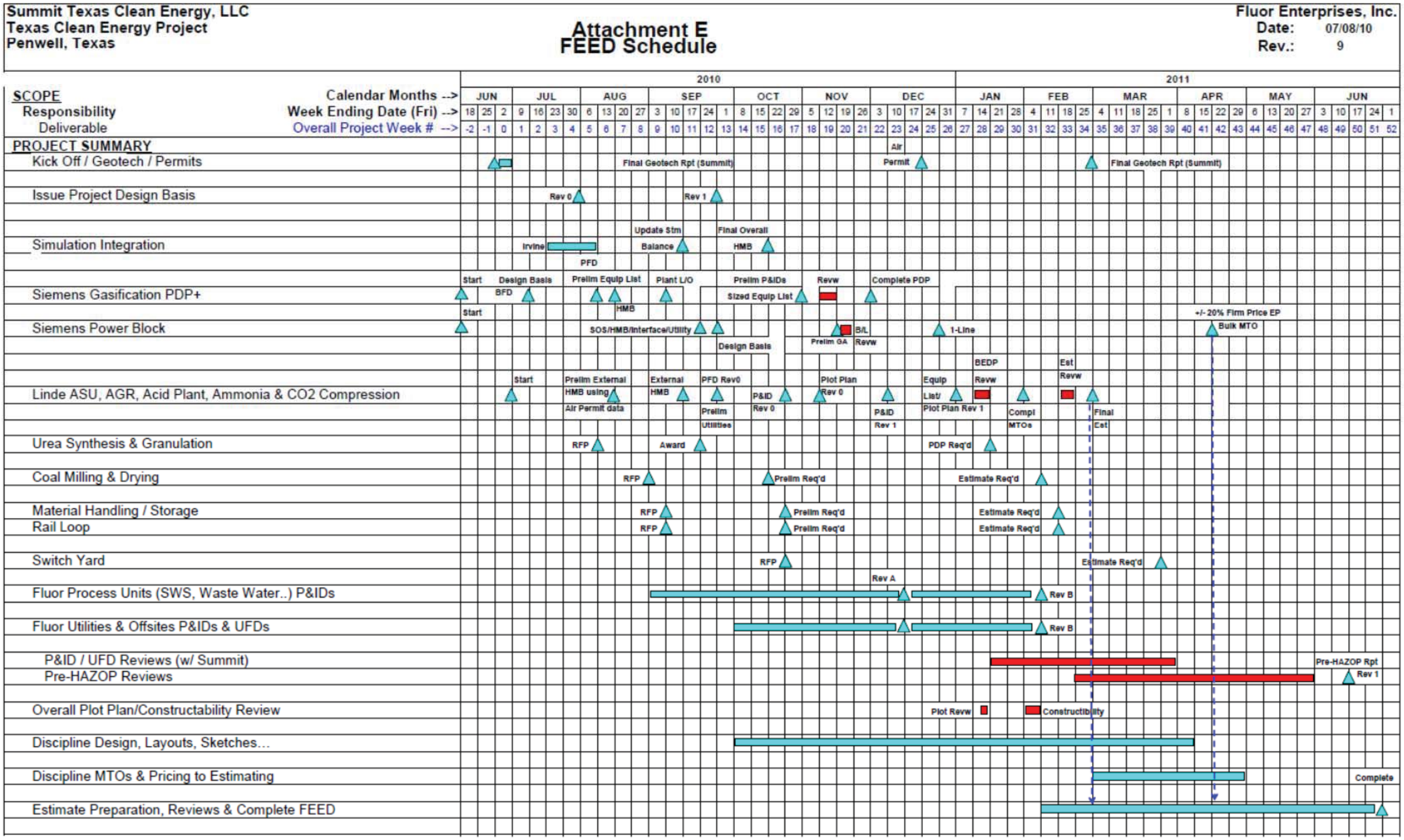
Completing the FEED by July 2011 would allow the development of EPC contracts and a detailed EPC cost estimate to support financial closing as soon as Quarter III, 2011. As noted previously, conceptual and preliminary engineering had been done by Summit, Linde and Siemens, in order to develop a basic plant configuration, block flow diagrams, and preliminary emission inventories for use in preparing the air permit application. In order to develop a financeable cost estimate for the EPC portion of the project, significantly more detailed engineering and design is required. This was the purpose of the FEED, and the reason that it took approximately one year for the FEED contractors to do all of the tasks required for their individual scopes of work, and then for the overall FEED coordinator (Fluor) to integrate all of the designs and interfaces. Once that was done, overall TCEP facility heat and material balances and performance data were developed.

After developing their initial engineering and interface data, the FEED contractors met to conduct "process simulations" (see next section for the details of this work). The heat and material balances and more detailed interface data were then used by the FEED contractors to prepare their FEED packages, which included:

- Basis of Design
- Block Flow Diagram
- Process descriptions
- Process Flow Diagrams
- Piping and Instrument Diagrams
- Site layouts
- Electrical plot plans
- Electrical loads
- Equipment lists (including dimensions, weights and design temperatures/pressures)
- Process engineering data sheets
- Estimates of consumption of utilizes, i.e. water, steam and natural gas
- Battery limit/interface stream properties
- Input/output counts for instrument and control systems
- Calculations for flare design
- Tank sizing
- Safety requirements

Once all of this FEED information was completed, each of the FEED contractors developed the FEED cost estimates for their individual portions of the TCEP facility. These were combined into an overall TCEP cost estimate at the end of the FEED.

FIGURE 5-1
TCEP FEED Schedule



6 Process Simulation

The first major FEED activities were a 16-week series of "Process Simulation" meetings which began on June 2, 2010. The purpose of the Process Simulations was to set the TCEP design basis and to expedite the early design of the plant by bounding the interfaces between the Gasification and Syngas Blocks, and the Power Block. Further, simulations of a range of specific cases were required, in order to reflect the range of conditions under which that the TCEP facility would be operated. This required an iterative process of simulations using engineering information from each of the FEED contractors, as well as the preliminary engineering information that had been used for development of the air permit application. Each of the FEED contractors started its work within its own scope area, and then met for a kickoff and alignment meeting in Fluor's offices on June 29-30, 2011.

The kickoff and alignment meeting was attended by representatives of the following companies:

- Summit
- CH2M HILL
- RW Beck
- Linde
- Siemens Fuel Gasification
- Siemens Power Generation (engineering and O&M)
- Fluor

The meeting agenda included the following items:

- Introductions
- Project vision, objectives and goals
- Design basis
- Operating philosophy
- Plot plan review
- Battery limit interfaces
- Roles and responsibilities
- Standard common design requirements
- Cost estimate plan
- Procedure for value suggestions
- Change management procedure and protocol
- FEED schedule overview
- Monthly reporting requirements
- Coordination and communication protocol
- Critical needs and interfaces

This meeting clarified the specific data that would be needed for the range of cases to be simulated as an integrated facility. The FEED contractors spent the next two weeks assembling the required data, and the all of the FEED contractors met in Fluor's offices beginning on July 19, 2010 to begin the Process Simulation work. The simulation cases included:

- Guarantee Case
- Maximum Power Output
- Maximum Urea Production
- Maximum Steam Flow to the Power Block
- Minimum Steam Flow to the Power Block
- One Gasifier Operating
- Two Gasifiers Operating

As the Process Simulation work continued, details of the TCEP design were further refined. One example was the moisturization of the syngas going to the combustion turbine. While this improves performance, the team needed to determine if it was cost effective. By having the right team members all in one place, running the simulations quickly with the right data provided the result that this specific design issue was cost effective, and it was used in the project design.

The key deliverable of the Process Simulations was a comprehensive set of Heat and Material Balances for the Guarantee Case, as well as for several other cases as noted above.

7 Design Basis Documents

7.1 Project Design Basis

The initial version of the Project Design Basis defined the technical information used for development of the performance and emissions estimates for the TCEP. That information provided a high level overview of the major equipment and design criteria for a turnkey polygen configuration required for preparation of the air permit application.

Information in the initial version included:

- TCEP plant site location and boundaries
- List of major plant equipment for Gasification and Power Block
- Storage tank sizing (i.e. hours or gallons of storage)
- Site elevation and climatic conditions
- Basic need for firing the Power Block with syngas and natural gas, and for switching between these fuels
- Coal feedstock properties
- Operational design criteria, including plant reliability requirements, and startup, shutdown, and turndown

Fluor developed and maintained this document, using information obtained from Summit, the other FEED contractors, RW Beck, and CH2M HILL. As the FEED progressed and changes were made in the TCEP design and/or configuration, those changes were documented in revisions to the Design Basis. Following is the Issued for FEED version of this document.

Part of the Design Basis included “generic”, site-related, and economic evaluation data which were later extracted and placed into a new separate document called “Basic Engineering Design Data” (BEDD). The Issued for FEED version of that document follows.

During the EPC re-cast, this Project Design Basis document was modified and updated, and the BEDD document (see Section 7.2) was incorporated into the Project Design Basis.

Summit Texas Clean Energy, LLC
Texas Clean Energy Project
Penwell, TX

Fluor Enterprises, Inc.
Aliso Viejo, Ca

TCEP PROJECT DESIGN BASIS

Client:	Summit Texas Clean Energy, LLC
Project:	Texas Clean Energy Project
Contract No:	A5PN
Document No:	A5PN-225-001

2	2 June 2011	Final Issue for FEED	RB	RB	DS			
1	26 Oct 2010	Issued for FEED	CC	RB	DS	KM	JC	FR
0	28 Jul 2010	Issued for Approval	BD	RB	DS	KM	JC	FR
B	29 Jun 2010	Markup in Kickoff Meeting	BD	RB	DS	KM	JC	FR
A	24 Jun 2010	Draft for Review	BD	RB	DS			
Rev	**Date**	**Description**	**By**	**Chk**	**App**	**Summit**	**Siemens**	**Linde**
			Fluor					

1.0 INTRODUCTION

This Project Design Basis (PDB) defines the technical information required to proceed effectively with design work for the Texas Clean Energy Project. The information defined in this document will enable the project team to proceed with proper consideration for the client's preferences and specific technical requirements.

2.0 CODES AND STANDARDS

The plant will generally be designed to contractor standard specifications and guidelines and Process Industry Practices (PIP). In general, the power block will use power block design standards, while the balance of plant will use process plant standards. The ASU will use CGA and Linde design standards. All equipment supplied shall comply with the requirements of all nationally recognized design and manufacturer's standards applicable to that type of equipment, including the National Electrical Code, Institute of Electrical and Electronics Engineers (IEEE), American Society of Mechanical Engineers (ASME), and American National Standards Institute (ANSI) standards. Siemens equipment and/or systems supplied from overseas may be in accordance with internationally accepted codes and standards of country of origin other than listed below with the exception of pressure vessels whose dimensions and design pressure are within the limits specified in Section VIII of the ASME Boiler and Pressure Vessel Code. These must be designed, fabricated, and Code stamped in accordance with Section VIII Division 1, 2, or 3 requirements.

2.1 Government Regulations

- Occupational Safety and Health Act (OSHA)
- 29 CFR 1910 - Occupational Safety and Health Standards
- 29 CFR 1926 - Safety and Health Regulations for Construction
- Environmental Protection Agency (EPA)
- EPA Standard of Performance for New Stationary Sources
- Homeland Security
- Other Applicable State, County and Local Codes and Regulations

2.2 Applicable Industry Codes and Standards from the following list:

2.2.1 Mechanical

- AGMA - American Gear Manufacturer's Association
- AMCA - Air Moving and Control Association
- ABMA - American Boiler Manufacturer's Association
- ANSI - American National Standards Institute, Applicable Codes and Standards
- ASME - American Society of Mechanical Engineers - Boiler and Pressure Vessel Code:
  - Section I - Power Boilers
  - Section II - Materials Specification
  - Section V - Nondestructive Examination
  - Section VIII - Unfired Pressure Vessels
  - Section IX- Welding & Brazing Qualifications
- ASME - American Society of Mechanical Engineers, B31-1 Power Piping Code
- PTC - Performance Test Codes - Applicable Test Codes
- STS-1 - Steel Stacks (wind loads per ASCE 7)
- ASNT - American Society for Nondestructive Testing
- ASTM - American Society for Testing and Materials
- AWS - American Welding Society
- AWWA - American Water Works Association
- CTI - Cooling Tower Institute
- EJMA - Expansion Joint Manufacturing Association
- HEI - Heat Exchanger Institute
- NFPA - National Fire Protection Association, National Fire Codes and Standards, including all requirements of
  - NFPA 850, Recommended Practice for Fire Protection for Electric Generating Plants

- TEMA - Tubular Exchanger Manufacturer Association
- HI - Hydraulic Institute Standards
- SSPC - Steel Structures Painting Council
- CEMA - Conveying Equipment Manufacturers Association
- HMI - Hoists Manufacturers Institute
- ASHRAE - American Society of Heating, Refrigeration, and Air Conditioning Engineers
- CMAA - Crane Manufacturers Association of America
- ASME B30.2 - Overhead and Gantry Cranes
- API - American Petroleum Institute
- NACE – National Association of Corrosion Engineers
- NBIC – National Board of Boiler and Pressure Vessel Inspectors

2.2.2 Electrical

- ASTM - American Society for Testing and Materials
- ANSI - American National Standards Institute
- FAA - Federal Aviation Administration - Standards for Marking and Obstruction Lighting for Aerial Navigation
- FM - Factory Mutual (FM)
- ICEA - Insulated Cable Engineers Association
- AEIC - Association of Edison Illuminating Companies
- IEEE - Institute of Electrical and Electronics Engineers
- LPC - Lighting Protection Code
- NEC - National Electrical Code

- NEMA - National Electrical Manufacturers Association
- NESC - National Electrical Safety Code
- NFPA - National Fire Protection Association
- IESNA - Illuminating Engineering Society of North America (IESNA)
- ISA - International Society for Measurement and Control
- UL - Underwriters Laboratories (UL)
- IEC - International Electrotechnical Commission (For non-US equipment)

2.2.3 Civil/Structural/Architectural

- SDI - Steel Deck Institute Standards
- SJI - Steel Joist Institute Standards
- AWWA - American Water Works Association
- PFI - Pipe Fabrication Institute
- IBC - International Building Code
- IMC - International Mechanical Code
- NSPC - National Standard Plumbing Code (2006)
- AISC - American Institute of Steel Construction
- Steel Construction Manual, 13th Edition
- AISI - American Iron and Steel Institute "Specification for Design of Cold-Formed Steel Structural Members," Parts 1 and 2
- AWS - American Welding Society "Structural Welding Code" (AWS D1.1)
- ACI - American Concrete Institute "Building Code Requirements for Reinforced Concrete" (ACI 318) and "Environmental Engineering Concrete Structures" (ACI 350R)
- MBMA - Metal Building Manufacturers Association
- NFPA 101 - Life Safety Code

- ASCE - Minimum Design Loads for Building and other Structures (ASCE 7-05)
- AWS - American Welding Society Welding of Reinforcing Steel (D1.4)
- SSPC - Steel Structures Painting Council
- Standard Specifications for Road and Bridge Construction, Department of Transportation

3.0 UNITS OF MEASUREMENT

Engineering design calculations will be done in the English / US system of measurements. Results will be reported in English units.

Dimension	English System	Symbol
Density	Pound per cubic foot	lb/ft^3
Energy, heat, work, internal energy, enthalpy	British Thermal Unit	Btu
Force	Pounds Force	lbf
Length	Foot Inch	ft in
Mass	Pounds Short tons	lbm or lb sT
Mass Flow	Pounds (mass) per hour	lb/hr
Molar Flow	Pound moles per hour	lbmol/hr
Power (Heat Flow)	Million Btu per Hour	MMBtu/hr
Power (Hydraulic Power, Shaft Power)	Horsepower	Hp
Power (Electrical)	Watt Kilowatt Megawatt	W kW MW
Pressure	Pounds Force per Square Inch Absolute / Gauge	psia / psig
Temperature	Fahrenheit	ºF
Velocity	Feet per Second	ft/s
Viscosity	Centipoise	cP
Voltage	Volt Kilovolt	V kV
Volume	Cubic Feet Gallons	ft^3 gal
Liquid Volumetric Flow	Gallons per Minute	gpm
Standard Volumetric Flow	Million Standard Cubic Feet per Day	MMSCFD

Standard conditions are defined as 14.696 psia and 60°F.

4.0 UNIT AND EQUIPMENT NUMBERING

Refer to FEED Execution Guideline – FEG 001 for unit numbering system and FEG 002 for equipment designation and numbering system.

5.0 PLANT / UNIT DEFINITION

5.1 Name and Location

CLIENT NAME: Summit Texas Clean Energy, LLC

PROJECT NAME: Texas Clean Energy Project

PROJECT LOCATION: Penwell, Texas

5.2 Scope of Facilities

5.2.1 Gasification & Common Units	The total number of equipment is indicated except when specified otherwise. For the capacity of equipment, 100% means the required capacity for the plant, except when specified otherwise.
Gasification	2 x 50%, 2 x SFG-500 Siemens gasifiers, nominal 500MWth (coal heat input, LHV).
Coal Receiving & Storage	Unsized coal will be delivered by unit train to the on-site rail loop. Coal unloading at 4000 TPH Coal reclaim at 1000 TPH Combined dead and active coal pile sized for nominally 45 days total storage capacity: 52,000 ton active storage (including 13,000 ton live storage) and 209,000 ton dead storage.
Coal Grinding / Drying	3 x 50% Vertical Mills sized for the maximum gasifier feed rate (nominally 5,800 sTPD on an as received basis). Each feed bin sized for 8 hours of gasifier feed per train.

Air Separation Unit (ASU)	1 x 100% unit common to both gasification trains. Single unit to include: 1 x 100% (to be confirmed) Main Air Compressor (MAC), 1 x 100% Cold Box, 2 x 50% Cryogenic Liquid O_2 Pump Systems (to be confirmed). Unit produces the following (reported pressures are at the users battery limits): GOX I: 99.5 mole % purity O_2 (682 psig). GAN I: High purity N_2 (<5 ppmv O_2 and <100 ppmv Ar) for ammonia synthesis (500 psig). GAN II: High pressure N_2 (<0.5 mol% O_2) as carrier gas for dry coal feed to gasifiers (870 psig). GAN III: Low pressure N_2 (<0.5 mol% O_2) for various users in the plant (90 psig). GAN IV: Medium pressure N_2 (<2 mol% O_2) for Gas Turbine diluent (470 psig). LIN II: Liquid N_2 (<5 ppm O_2) for Nitrogen Wash Unit (74 psig). Reliability to be >99.5% Includes liquid argon production, storage and railcar or truck loading as an option.
Liquid Oxygen (LOX) Storage	12 hours storage at total ASU design rate, uninterruptible.
Liquid Nitrogen (LIN) Storage	12 hours storage at total ASU design rate, uninterruptible. Excludes N_2 dilution to Power Block.
Slag Handling (Siemens)	2 x 50% One system per each gasification train. Two systems total in plant. Operationally independent systems, with each consisting of slag crusher, slag hopper, slag lock hopper, and water-cooled slag discharge conveyor.

Slag Storage & Transport	1 x 100% Slag loading designed for 400 TPH Material will be primarily transported offsite by railcar with an option to use truck.
Black Water Soot Cake (Filter Cake) Storage & Transport	1 x 100% Design rate of 20 TPH Filter cake material will be recycled to the coal milling and drying system. 10% Purge Capability for truck loading for transport offsite.
Sour Water System	2 x 100% system common to both trains. Stripped sour water product: <50 ppmw NH_3 and <30 ppmw H_2S, pH of 9.
Sulfuric Acid Plant	1 x 100% Product to be 93 weight percent H_2SO_4.
Sulfuric Acid Storage (93 wt%)	1 x 100% storage Sized to accommodate 10 days of production. Design rate of 60 sTPD.
Slag Water Gas Sulfur Removal	2 x 50% system per gasification train. Two systems total in plant.
Syngas Scrubbing	2 x 50%
CO Shift Unit (CSU)	2 x 50% Each train designed with two reactors in series (four reactors total) to maximize shift to meet greater than 90% carbon capture for the plant.
Low Temperature Gas Cooling (LTGC)	2 x 50%
Mercury Removal Unit (MRU)	1 x 100% Two sulfided carbon bed adsorbers to achieve >95% mercury removal from the syngas feed.
Rectisol Wash Unit (RWU)	1 x 100% Rectisol system used to achieve sulfur removal to <0.1 ppmv and CO_2 removal from syngas.
Temperature Swing Adsorption (TSA)	1 x 100%

Nitrogen Wash Unit (NWU)	1 x 100%
Refrigeration Unit (RFU)	1 x 100%
Ammonia Synthesis	1 x 100% Intermediate product to be 99.9 weight percent NH_3 (Anhydrous).
Ammonia Storage	1 x 100% Storage Sized to accommodate 3 days of production. No export facilities for ammonia.
CO_2 Compression for Urea and CO_2 Purification Unit (CO2U)	1 x 100% CO_2 purification unit 2 x 55% purified CO_2 compressor Removes sulfur from CO_2 product recovered from RWU prior to urea synthesis.
CO_2 Compression for EOR (CO2E)	1 x 100% integral gear centrifugal compressor. (2 x 55% may be provided if there are equipment size limitations)
Urea Synthesis & Granulation	1 x 100% urea synthesis Product before granulation to be urea + biuret solution with minimum purity of 96 weight percent. 1 x 100% urea granulation unit
Urea Handling & Storage	40 day storage in four 158 ft diameter domes. Design rate of 1,485 sTPD. Allow space for 90 days for future expansion. Urea Loading designed for 400 TPH by railcar or truck.
Gas Turbine	1 x 100% SGT6-5000F F3 (Siemens Dual Fuel: Syngas Primary / Natural Gas Backup) Includes auxiliaries such as inlet evaporative cooling and capable of firing high hydrogen shifted syngas and natural gas. Will be designed to use Natural Gas fuel with steam injection prior to initial operation of gasification plant.

Heat Recovery Steam Generators (HRSG)	1 x 100% Three pressure reheat drum type evaporation with syngas and process byproduct fuel duct firing and with SCR catalyst.
Steam Turbine	1 x 100% (Siemens SST-900RH) with air cooled condenser.

5.2.2 Offsites & Utilities

Coal Drying Heat Source	Natural gas will be used for coal drying. The dryer vent gas will be vented through the dryer stacks.
Plant Cooling	Air cooling of process streams to 140°F, water to be used for trim cooling. The Power Block will utilize an air cooled condenser. A mechanical draft cooling tower is to be provided for the cooling water loads for the balance of plant. Power Block to use closed loop system.
Chemical Treatment System for Cooling Systems	Includes all applicable chemical dosing systems.
Flare System	Small warm / sour gas flare sized to handle turndown, minor upset relief loads, and sour gas relief loads. Large warm flare will handle large relief loads (the small flare will continue handling a portion of the relief load) The large warm flare will also be sized to handle the maximum anticipated relief load. Cold Flare sized for largest cold relief load. Segregated from warm relief load with a dedicated header and flare stack to avoid thermal shock and ice formation. Ammonia Flare sized for largest ammonia relief load. Dedicated flare to ensure complete combustion of relief streams with high ammonia concentration.

Raw Water System	One raw water storage tank sized for 16 hours.
Demineralized Water System	6 x 20% RO trains and 4 x 25% EDI trains demineralizer system with upstream water softening and ultrafiltration. One demin water storage tank sized for 8 hours.
Potable Water System	Potable water package sized for plant personnel with 3000 gallon tank.
Fire Protection System	2 x 50% diesel firewater pump. 1 x 50% electric firewater pump. 1 x 100% pressure maintenance pump. Storage for 8 hours of fire water use.
Plant & Instrument Air	Primarily supplied by ASU 1 x 100% (for the entire plant requirement). Instrument Air and Plant Air Package (serves as backup for ASU). To be available for power block operation on natural gas.
Steam System (Balance of Plant)	Four levels of integrated plant wide distribution headers (nominal operating conditions): HP Superheated: 725 psig and 690°F HP Saturated: 725 psig and 510°F MP Saturated: 155 psig and 368°F LP Saturated: 58 psig and 305°F Letdown, attemperator and vent stations provide control and balance between the four headers.
Condensate System (Balance of Plant)	Two levels of plant wide collection headers (nominal operating conditions): MP Condensate: 100 psig and 337°F LP Condensate: 38 psig and 284°F MP Condensate is flashed for LP steam recovery. Remaining condensate and LP Condensate are flashed and pumped to Power Block deaerator.
Wastewater Treating	1 x 100% zero liquid discharge (ZLD) system.

Cooling Tower Blowdown Water Treating	1 x 100% zero liquid discharge (ZLD) system.
Sanitary / General Waste Water Treatment	Septic system / leach field.
Natural Gas Supply	1 x 100% system Meter to be supplied by others at the fence line.
Nitrogen Distribution	1 x 100% system
Drains and Blowdowns	1 x 100% system
Auxiliary Boiler Package	1 x 100% Natural Gas fired package with ultra low NOx burners with CEMS (NO_X, CO and O_2). Net Steam production = 150,000 lb/hr @ 725 psig and 690°F. Limited to 500 hours / year Turndown ratio = 10:1
Emergency Diesel Generator	1 x 100% Diesel Generator provides 1,500 kW. Low sulfur diesel fuel (< 15 ppm sulfur) required.

5.2.3 General

Plant Configuration	Plant nameplate capacity of 400 MWe (gross ISO conditions). Plant will produce a nominal 1,485 sTPD of Urea, 55 sTPD of Sulfuric Acid (on a 100% H_2SO_4 basis), and 8,600 sTPD of CO_2 for enhanced oil recovery. Potential argon sales. Two (2) 500 MWth gasification trains producing syngas for 1 x SGT6-5000F F3 Gas Turbine, Duct Burners, and Urea. HRSG with syngas and process byproduct fuel duct firing and SCR.

	Reheat Steam Turbine.
Black Start Capability	Not required.
Gasifier Turndown Capability	70% GID (Gasifier Input Demand) per gasifier.
Gas Turbine Turndown Capability	To 70% of load while maintaining emission compliance on syngas or natural gas.
Gas Turbine back-up fuel	Natural Gas (also for startup and shutdown).
Design Life	20 years for process units, 30 years for power block.
Availability	92.2% plant availability.
Winterization	Refer to FEED Execution Guideline FEG 013 Winterization Criteria

5.3 Feedstock Properties & Analysis

5.3.1 Feedstock Definition

The feedstock defined to operate the Gasification Island will be the following coal type:

Design Coal Type: Cordero Rojo Mine, “Rojo”

Alternate Coal Type: North Antelope Rochelle Mine, “Antelope”

Based on Siemens assessments to date, the North Antelope coal can be gasified in the gasification plant. If guaranteed performance is required for operation on the North Antelope coal, then a Change Order will be required. The Change Order would include additional balance calculations, testing on requirements for particle size distribution and moisture content as well as adjustment of guarantee figures needed if the design coal is changed from Cordero Rojo to Northern Antelope.

5.3.2 Feedstock Analysis (As Received Basis)

Item	Unit			Cordero Rojo Mine (Design Coal)	North Antelope Rochelle Mine (Alternate Coal)
Proximate Analysis	Moisture	M	wt%	29.50	26.70
	Ash	A	wt%	5.43	5.25
	Volatile matter	V	wt%	30.91	31.67
	Fixed Carbon	FC	wt%	33.85	37.08
Ultimate Analysis	Carbon	C	wt%	49.22	51.73
	Hydrogen	H	wt%	3.41	3.57
	Nitrogen	N	wt%	0.77	0.79
	Sulfur	S	wt%	0.31	0.24
	Oxygen	O	wt%	11.02	12.44
	Chlorine	Cl	wt%	0.01	0.01
Higher Heating Value (net calorific value)		HHV	Btu/lb	8,400	8,800
Hardgrove Grindability Index				74	61
Ash fusion (reducing Atm)	Initial Deformation Temperature	ID	°F	2145	2185
	Softening Temperature	ST	°F	2165	2205
	Hemispherical Temperature	HT	°F	2175	2220
	Fluid Temperature	FT	°F	2205	2245
	T250 Temperature		°F	2190	2290
Ash composition analysis (dry basis)	SiO2		wt%	33.95	31.82
	Al_2O_3		wt%	17.91	15.44
	TiO_2		wt%	1.48	1.22
	Fe_2O_3		wt%	5.07	6.28
	CaO		wt%	22.42	24.58
	MgO		wt%	3.99	5.65
	Na_2O_3		wt%	1.39	1.68
	K_2O		wt%	0.37	0.30
	SO_3		wt%	9.99	10.05
	Undetermined		wt%	1.20	1.27

Item		Unit	Rojo	Antelope
			Mean	Mean
Trace Elements (ppm wt, whole coal, dry basis)	Arsenic - As	ppm wt	1.17	0.91
	Antimony - Sb	ppm wt	0.83	0.59
	Barium - Ba	ppm wt	304.65	420.0
	Beryllium - Be	ppm wt	0.26	0.27
	Boron - B	ppm wt	30.80	31.03
	Bromine - Br	ppm wt	14.92	14.93
	Cadmium - Cd	ppm wt	0.18	0.16
	Chlorine - Cl	ppm wt	84.81	106.42
	Chromium - Cr	ppm wt	6.23	4.84
	Cobalt - Co	ppm wt	2.74	2.36
	Copper - Cu	ppm wt	10.96	9.16
	Fluorine - F	ppm wt	48.08	45.98
	Lead - Pb	ppm wt	4.01	2.46
	Lithium - Li	ppm wt	4.47	1.84
	Manganese - Mn	ppm wt	18.04	8.82
	Mercury - Hg	ppm wt	0.073	0.047
	Molybdenum - Mo	ppm wt	2.50	2.35
	Nickel - Ni	ppm wt	4.50	4.28
	Selenium - Se	ppm wt	0.98	0.80
	Silver - Ag	ppm wt	0.18	0.19
	Strontium - Sr	ppm wt	316.75	222.41
	Thallium - Tl	ppm wt	0.82	0.54
	Tin - Sn	ppm wt	1.20	1.04
	Thorium - Th	ppm wt	2.05	2.45
	Uranium - U	ppm wt	0.57	0.47
	Vanadium - V	ppm wt	16.72	10.86
	Zinc - Zn	ppm wt	7.04	11.33
	Zirconium - Zr	ppm wt	7.45	9.10

Note: For purposes of equipment and system sizing, the values below for Moisture, Sulfur, Ash, and HGI are based on "+2 Standard Deviations" composition data. The typical value (As Received) for each of these components is shown below:

Item	**Unit**			**Cordero Rojo Mine (Design Coal)**	**North Antelope Rochelle Mine (Alternate Coal)**
Proximate / Ultimate Analysis	Ash	A	wt%	6.62	8.75
	Sulfur	S	wt%	0.39	0.36
	Moisture	M	wt%	30.99	28.70
Sulfur Forms	Pyritic		wt%	0.07	0.06
	Sulfate		wt%	0.014	0.02
	Organic		wt%	0.31	0.32
Hardgrove Grindability Index				94	73

5.3.3 Feedstock Analysis (Calculated to 8.0 wt% Moisture Basis)

Item			Unit	Cordero Rojo Mine (Design Coal) calculated to 8.0 % moisture	North Antelope Rochelle Mine (Alternate Coal) calculated to 8.0 % moisture
Proximate Analysis	Moisture as received	M	wt%	29.59	27.50
	Moisture	M	wt%	8.000	8.000
	Ash	A	wt%	7.117	5.888
	Volatile matter	V	wt%	40.515	40.226
	Fixed Carbon	FC	wt%	44.368	45.937
Ultimate Analysis	Carbon	C	wt%	64.532	64.031
	Hydrogen	H	wt%	4.471	4.416
	Nitrogen	N	wt%	1.010	0.828
	Sulfur	S	wt%	0.406	0.267
	Oxygen	O	wt%	14.448	16.569
	Chlorine	Cl	wt%	0.013	0.001
Lower Heating Value (net calorific value)		LHV	Btu/lb	10,556	10,611
Ash fusion (reducing Atm)	Initial Deformation Temperature	ID	°F	2145	2145
	Softening Temperature	ST	°F	2165	2154
	Hemispherical Temperature	HT	°F	2175	2165
	Fluid Temperature	FT	°F	2205	2179
Ash composition analysis (dry basis)	SiO2		wt%	33.95	34.90
	Al_2O_3		wt%	17.91	16.80
	TiO_2		wt%	1.48	1.30
	Fe_2O_3		wt%	5.07	5.40
	CaO		wt%	22.42	22.80
	MgO		wt%	3.99	5.50
	Na_2O_3		wt%	1.39	1.90
	K_2O		wt%	0.37	0.40
	SO_3		wt%	9.99	8.80
	Undetermined		wt%	1.20	2.20

Item		Unit	Rojo	Antelope
			Mean	Mean
Trace Elements (ppm wt, whole coal, dry basis)	Arsenic - As	ppm wt	1.17	< 1
	Antimony - Sb	ppm wt	0.83	< 1
	Barium - Ba	ppm wt	304.65	350
	Beryllium - Be	ppm wt	0.26	0.2
	Boron - B	ppm wt	30.80	28
	Bromine - Br	ppm wt	14.92	< 20
	Cadmium - Cd	ppm wt	0.18	< 0.2
	Chlorine - Cl	ppm wt	84.81	13
	Chromium - Cr	ppm wt	6.23	4
	Cobalt - Co	ppm wt	2.74	2
	Copper - Cu	ppm wt	10.96	11
	Fluorine - F	ppm wt	48.08	65
	Lead - Pb	ppm wt	4.01	2
	Lithium - Li	ppm wt	4.47	3
	Manganese - Mn	ppm wt	18.04	7
	Mercury - Hg	ppm wt	0.073	0.06
	Molybdenum - Mo	ppm wt	2.50	< 2
	Nickel - Ni	ppm wt	4.50	3
	Selenium - Se	ppm wt	0.98	< 1
	Silver - Ag	ppm wt	0.18	< 0.2
	Strontium - Sr	ppm wt	316.75	166
	Thallium - Tl	ppm wt	0.82	< 1
	Tin - Sn	ppm wt	1.20	< 1
	Thorium - Th	ppm wt	2.05	-
	Uranium - U	ppm wt	0.57	-
	Vanadium - V	ppm wt	16.42	10
	Zinc - Zn	ppm wt	7.04	7
	Zirconium - Zr	ppm wt	7.45	14

5.3.4 Pulverized Coal Specification

Pulverized Coal:

Particle size distribution:	100 wt-%	less than	500 µm
	more than or equal to 94 wt-%	less than	250 µm
	more than or equal to 50 - 55 wt-%	less than	90 µm
	more than or equal to 35 - 50 wt-%	less than	63 µm

Moisture content: less than or equal to 8 wt%

Temperature of pulverized coal: min 140°F / normal 158°F / max 176°F

Content of oxygen in coal transport gas at Gasification Island Battery Limits: less than or equal to 1 vol.%

5.4 Products

Electric Power	
Basis for Net Electrical Output	At utility custody transfer meters
Grid Interconnect:	
Line Voltage	138 kV
Frequency	60 Hz
Scope of Supply Limit	Plant switchyard
Sulfuric Acid Product	93 wt% sulfuric acid
Urea Product	Urea solution (prior to granulation) to be minimum 96 wt% urea + biuret
Total Nitrogen	46.3 wt% max
Biuret	0.8 wt% max
Moisture	0.2 wt% max
Crushing Strength	4.1 kg (0:3 mm) min
Average Diameter	3.2 mm
Size Distribution	95 wt% min (2-4 mm)
Formaldehyde	0.4 wt% max
Carbon Dioxide Product	
CO_2	>95 vol%
O_2	<10 ppmv
H_2S	<10 ppmv for venting; <20 ppmv for pipeline
Total Sulfur (H_2S + COS)	<35 ppmv
Methanol	no spec for pipeline
Inerts	<1.0 vol%
CO	< 1000 ppmv
Glycol	< 25 ppmv (0.3 gallons / MMSCF)

Water	< 250 ppmw (30 lbs / MMSCF in vapor phase)
Nitrogen	< 4 mol%
Hydrocarbons	< 5 mol%
Temperature	<120°F
Delivery Pressure (for pipeline)	2,300 psig
Delivery Pressure (for Urea)	2,161 psia

Gasifier Slag

Carbon Content	0.5-1.5%
Moisture	30-40 wt%

Gasifier Filter Cake

Solid Content	35-40 wt%
Ash in Solid	15-45 wt%
Carbon in Solid	55-85 wt%

5.5 Design/Alternate Cases

The following cases will be run by the licensors:

Siemens Gasification

- Design Coal – Design Gasifier Throughput (Design Case)
- Design Coal – Minimum Gasifier Throughput
- Design Coal – Maximum Gasifier Throughput
- Alternate Coal – Maximum Gasifier Throughput
- Design Coal – Filter Cake Recycle

Linde – 3 cases to be completely documented; limited other information as needed for design

- Guarantee Case
- Maximum Power Production Case
- Alternate Coal Case

Siemens Power

- Multiple cases as needed to support the power block definition

5.6 Toxic / Hazardous Materials

To be developed during EPC.

6.0 BATTERY LIMIT REQUIREMENTS

6.1 Raw Water

Refer to Basic Engineering Design Data (BEDD) Document.

6.2 Natural Gas

Refer to Basic Engineering Design Data (BEDD) Document.

7.0 SITE / METEOROLOGICAL DATA

Refer to Basic Engineering Design Data (BEDD) Document.

8.0 UTILITY CONDITIONS

Refer to Basic Engineering Design Data (BEDD) Document.

9.0 ENVIRONMENTAL DESIGN CRITERIA AND SAFETY REQUIREMENTS

Sulfur in the Treated Syngas	<10 ppmv (COS + H_2S)
Atmospheric Emission Sources	Coal Storage and Handling System Coal Grinding and Drying ▪ Coal Dryer Vents Slag Storage and Handling ▪ Slag Bunker and Conveyors Filter Cake Storage and Handling ▪ Filter Cake Bunker and Conveyors ASU ▪ ASU Vent Rectisol Plant ▪ Methanol Storage Tank Sulfuric Acid Plant ▪ Sulfuric Acid Plant Stack Gas Turbine ▪ HRSG Stack Steam Turbine Ammonia Plant ▪ Ammonia Storage Tank Urea Plant ▪ Urea Plant LP Absorber ▪ Urea Plant Stack ▪ Urea Granulation Stack ▪ Urea Transfer / Storage / Unloading Vents Miscellaneous ▪ Process Cooling Tower ▪ Auxiliary Boiler Stack ▪ Diesel Generator ▪ Diesel Firewater Pump ▪ CO_2 Release Points ▪ Detention Ponds Flare System ▪ Warm Flares ▪ Cold Flare ▪ Ammonia Flare
Non-attainment Criteria Pollutants	None
Cooling Tower Drift Design Basis	0.0005%
CO in CO2 Vent	< 1000 ppmv

Methanol in CO2 Vent	Design for 500 ppm (max) without further treating

Gas Turbine Atmospheric Emission Requirements:
(based on HRSG stack with GTG burning syngas excluding duct burner contribution unless otherwise noted)

NO_x as NO_2	SCR Design Criteria: ≤15 ppm, dry @ 15% O_2 with syngas , 1 hour average ≤3.5 ppm, dry @ 15% O_2 with syngas , 30 day rolling average ≤2.5 ppm, dry @ 15% O_2 with natural gas, 30 day rolling average Annual average emission rate of ≤0.034 lbs/MMBtu gasifier heat input (HHV).
SOx as SO_2	≤ 2.0 ppmv – wet @ 15% O_2 30-day average emission rate of 0.04 lb/MMBtu gasifier heat input (HHV).
CO	≤ 25 ppmv – dry @ 15% O_2, 1 hour average ≤ 30 ppmv – dry @ 15% O_2, 30 day rolling average
UHC as CH_4	≤ 7.0 ppmv – wet @ 15% O_2
VOC	≤ 1.4 ppmv – wet @ 15% O_2
PM10 (Filterable)	Annual average emission rate of 0.015 lbs/MMBtu gasifier heat input (HHV)
PM2.5	Annual average emission rate of 0.015 lbs/MMBtu gasifier heat input (HHV)
H_2SO_4	0.2 lb/ton of product (0.000148 lb / MMBtu of coal)
NH_3 Slip in HRSG Stack	≤ 10 ppmv-dry @ 15% O_2
Stack Height	EPA GEP, 40 CFR Part 51

Liquid Effluents:

Gasification LP Cycle Water (Grey Water) Blowdown	To Waste Water Treatment Plant zero liquid discharge (ZLD) system
Storm/Surface Water	Retention basins to retain plant runoff
Steam System Blowdown	To Cooling Tower Basin
Cooling Tower Blowdown Treatment Plant Reject	To Raw Water Treatment Plant zero liquid discharge (ZLD) system

Slag Storage Pile Water	Recycle to Gasification Unit
Coal Storage Pile Runoff Water	Recycled to Coal Dust Suppression System
Filter Cake Runoff Water	Recycle to Gasification Unit
Sanitary Wastes	To onsite septic system
Oil/Water Separator	Oil to third party disposal Water to Waste Water Treatment Plant zero liquid discharge (ZLD) system
Plant Wash-down Water	To retention basin (except coal pile wash-down which is recycled to Coal Dust Suppression System)
Liquid Chemical Wastes	Captured and sent to third party disposal
Miscellaneous Plant and Transformer Oils	Oil to third party disposal

Solid Effluents:

Slag from Gasification	Shipped offsite for sale or to landfill
Spent Carbon from Hg Absorbers	Shipped offsite as hazardous waste
Spent Shift Catalyst	Shipped offsite to reclaimer
Spent Ammonia Catalyst	Shipped offsite to reclaimer
Spent Urea Catalyst	Shipped offsite to reclaimer
Spent Sulfuric Acid Catalyst	Shipped offsite to reclaimer
Spent SCR Catalyst	Shipped offsite for disposal
Water Treatment Solid Waste	Shipped offsite to landfill
Waste Water Treatment Solid Waste	Shipped offsite as hazardous waste
Black Water Soot Cake (Filter Cake)	Shipped offsite as hazardous waste

Noise

Near field	85 dBA @ 3 ft from equipment or enclosure (Noise level from the pulverizers is 90 dBA)
Far field	65 dBA @ property boundary Design to local noise ordinances

10. EQUIPMENT DESIGN CONSIDERATIONS

10.1 General Design Criteria

Contractor standard process design criteria shall be used for items such as establishing design pressure/temperature, based on operating pressure vessel surge time, etc. Licensor standards and practices may instead be used when applicable.

10.2 Design Margins

Refer to FEED Execution Guideline FEG 010.

10.3 Critical Service / Sparing Philosophy

"Critical service" is equipment that must be maintained in service in the event of a power failure in order to protect personnel, equipment, or catalyst. Equipment in critical service must have drivers which are reliable during a power failure, and spares adequate to provide the required capacity when essential maintenance is required. Motor drivers are generally preferred over turbine drivers.

Equipment in critical service may or may not be spared for essential maintenance. In general, if the equipment failure will result in a reduction of availability below the target set for the plant, then the equipment shall be spared. If the equipment is non-essential, for which failure for a limited time would not cause the unit to be unreliable, no sparing is required.

10.4 Flare Design

Refer to Basic Engineering Design Data (BEDD) Document.

11. ECONOMIC EVALUATION CRITERIA

Refer to Basic Engineering Design Data (BEDD) Document.

7.2 Basic Engineering Design Data (BEDD)

The BEDD includes the following types of design data and information which were used by all of the FEED contractors in their design work:

- Climatic Data for the TCEP site and area (i.e. humidity and air temperature minimum/maximum values), which are important in design and performance of wet cooling towers, combustion turbines, large compressors, etc.
- Seismic Design Data for the TCEP site and area, which is used in the design of foundations and structures
- Plant Elevation
- Soil Conditions, which is used in the design of foundations
- Utility Design Information, which includes temperatures and pressures of streams used throughout the plant, such as steam, cooling water, compressed air, and natural gas.
- Battery Limit Requirements, such as water quality requirements needed by the FEED contractors for raw water, demineralized water, and cooling water, for their use in designing equipment and systems within their specific "blocks"
- Point Source Emissions, which includes data used in the air permit application, for use in determining emission control requirements
- Electrical, such as voltage levels for specific types of motors
- Flare System data, which includes the number of flares and the types of gas streams which could be flared
- Economics, such as cost of water and value of power sales, used for calculating the cost-effectiveness of design changes and value suggestions

The Issued for FEED version of that document follows. During the EPC re-cast, this document was incorporated into the Project Design Basis document.

Summit Texas Clean Energy, LLC
Texas Clean Energy Project
Penwell, TX

Fluor Enterprises, Inc.
Aliso Viejo, Ca

BASIC ENGINEERING DESIGN DATA (BEDD)

Client: Summit Texas Clean Energy, LLC
Project: Texas Clean Energy Project
Contract No: A5PN
Document No: A5PN-225-002

3	31 May 2011	Final Issue for FEED	CR	SK	RB
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A	10 Aug 2010	Issued for Review	CR	SK	RB
Rev	**Date**	**Description**	**By**	**Chk**	**App**
			Fluor		

BASIC ENGINEERING DESIGN DATA

TABLE OF CONTENTS

Section **Page**

1.0 General Information

1.1	**Name:**	Summit Texas Clean Energy, LLC
1.2	**Address:**	Summit Texas Clean Energy, LLC 701 Winslow Way E, Suite B Bainbridge, WA 98110
1.3	**Telephone Number:**	(206) 780-3551
1.4	**Project Location**	Penwell, TX
1.5	**Texas County:**	Ector

2.0 Climatic Data

2.1 Pressure

2.1.1 The site atmospheric pressure is 13.2 psia.

2.2 Temperature

2.2.1 <u>Summer Day</u>

Dry Bulb	106.0°F
Coincident Wet Bulb	84.0°F
Extreme Maximum	116.0°F
Coincident Wet Bulb	69.0°F
Extreme Maximum (Indoor)	130°F

2.2.2 <u>Average Annual Day</u>

Dry Bulb	63.6°F
Coincident Wet Bulb	51.5°F

2.2.3 Winter Day

Dry Bulb	0.0°F
Coincident Wet Bulb	-1.4°F
Extreme Minimum	-11°F
Extreme Minimum (Indoor)	40°F

2.2.4 Design

2.2.4.1 -11°F shall be used for winterizing criteria.

2.2.4.2 -11°F shall be used for minimum design metal temperature.

2.2.4.3 Cooling Tower / Air Blower Design

Dry Bulb	100°F
Coincident Wet Bulb	69°F

2.2.4.4 Power Block Design Conditions for Performance Guarantees

Dry Bulb	82°F
Coincident Wet Bulb	67°F

2.2.5 Refer to Appendix D for temperature data for Penwell, TX in 2009.

Source: http://www.wunderground.com

2.3 Wind

2.3.1 Average Wind Speed / Prevailing Direction

2.3.1.1 9 mph – January / from the South

2.3.1.2 12.5 mph – July / from the Southeast

2.3.2 Design wind speed shall be 90 mph (3-second gust) per 2006 IBC.

2.3.3 Refer to Appendix A for the Wind Rose.

2.4 Precipitation

2.4.1 For design considerations, the maximum rainfall accumulations for a 1-hr, 2-hr, and 24-hr durations are 2.1, 2.5, and 4.3 inches, respectively, based on a 10-year return period, with an average of 15 inches per year.

2.4.2 For design considerations, the average snowfall accumulation is 4 inches per year.

2.4.3 Foundation design depth for frost penetration consideration is 0 inches.

2.4.4 Design ground snow load per 2006 IBC shall be 5 lb/ft^2.

2.5 Severe Weather Events

2.5.1 Tornadoes

The National Oceanic Atmospheric Administration (NOAA) documents tornado activity for each Texas county (NOAA, 2006). The Fujita Scale is a standard qualitative metric to characterize tornado intensity based on the damage caused. This scale ranges from F0 (weak) to F6 (violent). From 1950 to 2007, 37 tornadoes were reported in the 907 square miles of Ector County, including 30 F0 tornadoes, three F1 tornadoes, and four F2 tornadoes (NOAA, 2006). Based on historical tornado activity within Ector County, there could be 6 F1 or greater tornadoes in the county (over 901 square miles) over the possible 50 year lifespan of the Texas Clean Energy Project. For comparison purposes with the other candidate sites, using a nominal county size of 850 square miles, the tornado frequency would equate to approximately 6 F1 or greater tornadoes over 50 years. From 1950 to 2007, 61 tornadoes were reported in the 4,764 square miles of Pecos County (location of the sequestration site), including 38 F0, 15 F1, six F2, one F3, and one F4. For Pecos County, for an 850 square mile area, there could be 10 F1 or greater tornadoes over 50 years.

2.5.2 Floods

The entire proposed power plant site and transmission line corridor is located outside of the 500-year floodplain. Small portions of the proposed water supply corridors and CO_2 pipeline corridors would be within the 100-year floodplain. The NOAA database shows that, from 1993 to 2006, 60 floods have been reported in Ector County. Thirty-six of these floods caused no damage, 18 caused damage between $5,000 and $30,000, and three caused damage between $75,000 and $300,000. The most severe flood occurred in the early fall of 2004 with an estimated $2 million of damage. Total flood damage in Ector County since 1993 is $3.2 million.

2.5.3 Drought

Texas has suffered notable periods of drought since the 1930s with extended periods of severe to extreme drought in 1933 to 1935, 1950 to 1957, 1962 to 1967, 1988 to 1990, 1996, and 1998 to 2002. These droughts were more common and widespread in the Rio Grande Basin in the western part of the state. A statewide network of data collection sites, operated by state and federal agencies, has been established to monitor drought conditions. These sites provide real-time climate, stream flow, aquifer, and reservoir information to water management professionals to develop drought mitigation and response plans. Additional information on the State of Texas Drought Preparedness Plan can be found at http://www.txwin.net/DPC/State_Drought_Preparedness_Plan.pdf.

2.6 Additional Climate Data

2.6.1 Refer to Appendix C for additional climate data for Penwell, TX between 1971 to 2000 from the National Climatic Data Center.

3.0 Seismic Design Data

3.1 Building Code

Seismic Design Category:	B
Seismic Site Class:	D (to be confirmed)
Importance Factor:	1.15
Spectral Response Acceleration At Short Period	S_{DS} = 0.25 g (to be confirmed)

Spectral Response Acceleration at One-Second Period — S_{D1} = 0.07 g (to be confirmed)

4.0 Plant Elevation

4.1 The plant will be approximately 2,950 ft above sea level.

5.0 Soil Conditions

5.1 Material Characteristics

Subsurface materials at site consist of an uppermost stratum of brown clayey or silty sand varying in thickness from 2.5 to 5.0 feet. The next underlying stratum consist of tan caliche (some rock-like) from 0 to 5.5 feet in thickness. The lowermost stratum to a depth of 20 feet consists of tan caliche. The clayey and silty sands are generally in medium dense to dense relative density condition. The caliches are a mixture of silts, sands, and clays and calcareous particles in a matrix of calcium carbonate in well to highly cemented condition. Groundwater is not present within 20 feet of the surface.

5.2 Frost Depth

The published frost depth for the area is four inches.

6.0 Utility Design Information

6.1 Refer to Table 1 for utility design information.

TABLE 1- UTILITY DESIGN INFORMATION (PROCESS BLOCK)

	Utility Service	Symbol	Operating Conditions						Mechanical Design		Flange Rating	Note(s)	Revision
			Pressure, psig			Temperature, °F							
			Min (Note 2)	Nor. (Note 3)	Max (Note 2)	Min (Note 2)	Nor. (Note 3)	Max (Note 2)	psig	°F			
STEAM	High Pressure Steam (Superheated)	**HSS**	711	725	740	662	690	716	860	752	600 #	4	1
	High Pressure Steam (Saturated)	**HS**	711	725	740	507	510	512	860	752	600 #	5	0
	Medium Pressure Steam (Saturated)	**MS**	145	155	160	363	368	370	195	400	150 #	6	0
	Low Pressure Steam (Saturated)	**LS**	44	58	65	291	305	311	90	400	150 #	7	1
COND.	Medium Pressure Condensate	**MC**	90	100	110	331	337	344	195	400	150 #	1, 8	2
	Low Pressure Condensate	**LC**	30	38	45	273	284	292	90	350	150 #	1, 8	2
	LP Pumped Condensate	**LPC**	195	210	240	212	227	239	310	350	300 #	1, 22	3
BFW	Cool HP BFW	**CBW**	831	846	860	95	100	105	1010	300	600 #	1, 13	1
	HP BFW (Process Block)	**HBW**	841	856	870	212	240	266	1010	300	600 #	1, 9	A
	MP BFW (Process Block)	**MBW**	247	261	290	212	240	266	350	300	300 #	1, 9	A
COOLING WATER & MIS. WATER SERVICES	Cooling Water Supply	**CWS**	-	65	75	60	80	92	150	150	150 #	1, 10	A
	Cooling Water Return	**CWR**	35	40	-	80	100	120	150	150	150 #	1, 10	A
	Potable Water	**PW**	45	50	65	50	60	70	136	100	150 #	1, 11	2
	Utility Water	**UW**	45	50	65	50	70	80	100	125	150 #	1, 8	1
	Raw Water	**RW**	40	50	60	50	70	95	145	125	150 #	1,	2
	Process Water	**PRW**	475	500	676	70	80	100	732	150	600 #	1	2
	Gasification Process Water	**GPW**	711	825	862	70	80	100	970	150	600 #	1, 24	2
	Fire Water	**FW**	90	100	140	50	70	80	175	100	150 #	1, 12	3
	Demin Water	**DW**	90	153	174	50	70	95	187	125	150 #	1, 23	2
SEW	Oily Water Sewer	**OWS**	0	0	5	60	80	100	45	150	150 #	8, 13	2
	Pumped Oily Water	**POW**	25	50	70	60	80	100	150	150	150 #	8, 13	2

	Utility Service	Symbol	Operating Conditions						Mechanical Design		Flange Rating	Note(s)	Revision
			Pressure, psig			Temperature, °F							
			Min (Note 2)	Nor. (Note 3)	Max (Note 2)	Min (Note 2)	Nor. (Note 3)	Max (Note 2)	psig	°F			
	Potentially Contaminated Sewer	**PCS**	0	0	10	40	64	106	15	120	150 #	8, 13, 27	3
AIR	Plant Air	**PA**	70	100	118	50 (86)	73 (95)	104	150	150	150 #	14, 25	2
	Instrument Air	**IA**	70	100	118	50 (86)	73 (95)	104	150	150	150 #	14, 25	2
O_2	Oxygen	**OXY**	667	682	692	41	80	104	812	176	600 #	15	2
NG	HP Natural Gas	**HNG**	689	703	718	90	100	110	950	150	600 #	13, 15	2
	LP Natural Gas	**LNG**	50	55	95	60	65	70	100	150	150 #	8	3
N_2	HP Nitrogen (Gasification)	**HN**	841	870	880	135	158	176	1001	248	600 #	15	2
	High Purity Nitrogen (Ammonia)	**HPN**	490	500	510	41	80	104	570	150	300 #	17	2
	MP Nitrogen (GT)	**MN**	460	470	480	235	260	280	530	350	300 #	16	2
	Liquid Nitrogen (Nitrogen Wash)	**LIN**	TBD	74	84	TBD	-290	TBD	TBD	TBD	150 #	17	3
	LP Nitrogen	**LN**	80	90	100	140	158	176	150	248	150 #	15	2
BLOW DOWN	Continuous Blowdown Header	**MPB**	25	30	35	274	287	298	75	350	150 #	21	0
	Intermittent Blowdown Header	**LPB**	40	50	60	286	287	307	150	350	150 #	21	3
FLARE	Warm Flare Header	**WF**	TBD	0	TBD	0	64	-	100	550	150 #	18, 26	2
	Cold Flare Header	**CF**	TBD	0	TBD	0	64	-	100	380	150 #	8, 19, 26	2
	Ammonia Flare Header	**AF**	TBD	0	TBD	0	64	-	100	360	150 #	8, 20, 26	2

Notes:

1. For liquid services, all pressures are referenced at grade level.
2. The maximum pressure/temperature is the required pressure/temperature at the producer. The minimum pressure/temperature is the lowest pressure/temperature at the consumer.
3. The normal pressure and temperature are at consumer's unit battery limit.
4. Conditions were per the SFGT Design Basis. Design pressure updated per Fluor recommendation. Normal operating temperature updated per SFGT Battery Limit Sheet.
5. Min, max and design conditions were per Fluor recommendation.
6. Conditions were per Fluor recommendation.
7. Min and max conditions were per SFGT Design Basis. Design conditions were per Fluor

recommendation.

8. Conditions were per Fluor recommendation.
9. Conditions were per the SFGT Design Basis. Design conditions were updated per Fluor recommendation.
10. Normal operating temperature was per the Fluor Design Basis. Additional conditions were per Fluor recommendation.
11. Initial normal conditions were per the Fluor Design Basis. Initial design conditions were per the SFGT Design basis. Min and max conditions were per Fluor recommendation. Normal pressure was updated per Fluor recommendation.
12. Normal pressure was per the Fluor Design Basis. Min, max, and design conditions were per Fluor recommendation.
13. To be reviewed.
14. Min pressure was per the SFGT Design Basis. Min and max temperature were per the Fluor Design Basis. Normal, max, and design pressures, and normal temperatures were per Fluor recommendation.
15. Conditions were per the SFGT Design Basis.
16. Conditions set by Siemen's GT requirement.
17. Temperature conditions will be subcooled or at boiling point. Conditions set by Linde's Nitrogen wash unit requirement.
18. The superimposed back pressure is shown as 0 psig. However, a slight positive pressure will be present in the flare headers due to purge gas.
19. From Rectisol Unit.
20. From Ammonia / Urea Plant.
21. Continuous blowdown for both high pressure and low pressure steam drum will be 1% of BFW makeup and will go to central atmosphere blowdown drum via continuous blowdown header. The flashed blowdown will be pumped to the Cooling Tower. Intermittent blowdown will be routed to a local unit atmospheric blowdown drum. Flashed intermittent blowdown will be pumped to the Cooling Tower via intermittent blowdown header.
22. Normal operating pressure was per Siemens Power Design Basis.
23. Minimum pressure set by Siemens Power Block.
24. Operating pressures were per SFGT requirement.
25. Normally, plant and instrument air will be supplied from the ASU at a temperature of 73°F. If the ASU trips, the back up air compressor will come online, and the temperature of the plant and instrument air will be 95°F
26. The minimum and normal flare header operating temperatures are based on the average winter and annual ambient temperatures. The maximum flare header operating temperature will be based on an individual relief scenario.
27. The potentially contaminated sewer (PCS) minimum, normal, and maximum operating temperatures are based on cold weather average annual, and average summer ambient temperatures, respectively.

7.0 Battery Limit Requirements

7.1 Raw Water

7.1.1 Refer to Table 2 for raw water requirements. Customer is responsible for treating the water to meet the following raw water specification or ensure suitable design and metallurgy/materials.

TABLE 2 – RAW WATER

Parameter	Maximum Allowable Concentration in any Raw Water allowed by SEI.	Units
Arsenic	0.025	mg/L
Biological Oxygen Demand (5 day)	20	mg/L
Cadmium	0.025	mg/L
Calcium	70	mg/L
Chemical Oxygen Demand	50	mg/L
Chloride	225	mg/L
Chromium	0.1	mg/L
Copper	0.1	mg/L
Cyanides	0.2	mg/L
Electrical Conductivity	1150	µS/cm
Fecal Coliform Bacteria	150	NMP/100 ml
Greases and oils	2	mg/L
Hexavalent Chromium	0.1	mg/L
Iron (total)	0.2	mg/L
Lead	0.05	mg/L
M-alkalinity (as $CaCO_3$)	200	mg/L
Magnesium	20	mg/L
Manganese	0.05	mg/L
Mercury	0.001	mg/L
Nickel	0.5	mg/L
pH	Min = 6 / Max = 8	pH
Phenols	0.1	mg/L
Sediment Solids	0.2	mg/L
Silica Colloidal	10	mg/L
Silica Reactive	20	mg/L
Silica Total	20	mg/L
Sulfate	300	mg/L
Total Dissolved Solids (Note 1)	750	mg/L

Parameter	Maximum Allowable Concentration in any Raw Water allowed by SEI.	Units
Total Nitrogen as N	8	mg/L
Total Organic Carbon	5	mg/L
Total Phosphorus as PO_4	0.5	mg/L
Total Suspended Solids	5	mg/L
Water Temperature	Min = 50 / Max = 95	°F
Zinc	0.25	mg/L
Limits are stated as the constituent unless noted.		

Notes:

1. Balancing the cations and anions show that the total TDS to be 1110 mg/mL (as ions). Balance to be Na. This will be the basis for water treatment design.

7.2 Demineralized Water

7.2.1 Refer to Table 3 for demineralized water requirements.

TABLE 3 – DEMINERALIZED WATER

Parameter	Unit	Design Condition (Note 6)
pH @ 77°F (Note 1)		6.8
Total hardness	ppm wt	ND
Total dissolved solids (Note 1)	ppm wt	< 0.05
Conductivity (Note 1, 2)	μS/cm	< 0.1
Na	ppm wt	< 0.005
Total iron, copper, nickel	ppm wt	< 0.01
Silica	ppm wt	< 0.01 (as SiO2)
Copper	ppm wt	< 0.002
Nonvolatile TOC	ppm wt	ND
TOC	ppm wt	< 0.1
Turbidity	NTU	ND
Oily matter	--	ND
Calcium	ppm wt	ND
Chlorides	ppm wt	< 0.01
Sulfate	ppm wt	< 0.01
Phosphate	ppm wt	< 0.01

Notes:
1. Continuous analysis recommended.
2. Downstream of a strong cation exchanger.
3. Deleted.
4. Deleted.
5. ND – Not Detectable
6. Demin water quality meets all licensor’s requirements.

7.3 Boiler Feed Water

7.3.1 Refer to Table 4 for boiler feed water requirements.

TABLE 4 – BOILER FEED WATER

Parameter	**Unit**	**Design Condition (Note 4)**
pH @ 77°F (Note 2)	-	9.6-9.8
Degassed	-	Yes
Oxygen	ppb wt	< 2-20
Conductivity (Note 3)	μS/cm	< 0.2
Total silica	ppb wt	< 10 (as SiO2)
Total iron	ppb wt	< 10 (as Fe)
Total copper	ppb wt	< 2 (as Cu)
Total sulfur	ppb wt	< 10 (as SO_4^{2-})
Total chlorides	ppb wt	< 10 (as Cl^-)
Phosphate	ppb wt	< 10 (as PO4) (Note 5)
Na (Note 1)	ppb wt	< 5
Oily matter	ppb wt	ND
Total hardness	μmol/L	ND
Oil, fat, grease	-	ND
TOC	ppb wt	< 100

Notes:
1. After commissioning, this is a control parameter during startup until ST reaches 20% load.
2. pH adjusted by use of ammonia or amine – TBD.
3. Downstream of a strong cation exchanger.
4. Boiler Feed Water quality meets all licensor's requirements.
5. Value does not include any phosphate addition for antiscalant to BFW downstream of desuperheater take off.
6. ND – Not Detectable

7.4 Process Water

7.4.1 Refer to Table 5 for process water requirements.

Parameter	Unit	Avg. Operation Condition (Note 1, 2)
pH @ 77°F	-	6.3
Conductivity	μmhos	180
Chlorides	mg/L	15
Calcium hardness	mg/L (as CaCO3)	2
Total Suspended Solids (TSS)	mg/L	0
Total Dissolved Solids (TDS)	mg/L	125
Total alkalinity	mg/L (as CaCO3)	20
Total iron + manganese	mg/L	0
Nitrate + Nitrite	mg/L	20
Silicate	mg/L	1
Ammonia	mg/L	0
Sulfate	mg/L	10
Chemical Oxygen Demand (COD)	mg/L	5
Free Chlorine	mg/L	0
Oil and Grease	mg/L	0.1

Notes:

1. Process Water is the water for use in the Power Block Evaporative Cooler and shift gas condensate makeup. Makeup Process Water is a blend of EDI Reject, RO Permeate, and Brine Concentrator Distillate.
2. Gasification process water is the water for use as Gasification valve purge and will be supplied mainly with water from gasification waste water ZLD distillate and blended with process water as shown here. It is expected that gasification valve purge water quality will not be worse than that shown here. Gasification waste water ZLD distillate may contain some level of formates and ammonia during biooxidation unit upset. Hence, gasification waste water ZLD distillate will only be recycled to gasification unit.

7.5 Cooling Water

7.5.1 Refer to Table 6 for cooling water requirements.

TABLE 6 - COOLING WATER

Parameter	**Unit**	**Design Condition (Note 5)**	**Normal Operation Case (Note 6)**
pH @ 80°F		7.5	7.5
Conductivity	(µS/cm)	6,857	5,036
TDS (Total Dissolved Solids)	(mg/L)	4,800	3,525
TSS (Total Suspended Solids)	(mg/L)	20	16
Total Hardness	(mg/L) as $CaCO_3$	610	570
Total Alkalinity (m-value) (Note 2)	(mg/L) as $CaCO_3$	210	193
Sodium	(mg/l)	1,050	685
Magnesium	(mg/L) as $CaCO_3$	290	268
Chloride	(mg/L)	1,005	735
Sulfate	(mg/L)	1,800	1,304
Nitrate + Nitrite	(mg/L)	160	114
Phosphate	(mg/L)	2.2	1.6
Silica	(mg SiO_2/L)	90	65
Iron (dissolved) (Note 3)	(mg/L)	0.9	0.7
Manganese (Note 3)	(mg/L)	0.3	0.2
Free Chlorine	(mg/L)	TBD	TBD
Turbidity	NTU	TBD	TBD
COD	(mg/L)	TBD	TBD
Potassium	(mg/L)	TBD	TBD
Carbonate	(mg/L)	TBD	TBD
Bicarbonate	(mg/L)	252.2	235.9
Fluoride	(mg/L)	TBD	TBD
Hydrogen Sulfide	(mg/L)	TBD	TBD
Copper	(mg/L)	TBD	TBD
Oils	(mg/L)	TBD	TBD

Notes:

1. Deleted.
2. The total alkalinity can be changed by acid dosage.
3. The limit of 0.2 mg/L can be increased to 1 mg/L when an iron dispersant is dosed in case (Fe^{2+} + Mn^{2+}) exceeds 1 mg/L and a Fe/Mn removal unit is required.
4. Deleted.
5. Design condition is based on design Cooling Tower duty, evaporation at design ambient condition, which reflects max cooling tower evaporation rate. This condition will occur for a very short period of time.
6. Normal operating case is based on normal Cooling Tower duty and evaporation at average annual ambient condition. It is expected that the Cooling Tower will operate at this condition the majority of the time.

7.5.2 Refer to Table 13 for a summary of cooling water supply and expected return temperatures at various ambient dry and wet bulb conditions.

TABLE 13 - AMBIENT DRY AND WET BULB CONDITIONS

	Design & Guarantee	Summer Peak	Summer Average	Yearly Average	Winter	Case 1 (Note 3)	Case 2 (Note 3)
Dry Bulb	100.0°F	106.0°F	91.8°F	63.6°F	-11°F	96.0°F	116.0°F
Wet Bulb	69.0°F	84.0°F	68.9°F	51.5°F	(Note 2)	75.0°F	69.0°F
Cooling Water Supply	80.0°F	92.0°F	80.0°F	71.0°F	50.0°F	83.9°F	80.0°F
Cooling Water Return	100.0°F	112.0°F	100.0°F	91.0°F	70.0°F	103.9°F	100.0°F

Notes:

1. Cooling water supply temperatures were estimated by cooling tower vendor.
2. Based on 50% RH. Cooling Tower to be operated with a targeted cooling water supply temperature of 50°F. This will be maintained by shutting off fans.
3. Case 1 and 2 are for ASU design.

7.6 Steam

7.6.1 Export steam to the process island and process return steam to the Power Block will meet the feedwater requirements, as well as the demineralized water requirements.

7.6.2 Refer to Table 7 for HP steam requirements.

TABLE 7 - STEAM

Parameter	**Unit**	**Design Condition (Note 1)**
pH	-	9.6 - 9.8
O_2	ppm wt	< 0.002 - 0.02
Na	ppm wt	< 0.005
SiO_2	ppm wt	< 0.01
Fe	ppm wt	< 0.02
Cu	ppm wt	< 0.002
TOC	ppm wt	< 0.1
Acid Conductivity	µS/cm	< 0.2

Notes:
1. Steam quality meets all licensor's requirements.

7.7 Nitrogen

7.7.1 Refer to Table 8 for nitrogen requirements.

TABLE 8 - NITROGEN

Parameter	Unit	High Pressure Nitrogen	High Purity Nitrogen	MP Nitrogen	Liquid Nitrogen	LP Nitrogen
Purity	mol %	≥ 99.5	≥ 99.999	≥ 98	≥ 99.999	TBD
Oxygen	mol %	≤ 0.5	< 0.0005	< 2	< 0.0005	≤ 0.5
Carbon dioxide	ppm mol	≤ 10	Free	TBD	TBD	TBD
Carbon monoxide	ppm mol	≤ 10 or according local regulations for emission to atmosphere	TBD	TBD	TBD	TBD
Hydrogen sulfide	ppm mol	according local regulations for emission to atmosphere	TBD	TBD	TBD	TBD
Other components		according local regulations for emission to atmosphere	TBD	TBD	TBD	TBD
Oil, grease, and dust		Free	Free	TBD	TBD	TBD
Argon	ppm mol	TBD	< 100	TBD	< 100	TBD
Water	ppm mol	TBD	< 1	TBD	< 1	TBD
Hydrocarbon		TBD	Free	TBD	TBD	TBD
Catalyst Poisons		TBD	Free	TBD	TBD	TBD
Dew point @ operating pressure	°F	≤ -49	TBD	TBD	TBD	TBD

7.8 Oxygen

7.8.1 Refer to Table 9 for oxygen requirements. The oxygen must be free of impurities such as dust, oil and oily matter as well as grease and greasy matter at the battery limit as specified below.

TABLE 9 – OXYGEN

Parameter	Units	Design Condition
Purity	mol %	99.5

7.9 Instrument Air

7.9.1 Refer to Table 10 for instrument air requirements.

TABLE 10 – INSTRUMENT AIR

Parameter	Unit	Design Condition
Dew point	°C / °F	≤ -40 / -40 (Note 1)
Oil and grease content	-	Free
Dust content	-	Free

Notes:
1. At 0.8 Mpa (a) / 102 psi (g)
2. Design conditions apply to ASU and Air backup system.

7.10 Plant Air

7.10.1 Refer to Table 11 for plant air requirements.

TABLE 11 – PLANT AIR

Parameter	**Unit**	**Design Condition**
Dew point	°C / °F	≤ -40 / -40 (Note 1)
Oil and grease content	-	Free
Dust content	-	Free

Notes:
1. At 0.8 Mpa (a) / 102 psi (g)
2. Design conditions apply to ASU and Air backup system.

7.11 Natural Gas

7.11.1 Refer to Table 12 for natural gas requirements (final composition to be determined by Summit).

TABLE 12 – NATURAL GAS

Parameter	Units	Design Condition (Note 1)	Preliminary
Specific Gravity	-	TBD	TBD
Btu content, LHV	BTU/lb	22,100 – 25,600	20,981
Methane (C_1)	mol%	-	98.00
Ethane (C_2)	mol%	-	0.60
Propane (C_3)	mol%	< 0.34 gallon/MScf	0.00
Normal Butane (n-C_4)	mol%	-	0.00
Normal Pentane (n-C_5)	mol%	-	0.00
Nitrogen (N_2)	mol%	< 3.00	1.40
Carbon Dioxide (CO_2)	mol%	< 2.00	0.00
Water (H_2O)	-	< 7 lb/MMScf	< 7 lb/MMScf
Sulfur	-	< 5 grains/100 Scf (Note 2)	< 1 grains/100 Scf
Dew Point - Moisture	°F	TBD	TBD
Dew Point - Hydrocarbon	°F	TBD	TBD
Oxygen	mol%	< 0.20	TBD
Mercury	-	ND	ND
Hydrogen Sulfide (H_2S)	-	< 0.25 grains/100 Scf	TBD
Mercaptans	-	< 0.75 grains/100 Scf	TBD

Notes:
1. Quality is per NG supplier (ONEOK), and is still under review.
2. Per discussion with Summit Environmental Group, the amount of sulfur guaranteed in the NG delivery contract will be negotiated to < 1 grains/100 Scf.

8.0 Point Source Emissions

8.1 Refer to Appendix B for emissions summary.

9.0 Electrical

Service (Frequency Range of 59.0 Hz to 61.2 Hz)	Motor or Generator Rated Voltage	System Voltage
Motors 0.75 Hp and below (1-Phase)	115 V	120 V
Low Voltage motors from 0.75 Hp to 250 Hp and motor operated valves (3-Phase)	460 V	480 V
Motors 300 Hp to 5,000 Hp	4,000 V	4,160 V
Street or area flood lighting	-	480 V
Lighting, receptacles, space heaters, heat tracing	-	208/120 V
UPS power (1-Phase)	-	120 V
Protection system, LV & MV switchgear controls, UPS input power	-	125 Vdc
Utility Interface Operating Voltage	-	345 kV
In-house Service Operating Voltage	-	138 kV
DCS instrumentation and controls	-	24 Vdc
Cooling Tower and Air Cooled Condenser Motors Greater than 200 HP 200 HP and below	 4,000 V 460 V	 4,160 V 480 V
Plant Large Sync Motors with LCI Soft Starting	13.8 kV	13.8 kV
Plant Large Ind Motors with Direct on Line Starting	13.2 kV	13.8 kV
GTG / STG Generator Voltage	25 kV / 25 kV	25 kV / 25 kV
Emergency Generator Voltage	TBD V (Probably 13.8 or 4.16 kV)	TBD V (Probably 13.8 or 4.16 kV)
Emergency lube oil pump motors and other dc motors less than 30 HP	-	125 Vdc
Emergency lube oil pump motors and other dc moto greater than 30 HP	-	250 Vdc

10.0 Flare System

10.1 Based on the anticipated relief streams, the number and type of flare stacks will likely be as follows:

- **Small warm/sour gas flare:** This flare will handle turndown, minor upset relief loads, and sour gas relief loads.

- **Large warm flare:** This flare will handle large relief loads that start with the small warm flare and are shifted to the large warm flare based on back pressure.

- **Cold Flare:** Cold relief loads are segregated from warm relief loads with a dedicated header and flare stack to avoid thermal shock and ice formation that can be cause by mixing of cold dry gases and warm wet gases in common cold/warm flare headers.

- **Ammonia flare:** A dedicated ammonia flare is required to ensure complete combustion of relief streams with high ammonia concentration.

Notes:

1. Deleted.
2. The design of the flare and flare headers are preliminary and are still under review.

11.0 Economics

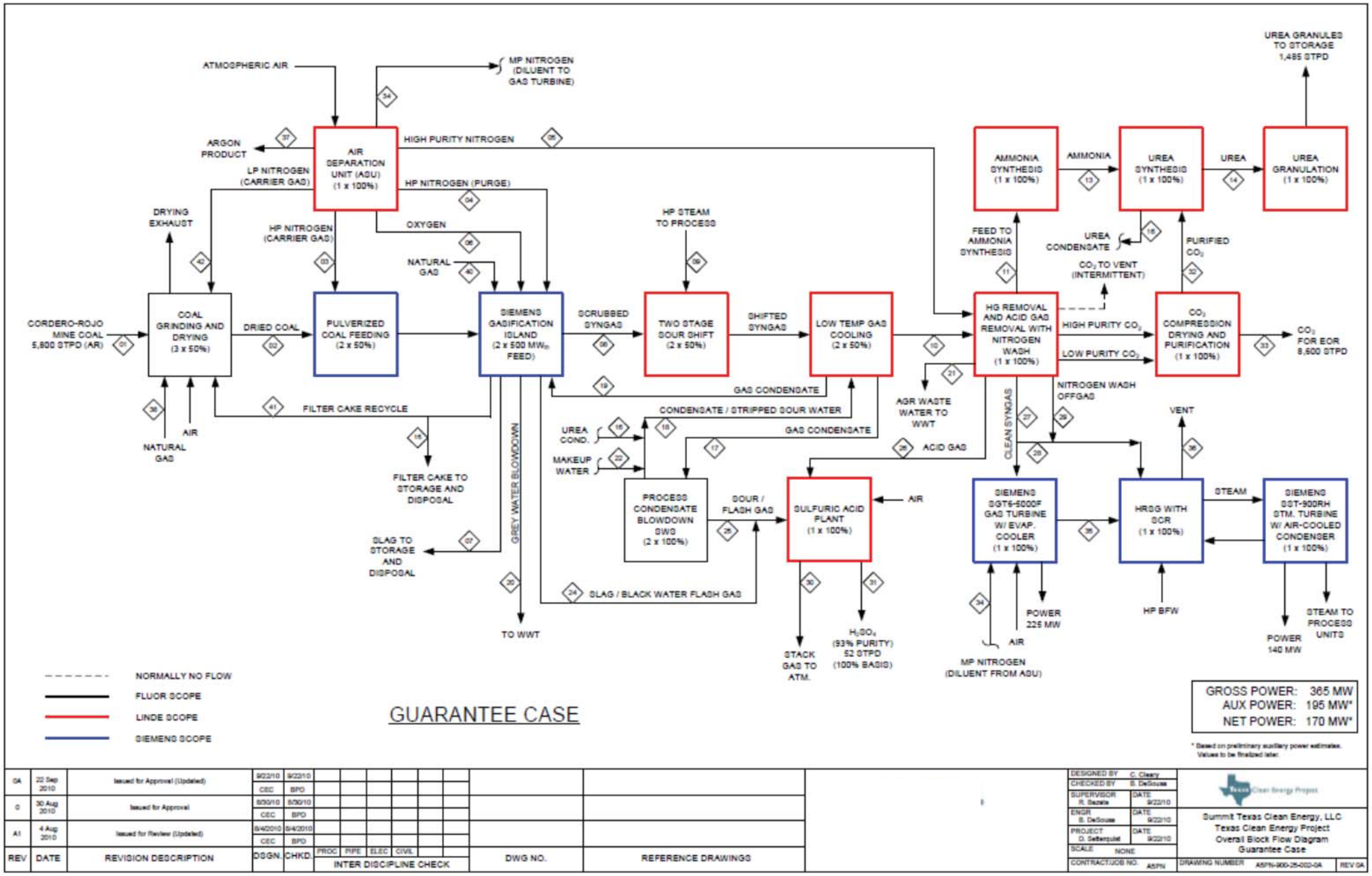
Economic Criteria for Tradeoff Studies	
Coal price	\$2 / MMBtu HHV delivered
Power sales	\$60 / MWh
Sulfuric acid sales	\$60 / ton
Carbon dioxide sales	\$20 / ton
Urea sales	\$325 / ton
Raw water	\$5 / 1000 gal
Natural gas	\$5.80 / MMBtu HHV
Simple Payback for Tradeoff Studies	5 years

8 Performance and Design Feedstocks, Fuels, Products and By-products

8.1 Block Flow Diagram of the TCEP

The block flow diagram for the “Guarantee Case” is shown in Figure 8-1. This diagram provides input and output information for this case based on the heat and material balance. For the purposes of this section of the report, the diagram provides values for the quantity of coal feedstock used for this case, as well as the values for production of products (electricity, urea and CO_2) and by-products (sulfuric acid, slag, and argon).

FIGURE 8-1
Block Flow Diagram of the TCEP



8.2 Feedstocks

8.2.1 Design Feedstock

In a coal gasification process, the coal is actually a feedstock, not a fuel. TCEP will utilize coal as the feedstock for conversion to a syngas. The syngas will be divided into two separate streams: one stream will be used as the fuel for a combustion turbine in combined cycle configuration for power generation, and the other stream will be used in the production of urea fertilizer. For TCEP, the design feedstock is Rio Tinto's Cordero Rojo mine sub-bituminous coal from the Powder River Basin. The Cordero Rojo mine is located approximately 25 miles south of Gillette, Wyoming. The coal will be transported to the TCEP site by the Union Pacific Railroad.

The characteristics of the Cordero Rojo coal are included in the Design Basis document in Section 7 of this report. The Cordero Rojo coal was used to set the design basis for Siemens Fuel Gasification so that it could develop its FEED information, including quantity and quality of syngas produced. Linde and Siemens Power Generation utilized that information to develop their FEED information.

For the Guarantee Case developed during the FEED, TCEP will use 5,800 tons/day (on an as received basis) of Cordero Rojo coal.

8.2.2 Alternate Feedstock

In order to maintain flexibility in coal delivery, availability, and pricing, the North Antelope Rochelle mine, owned and operated by Peabody Energy, was selected as an alternate coal supplier/source of feedstock for potential use in TCEP. While this is also a sub-bituminous Powder River basin coal, it is from a different area in the basin and has somewhat different characteristics. The characteristics of the North Antelope Rochelle mine coal are included in the Design Basis document in Section 7 of this report.

Siemens Fuel Gasification developed process simulations to determine the inputs to and outputs from its gasification system if that coal were used in lieu of the Cordero Rojo coal. Using the syngas quality and quantity produced using that coal, Linde and Siemens Power Generation developed simulations of plant performance based on that coal.

Table 8-1 provides a summary comparison of the Cordero Rojo (design) and North Antelope Rochelle (alternate) coal characteristics.

TABLE 8-1
Comparison of Design and Alternate Coal Characteristics

Coal Analysis (As Received Basis)	Cordero Rojo (Design Feedstock Coal)	North Antelope Rochelle (Alternate Feedstock Coal)
% Moisture	29.50	26.70
% Ash	5.43	5.25
% Volatile Matter	30.91	31.67
% Fixed Carbon	33.85	37.08
% Sulfur	0.31	0.24
Btu/lb	8,400	8,800

8.3 Fuels

Several different fuels will be utilized in the TCEP. They include:

- High-H_2 syngas that will be produced from the coal feedstock and burned in the combustion turbine (after moisturization and then blending with diluents N_2)
- Offgas from the nitrogen wash system, which will be blended with the syngas and burned in the duct burners in the Heat Recovery Steam Generator in the Power Block
- Natural gas, which will be used as a start-up and back-up fuel for the combustion turbine, and as a fuel for the auxiliary boiler, for the coal drying system, and for the various pilots in the plant.
- Diesel oil, which will be used as a fuel in on-site vehicles (primarily in the coal storage area), as well as a fuel for the emergency generators and the diesel-fueled fire pump. This fuel will be acquired as needed. It will meet the very low sulfur concentration requirements for diesel fuel.
- The characteristics of the high-H_2 syngas and nitrogen wash gas are shown in Table 8-2 (as listed in the Heat and Material Balances for the Guarantee Case):

TABLE 8-2
Syngas Characteristics

Component	High-H_2 Syngas % by Volume (mol %)	Nitrogen Wash Gas % by Volume (mol %)
CO	2.47	28.71
H_2	90.98	1.93
CO_2	0.49	0
H_2O	0.00	0.00
CH_4	0.01	0.15
Ar (Argon)	0.00	0.01
N_2 (Nitrogen)	6.05	69.2

The specification for the natural gas to be used on site is shown in Table 8-3.

TABLE 8-3
Natural Gas Specification

Parameter	Units	Design Condition
Specific Gravity	-	TBD
Btu content, LHV	BTU/lb	22,100 – 25,600
Methane (C_1)	mol%	-
Ethane (C_2)	mol%	-
Propane (C_3)	mol%	< 0.34 gallon/MScf
Normal Butane (n-C_4)	mol%	-
Normal Pentane (n-C_5)	mol%	-
Nitrogen (N_2)	mol%	< 3.00
Carbon Dioxide (CO_2)	mol%	< 2.00
Water (H_2O)	-	< 7 lb/MMScf
Sulfur	-	< 5 grains/100 scf
Dew Point - Moisture	°F	TBD
Dew Point - Hydrocarbons	°F	TBD
Oxygen	mol%	< 0.20
Mercury	-	ND
Hydrogen Sulfide (H_2S)	-	< 0.25 grains/100 scf
Mercaptans	-	< 0.75 grains/100 scf

8.4 Products and By-products

As a polygen facility, one of the key highlights of the TCEP is that it will produce multiple commercially salable products and by-products. For the TCEP, the products will be electricity, urea and CO_2. The by-products will be sulfuric acid, slag and argon; their production comes as a result of the primary operation of the TCEP facility to produce electricity, urea and CO_2.

8.4.1 Electricity

The nameplate capacity of the TCEP Power Block is 400 MW gross. The polygen facility will have internal loads required for generation of products (electricity, urea and CO_2), as well as loads more traditionally viewed as parasitic. The net output of the plant, which includes the total of the power to the grid plus the internal loads for production of urea and CO_2, is approximately 318 MW. On June 20, 2011, TCEP announced that it will enter into a 25-year power purchase agreement (PPA) with the country's largest municipally owned natural gas and electric utility, CPS Energy of San Antonio, Texas, for 200 MW. A new transmission line will be constructed as part of the TCEP for interconnection to the grid and delivery of the electricity to the user.

8.4.2 Urea

Based on the FEED information for the Guarantee Case, the TCEP will produce 1,485 tons/day (or approximately 500,000 tons/year) of granulated urea fertilizer for commercial sale. TCEP urea is already under long-term contract with a third party for use as a fertilizer. The specification for the urea is provided in the Design Basis document. The urea will be transported offsite by rail car.

8.4.3 CO_2

As described previously in this report, CO_2 will be captured in the Rectisol® acid gas removal (AGR) system, in order to achieve an overall 90% carbon capture level for the TCEP. Based on the FEED information for the Guarantee Case, the TCEP will produce 8,600 tons/day (or approximately 2.9 million tons/year) of CO_2 for use in EOR in the Permian Basin area of west Texas. The specification for the CO_2 is provided in the Design Basis document. The compressed CO_2 will be delivered to the local pipeline system via a short lateral.

8.4.4 Sulfuric Acid

The Powder River Basin sub-bituminous coal contains approximately 0.3 % sulfur. In the gasification process, the sulfur is converted primarily to hydrogen sulfide (H_2S) and carbonyl sulfide (COS). Over 99% of those sulfur compounds will be removed in the AGR system. A concentrated stream of sulfur H_2S and COS will be piped from the AGR system to the sulfuric acid plant for recovery of the sulfur components as commercially saleable 93% sulfuric acid. Based on the FEED information for the Guarantee Case, the TCEP will produce 52 tons/day (100% purity basis) of sulfuric acid, or approximately 17,500 tons/year.

The TCEP will enter into an agreement with a third party to sell the sulfuric acid for commercial use. The specification for the sulfuric acid is provided in the Design Basis document. Sulfuric acid is commonly used in municipal water and wastewater treatment, as well as for industrial use. The sulfuric acid can be loaded into rail tank cars or trucks for transportation offsite.

8.4.5 Slag

The coal feedstock contains approximately 5.4% ash, mostly in the form of inorganic mineral materials. In the coal gasification process, this ash is heated to high temperatures in the gasifier, which are above the melting temperatures of those ash constituents. The ash melts into a molten substance called slag. This slag flows by gravity to the bottom of the gasifier, where it enters the water quench portion of the gasifier, solidifying and crystallizing into a black, glassy inert solid. The solid slag is recovered from the bottom of the gasifier, where it is crushed into small particles and removed by a chain conveyor onto a concrete pad. Based on the FEED information for the Guarantee Case, the TCEP will produce 489 tons/day of wet slag (at 40% moisture), or approximately 165,000 tons/year. The slag will be transported off site by truck or rail.

The TCEP plans to enter into a contract with a third party to sell the slag. The slag will be sold as a raw material for construction uses. If it cannot be sold, it will be disposed of off-site in a properly licensed landfill.

During the gasification process, fine ash is produced and carried over into the scrubber system where it is removed. This ash is eventually sent to a press filter where it is dried to approximately 50% moisture. Since this material has high carbon content, a large portion of it will be recycled to the gasification section.

8.4.6 Argon

In the air separation process, the ASU produces concentrated streams of oxygen and nitrogen which are primarily used in the gasification, urea production and power generation portions of the facility. Since the ASU will produce high purity oxygen, it will allow for recovery of a high-purity stream of argon gas (>99.998% purity, with <1ppmv O_2 and <1 ppmv N_2). Argon is a commercially marketable product. The quantity and quality of the argon will be determined during detailed engineering. The TCEP intends to enter into a contract with a third party for sale of that argon. The argon will be transported offsite by rail car.

9 Reliability, Availability, Maintainability and Operability

9.1 Reliability, Availability and Maintainability (RAM)

For the TCEP, it is critical that the facility demonstrate reliable operation, experience minimal outages and produce the design quantities of all products, while utilizing the design quantities of resource inputs such as coal, water, and internal power use. In a stand-alone IGCC plant, the industry standard definitions for reliability and availability can be applied. However, for the TCEP, which will be the first commercial-sized facility incorporating IGCC <u>and</u> chemicals production, those definitions need to be modified.

This subsection of the report addresses the individual definitions for these terms. While there is certainly a level of interdependence, it is important to refer to the concept of Reliability, Availability and Maintainability, or "RAM", as a grouping of methods and techniques to analyze systems to determine plant performance as it relates to reliability and performance. The results of RAM analyses are used to determine numbers of systems and their individual design capacities (i.e. 4 systems each sized at 25% of maximum throughput), the quantity of operating pieces of equipment and spares (i.e. 2 operating gasifiers and 1 spare gasifier), and the economic costs and benefits for enhancing reliability by changing those quantities. For example, additional capital and/or operating expenses may be justified by the ability to generate revenues that are greater than those expenses.

A detailed RAM analysis for a facility such as the TCEP would model major systems or pieces of equipment, such as the number/sizing of coal milling systems, air separation units, gasifier trains, acid gas removal systems, and CO_2 compressors. The results of a detailed RAM analysis can provide designers with a guide for making decisions on the number and size of specific pieces of equipment as well as major systems. In addition, the results can be used to plan operations and maintenance staffing and maintenance programs.

For TCEP, a RAM analysis of the entire facility was done by Siemens, using reliability, availability and maintainability data provided by Siemens and Linde for the following systems:

- Coal milling
- Gasification
- CO shift
- Rectisol
- Temperature Swing Adsorber
- Nitrogen Wash Unit
- Refrigeration system
- Sulfuric Acid Plant
- Ammonia Plant
- Urea Plant
- CO_2 compressor for EOR

- CO_2 compressor for urea
- Air Separation Unit
- Gas Turbine

The data used in the RAM analysis took into consideration planned outage rates and durations, as well as assumptions on forced outages. The RAM analyses were used to determine optimized numbers and types/sizes of equipment and systems for the operational scenarios, including:

- Independent operation of the Chemical Block
- Impacts of tripping of the Power Block and switching from export to import power for the Chemical Block
- Operation with one gasifier
- Loss of the Air Separation Unit
- Loss of the Ammonia Plant
- Loss of the Urea Plant
- Operation of the Power Block

The results of the RAM analysis for TCEP were used to optimize the design conditions. One example was the addition of a 100%-sized Sulfuric Acid Plant, so that the facility would have 2x100% Sulfuric Acid Plants. This change was based on the number and duration of planned outages for catalyst change-outs, and the impact on overall TCEP availability and project economics. The results of the RAM analyses, when used in the TCEP financial model, showed that the additional Sulfuric Acid Plant was a cost-effective change to the plant design.

9.2 Reliability

In order to meet the requirements of the contracts for sale of the products, the TCEP facility will need to be very reliable. According to the North American Electric Reliability Corporation (NERC), Reliability is defined as:

> *"the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. "*

This relates to the ability of the overall electric generation, distribution and transmission system to perform. For the purposes of the TCEP, which is a polygeneration facility, Reliability can be more accurately defined as:

> *"the ability of the facility to supply the aggregate electric power, energy, urea, and CO2 production to the buyers of those products at all times, taking into account scheduled and reasonably expected unscheduled outages of TCEP systems and components."*

9.3 Availability

NERC defines Availability as:

> *"the amount of time the plant is available for power production divided by the total time, which is the sum of the operational time and the down time. For a base-loaded plant, it is assumed that all downtime is associated exclusively with either scheduled or unscheduled maintenance."*

The NERC calculation for Availability is:

$$\text{Availability} = \frac{\text{Operational Time}}{\text{Operational Time} + \text{Scheduled Down Time} + \text{Unscheduled Down Time}} \times 100\%$$

Operational Time is the power production time over a set period of time. Scheduled Down Time is the sum of regularly scheduled maintenance periods. The Unscheduled Down Time is the summation of maintenance times to repair operation failures that cause the plant to cease power production. Failures that do not cause a power interruption are not considered.

The TCEP has three primary products: Power, Urea and CO_2. Over a year's time, different operating scenarios will occur based on the Availability of the different major portions of the plant. Three key scenarios (and how they may occur) are described below:

- Power priority
  - If sufficient syngas is not available to fire the Power Block at full load, i.e. if one gasifier is down, then a mix of syngas and natural gas would be used to operate the Power Block at full load.
- Urea priority
  - If the Power Block is down, then the syngas would be directed to urea production (up to the maximum amount of syngas that the urea plant is designed to utilize).
  - If one gasifier is down, then the available syngas would be directed to urea production.
- CO2 priority
  - Using the maximum amount of syngas for urea production will also maximize the amount of CO2 captured for sale for EOR.

Based on the RAM analyses described above, the compilation of the percentages of the year that each of these scenarios occurs provides the quantities of each of the products produced in the year. Summit requires an overall plant availability of approximately 92% to maintain the project's economic viability. This means producing 92% of the power, the urea, and the CO_2. Each of the FEED contractors have developed their designs so that taken together, the 92% overall plant availability can be met.

9.4 Maintainability

The TCEP will have hundreds of individual pieces of equipment. As part of the design of the overall facility, designs for such equipment include methods and procedures so that the equipment can be easily maintained. This includes:

- Access for maintenance personnel

- Sufficient electrical locations for welding equipment
- Washdown systems to maintain plant cleanliness
- Overhead cranes for major equipment
- Design for equipment disassembly, such as for tube bundle removal

By designing for maintainability, this will increase overall plant reliability and availability by reducing the downtime required for scheduled and unscheduled maintenance.

9.5 Operability

The TCEP will be a complex facility. It will, for the first time, bring together coal gasification, chemicals production, and power generation technologies. In itself, IGCC technology has proven to be difficult to operate at the five current worldwide coal-based IGCC plants. Further integrating that IGCC technology with a urea production plant, along with capture of the CO_2 for commercial sale, will result in a facility that must be designed properly so that it can be started up, operated, and shut down in a safe, controlled manner.

While NERC does not specifically define "Operability", many NERC documents do use the term in ways that relate to the ability of a power plant, generating unit, or electric system to be effectively operated <u>as designed</u> by its owner/operator.

For the TCEP, Operability will be a function of:

- Overall plant design
- Integration of the gasification, syngas cleaning, chemicals production and power generation blocks
- Design and integration of control systems
- Training of plant staff
- The ability to change from using syngas for generating power to producing urea, as needed.

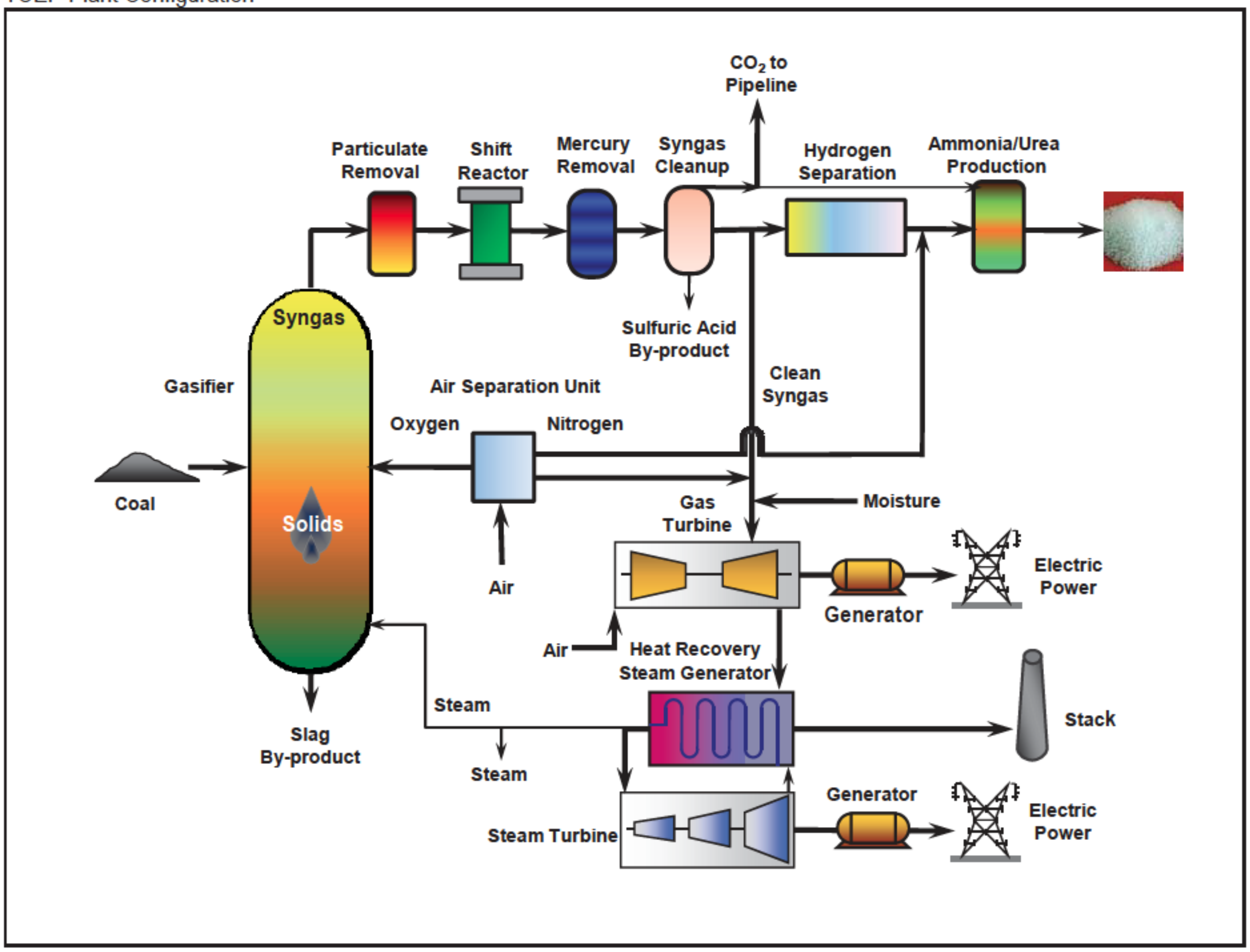
10 Plant Configuration, Plant Components and Plot Plan

10.1 Plant Configuration

10.1.1 Overall TCEP Process

The TCEP will be a polygen facility, incorporating IGCC technology with the production of urea fertilizer. Figure 10-1 shows the overall TCEP plant process.

FIGURE 10-1
TCEP Plant Configuration



10.1.2 Technology Selection

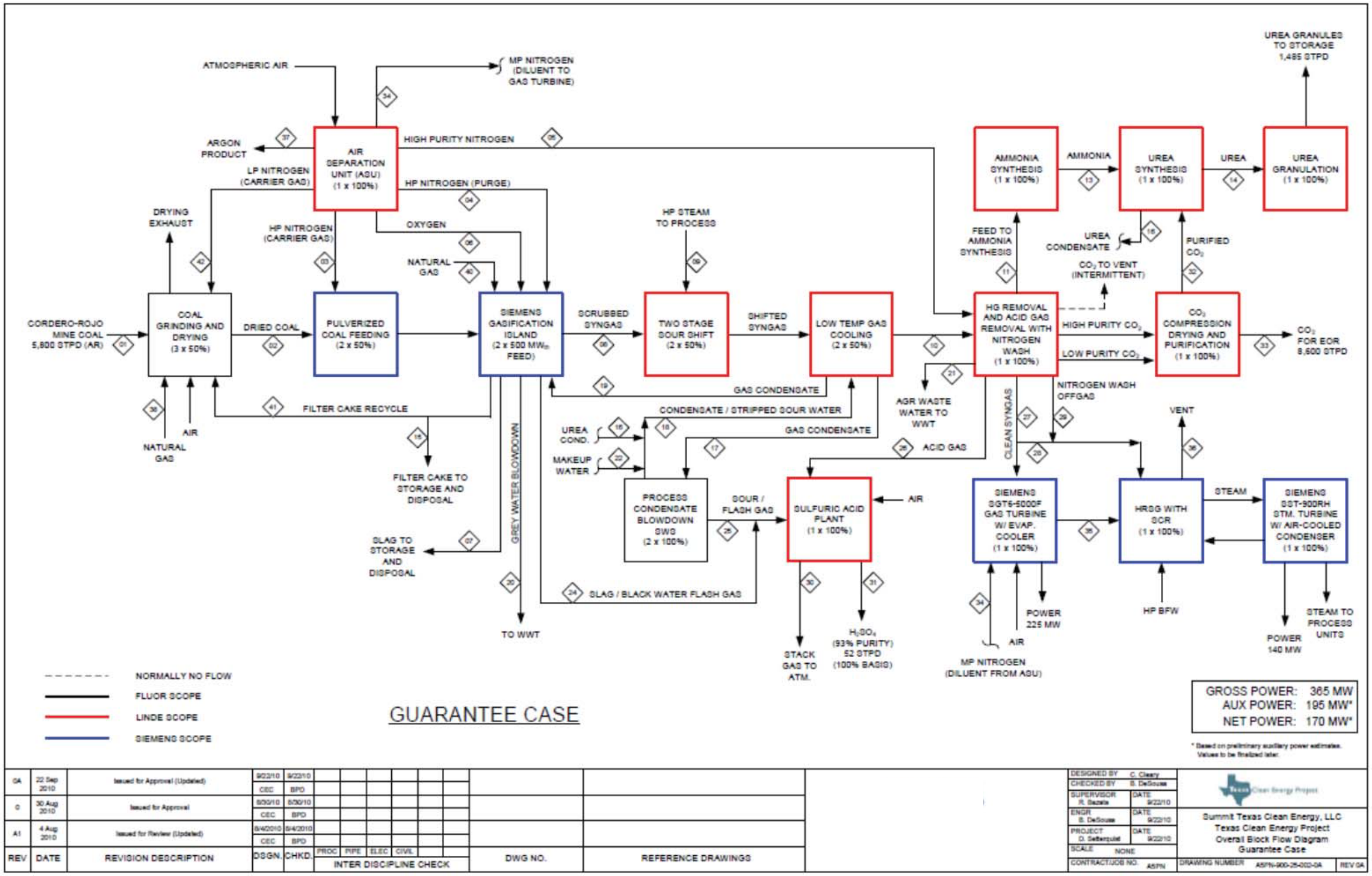
TCEP will use two Siemens Fuel Gasification SFG-500 (500 MW thermal) gasifiers to produce syngas that will be quenched and cleaned, shifted to a high-H_2 concentration, treated for removal of sulfur compounds and CO_2, blended with nitrogen, saturated with moisture and then used as the fuel in a Siemens combined cycle power block that includes one Siemens SGT6-5000F combustion turbine (designed to combust a blend of high-hydrogen syngas and nitrogen diluent), one triple-pressure Heat Recovery Steam Generator (HRSG), and one Siemens SST-900RH reheat steam turbine.

Present day designs for a "reference plant" IGCC typically utilize two gasifiers, each rated at 50% of the total plant syngas requirements, in order to fully load two "F-class" combustion turbines (CTs). In those cases, the gasifiers are designed so that the syngas output of one gasifier can fully load one CT. The Siemens gasification technology is different, in that the Siemens gasifier is rated at 500 MW (thermal), or a theoretical syngas output of 1,706 MMBtu/hr (HHV). That syngas production level is not sufficient to fully load the Siemens SGT6-5000F CT, which typically has a heat input requirement of >2,100 MMBtu/hr (HHV). Therefore, the syngas production from one gasifier provides about 80% of the one CT requirement. Using two Siemens gasifiers would produce significantly more syngas than required for one CT, but not enough to fully load two CTs.

As part of the initial planning and design for the TCEP, a study was conducted to determine the types of downstream products that could be produced using that "additional" syngas, and what the markets and potential revenues will be from commercial sale of those products. The results of that study showed that production of ammonia and its conversion to urea fertilizer was a preferred alternative. Based on those results, a decision was made to use two Siemens gasifiers. This configuration will supply sufficient syngas to fully load the single CT, with the additional syngas used to produce ammonia, which is then converted to urea fertilizer.

Figure 10-2 presents an overall block flow diagram of the TCEP. The following sub-section provides descriptions of the major TCEP plant systems shown in the block flow diagram.

FIGURE 10-2
TCEP Block Flow Diagram



10.1.3 Major Process Systems and Equipment

The major functional plant systems for the TCEP are identified below. The number of trains and percentage train capacity for each of those systems are also identified. Capacities for some of the major pieces of equipment are identified, using the values from the Guarantee Case.

Coal Handling (1 x 100%)

- Rail car unloading facilities (rapid discharge, bottom dump cars)
- Total of 45 days storage (261,000 tons)
  - Active coal storage (9 days)
  - Inactive/dead coal storage (36 days)
- Underground reclaim system
- Conveyor to coal milling and drying system

Coal Milling and Drying (3 x 50%)

- 3 x 50% coal feed silos
- 3 x 50% vertical bowl mills (2 trains needed at full load to process 5,800 tons/day)
- 3 x 50% coal drying systems (2 trains needed at full load to process 5,800 tons/day)), using natural gas and liquid nitrogen wash offgas as a fuel to produce hot flue gases for coal drying

Air Separation Unit (1x 100%)

- 3,270 tons/day of high pressure 99.5% O_2
- 689 tons/day of medium pressure 99.9% N_2 for urea production
- 2,858 tons/day of medium pressure 99.9% N_2 for syngas dilution in Power Block
- 1 x 100% main air compressor
- 1 x 100% cold box
- 2 x 100% cryogenic liquid O_2 pumps
- Liquid O_2 storage (12 hours at the ASU design rate)
- Liquid N_2 storage (12 hours at the ASU design rate, not including N2 for dilution in the Power Block)

Gasification Island (2 x 50%)

- 2 x 50% dense flow coal feeding systems (coal bunker, lock hoppers and feeder vessel) using N2 as the carrier gas
- 2 x 50% Siemens dry feed, oxygen-blown, quench gasifiers with cooling screens
- 2 x 50% raw syngas treatment systems (venturi scrubbers and syngas conditioning)
- 2 x 50% slag discharge units (slag crusher, slag hopper, slag lock hopper, and water-cooled slag discharge conveyor)
- 1 x 100% slag loading system

- 2 x 50% flash systems
- 1 x 100% black water treatment system
- 1 x 100% black water filter cake transport and storage system (filter cake will be recycled to coal milling and drying system)

Sour Gas Shift, Low-Temperature Gas Cooling and Mercury Removal Units

- 2 x 50% sour gas shift systems
- 1 x 100% low temperature gas cooling systems
- 1 x 100% mercury removal unit

Acid Gas Removal

- 1 x 100% Rectisol® system

Sour Water Stripping

- 2 x 100% systems common to both gasification trains, including a caustic addition unit

Sulfuric Acid Plant

- 2 x 100% sulfuric acid plants (59 tons/day of 93% purity sulfuric acid)

Carbon Dioxide Compression and Drying

- CO_2 compression for urea and CO_2 purification system (1,083 tons/day to urea synthesis)
  - 1 x 100% CO_2 purification system
  - 1 x 100% CO_2 compressor
- CO_2 compression for EOR (8,633 tons/day)
  - 1 x 100% CO_2 compressor

Liquid Nitrogen Wash

- 1 x 100% nitrogen wash unit

Ammonia Synthesis Unit

- 1 x 100% ammonia synthesis system producing 99.9% anhydrous ammonia

Urea Synthesis Unit

- 1 x 100% urea synthesis system (product before granulation is 96%purity urea)
- 1 x 100% urea granulation system (1,485 tons/day urea)

Urea Handling and Storage

- 50 days storage in four domes
- Urea loading to rail car or truck (design rate at 1,000 tons/hour)

Combined Cycle Power Block

- 1 x 100% Siemens SGT6-5000F F3 combustion turbine-generator with inlet evaporative cooling
  - Primary fuel: high-H_2 syngas
  - Backup/Startup fuel: natural gas
- 1 x 100% triple pressure Heat Recovery Steam Generator with syngas and natural gas duct firing capability, and with Selective Catalytic Reduction (SCR) and CO catalyst
- 1 x 100% Siemens SST-900H steam turbine-generator with 20-cell air-cooled condenser

General Facilities

- Raw water system (16 hours storage)
- Demineralized water system
  - Water softening and ultra-filtration
  - 6 x 20% RO trains
  - 4 x 25% EDI trains
- Potable water system
- Fire protection system (8 hours storage)
  - 2 x 50% diesel firewater pumps
  - 1 x 50% electric firewater pump
  - 1 x 100% pressure maintenance pump
- 1 x 100% plant and instrument air package
- Mechanical draft cooling tower for process cooling
- Flares
- Process grey water treatment
  - 1 x 100% zero liquid discharge system
    - ♦ Cooling tower blowdown water treatment
  - 1 x 100% zero liquid discharge system
    - ♦ Sanitary/general wastewater treatment (septic system/leach field)
    - ♦ 1 x 100% auxiliary boiler (dual fuel fired (syngas or natural gas)
- 1 x 100% diesel generator for backup power

10.2 Plant Components

10.2.1 Process Chemistry

Gasification

In the gasifier, coal and O_2 react to form a number of gaseous compounds. A very small portion of the coal is partially oxidized to provide the heat necessary for gasification. The gasification temperature is high enough to break essentially all the chemical bonds present in the coal and establish a new mix of smaller molecules based on the following primary reactions:

- $C + O_2 = CO_2$ (rapid exothermic, or heat releasing, oxidation reaction)
- $C + ½ O_2 = CO$ (rapid exothermic oxidation reaction)
- C + H2O = CO + H_2 (slower endothermic, or heat consuming, reaction)
- $C + CO_2 = 2CO$ (slower endothermic reaction)
- $CO + H_2O = H_2 + CO_2$ ("water gas shift reaction", exothermic and rapid)
- $CO + 3H_2 = CH_4 + H_2O$ ("methanation reaction", exothermic)
- $C + 2H_2 = CH_4$ (direct methanation, exothermic)

Most of the sulfur in the coal is converted to hydrogen sulfide (H_2S) during gasification. A small portion of the sulfur is converted into carbonyl sulfide (COS). Most of the nitrogen in the coal is converted to ammonia (NH_3). The syngas composition leaving the gasifier is determined by the gasifier operating temperature and the relative kinetics of the above reactions. Most of the energy in the coal is ultimately converted into CO, H_2, and a small amount of methane.

10.2.2 Major Process Systems

Coal Receiving, Storage and Handling System

The TCEP will consume approximately 5,800 tons/day of Powder River Basin sub-bituminous coal, which will be delivered to the site by rail from Wyoming. A single system for receiving, storing, and handling coal will feed both gasifiers. 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 active storage pile, recover the coal from the storage pile, crush the coal, and convey it to the coal silos in the coal grinding and 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 from the railcars at a rate of 4,000 tons/hour. Belt feeders will transfer coal from the unloading hoppers to a conveyor, which will transfer coal to the coal storage piles. From the coal pile, 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. The feed conveyors will transfer the coal to the coal grinding and drying feed silos. All conveyors will be enclosed to reduce particulate emissions, and the coal handling and drying building will be fully enclosed with dust suppression sprays and collection systems used to control dust and noise.

Coal Milling and Drying System

A traveling trip conveyor will feed each of the two grinding trains, distributing the coal into feed bins serving each train. The coal will be simultaneously dried to approximately 8 weight % moisture and ground to less than 200 micrometers in diameter in two bowl mills. Hot drying gases (heated by combusting natural gas) will also enter the mill from the bottom, and then carry the dried, crushed coal and gases out of the mill and to a cyclone classifier, which will return particles larger than the desired size to the mill. 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 cyclone. The dry, ground coal will then be pneumatically conveyed (using N_2 gas) to the individual storage bins that serve each gasifier.

Air Separation Unit

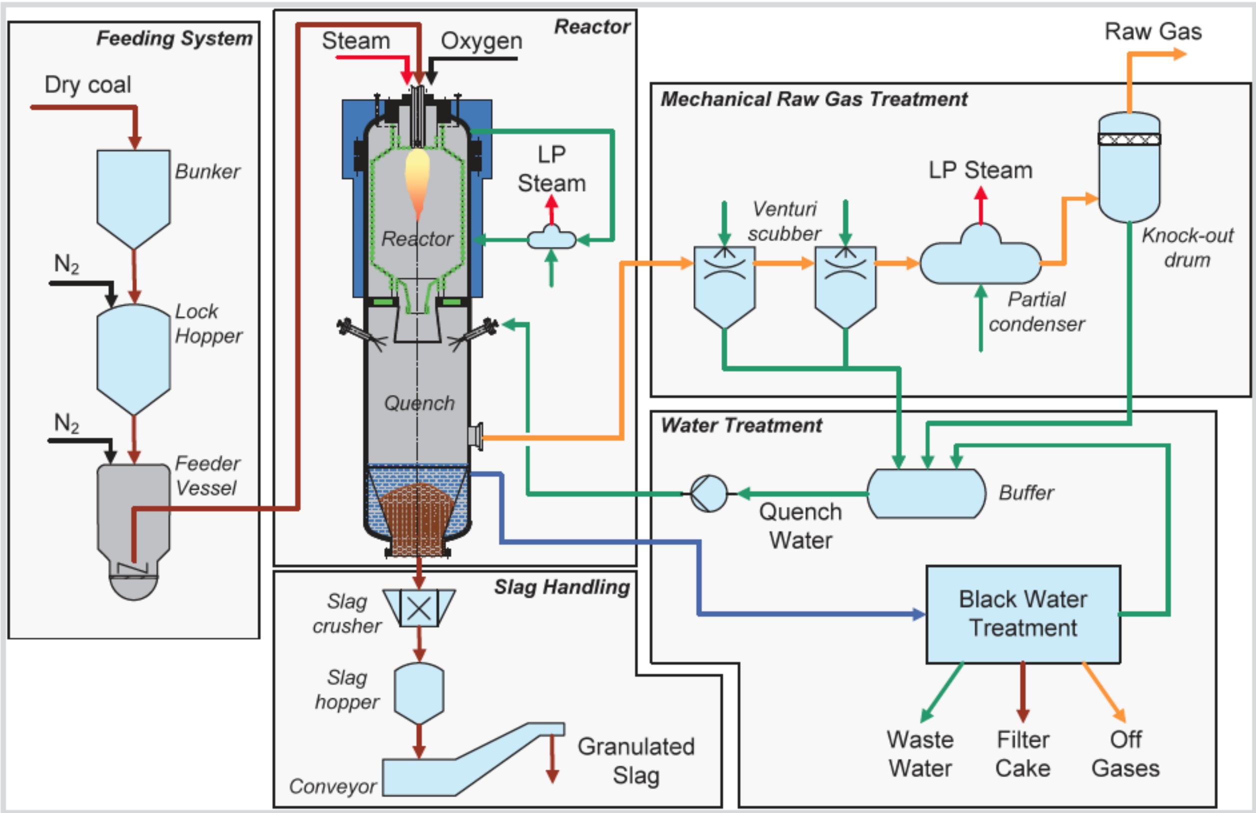
A single ASU will provide O_2 and N_2 for the entire TCEP plant. The ASU will produce 99.5 % pure O_2 gas for use as an oxidant in the gasifiers, and 99.9 % pure N_2 gas for use as a diluent in the CT and for producing urea fertilizer. In addition, N_2 gas at various pressure levels will also be used as a carrier gas for feeding the dried, pulverized coal to the gasifiers and for purging purposes in the gasification island. Producing high-purity O_2 gas in the ASU will also allow for a high-purity stream of argon gas to be recovered. This is 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 for 12 hours of plant operation.

Gasification Island

The gasification island will use two Siemens SFG-500 entrained flow, O_2-blown gasifiers to produce a raw syngas from the pulverized coal. The gasification island includes a pulverized coal feeding system, two gasifiers (including the quench sections), raw syngas scrubbers, black water treatment, and a slag discharge unit. The Siemens gasification island is shown in Figure 10-3.

FIGURE 10-3
Siemens Gasification Island



Gasifiers

The coal feeding system will receive the pulverized and dried coal from the coal milling and drying system described above, and feed it into the gasification reactors where the gasification reactions will take place. The coal will be almost totally gasified in this high-temperature environment to form raw syngas consisting principally of H_2, CO, CO_2, and water. Other constituents are formed (which will need removal) are ammonia, H_2S and 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 (as shown in the figure above) 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.

The mixture of granulated slag, quench water, and some unreacted char forms a mixture referred to as black water. The black water stream 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 (see description below). Water carried out of the slag discharge system will be collected and pumped to the black water treatment plant. Water needed in the slag discharge system will be recycled from the black water treatment plant.

The raw syngas from the quench section will be sent to a venturi scrubber system for removal of fine ash, chlorides and char. A portion of the scrubber water will be directed to the black water treatment plant. To reduce fine particles in the raw syngas, a partial condenser will be installed downstream of the scrubber unit. A flare for emergency relief or startup will be located immediately downstream of the separator. 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 Plant

The black water treatment system will include one flash vessel for each of the two gasifiers, chemical dosing (for precipitation and flocculation to remove suspended solids), a settling basin, the waste water vessel, and a sludge filter press.

Liquid effluents from the quench chambers, the slag discharge units and blowdown scrubbing water from the syngas scrubbers, as well as remaining syngas condensate, will contain fine particulate matter, soot, salts, and condensed heavy metal sulfides removed from the syngas stream. The pressurized black water will be sent to the flash vessels to remove dissolved gases and to cool the black water.

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 precipitate will be removed in a gravity settler, thickened and dewatered using a fabric filter press to separate the solids from the black water stream. Most of the dried filter cake (containing a large fraction of unreacted carbon) will be mixed with coal and recycled in the gasifiers to produce more syngas, and the remainder will be containerized 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 routed to the zero liquid discharge (ZLD) brine water treatment system for further treatment.

Slag Handling, Storage, and Loading

This system will remove and collect inert gasifier slag and convey it to storage for the loadout system. The inert slag 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 chain reclaimers. The chain reclaimers will convey the slag onto belt conveyors that transfer the slag to a loadout for rail or truck.

Slag from coal gasification and IGCC plants can be used in the manufacture of cement, as a road base, for manufacturing roofing tiles, as an asphalt filler, and as a sandblasting agent. The TCEP plans to sell the slag for such uses. Should the slag not be sold, it will be trucked or sent by rail to a permitted off-site solid waste landfill.

Sour Shift, Low-temperature Gas Cooling and Mercury Removal Units

The hot raw syngas will be further cooled and cleaned for use downstream for power generation and urea production. The main process units are described below.

Sour Shift Unit

To increase the H_2 content and decrease the CO content of the syngas for low-CO_2 power generation and for production of urea, the water-gas shift reaction will be used to shift the syngas composition. In the shift process, CO present in the raw syngas from the gasification island will react with steam over a catalyst bed to form CO_2 and H_2. Once the syngas is shifted to a high concentration of CO_2, the CO_2 can be efficiently removed downstream in the Rectisol AGR unit, thereby removing most of the carbon from the syngas to be used as a fuel in the CT.

The sour shift unit is also called a water-gas shift unit because the water-gas shift reactions will be accomplished prior to the AGR system, meaning that the syngas will still 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 medium pressure steam for use in other areas in the polygen plant.

In addition to converting CO, the shift catalyst will convert COS in the syngas to H_2S, which will be much easier to remove in the AGR system than COS. After H_2S removal, the syngas will have a very low concentration of sulfur, which will minimize sulfur dioxide (SO_2) emissions in the CT exhaust and will reduce sulfur in the feed stream sent to the urea plant.

Low-temperature Gas Cooling Unit

Condensate from the water-gas shift unit will be cooled further in the low-temperature gas cooling unit. Water will condense from the syngas as it was cooled. The condensate will be collected and stripped of ammonia and minor dissolved gasses, heated, and returned to the gasification island for use in the syngas scrubber. The cooled overhead sour scrubber gases, which will contain primarily sulfur gases, will be sent to the H_2SO_4 plant. The cooled syngas will be sent to the mercury (Hg) removal unit.

Mercury Removal Unit

Hg removal will be accomplished by passing the syngas through sulfur-impregnated activated carbon beds, where the Hg compounds will be adsorbed and converted to stable mercuric sulfide. The system is expected to achieve greater than 95 % Hg removal from the syngas, based on the performance of this technology in other coal gasification plants. At the end of their useful lives, the carbon beds will be removed and transported off-site to appropriate facilities for disposal or recovery of the Hg compounds.

Acid Gas Removal

The clean, shifted syngas stream will be sent to a Rectisol AGR system, which will use concentrated methanol (greater than 99 % by weight) as a solvent in a recirculating wash column to physically dissolve and remove the acid gas components (H_2S, COS and CO_2), produce two syngas streams of different qualities for downstream use, and produce concentrated streams of H_2S and CO_2 for downstream processing. This unit operates at cold temperatures unlike many other chemical solvents, and therefore has a large chiller system associated with it.

The H_2S and COS will be removed in the lower section of the Rectisol wash column, with the CO_2 being removed in the upper section. Clean syngas streams will exit the Rectisol system for downstream use. The first syngas stream will be rich in H_2 (approximately 88 mol %) with a very low content of CO_2 and a total sulfur concentration of less than 0.1 parts per million by volume (ppmv). Approximately 75 percent of the syngas will be sent to the power block as a fuel for the CT. The remainder of the H_2-rich syngas (approximately 89 mol %) will be sent to the N_2 wash unit for final purification before going to NH_3 synthesis and production of urea. The second syngas stream will contain a very low concentration of CO_2 in a range of 0.5 to 1 % by volume, and will be used as a fuel gas in the duct burners in the power block. The sulfur-containing gases that are captured and removed will be sent to the H_2SO_4 plant.

The higher-purity CO_2 stream will be sent to the urea synthesis plant. The lower-purity stream and the remaining part of the high-purity CO_2 stream that could not be used in the urea production plant will be combined, dried, and compressed for off-site use in EOR.

Sour Water Treatment

The coal gasification process will generate the following sour (sulfur-bearing) waste water streams:

- Gray water effluent from the black water clarifiers
- Black water clarifier sludge from the gasification block
- Syngas condensate from the raw syngas stream in the piping and in the syngas coolers upstream of the acid gas removal unit

The TCEP will incorporate a sour water stripper to treat those sour waste water 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 plant. 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 ammonia (NH_3) in the sour water feed will be removed in this column. Sodium hydroxide will be injected as needed to facilitate the release of NH_3 from the condensate. Stripped sour water will then be sent to the ZLD system for cleaning.

Sulfuric Acid Plant

Acid gas streams from the AGR and sour water treatment units, along with flash gas from the gasification island, will be sent to the H_2SO_4 plant. 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 system to reduce nitrogen oxides (NO_X) formed during combustion. After NO_X reduction, the gas will enter a catalytic SO_2 converter, where SO_2 will be oxidized to sulfur trioxide. 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 sulfur trioxide 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. Concentrated H_2SO_4 product will be stored in a carbon steel tank coated with a fluorinated polymer. The on-site storage tank will hold approximately 36,000 gallons of H_2SO_4, or about four days of production. The product will be 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 consisting of a quench tower, scrubber column, mist eliminator, and clean gas blower. The gas will first enter a quench tower, where the temperature of the stream will be reduced by evaporating water into the gas. After being cooled, the gas will be routed to a packed scrubber tower to be treated with hydrogen peroxide to remove any residual SO_2. Finally, the overhead vapor will pass through an electrostatic mist filter to remove entrained acid mist. The cleaned gas will be sent to the H_2SO_4 plant stack.

Carbon Dioxide Compression and Drying

The CO_2 captured by the Rectisol process will be dried, compressed, and split into two streams. The AGR system will provide CO_2 at several pressure levels. CO_2 recovered at lower pressure will be routed to a low-pressure CO_2 compressor to be compressed in multiple stages with cooling between each stage. After exiting the low-pressure CO_2 compressor, the compressed gas will be mixed with the flash gas recovered from the high-pressure drum and sent to a drying package. Residual water will then be removed using molecular sieve technology. This CO_2 stream will be further compressed in the high-pressure CO_2 compressor. Some of the intermediate-pressure CO_2 will be passed through two catalytic reactors to remove residual H_2S and COS. After purification, this stream will be compressed and the majority of the CO_2 will be transported off-site for EOR, and the remainder will go to the urea production plant.

Liquid Nitrogen Wash

The H_2-rich syngas stream exiting the Rectisol AGR system, along with high-pressure N_2 from the ASU, will be fed to the liquid N_2 wash unit. Traces of water, CO_2, and AGR solvent (methanol) will be removed in the adsorber unit. Both incoming streams of H_2-rich fuel gas and high-pressure N_2 will be cooled against product gas. The syngas stream will be fed to the bottom of the N_2 wash column, and high-pressure N_2 will be fed at the top of the column. Trace components (offgas) will be removed and separated at the bottom of the column as a fuel that will be used in the duct burners (direct-fired gas burner located in the HRSG in the combined cycle power block (see description below). 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).

Ammonia Synthesis Unit

The high-H_2 concentration stream from the N_2 wash will be compressed and cooled, then mixed with N_2 from the ASU. 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 using an iron-based catalyst. 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 NH_3 synthesis plant. Liquid NH_3 will enter the receiver, where it will be split into two streams. Multiple heat exchangers will be used to 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. Liquid NH_3 product from the bottom of the separators will be pumped to storage.

Urea Synthesis Unit

The urea synthesis unit will take the NH_3 product and convert it to urea. CO_2 from the AGR system will be compressed and sent to a urea reactor where it will combine with liquid NH_3 from the NH_3 synthesis unit. Ammonium carbamate will be formed and then will be allowed to decompose to urea.

The concentrated urea solution will be sprayed by a liquid jet into a granulator bed. The bed of particles will be fluidized with fluidization air. When the particles reached 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 plant will include storage facilities for 40 days of urea production, not including railcars. The urea synthesis unit will produce 1,485 tons/day of urea, requiring the input of 1,080 tons/day of CO_2.

Urea Handling

The urea handling system will transfer urea from the urea synthesis unit to the rail loadout. A transfer conveyor will deliver urea from the plant to the tripper conveyor, which will transfer the urea to four storage domes at a rate of 150 tons/hour. Another conveyor will pick up and transfer the 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 at a rate of 400 tons/hour, 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.

Combined Cycle Power Block

The Power Block will consist of a Siemens SGT6-5000F3 combustion turbine-generator configured to use H_2-rich syngas as the primary fuel and natural gas as a startup and backup fuel, an HRSG, duct burners using a mixture of syngas and liquid N_2 wash system offgas as a fuel, a reheat steam turbine-generator, an air-cooled condenser, flash drums, condensate pumps, and boiler feed water pumps.

The CT will be specially designed to combust a preheated H_2-rich syngas as the primary fuel. The H_2-rich syngas 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 CT, will accomplish two key goals: 1) cooling the combustion flame to reduce the formation of thermal NOx, and 2) increasing the mass flow through the CT, boosting the CT power output. The CT will have a nominal electric generating capacity of 230 MW.

The HRSG will convert the heat in the CT exhaust to steam, which will then be used in the steam turbine to generate additional power. This configuration, which integrates the CT with the HRSG and a steam turbine-generator, is called a combined cycle power plant and is one of the most efficient technologies for generating electricity. When conditions required additional power-generation capacity, duct burners fired with a mixture of syngas and offgas will augment the energy contained in the CT exhaust, producing additional steam for the steam turbine.

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 (2,154 psia and 1,017°F), reheat steam (725 psia and 1,016°F), and low-pressure steam (85 psia and 497°F). Some steam will be transferred to other locations in the plant to support functions other than driving the steam turbine. Superheated high-pressure steam will be supplied to the high-pressure section of the steam turbine by the HRSG. The exhaust from the high-pressure section of the steam turbine is called cold reheat steam because it is reduced in temperature and pressure. This steam will be returned to the HRSG, then reheated and combined 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.

Plant Utility Systems

The following plant facilities will also be components of the TCEP.

Cooling System

Two types of cooling systems will be used at the polygen plant: wet and dry cooling. An air-cooled condenser will be used for the combined cycle power block. For the chemical process 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 process portions of the polygen plant where less cooling is required. Makeup water for the wet cooling tower will be obtained from treated municipal waste water or, under some options, ground water. Cooling tower blowdown from the wet cooling tower will be directed to the ZLD system. The cooling tower will be equipped with a drift eliminator designed to limit drift losses to 0.001 percent of the circulation rate.

Flare Systems

Flare systems will be provided to allow for the safe venting of gases produced during startup, shutdown, and upset conditions. Two flares, each approximately 200 feet high, will be provided.

The two flares will be as follows:

- Warm flare – sized to handle system startup, shutdown and turndown, large relief loads, minor upset relief loads and sour gas relief loads
- Ammonia flare – this is a dedicated flare to assure complete combustion of relief streams with high ammonia concentration. It will be sized for the largest ammonia relief load.

The warm 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 combustion 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 acid gas removal 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.

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. During normal operation, heat input to each flare will include 300 standard cubic feet/hour of natural gas used for pilot lights. Peak flaring will occur during planned gasifier startups.

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 % destruction of the CO (by combustion with air) in the flared stream. NOx emissions are based on the TCEQ-approved factor for flares plus 50 % conversion of the NH_3 to NOx. H_2S and SO_2 emissions are based on 98 % conversion of the H_2S and COS in the stream being converted (by combustion with air) to SO_2.

Auxiliary Boiler

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 million British thermal units per hour (HHV). The boiler will be primarily used during startup and shutdown. The auxiliary boiler will be equipped with ultra-low NOx burners and flue gas recirculation to control NO_X emissions.

Brine Water Systems

Brine water discharges will be handled by either the ZLD system or deep well injection, as follows.

Zero Liquid Discharge System

The primary brine water sources for the TCEP will be the gasification grey water purge and cooling tower blowdown. The largest volume of brine water will be generated by the wet cooling tower blowdown, which will be treated using lime softening and reverse osmosis to recover most of the water for reuse at the plant site. All brine water will be treated on-site by the ZLD system with no liquid wastes being discharged. The polygen plant is being designed to optimize water reuse through recycling of process waste streams, thus minimizing the overall volume of process water required for the project and the volume of brine water to be treated by ZLD system. The primary ZLD system proposed for the project will consist of a brine concentrator and/or crystallizer, which will evaporate the reverse osmosis stream, thus forming a solid cake. A filter press or centrifuge may also be required to remove water from the ZLD unit. The solid filter cake will be transported to a licensed landfill for final disposal. The cake is expected to be nonhazardous but will be tested to confirm its characteristics.

An alternative option for the ZLD system is being considered for the TCEP. This option will use solar evaporation pond(s) in place of the brine concentrator and filter press system. The concentrated liquid wastes will be placed in the solar evaporation ponds that will be constructed with multiple individual cells that will facilitate the removal of the concentrated solids for disposal at an existing approved landfill. A minimum of two evaporation ponds will be constructed under this option. The size of the evaporation ponds will be dependent upon the final volume and source of the process water.

Deep Well Injection of Nonhazardous Brine Water

Another alternative option to the ZLD system described above will be the use of deep well injection of the reverse osmosis brine water. Under this option, the reverse osmosis brine water will be disposed of using up to three deep injection wells. The maximum instantaneous injection rate will be 126 gallons/minute, with an average rate of 85 gallons/minute over the 30-year design life of the polygen plant.

The injection wells will deliver the reverse osmosis brine water from the surface to the underground geologic Queen Formation through tubing, 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.

The injection well pumping station will be capable of pumping the peak flow estimated to be 126 gallons/minute with one pump out of service. This will provide 100 percent pumping redundancy. In addition, the polygen plant will have a redundant power supply and automatic transfer switch along with redundant programmable logic controllers to help ensure the polygen plant was always available for service. The overall system design will provide flexibility to operate over a wide range of flows and pressures up to 950 psi. The piping configuration will allow both pumps to pump to the injection well header and into all of the injection wells. Typically only one pump will be operated at a time.

Emergency Diesel Engines

One 350-horsepower, diesel-fueled fire-water pump and two 2,205-horsepower, diesel-fueled emergency generators will be located 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 nonemergency 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 work stations will give the plant engineering workforce the ability to monitor plant operations and update software and control schemes as needed.

10.3 Plot Plan

The plant was laid out to maximize the efficiency of the interconnections with existing laterals, i.e. roadways, transmission system, and pipelines (CO_2, natural gas and water). Minimizing pipe runs between major systems was also an important criterion to minimize cost. The prevailing wind for the TCEP is from the south-southeast. Due to the prevailing wind direction, the TCEP systems and “blocks” have been laid out using the following key criteria for IGCC plant layout:

- The ASU compressor inlet should be upwind of the coal pile to minimize hydrocarbon dust ingestion into the ASU inlet air filter.
- The CT compressor inlet should be upwind of the coal pile to minimize dust ingestion into the CT compressor inlet air filter.
- The electrical switchyard should be upwind of the coal pile to minimize dust compromising the conductors or switches.
- The flare stack(s) should be either distant from or downwind of the ASU compressor inlet and the CT compressor inlet, to avoid ingesting contaminants, hot gases, flame, or soot from the flare(s) into either system.
- The flare stack(s) should be distant from or downwind of the coal pile or oil tanks to avoid any possibility of the flare impinging on the combustibles.
- The flare stack(s) should be distant from or downwind of the wet cooling tower to avoid degrading its performance.

11 Air Permit Conditions

11.1 Air Permit Application

The initial air permit application (application for an Air Quality Permit) for the TCEP was submitted to the Texas Commission on Environmental Quality (TCEQ) on April 8, 2010. The plant and process descriptions, emission sources and inventories, and the Best Available Control Technology (BACT) analysis were based on the data provided from the TCEP preliminary engineering. This included preliminary vendor data from Siemens Fuel Gasification Technology, Linde, and Siemens Power Generation. The initial air permit application was based on the then current TCEP configuration and Design Basis.

The FEED work began just after the submittal of the initial air permit application. During the FEED, changes were made in the Design Basis and the TCEP plant configuration. On October 19, 2010, the TCEQ issued its preliminary determination and a draft permit. As part of the review of the draft permit, TCEP submitted comments to the draft permit text. The submittal also included updates and changes to the plant and process descriptions, as well as to the emission sources and inventories, based on the data available from the FEED.

The updates and changes in that submittal included:

- The Acid Gas Removal system technology was changed from Selexol™ to Rectisol®
- Change from a pressure swing adsorber to a nitrogen wash unit
- Clarification of the basis of some emission rates in the draft air permit
- Update in gas turbine emissions based on changes in syngas composition
- Updated emission inventories
- Updated TCEP block flow diagram
- Updated site plan

11.2 Final Air Permit

On December 28, 2010, the TCEQ issued the final air permit. Table 11-1 below presents emission limits for the Power Block from the final air permit. Table 11-2 presents maximum allowable emission rates, on an hourly basis, from the Power Block.

TABLE 11-1
Air Permit Emission Limits

NOx (1-hr average, syngas or natural gas)	15.0 ppmvd
NOx (30-day rolling average, syngas)	3.5 ppmvd
NOx (30-day rolling average natural gas)	2.5 ppmvd
CO (1-hr average, syngas or natural gas)	25.0 ppmvd
CO (12-month rolling average, syngas or natural gas)	10.0 ppmvd
NH_3 slip (1-hr average, syngas or natural gas)	10.0 ppmvd

Notes

- All limits are at 15% O_2
- Selective catalytic reduction system included for NOx control
- Natural gas sulfur limit of ≤2.0 grains total sulfur/100 dry standard cubic feet (dscf)
- Undiluted syngas sulfur content limit is 10 ppmvd
- Duct burners can burn mixture of syngas/offgas or natural gas
- Activated carbon beds or alumina catalyst to remove mercury.

TABLE 11-2
Maximum Allowable Emission Rates from Power Block

	Combustion Turbine and Duct Burner Fired with Syngas/Offgas lbs/hr	**Combustion Turbine Fired with Natural Gas lbs/hr**
NOx	161.28	120.10
NOx (startup)	-	240.21
SO_2	17.83	11.14
CO	141.19	121.84
CO (startup)	-	1,705.81
VOC	6.70	5.57
VOC (startup)	-	194.95
PM	27.12	18.30
PM10	27.12	18.30
PM2.5	27.12	18.30
H_2SO_4	2.73	1.70
NH_3	31.27	29.59

The air permit also includes emission rates (hourly and annual basis) for the facility's other emission sources. As noted previously in this report, the capture and use of CO_2 is an important part of the TCEP. However, it is possible that interruptions in the operation or availability of the AGR system, the EOR CO_2 compressor, or the CO_2 pipeline system could occur, and the CO_2 stream would need to be vented. In order to address this, venting of this CO_2 stream is limited to no more than 5% of the year at the maximum flow rate.

12 Water Supply

12.1 Process Water

The TCEP will use require an average of 4.2 million gallons/day and a maximum of 4.5 million gallons/day of water for all plant uses. Water used for steam production in the HRSG must be of very high quality and, for economic reasons, will be condensed and reused rather than vented to the atmosphere as steam. Water for the plant will be supplied by a pipeline from one or more of the three primary sources as described below. The preferred primary process water provider is the Gulf Coast Waste Disposal Authority (GCA). A number of backup process water supply sources have been identified and will be used only in the event that the selected primary process water source is not available due to a disruption of service. Backup process water supply sources are also described below. The locations of the waterline options for the TCEP are shown in Figure 12-1.

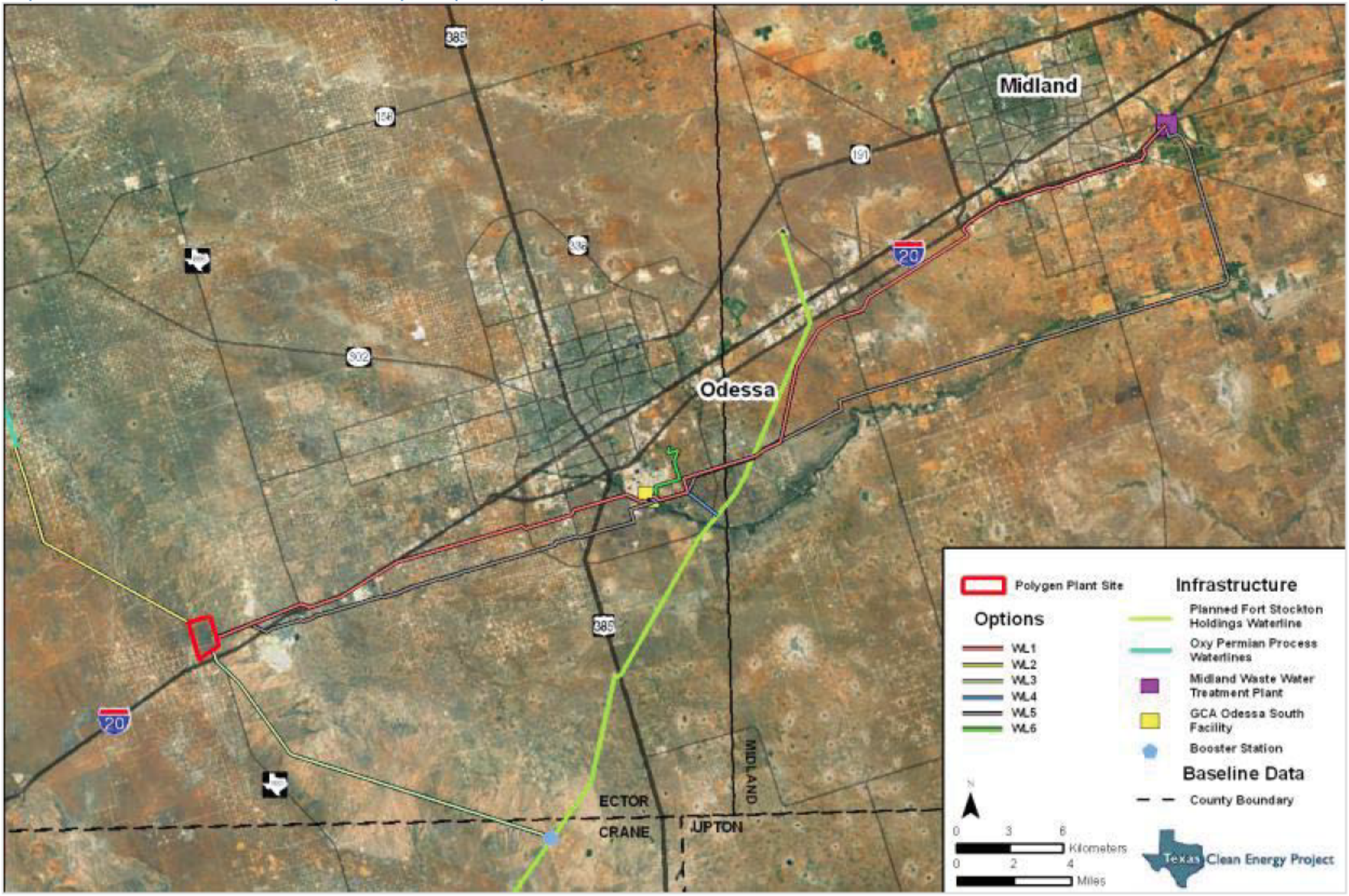
12.1.1 Primary Water Supply Options

Gulf Coast Waste Disposal Authority

The GCA owns and operates the Odessa South Facility, an existing facility in Odessa that treats municipal sewage from the city of Odessa and industrial wastewater from nearby industries. GCA's current capacity (as limited by their discharge permit daily maximum) is 7.0 million gallons/day and on average, the plant treats and discharges 2.8 million gallons/day. GCA has a minimum required discharge rate of approximately 2.0 million gallons/day into Monahans Draw. In anticipation of receiving wastewater from the city of Midland to support TCEP's needs, GCA requested approval from the Texas Council on Environmental Quality (TCEQ) to increase their discharge limits to a daily average of 10.6 million gallons/day with a daily maximum of 12.0 million gallons/day. Total dissolved solids limits will not be changed as part of GCA's requested permit modification. GCA currently has no water reuse customers.

As one of the process water sources under consideration, GCA will provide water to the TCEP from treated water from the Odessa South Facility. The Odessa South Facility will continue to receive wastewater from the existing sources and will also receive wastewater from the city of Midland Waste Water Treatment Plant (WWTP), which currently treats its wastewater (primary treatment only) and disposes of it through land application for agricultural irrigation. Under the GCA source option (routes Water Line 1 [WL1] or Water Line 5 [WL5]), wastewater from the city of Midland WWTP will be piped to the GCA Odessa South Facility where it will receive additional, secondary treatment and filtration. GCA will need to construct additional handling and treatment capacity at its existing facility, and existing but currently unused systems will be refurbished and put into service. GCA will then pipe the treated water to the TCEP, as needed, for use as process water.

FIGURE 12-1
Proposed Routes for the Process Water Pipeline Options (WL1–WL6)



There are two GCA waterline options that could transport the secondary-treated water to the polygen plant. WL1 will require the construction of a 30-inch diameter pipeline from the city of Midland WWTP to the GCA Odessa South Facility and from the GCA Odessa South Facility to the polygen plant site. The pipeline will be approximately 41.3 miles long, of which approximately 20 miles will require a new right-of-way (ROW). WL5 will require the construction of a 30 inch diameter pipeline connecting the city of Midland WWTP, the GCA Odessa South Facility, and the polygen plant site. The pipeline will be approximately 44.5 miles long, of which approximately 30 miles will require new ROW. Both WL1 and WL5 will require lift stations at or near the Midland WWTP as well as at the GCA Odessa South Facility. The lift stations will be needed to provide the necessary pumping capacity and will consist of three electric pumps enclosed in an approximately 30 × 30 foot building. The lift stations could either be: 1) constructed within the city of Midland WWTP, or b) constructed approximately 620 feet upstream of the incoming pipeline to avoid 90 percent of the industrial customer drains, which have the potential to discharge waste outside the limits of the GCA discharge permit. The lift station at the GCA Odessa South Facility will be located within the facility boundary. WL5 is Summit's preferred GCA option.

The specific quantity of waste water to be transferred from the city of Midland to the GCA Odessa South Facility is currently being negotiated by those two entities. The objective of these negotiations is to secure the needed water for the TCEP while not decreasing GCA's current discharge into Monahans Draw. The quality of the treated waste water discharged into Monahans Draw from the GCA Odessa South Facility will be similar under this primary water source option (WL1 or WL5). At a minimum, the city of Midland WWTP will provide a flow volume of approximately 6.0 million gallons/day to GCA. The daily average discharge into Monahans Draw from the GCA Odessa South Facility will increase by approximately 0.4 to 1.4 million gallons/day (annual average will be 0.75 million gallons/day), with the greater amounts discharged during the winter months when the polygen plant will need less water for cooling. The sanitary sewer system for the city of Midland WWTP is separate from its storm water sewer system; therefore, no storm water from the city of Midland will be transferred to the GCA Odessa South Facility.

Non-transferred waste water will continue to be sent from the city of Midland WWTP to irrigate croplands, although at a reduced level (approximately 6.0 million gallons/day less) compared to current levels. Based on communication between Summit representatives and representatives of the city of Midland and the GCA, the city of Midland will continue sending nearly half of its wastewater to Midland's spray irrigation fields for disposal. Midland's current rate of spray disposal exceeds the optimal land irrigation rates for crops, and that diversion of excess wastewater to the TCEP will be beneficial to the spray disposal system currently in use by Midland without reducing the production of crops. In addition, the city of Midland will continue to provide wastewater, fertilizer, and seed base to the selected bidders and collect a small percentage of the profit.

The city of Midland also has plans to treat a small percentage of its wastewater (to a higher quality) through a small WWTP (to be installed at or near the point of use). This treated wastewater will be for reuse purposes, including landscaping and lawn maintenance at Midland College. Accounting for these applications, there will be sufficient wastewater remaining to meet the needs of the TCEP.

Oxy Permian

Oxy Permian operates a network of pipelines that provide brackish (highly saline and nonpotable) ground water from the Capitan Reef Complex Aquifer. The Oxy Permian Waterline option (WL2) will provide process water to the TCEP from the existing pipeline system through a new 9.3-mile, 16 inch diameter pipeline. Of the 9.3 mile length, approximately 8.7 miles of new ROW will be required. Process water from Oxy Permian will require treatment to meet Siemens' gasifier specifications.

Fort Stockton Holdings

Currently in the developmental stages, the Fort Stockton Holdings (FSH) waterline project has been proposed to provide drinking water to the cities of Midland and Odessa. Under this option, FSH will provide water to the TCEP from one of two potential waterlines (WL3 and WL4). The viability of the main FSH waterline project will be independent of the TCEP. If it were built, the TCEP could use approximately 10 percent of the total water that will be available through the FSH waterline. The FSH water source will be ground water from the Edwards-Trinity (Plateau) Aquifer located near the city of Fort Stockton, which is approximately 66 miles southwest of the TCEP site. Process water from the FSH option will require treatment to meet the gasifier manufacturer's specifications. WL3 will require construction of a 14.2-mile connector pipeline from the TCEP site to the FSH pipeline using 9.2 miles of new ROW.

12.1.2 Backup Water Supply Options

Summit is also considering a number of backup water supply options. These options will supply water to the TCEP in the event of a disruption in the primary water source. Because of the designed reliability of the primary water source options, it is anticipated that the backup water supply sources will be used infrequently and for periods of short duration. Backup water supply options under consideration are described below.

Texland Great Plains Water Company

Under this option, the Texland Great Plains Water Company (Texland) will provide the backup water supply using their existing firm service capacity reserved for the Odessa-Ector Power Partners (OEPPP) project. OEPP operates as an intermediate power provider in the ERCOT system. Currently, the OEPP facility is dispatched in the range of 12–15 percent per year. When the OEPP facility is online, water could not be made available for backup service to the TCEP. The Texland water will only be paid for by TCEP when used. Texland was not considered as a primary water supplier for the TCEP because all of its available capacity is under contract to other users.

Texland pumps water from the Ogallala Aquifer and is currently serving electric power plants, oil and gas field waterfloods and gas plants, a municipal water system, and agricultural users. Texland has agreed to develop commercial terms with TCEP to provide the needed water quantity when: 1) TCEP calls upon the service, and 2) it is not being used by OEPP.

If GCA is chosen as the primary water source option (WL1 or WL5), a new 16-inch diameter pipeline (WL6) between the existing OEPP facility and the GCA Odessa South Facility (a distance of approximately 3 miles with 0.9 miles of new ROW) will be required for the backup water supply. From the GCA Odessa South Facility, backup water from the Texland system will then be transported to the polygen plant site in either the WL1 or WL5 pipeline options. A new

16-inch diameter pipeline will also be required if WL2 is chosen as the primary water source option. This pipeline will be constructed between the OEPP facility and TCEP, a distance of 17 miles, following one of the alignments proposed for WL1 or WL5 between the GCA Odessa South Facility and the polygen plant site.

Fort Stockton Holdings

If the FSH pipeline is constructed, this water source could be used as a backup water source for the polygen plant. As a backup to WL1 or WL5 (from the GCA Odessa South Facility), a 2.7-mile, 16-inch diameter pipeline (WL4) could be constructed from the main FSH waterline to the existing GCA Odessa South Facility. Water will be filtered and piped from the GCA Odessa South Facility to the polygen plant site using WL1 or WL5. Approximately 1.3 miles of WL4 will require a new ROW. As a backup water source for WL2, backup water from the FSH waterline could be piped to the polygen plant using WL3.

Other Backup Sources

Backup water supply sources could also come from treated waste water from the city of Odessa Derrington Water Reclamation Plant or from the GCA Odessa South Facility. If the city of Odessa Derrington Water Reclamation Plant is chosen as a backup water source, additional wastewater from this plant could be routed to the GCA Odessa South Facility, or Summit could tap into the existing Odessa reuse line that runs adjacent to the GCA Odessa South Facility. Although the city of Odessa has over-committed their reuse water, they do have excess water that discharges into Monahans Draw in the winter months that could potentially be used as a backup water source on a short-term basis. Summit could purchase secondary or tertiary water rights during these months as a backup water supply.

The GCA Odessa South Facility base flow of approximately 2.8 million gallons/day could also be used as a potential backup water source in the event effluent from the city of Midland WWTP was interrupted. Under this scenario, part or all of the GCA Odessa South Facility base flow could be diverted to the TCEP on a temporary basis. These backup water source plans will be refined, and a final backup water source plan developed for the TCEP prior to plant operation.

13 Cost Reduction and Final FEED Cost Estimate

13.1 Cost Reduction

13.1.1 Cost Reduction Team

In early February, 2011, Summit received preliminary TCEP cost estimates from the FEED contractors. Summed together, the total project cost was estimated to be approximately $2.7 billion (on a basis that included the "inside the site boundary" portion of the TCEP, and did not include laterals, coal feedstock, financing, insurance or other owner's costs). This cost was viewed as too high for the project to continue forward to financial closing. A Cost Reduction Team (CRT) initiative was established to find and implement significant cost reductions.

The charter for the CRT was set up as follows:

Statement of Purpose

- The Cost Reduction Team shall undertake a serious, off-project effort to reduce the overall capital cost of the Texas Clean Energy Project. The effort shall be aimed at:
- Eliminating or modifying scope that adds costs to the project, but has limited value to the project or the client's business needs.
- A review of current capital cost estimates to ensure correctness, consistency, and effective execution approach.
    - o Identify areas of duplication, overlaps, and/or gaps between the FEED contractors; scopes of works.
    - o Identify contingency allocation within the cost estimates.
    - o Analyze the estimates of bulk materials for consistency.

Responsibilities

The Cost Reduction Team is to develop a strategy to review and evaluate the current plant designs with the primary aim of capital cost reduction, without sacrificing quality, safety, and the business objectives. This is to be a dedicated, independent, and parallel effort with the ongoing project FEED activities. Each Project Participant is to assign a representative to the Cost Reduction Team.

Each Project Participant shall provide the Cost Reduction Team with its previous Project Histories for similar Cost Reduction reviews. Open cooperation among all parties is paramount.

Each Project Participant shall assign a team to examine its respective current Project Design Basis and Cost Estimates, and identify Potential Cost Reduction Measures. Areas to be examined shall include, but are not limited to the following:

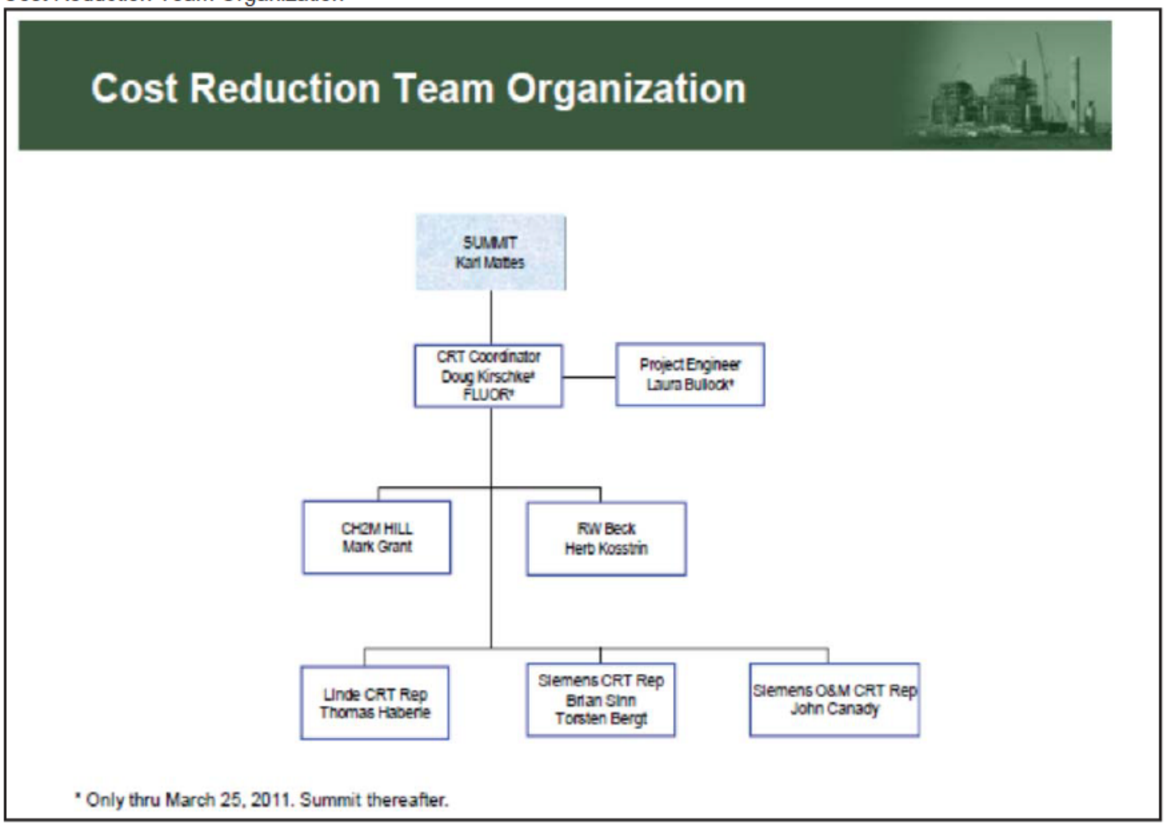
- The use of engineering specifications and standards which are in excess of fit-for-purpose, industry standards, i.e., "gold plating".

- The use of unnecessarily conservative design allowances to achieve performance criteria.
- Installations containing redundant or parallel systems that are thought to be needed for plant availability. Re-evaluate the equipment sizes, and/or consider deferring the installation of these systems, or utilizing warehouse spares, based on actual operating experience.
- The identification of equipment or systems that could be leased to transfer costs from initial capital to operating costs.
- The identification of systems or units that could be owned/operated by third parties, with TCEP paying for the product as part of O&M, i.e. ASU and Sulfuric Acid Plant for oxygen/nitrogen and sulfuric acid respectively.
- Additional design capacities that may have been put into place to cover process guarantees and/or liquidated damages.
- The consistency of the Cost Estimate Basis across all Cost Estimates.
- The best pricing of Equipment and Materials in the Cost Estimates.
- The best derivation and consistency o the pricing of Construction Costs.
- The cost estimate basis for "Packaged Scope" items to ensure consistency and effective execution approach.
- The Interfaces and Scope Inclusions in the Cost Estimates for correctness, i.e., no overlaps or gaps.
- Each Cost Reduction Team shall internally evaluate, and then estimate, the cost for each of its Potential Cost Reduction Measures. A log is to be maintained of all potential Cost Reduction Measures identified by each Participant. It is also recommended that each Cost Reduction Team should utilize its own established project Value Awareness and/or Change Management recommendation forms and procedures to document each Proposed Cost Reduction Measure. The documentation is to include a brief description of the Proposed Cost Reduction Measure, the estimated total cost savings, and the identification of related constraints and or project impacts, if the proposed measure were to be implemented.
- All Cost Estimates are to be prepared in a consistent basis. Fluor will provide a Cost Estimate Basis Checklist to assist in this effort.
- The target is to achieve an overall reduction in the total project cost of $700 million.
- There is no intent at this time to compromise the 2014 project completion date. Accordingly, the schedule for the Environmental Impact Statement (EIS) will need to be maintained. However, all Potential Cost Reduction Measures are to be identified, even if there will be a potential of impacting these schedule restraints should the measure be implemented.
- Also, it is not the intent to disrupt the current FEED schedule.

- The team will travel as required to meet with Siemens, Linde or Fluor in their respective home offices or location where the FEED work is being conducted, for the purposes of reviewing information.
- Each Participant shall submit its List of Proposed Cost Reduction Measures, with supporting documentation for each proposed measure, to the Fluor Cost Reduction Team for consolidation. Fluor will prepare a consolidated report for Summit Project Management, prior to the Executive Management Committee Meeting at the end of March, 2011.

Representatives from each of the FEED contractors, as well as from CH2M HILL and RW Beck, were assigned to the CRT. A representative from Fluor was assigned to lead the CRT and to compile the cost reductions. Figure 13-1 shows the CRT organization.

FIGURE 13-1
Cost Reduction Team Organization



The team members worked closely together for several months. Constant coordination and discussion was critical, as potential changes in one contractor's "area" will often result in impacts on another's. Potential reductions in capital cost often led to increases in O&M. Key tasks were as follows:

- Team kick-off and alignment teleconferences
- Fluor prepared initial lists of potential cost reduction measures for all areas, based on past similar projects

- CRT members, including CH2M HILL and RW Beck, added potential cost reduction measures for consideration
- Each contractor team logged, reviewed, and evaluated each potential measure, and estimated ROM cost savings for each
- The team identified constraints and/or project impacts if the cost reduction measure was implemented
- The team held weekly Status Teleconferences – this helped to maintain focus on the goal of the CRT, resolve coordination efforts, and address action items

By the end of February, the CRT had developed almost 200 potential savings ideas. They are shown in Table 13-1 below.

TABLE 13-1
Preliminary Cost Reduction Team Savings Ideas

FEED Contractor Area	Total Identified	Already Included in Design or No Savings	Total Evaluated for Savings	Potential Savings (Number of Ideas)		
				<$1M	$1MM-$10M	>$10M
Syngas Block	76	40	18	4	13	1
Gasification Island	26	13	2	0	2	0
Power Block	19	13	5	0	5	0
Balance of Plant	74	44	29	14	13	2
TOTALS	195	110	54	18	33	3

The CRT then began detailed technical and economic evaluations of the ideas selected for further review. As those were evaluated, more potential savings ideas were added to the CRT list for further evaluation.

Table 13-2 below summarizes the status at the end of February.

TABLE 13-2
Potential Savings from Preliminary CRT Ideas

FEED Contractor Area	Total Evaluated for Potential Savings to Date	Total Potential Savings $M	Remaining to be Evaluated
Syngas Block	18	$72M	18
Gasification Island	2	$11M	0
Power Block	5	$8M	0
Balance of Plant	29	$62M	2
TOTALS	54	$153M	20

13.2 Final FEED Cost Estimate

After incorporating the savings provided through the CRT's work, the final cost estimate prepared at the end of the FEED was as follows:

	$ Million	% of Total
Syngas Block	1,140	45.4%
Gasification Island and Power Block	740	29.5%
Balance of Plant	560	22.3%
Project and Construction Management:	70	2.8%
Total	**$2,510**	**100.0%**

Based on information developed during the FEED, Table 13-3 presents the approximate quantities of the major types of materials that will be used in the construction of the TCEP.

TABLE 13-3
Approximate Quantities of Construction Materials

Construction Materials	Quantity
Concrete	75,000 cubic yards
Structural Steel	19,500 tons
Piping	1.8 million linear feet (343 miles)
Electrical	2.5 million linear feet (475 miles)