6^{th} International Supercritical CO_2 Power Cycles Symposium
March 27 - 29, 2018, Pittsburgh, Pennsylvania

Integration of Indirect-Fired Supercritical CO_2 Power Cycles with Coal-Based Heaters

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Introduction

The primary goal of this project is to prepare designs for indirect-heated, oxy-combustion-based, coal-fired, supercritical CO_2 (sCO_2) Brayton cycle power plants, to assess the potential benefits that this marriage of technologies might offer when compared to more conventional, oxy / coal-fired steam-electric power plants. The oxy-combustion technologies under investigation in this project are atmospheric-pressure, oxy-pulverized coal (PC) cases as well as atmospheric-pressure chemical-looping-combustion (CLC) cases. In addition, the use of high-temperature (HT) air-heater (AH) technology that could enable a high-efficiency recompression (RC) closed sCO_2 power cycle will be assessed – one that in some cases utilize a low-grade (LG) heater to recover heat from the air separation unit (ASU). The specific objectives of the project are to:

- Identify suitable baseline cases for comparisons of project results;
- Develop multiple test case sCO_2 cycle power-plant designs for integrating the power cycle with the coal-fired heater, with the goal to maximize net plant efficiency and identify any potential technology gaps; and
- Develop capital and operations and maintenance (O&M) cost estimates of selected test case plant designs, with which levelized cost of electricity (LCOE) and first-year power costs will be calculated.

This report provides an overview of the performance and economic calculations that were made for each case, with particular focus on the economics. Association for the Advancement of Cost Engineering International (AACE) Class-5 capital cost estimates along with levelized cost of electricity (LCOE) and first-year power costs are presented.

The analysis shows that the sCO_2 power cycles are 2–4% points more efficient than comparable steam-Rankine cycles, but do not show a cost advantage either in capital costs or LCOE.

Overview of Base and Test Cases

Six test cases are under investigation in this project as indicated in Table 1. The parameters that vary between the test cases are combustion technology (oxy-PC with CO_2 capture, CLC with CO_2

capture,[1] and air-fired PC with no CO_2 capture), turbine inlet temperature (593°C and 730°C), and size (550 MW[2] and 90 MW).

Table 1
Test Case Specifications

Test Case	Net Plant Size, MW	Turbine Inlet Conditions, °C / MPa	Air- or Oxy-Fired	sCO_2 Power Cycle Architecture	Fired-Heater Technology
1	550	593 / 24.1	Oxy	RC+LG*	PC
2		730 / 27.6	Oxy	RC+LG**	PC
3		593 / 24.1	Oxy	RC*	CLC
4		730 / 27.6	Oxy	RC**	CLC
5	90	593 / 24.1	Air	RC*	PC
6		730 / 27.6	Air	RC**	PC

(*) RC cycle with HT AH
(**) RC cycle with LG primary heater block and standard-temperature AH.

Base Case Overview

One of the overall project objectives is to compare performance and cost of power plants employing oxy-coal-fired sCO_2 power cycle technology to the performance and cost of similar coal-fired plants using familiar steam-Rankine power cycle technology. To that end, the project team selected from literature baseline steam-Rankine cycle power plants that employ the same gas-side combustion and flue gas treatment technology as that proposed for each project test case. The design bases in the base cases were then used as design bases for the test cases under consideration in the project to isolate the effects of employing a sCO_2 power cycle in place of a steam-Rankine power cycle.

DOE / NETL cases S12F and S13F were selected as base cases for Test Cases 1 and 2, respectively.[3] These cases refer to oxy-combustion cycles with 90% CO_2 capture at the standard 550 MWe output and both use Powder River Basin (PRB) sub-bituminous coal. The primary difference between S12F and S13F is steam conditions with S12F having 24.1 MPa and 593°C inlet conditions and S13F having 27.6 MPa and 730°C. A gas-side flow schematic of the 550-MW oxy-PC cases is shown in Figure 1. The heat transfer to the water / steam is conventional, employing both radiant and convective heat transfer surfaces. The gas-side flow sheets are essentially the same for Base Cases 1 and 2.

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[1] The CLC technology used is GE's Limestone-based Chemical Looping Combustion (LCL-C™).

[2] All MW labels in this report represent units of electric power. If the label "th" is added to MW, the units are MW thermal power.

[3] "Cost and Performance of Low-Rank Pulverized Coal Oxycombustion Energy Plants: Final Report," DOE/NETL-401/093010, September 2010.

The CLC base cases were developed for both supercritical and advanced ultra-supercritical (A-USC) steam conditions.[4] The CLC gas-side flow sheets for Base Cases 3 and 4 are essentially the same. The flow sheet is shown in Figure 2. Heat is transferred to the water / steam side in four locations: the two moving-bed heat exchangers (MBHE) associated with return solid flows to the Reducer and Oxidizer, respectively, and the two convective heat exchangers cooling the gas leaving the Reducer and Oxidizer, respectively. These four heat transfer locations also will be where heat is transferred to CO_2 in the test cases.

The Base Case 5 gas-side flow sheet is conventional for air / PC-fired steam generators. The steam temperature and pressure are lower than that used for the corresponding Test Case 5 as these units in the field operate at the lower steam conditions. The steam cycle is a no-reheat cycle with four closed feedwater heaters and a deaerator. This steam cycle is typical of steam-electric power plants less than 120 MW. Costs and performance for Base Case 5 were provided from a plant design done in 2011.

Note that a decision was made that Base Case 6 would be the same as Base Case 5, since no coal unit at this size has been or is foreseen to be built at the elevated steam conditions of 730°C and 27.6 MPa; hence no base case exists to draw data from.

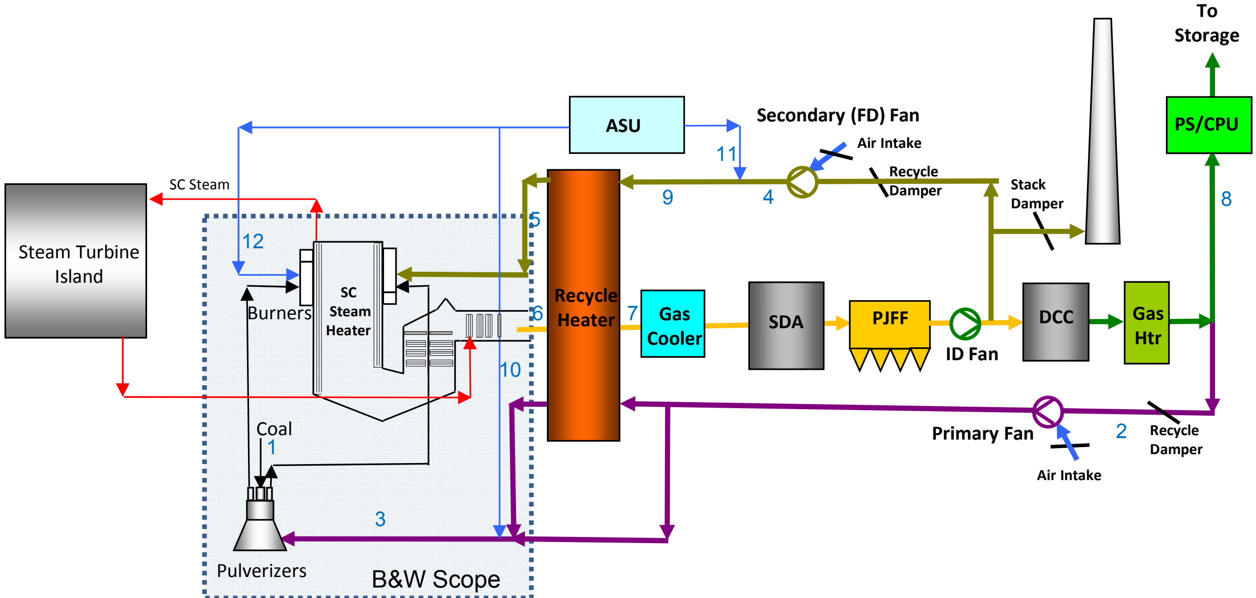


Figure 1
550-MW Oxy-PC Base Case Gas-Side Flow Sheet

[4] "Alstom's Chemical Looping Combustion Technology with CO_2 Capture for New and Retrofit Coal-Fired Power Plants: Task 2 Final Report," DOE/NETL Cooperative Agreement No. DE-FE0009484, June 2013.

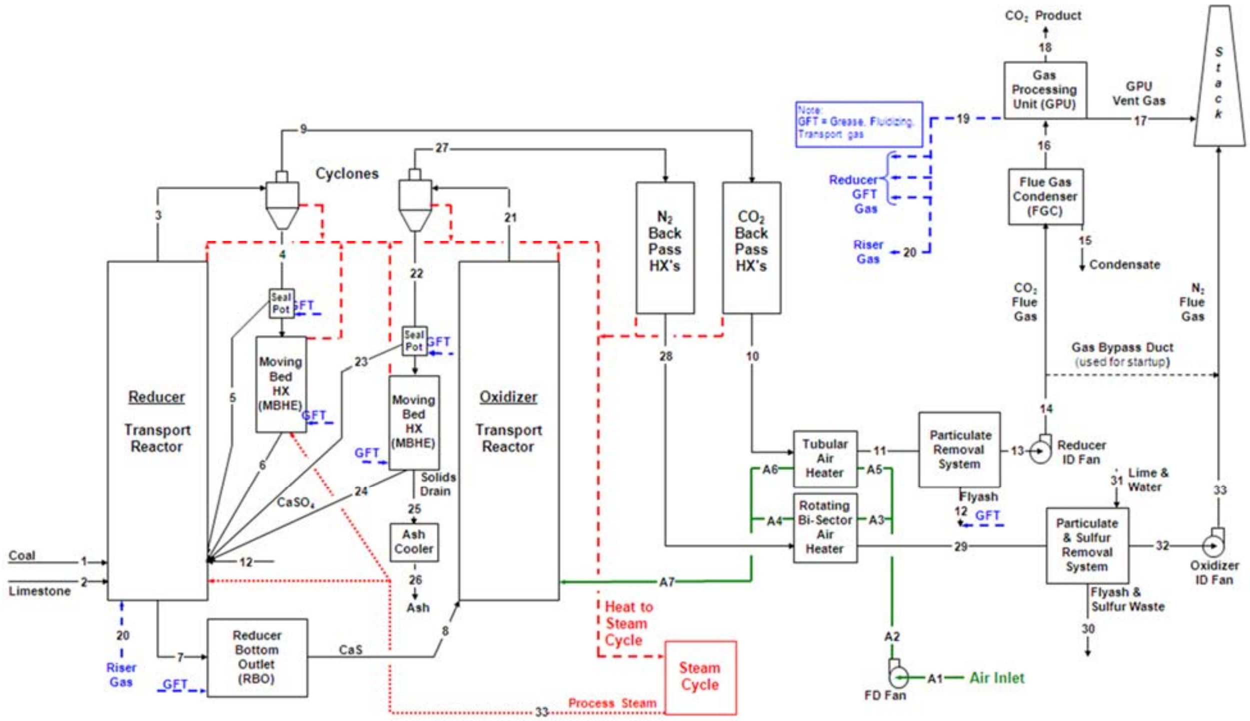


Figure 2
550-MW CLC Base Case Gas-Side Flow Sheet

Table 2 lists the base case data critical to specifying the thermodynamic conditions of the sCO_2 power cycle for the associated test cases as well as the efficiency data that will be used for comparison. (Note that the base case identifier used, e.g., “S12F”, matches up with that used in the associated DOE / NETL report.)

Table 2
Base Case Performance Data

Test Case	Base Case	Net Power, MW	Auxiliary Power, MW	Net Plant Efficiency, % HHV	Fuel	Oxidant	Main Steam Pressure, MPa	Main Steam Temp, °C	Reheat Steam Temp, °C	Steam Cycle Efficiency %	CO_2 Capture, %
1	S12F	550	198.3	31.0	PRB	95% O_2	24.1	593	593	47.0	90
2	S13F	550	182.6	34.3	PRB	95% O_2	27.6	730	760	50.6	90
3	SC LCL-C™	550	99.7	35.8	Illinois #6	CLC	24.1	593	593	46.9	97
4	A-USC LCL-C™	550	88.3	40.4	Illinois #6	CLC	27.6	730	760	52.1	97
5 / 6		90	10.6	33.0	PRB	Air	10.6	538	-	38.8	-

References:

Test Cases 1, 2: *Cost and Performance of Low-Rank Pulverized Coal Oxycombustion Energy Plants: Final Report.* DOE/NETL-401/093010. September 2010.

Test Cases 3, 4: *Alstom's Chemical Looping Combustion Technology with CO_2 Capture for New and Retrofit Coal-Fired Power Plants. Task 2 Final Report*. DOE/NETL Cooperative Agreement No. DE-FE0009484. June 2013.

Test Cases 5, 6: Internal design documents for a project undertaken in 2001.

Test Case Overview

Fired Heaters

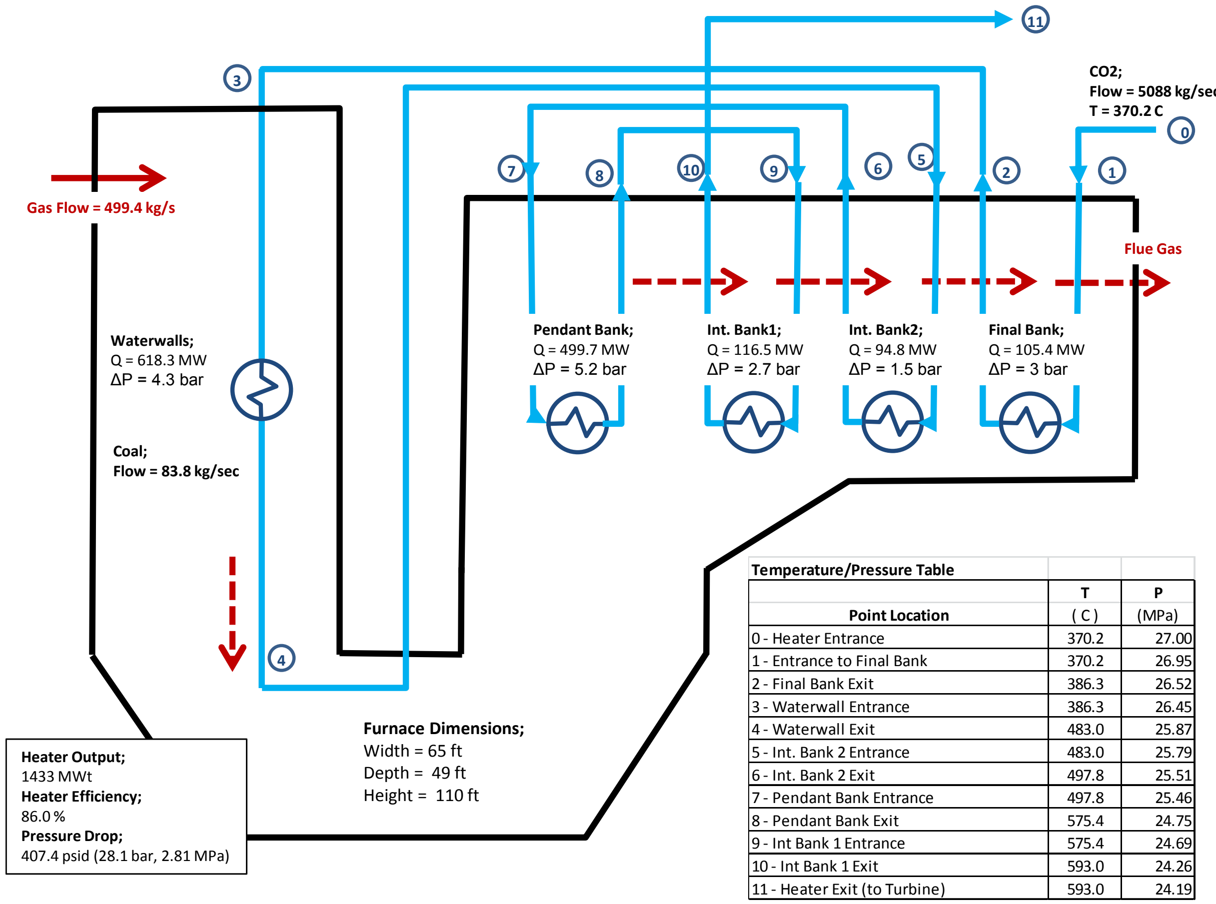
Test Cases 1, 2, 5, and 6

Oxy-combustion plants remove most of the nitrogen in air prior to combustion, thereby burning fuel in oxygen instead of air. This produces a flue gas containing primarily CO_2 and water, allowing relatively simple "CO_2 purification" by condensing out the moisture and removing small amounts of additional byproducts. The atmospheric oxy-combustion power cycle is nearly identical to those used in conventional coal-fired power plants. On the gas side, the primary differences are found in the provision of oxidant to the boiler via a cryogenic ASU and the CO_2 capture process. On the power side, either steam or CO_2 can be used as the working fluid without significant modifications to the gas side other than the boiler or fired-heater design. Similarly, a conventional PC unit without CO_2 capture can also utilize either steam or CO_2 in the power island, again with primarily only boiler modifications required.

Conceptual designs for Test Cases 1, 2, 5, and 6 served as the basis for the preliminary cost estimates. The basic design is based on the inverted tower configuration. The configuration features an inverted furnace in which coal and primary / secondary oxidant (air or recycle gas) enters burners at the top (or upper sides) of the furnace, and flows downward as combustion occurs. The furnace features hanging curtains as the furnace walls, which are constructed from near-tangent tubes to absorb the radiant heat. The flue gas then flows through a tunnel before flowing up through the pendant tube bank section, where additional radiant heat absorption occurs. The gas flow subsequently travels horizontally through hanging tube banks of progressively tighter transverse pitch before exiting the fired heater. The sCO_2 working fluid generally enters the tube bank nearest the fired-heater exit and travels through the heater tube banks and furnace walls before flowing into the turbine. The inverted configuration offers the advantage of shortening the length of header piping that connects the furnace to the turbines to minimize the cost of the piping, which could be made from expensive high-temperature alloy.

A fired-heater flowchart for Test Case 1, which is similar to the design concept for Test Cases 2, 5, and 6, is shown in Figure 3. An array of burners is located in the upper portion of the furnace on opposing walls. In addition to the platens (pendants), the unit utilizes three convective pass heat exchangers.

In all cases, nickel-alloy materials have been used in the furnace and platen regions because of the high temperatures. Some of the convective tube banks are also nickel alloy in an attempt to reduce total pressure drop resulting from thinner tubes (higher allowable stresses).



Temperature/Pressure Table		
Point Location	T (C)	P (MPa)
0 - Heater Entrance	370.2	27.00
1 - Entrance to Final Bank	370.2	26.95
2 - Final Bank Exit	386.3	26.52
3 - Waterwall Entrance	386.3	26.45
4 - Waterwall Exit	483.0	25.87
5 - Int. Bank 2 Entrance	483.0	25.79
6 - Int. Bank 2 Exit	497.8	25.51
7 - Pendant Bank Entrance	497.8	25.46
8 - Pendant Bank Exit	575.4	24.75
9 - Int Bank 1 Entrance	575.4	24.69
10 - Int Bank 1 Exit	593.0	24.26
11 - Heater Exit (to Turbine)	593.0	24.19

Figure 3
Test Case 1 Fired-Heater Flowchart

Test Cases 3 and 4

LCL-C^{TM} is a coal-based power generation system that separates oxygen from air using an oxygen carrier, in effect producing oxy-combustion without cryogenic air separation. LCL-C^{TM} uses limestone particles as the oxygen carrier that are oxidized in an exothermic reaction at high temperature in an Oxidizer and then transferred to Reducer, where the solid-oxygen reaction is reversed and fuel is combusted. The reduced solid limestone carrier is returned to the Oxidizer and the “loop” restarts. The process provides a high CO_2 content product gas stream for additional purification in a CO_2 gas processing unit. It can use either steam or CO_2 as the working fluid in the power cycle. Figure 4 shows a simplified process flow diagram for the LCL-C^{TM} sCO_2 heater island for both Test Cases 3 and 4.

From a process perspective, the two sCO_2 design cases, Test Cases 3 and 4, are identical and their gas-side flow schematics are the same. Both plants are designed to generate 550 MW of net electrical output. Because of the efficiency increase associated with the higher turbine inlet temperature, the required coal flow and all associated gas and solids flows throughout the system will be reduced in Test Case 4 as compared to Test Case 3, resulting in smaller equipment size.

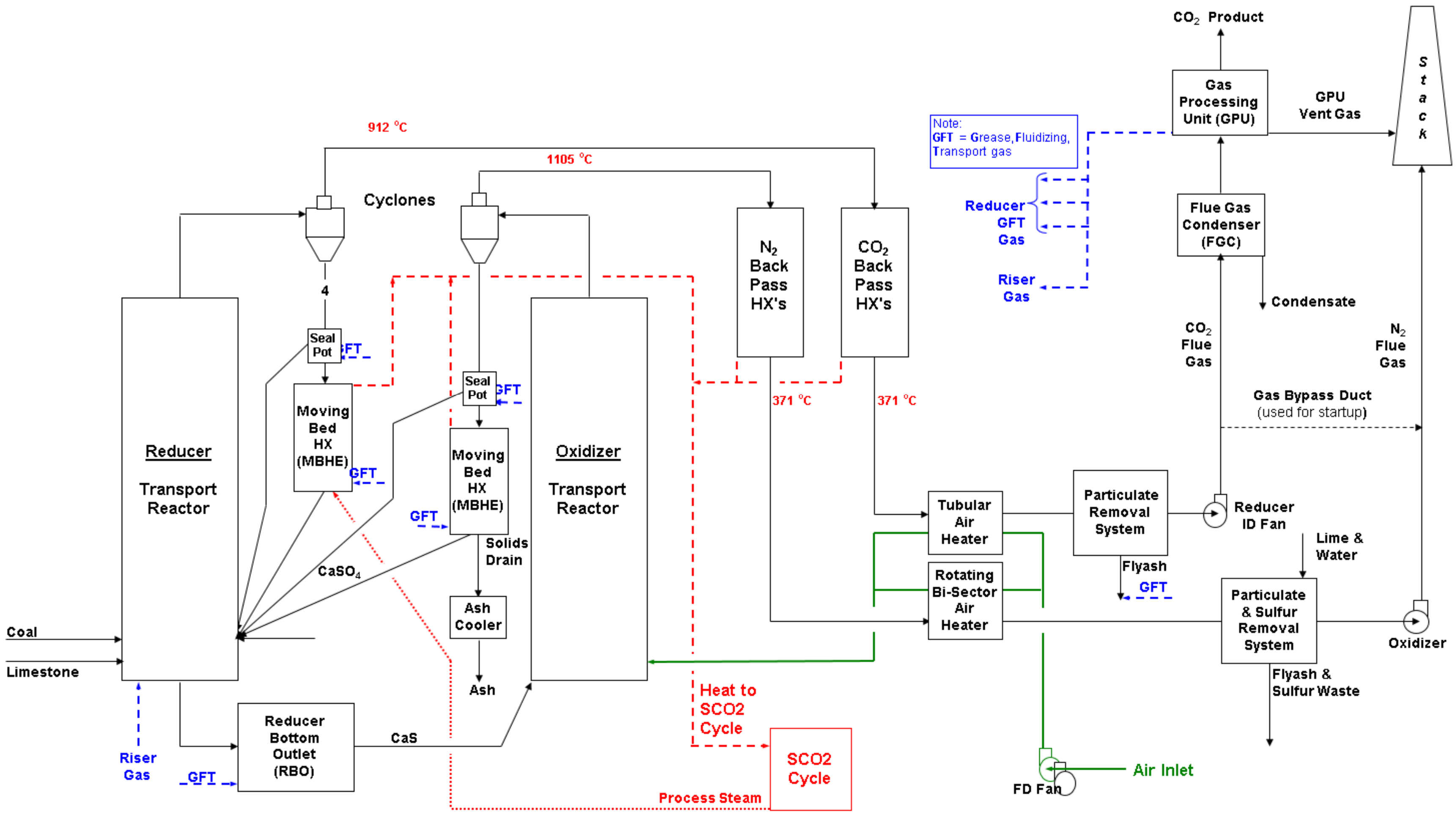


Figure 4
CLC Flow Schematic for Test Cases 3 and 4

For reference, the base case LCL-C™ boiler island isometric drawing is shown in Figure 5. The LCL-C™ sCO_2 heater island arrangement will largely remain the same with exceptions on the dimensions of the backpasses and moving-bed heat exchangers. Major fuel- and gas-side components including the reactors, cyclones, AHs, and coal and limestone silos will have similar sizes as the base case.

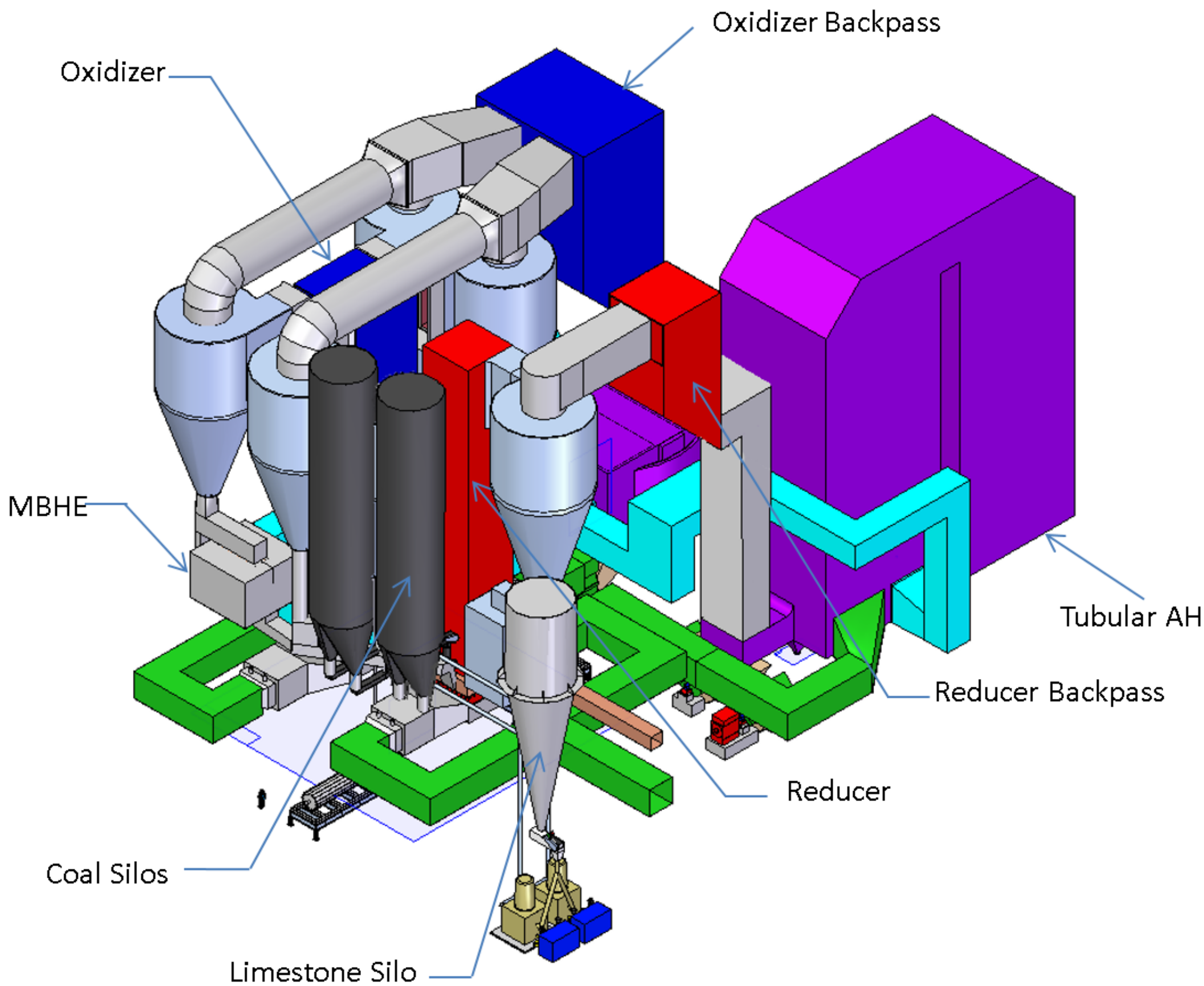


Figure 5
Isometric View of Base Case LCL-C™

The LCL-C™ sCO_2 heater island has four physically separated locations, where heat transfer to the sCO_2 fluid can take place. On the Oxidizer side, there is a convective backpass and a MBHE filled with solids. A similar but smaller convective backpass and MBHE also exist on the Reducer side. The main sCO_2 flow stream is first split between the fired heaters in the Oxidizer backpass and Reducer backpass before it is heated in the final MBHE. The parallel arrangement of the fired heaters in the convective backpasses can help reduce the pressure drop, while still absorbing adequate heat. The inlet streams in Test Case 3 and 4 both are comprised of a HT sCO_2 flow and a separate small LT sCO_2 flow.

sCO_2 Power Cycle

The sCO_2 power cycle configuration used for the test cases is the RC or recompression Brayton cycle. In the RC, heat is taken at high average temperatures from the fired heater, not unlike a boiler in concept, and as such maximizes cycle efficiency. The cycle is constrained by material thermal limits of the fired heater itself and the air/oxy-flue gas heater located before and after the fired heater. The RC cycle splits working fluid compression across two parallel components—a low-temperature compressor (LTC) sees the majority of system mass flow and is fed by the outlet of the air-cooled condenser (ACC), while a high-temperature compressor (HTC) is fed from the final low-side recuperator outlet. Cycle recuperation is split into a high-temperature recuperator (HTR) and low-temperature recuperator (LTR). On the LP side, the HTR and LTR are connected in series; at the final discharge, flow is split between the HTC and the ACC-LTC path. On the HP side, the LTR is supplied by the LTC discharge. This is then mixed with the HTC flow and passes through the HTR. Balancing the heat duty across the LTR by setting the bypass fraction at the optimal value is crucial to achieving peak efficiency as the approach temperatures across the recuperators are minimized. HT flow exiting the boiler island is split between the sCO_2 power turbine and independent drive turbines for the LTC and HTC; the three turbine discharge streams are remixed before entering the HTR.

High-level summaries of the designs for each test case are provided below.

Test Cases 1 and 2

For Test Cases 1 and 2, the sCO_2 power island was integrated with the fired heater in the 550-MW atmospheric oxy-combustion system design. For these cases, integration of LT thermal resources was performed by taking flow from the LTC to provide cooling to the ASU and CO_2 purification unit via a low-grade heat exchanger (LGHX) in a manner comparable to the base cases. Incorporating this LT heat in the power cycle has the net effect of shifting flow from the HTC to the LTC with a net reduction in overall compression power. The resultant block flow diagram for Test Case 1 is shown in Figure 6. Test Case 2 is similar, but a small sCO_2 stream from between the LTR and HTR is provided to the boiler island to meet AH temperature requirements.

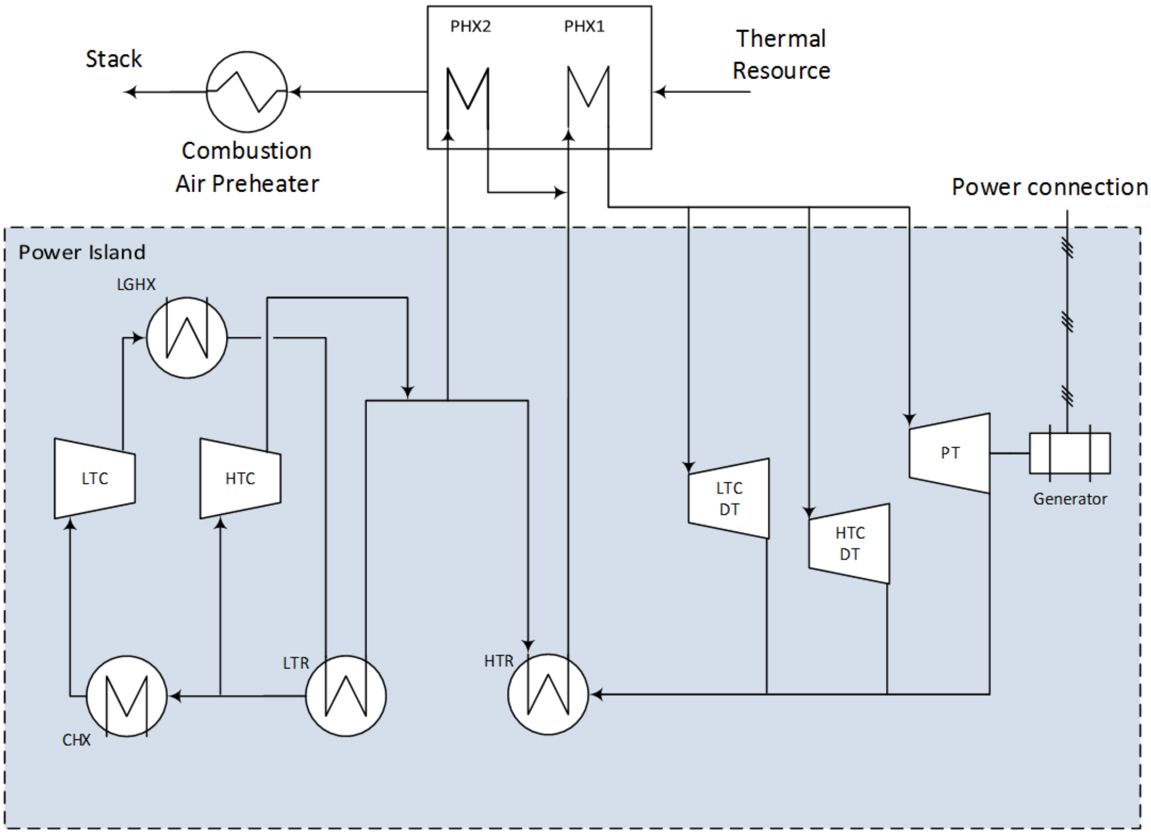


Figure 6
Test Case 1 550-MW Oxy-PC sCO_2 Power Island

Test Cases 3 and 4

For Test Cases 3 and 4, the sCO_2 power island was integrated with the fired heater in the 550-MW LCL-C™ system design. For these cases, there are two flows being provided to the fired heater as the CLC design provides heat from both the MBHE and the backpasses. There is no LGHX in these cases as there is no ASU to draw heat from. The resultant block flow diagram for Test Case 3, which is similar to Test Case 4, is shown in Figure 7.

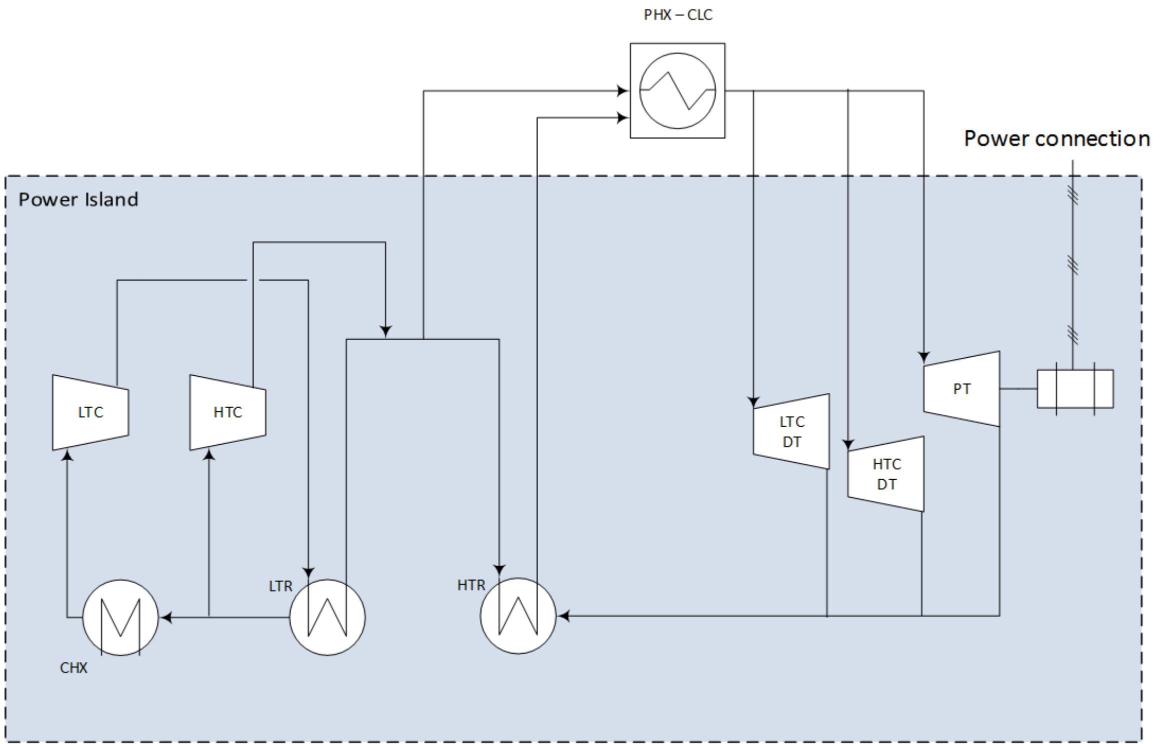


Figure 7
Test Case 3 550-MW CLC sCO_2 Power Island

Test Cases 5 and 6

For Test Cases 5 and 6, the sCO_2 power island was integrated with the fired heater in the 90-MW air-fired PC system design. For these cases, the cycle used is a traditional RC. The resultant block flow diagram for Test Case 5 is shown in Figure 8. Test Case 6 is similar, but a small sCO_2 stream from between the LTR and HTR is provided to the boiler island to meet AH temperature requirements.

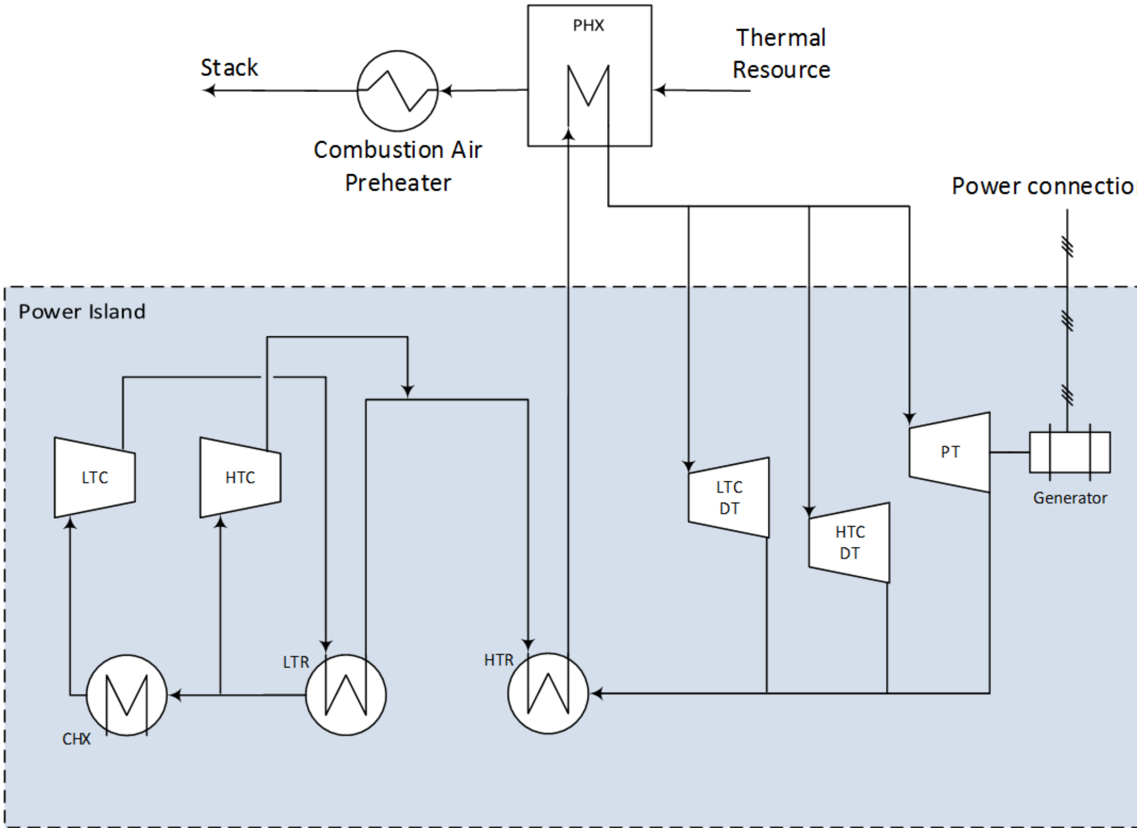


Figure 8
Test Case 5 90-MW Air-PC sCO_2 Power Island

Summary

Based on sCO_2 power block/coal-fired heater flow sheet designs developed for each of the test cases, the calculated net plant efficiencies for these sCO_2 test cases were higher than the steam-Rankine base case efficiencies used for comparison by 2 to 4% points. These results are listed in Table 3.

Table 3
Comparison of Test Case and Base Case Net Plant Efficiency

Case[1]	Net Power, MW	sCO_2 Power Cycle Architecture	Test Case Turbine Inlet Conditions,[2] °C / °C / MPa	Base Case Net Plant Efficiency, % (HHV)	Test Case Net Plant Efficiency, % (HHV)	Improvement Test over Base, % points
1	550	RC+LG	593 / 593 / 24.1	31.0	33.0	2.0
2	550	RC+LG	730 / 760 / 27.6	34.3	38.0	3.7
3	550	RC	593 / 593 / 24.1	35.8	38.5	2.7
4	550	RC	730 / 760 / 27.6	40.4	43.0	2.6
5	90	RC	593 / 24.1[3]	33.0	36.0	3.0
6	90	RC	730 / 27.6[3]	33.0	41.0	8.0[4]

Notes:

1. All test cases use direct, dry-air cooling. All base cases use water-cooled condensers. Base Cases 3–6 use a 100% wet cooling tower. Base Cases 1 and 2 use 50% wet cooling tower, 50% dry cooling tower.
2. Base Cases 1–4 steam turbine cycles include single reheat, while Test Cases 1–4 sCO_2 power cycles do not include reheat.
3. Base Cases 5 and 6 use a no reheat steam cycle with 538°C / 10.6 MPa turbine inlet conditions. Hence the net efficiency for both of these base cases is listed as the same.
4. The improvement in net plant efficiency in this case is not an "apples-to-apples" comparison since the turbine inlet conditions are significantly different between Test Case 6 and Base Case 5.

Cost Design Basis

Site-Related Conditions

The PRB coal plants for Base and Test Cases 1, 2, 5, and 6 are located at a generic plant site in Montana, which was selected to be consistent with the NETL base cases. It is important to note that while Base Cases 1 and 2 assume a greenfield site for the plant, the Base Case 5 assumes that the 90-MW system is an addition to an existing plant and can thereby use some of the existing infrastructure and support systems as well as buildings, facilities, and shared resources. The site is in Seismic Zone 1, at an elevation of 1036 meters above sea level and relatively level and with no special requirements related to hazardous materials, archeological artifacts, or excessive rock.

The assumed site location for Base and Test Cases 3 and 4 are a generic plant site in Midwestern U.S. The site is typical of Midwestern power generation facilities and has access to water and rail transportation. The site is assumed to be clear and level with no special problems; however, 30 meter pile foundations are required. The site is in Seismic Zone 0 at an elevation of 180 meters above mean sea level.

Coal Characteristics

The design fuels used for each test case are identical to those used in the corresponding base cases. Table 4 lists the proximate, ultimate, and HHV data for the design fuels.

The cost of coal delivered to the Midwestern U.S. site is $3.10/GJ (HHV) for Illinois #6 bituminous and for the Wyoming site is $1.21/GJ (HHV) for PRB sub-bituminous coal.

Costing Methodology

Capital Cost Estimating Basis

Capital costs are reported in June 2017 dollars (base-year dollars) to put them on a consistent and up-to-date basis—this was important as some of the primary component costs for the sCO_2 power cycles were quoted based on current estimates. Construction costs at the reference site were based on union labor.[5]

Cost Estimate Classification

Recommended Practice 18R-97 of the AACE describes a Cost Estimate Classification System as applied in EPC for the process industries. The capital cost estimate done for this study shall be classified as an AACE Class 5 Conceptual/Screening Study. Typical accuracy ranges for AACE Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side.

[5] NETL economic studies typically assume non-union labor rates. Union labor rates were chosen to better match up with conditions in 2017 and based on other studies performed by EPRI.

Table 4
Test Case Fuel Specifications (as received, % wet)

	Cases 1, 2, 5, and 6	Cases 3 and 4
	Montana Rosebud PRB Sub-bituminous	Illinois #6 Bituminous
Proximate Analysis		
Moisture	25.77	11.12
Volatile Matter	30.34	34.99
Fixed Carbon	35.70	44.19
Ash	8.19	9.70
Total	100.00	100.00
Ultimate Analysis		
Carbon	50.07	63.75
Hydrogen	3.38	4.50
Oxygen	11.14	6.88
Sulfur	0.73	2.51
Nitrogen	0.71	1.25
Chlorine	0.01	0.29
Moisture	25.77	11.12
Ash	8.19	9.70
Total	100.00	100.00
Calorific Value		
HHV, kJ/kg	19,920	27,113

System Code of Accounts

The costs are grouped according to a process/system-oriented code of accounts. Consistent with other DOE/NETL economic studies, 14 accounts are used (the accounts are shown in Table 5; note that there is some variation in Account 8 for the test cases to account for the differences between a steam and sCO_2 power cycle). This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process so they are included in the specific system account. In addition, costs for each code of account is further broken down into major equipment cost, material cost, and labor cost. Labor cost includes both direct and indirect costs.

Table 5
Accounts for the Capital Costs

1 COAL & SORBENT HANDLING
1.1 Coal Receive & Unload
1.2 Coal Stackout & Reclaim
1.3 Coal Conveyors
1.4 Other Coal Handling
1.5 Sorbent Receive & Unload
1.6 Sorbent Stackout & Reclaim
1.7 Sorbent Conveyors
1.8 Other Sorbent Handling
1.9 Coal & Sorbent Handling Foundations
2 COAL & SORBENT PREP & FEED
2.1 Coal Crushing & Drying
2.2 Coal Conveyor to Storage
2.3 Coal Injection System
2.4 Misc. Coal Prep & Feed
2.5 Sorbent Prep Equipment
2.6 Sorbent Storage & Feed
2.7 Sorbent Injection System
2.8 Booster Air Supply System
2.9 Coal & Sorbent Feed Foundation
3 FEEDWATER & MISC. BOP SYSTEMS
3.1 Feedwater System
3.2 Water Makeup & Pretreating
3.3 Other Feedwater Subsystems
3.4 Service Water Systems
3.5 Other Boiler Plant Systems
3.6 FO Supply Sys & Nat Gas
3.7 Waste Treatment Equipment
3.8 Misc. Equip. (Cranes, Air Comp., Comm.)
4 PC BOILER & ACCESSORIES
4.1 PC Boiler
4.2 ASU/Oxidant Compression
4.4 Boiler BOP (w/ ID Fans)
4.5 Primary Air System
4.6 Secondary Air System
4.8 Major Component Rigging
4.9 PC Foundations
5 FLUE GAS CLEANUP
5.1 Absorber Vessels & Accessories
5.2 Other FGD

5.3 Bag House & Accessories 5.4 Other Particulate Removal Materials 5.5 Gypsum Dewatering System 5.6 Mercury Removal System
5B CO2 REMOVAL & COMPRESSION
5B.1 CO2 Condensing Heat Exchanger 5B.2 CO2 Compression & Drying
6 COMBUSTION TURBINE/ACCESSORIES 7 HRSG
7.1 Flue Gas Recycle Heat Exchanger 7.2 SCR System 7.3 Ductwork 7.4 Stack 7.9 HRSG, Duct & Stack Foundations
8 STEAM TURBINE GENERATOR
8.1 Steam TG & Accessories 8.2 Turbine Plant Auxiliaries 8.3 Condenser & Auxiliaries 8.4 Steam Piping 8.9 TG Foundations
9 COOLING WATER SYSTEM
9.1 Cooling Towers 9.2 Circulating Water Pumps 9.3 Circ. Water System Auxiliaries 9.4 Circ. Water Piping 9.5 Make-up Water System 9.6 Component Cooling Water System 9.9 Circ. Water System Foundations
10 ASH/SPENT SORBENT HANDLING SYS
10.1 Ash Coolers 10.2 Cyclone Ash Letdown 10.3 HGCU Ash Letdown 10.4 High Temperature Ash Piping 10.5 Other Ash Recovery System 10.6 Ash Storage Silos 10.7 Ash Transport & Feed Equipment 10.8 Misc. Ash Handling Equipment 10.9 Ash/Spent Sorbent Foundation
11 ACCESSORY ELECTRIC PLANT
11.1 Generator Equipment 11.2 Station Service Equipment 11.3 Switchgear & Motor Control

11.4 Conduit & Cable Tray
11.5 Wire & Cable
11.6 Protective Equipment
11.7 Standby Equipment
11.8 Main Power Transformers
11.9 Electrical Foundations
12 INSTRUMENTATION & CONTROL
12.1 PC Control Equipment
12.2 Combustion Turbine Control
12.3 Steam Turbine Control
12.4 Other Major Component Control
12.5 Signal Processing Equipment
12.6 Control Boards, Panels, & Racks
12.7 Distributed Control System Equipment
12.8 Instrument Wiring & Tubing
12.9 Other I & C Equipment
13 IMPROVEMENTS TO SITE
13.1 Site Preparation
13.2 Site Improvements
13.3 Site Facilities
14 BUILDINGS & STRUCTURES
14.1 Boiler Building
14.2 Turbine Building
14.3 Administration Building
14.4 Circulation Water Pumphouse
14.5 Water Treatment Buildings
14.6 Machine Shop
14.7 Warehouse
14.8 Other Buildings & Structures
14.9 Waste Treating Building & Str.

Time Escalation of Costs

For this study, the cost basis is in June 2017 dollars. The Chemical Engineering Plant Cost Index (CEPCI) was used to escalate all prior year costs to June 2017 dollars. Figure 9 shows the CEPCI from June 2002 to June 2017.

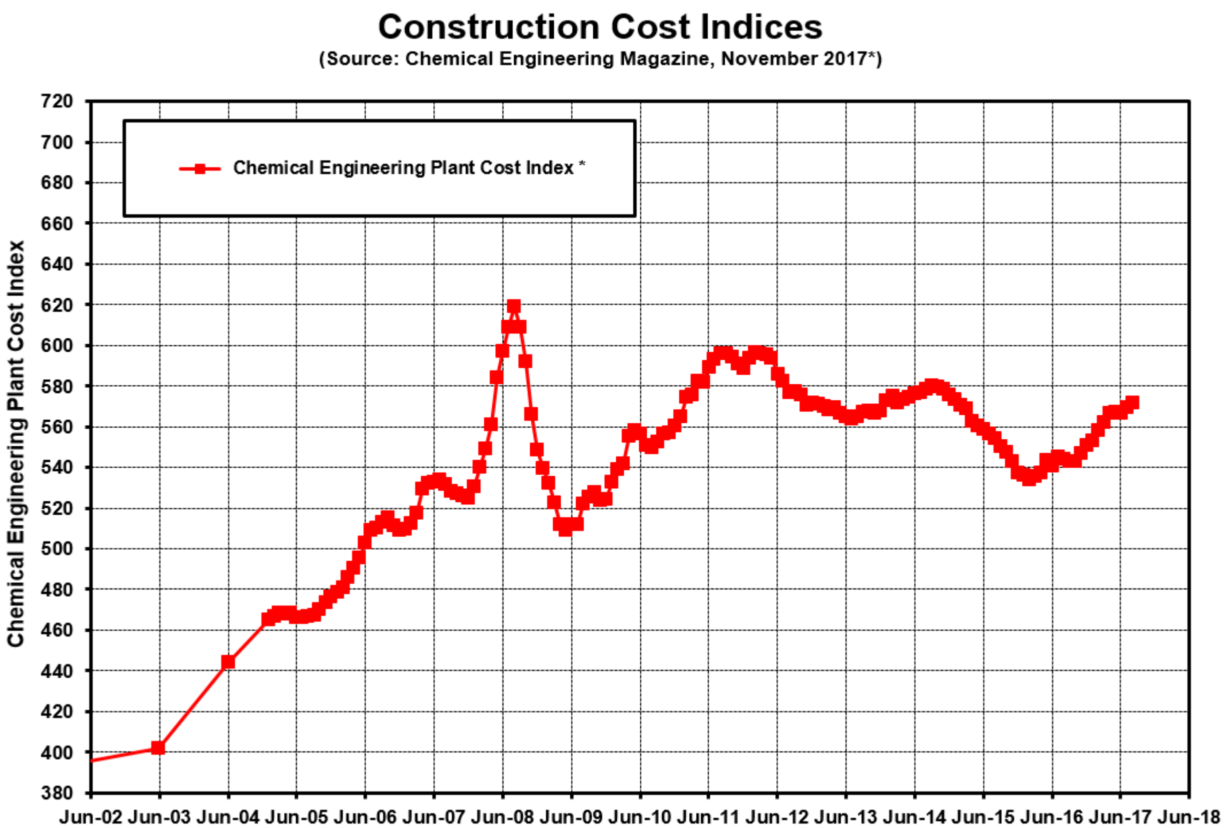


Figure 9
Chemical Engineering Plant Cost Index

Labor Rates

The all-in union construction craft labor rate for the Wyoming site for Base and Test Cases 1, 2, 5, and 6 was assumed to be $61.45/hour. The all-in union construction craft labor rate for the Midwestern U.S. site for Base and Test Cases 3 and 4 was assumed to be $81.28/hour.

The estimates are based on a competitive bidding environment with adequate skilled craft labor available locally. Labor is based on a 50-hour work week (five x 10-hour days).

Contingency

Process and project contingencies are included in estimates to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared. Capital cost contingencies do not cover uncertainties or risks associated with:

- Scope changes
- Changes in labor availability or productivity

- Delays in equipment deliveries
- Changes in regulatory requirements
- Unexpected cost escalation
- Performance of the plant after startup (e.g., availability, efficiency).

Process Contingency

Process contingency is intended to compensate for uncertainty in costs caused by performance uncertainties associated with the development status of a technology. Process contingency is applied to each component based on its current technology status.

As shown in Table 6, AACE International Recommended Practice 16R-90 provides guidelines for estimating process contingencies.

Table 6
AACE Guidelines for Process Contingency

Technology Status	Process Contingency (% of Associated Process Capital)
New Concept with Limited Data	40+
Concept with Bench-Scale Data	30–70
Small Pilot Plant Data	20–35
Full-sized Modules Have Been Operated	5–20
Process is Used Commercially	0–10

Project Contingency

The project contingency is a capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at an actual site. AACE 16R-90 states that project contingency for a "budget-type" estimate (AACE Class 5) should be 15 to 30% of the sum of BEC, EPC fees, and process contingency.

O&M Costs

O&M costs are to be estimated for a year of normal operation and presented in the base-year dollars. O&M costs for a generating unit are generally allocated as fixed and variable O&M costs.

Fixed O&M costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced, and are expressed in $/kW-year. Fixed O&M costs are composed of the following components:

- Operating labor
- Total maintenance costs (may also have a variable component)
- Overhead charges.

Taxes and insurance are considered as fixed O&M costs and are estimated as 2% of the total plant cost.

Variable O&M costs and consumables are directly proportional to the amount of kilowatts produced. They are generally in mills/kW-hour.

The estimation of these cost components is discussed below.

Operating Labor

Operating labor is based on the number of personnel required to operate the plant per shift. The total operating cost is based on the labor rate, supervision, and overhead.

Total Maintenance Costs

Annual maintenance costs for new technologies were estimated as a percentage of the installed capital cost of the facilities. The percentage varies widely, depending on the nature of the processing conditions and the type of design. The ranges shown in Table 7 are representative.

Table 7
Maintenance as a Percentage of Total Plant Cost

Type of Processing Conditions	Maintenance % of Total Plant Capital Cost/Year*
Corrosive and Abrasive Slurries	5–10+
Severe (Solids, High-Pressure, and Temperature)	3–6+
Clean (Liquids and Gases Only)	1.5–4
General Facilities and Steam Electrical Systems	1–3

* Minimum capital cost plants will generally experience maintenance costs at the high end of the range.

Maintenance cost estimates can be developed separately for different sections of the plant. Estimates should be separately expressed as maintenance labor and maintenance materials. A maintenance labor-to-materials ratio of 40:60 was used for this breakdown if other information is not available.

Table 8 shows the percentages that were used for each Account area in the plant.

Table 8
Maintenance as a Percentage of Plant Account Cost

Account Description	% Maintenance	Account No.
Solid Handling and Storage	2.5%	1, 2, 10
Feedwater and Miscellaneous BOP Systems	2.0%	3
Boiler and Flue Gas Cleanup	2.5%	4, 5
CO_2 Condensing and Compression	1.5%	5A, 5B
Heat Recovery Steam Generator	2.0%	7
Power Cycle	2.0%	8 / 8B
Cooling Water	2.0%	9
BOP	1.5%	11, 12, 13, 14

Consumables

Consumables are the principal components of variable O&M costs. These include water, catalysts, chemicals, solid waste disposal, and other materials that are consumed in proportion to energy output. Costs for consumable items are shown in Table 9.

Table 9
Cost Data for Consumable Items

Consumables and Variable Cost Items	Unit Cost
H_2O and Chemicals	
Raw Water, $/1000 liters	0.45
Ammonia (aqueous 29.4% weight), $/tonne	194
Sorbent (Delivered)	
Lime, $/tonne	155
Limestone, $/tonne	45
Dry Disposal	
Bottom and Fly Ash, $/tonne	15
Other	
Activated Carbon, $/tonne	1455
Urea, $/tonne	454

Cost of Electricity

The first-year COE (or power cost) is the revenue received by the generator per net MWh during the first year of operation assuming that the COE escalates at a nominal annual rate equal to the general inflation rate (i.e., remains constant in real terms over the operational period of the plant). The LCOE is the revenue received by the generator per net MWh during the first year of operation assuming that the first year of operation COE escalates at a nominal annual rate of 0% (i.e., remains constant in nominal terms over the operation period of the plant). NETL's Power Systems Financial Model (PSFM) provides a reference for COE calculations. The model accepts all of the economic assumptions outlined, along with specific information on the capital cost and fixed/variable O&M costs.

The approaches used to calculate both first-year power costs and LCOE are described below.

First-Year Power Cost

A simplified method provided in the DOE Financial Model User's Guide was used to calculate the first-year power cost.[6] A first-year capital charge factor (CCF) can be used to calculate the COE with this simplified equation:

$$COE = [\ (CCF)(TOC) + OC_{FIX} + (CF)\ OC_{VAR}\ ]\ /\ (CF)\ (MWh)$$

where:

- COE = revenue received by the generator ($/MWh) during the power plant's first year of operation (expressed in 2017 dollars), assuming that the COE escalates at a nominal annual rate equal to the general inflation rate; i.e., that it remains constant in real terms over the operational period of the power plant
- CCF = is the first-year CCF that matches the applicable finance structure and capital expenditure period
- TOC = Total Overnight Capital in 2017 dollars
- OC_{FIX} = the sum of all fixed annual operating costs in 2017 dollars
- OC_{VAR} = the sum of all variable annual operating costs, including fuel at 100% capacity factor, in 2017 dollars
- CF = plant capacity factor, assumed to be constant over the operational period
- MWh = annual net megawatt-hours of power generated at 100% capacity factor.

Based on the economic factors specified by the DOE, the CCF for a low-risk IOU and five-year capital expenditure period is 0.116 (such as a commercial project like Base Case 5). The CCF for a high-risk IOU and five-year capital expenditure period is 0.124 (such as a novel system like CLC). As a result, for this study, the following CCFs were used:

- Base and Test Cases 1 and 2: CCF = 0.124
- Base and Test Cases 3 and 4: CCF = 0.124
- Base and Test Cases 5 and 6: CCF = 0.116.

[6] "Power Systems Financial Model Version 6.6 User's Guide," DOE/NETL-2011/1492, May 2011.

LCOE

The PSFM provides the LCOE on a current dollar basis over a levelization period equal to the plants operational life; i.e., the LCOE is constant in current dollars over this period. The model provides a levelization factor that can be multiplied by the COE to give the LCOE in base-year dollars. The levelization factor for NETL-defined economic inputs is 1.268.

Economic Analysis

This section provides details on how the specific costs were estimated for the base and test cases, highlighting key components that the team focused on developing unique cost estimates for: fired heaters and the sCO_2 power cycles for the test cases. These descriptions are then followed by the presentation of the capital and O&M costs for each case along with the first-year power cost and LCOE.

It should be noted that the data provided by suppliers, including in particular the cost estimates for more novel equipment like the fired heaters and sCO_2 power turbines, should not be considered a binding quote or firm-fixed, not-to-exceed proposal.

Fired Heater Costing

Account 4 contains the majority of the fired heater costs. Note that included in Account 4 with the fired heater costs for all sCO_2 test cases is the costs for a small packaged boiler required to heat up the CO_2 working fluid during startup (Sub-Account 4.3). The costs for the interconnecting piping between the fired heater and the turbine island are also included within the fired heater costs that are given in Sub-Account 4.1. The costs of the boiler house are included in Account 14.

sCO_2 Power Cycle Costing

A special Account 8B was created to capture the sCO_2 power cycle costs as the system has intrinsic differences from a steam-Rankine power cycle and hence required a different set of sub-accounts as shown in Table 10. Most of the items are self-explanatory save for CO_2 system foundations, which includes the CO_2 storage system and the building for the power cycle.

BOP Costing

For all of the test cases, all of the remaining costs for the various sub-accounts beyond the fired heater (Sub-Accounts 4.1, 4.2, and 4.3 and 14.1) and the sCO_2 power cycle (all sub-accounts in the new Account 8B) were estimated using the appropriate QGESS scaling factors applied to the selected base cases.

Table 10
Sub-Accounts Contained in the New Account 8B for sCO_2 Power Cycle Costs

8B sCO_2 POWER CYCLE
High-Temperature CO_2 Compressor
Low-Temperature CO_2 Compressor
High-Temperature CO_2 Recuperator
Low-Temperature CO_2 Recuperator
CO_2 Air-Cooled Condenser
CO_2 Power Turbine
Compressor CO_2 Turbines
System Piping
CO_2 System Foundations

Cost Results

Base Case 1

The capital costs for Base Case 1, a 550-MW oxy-coal power plant utilizing a steam-Rankine cycle with turbine inlet conditions of 593°C and 24.1 MPa, were taken directly from the reference NETL Base Case S12F in "Cost and Performance of Low-Rank Pulverized Coal Oxycombustion Energy Plants: Final Report. DOE/NETL-401/093010. September 2010" and escalated to June 2017 dollars.

Base Case 2

The capital costs for Base Case 2, a 550-MW oxy-coal power plant utilizing a steam-Rankine power cycle with turbine inlet conditions of 730°C and 27.6 MPa, were derived using the following process:

- Costs were first taken directly from the reference NETL Base Case S13F in "Cost and Performance of Low-Rank Pulverized Coal Oxycombustion Energy Plants: Final Report. DOE/NETL-401/093010. September 2010," which has turbine inlet conditions of 649°C and 27.6 MPa.
- These costs were adjusted to account for increasing the steam conditions to 730°C and 27.6 MPa. A model was developed to determine the heat and mass balance for the steam cycle based on these new steam conditions and values from this were used to scale the costs from the 649°C and 27.6 MPa values to 730°C and 27.6 MPa using procedures specified in the QGESS Capital Cost Scaling Methodology document. This was done for all sub-accounts save for the boiler, steam turbines and the associated steam piping, which was estimated uniquely to account for the need to use higher-grade materials to withstand the elevated temperature conditions.

- Steam turbine costs were escalated 28% to reflect the temperature change (and hence material changes) for 730°C operation. This is based on the cost differences of the 593°C/760°C steam cases within the NETL report "TEA of Utility-Scale Power Plants Based on the Indirect sCO_2 Brayton Cycle." These costs were checked against the QGESS scaling parameters using steam flow as the reference parameter to evaluate the material case cost uplift (+41%), this was then adjusted as the temperature change was only 649°C to 730°C (i.e., a smaller size change but the same material change).
- The steam piping cost difference was assessed against flow to identify the material uplift to Inconel 740H. The net cost factor applied was 29% to reflect the application of 740H.
- The increase in boiler costs and piping connecting the boiler to the turbine to account for the temperature increase was estimated. A full redesign of the boiler was not done, rather a rough estimate on the increased materials required and the associated cost was done.
- Finally, the costs were then escalated to June 2017 dollars.

Base Case 3

The capital costs for Base Case 3, a 550-MW LCL-C™ coal power plant utilizing a steam-Rankine cycle with turbine inlet conditions of 593°C and 24.1 MPa, were taken directly from the reference "Alstom's Chemical Looping Combustion Technology with CO_2 Capture for New and Retrofit Coal-Fired Power Plants. Task 2 Final Report. DOE/NETL Cooperative Agreement No. DE-FE0009484. June 2013" and escalated to June 2017 dollars.

Base Case 4

The capital costs for Base Case 4, a 550-MW LCL-C™ coal power plant utilizing a steam-Rankine cycle with turbine inlet conditions of 730°C and 27.6 MPa, were taken directly from the reference "Alstom's Chemical Looping Combustion Technology with CO_2 Capture for New and Retrofit Coal-Fired Power Plants. Task 2 Final Report. DOE/NETL Cooperative Agreement No. DE-FE0009484. June 2013" and escalated to June 2017 dollars.

Base Case 5

The capital costs for Base Case 5, a 90-MW air-fired PC power plant utilizing a steam-Rankine cycle with turbine inlet conditions of 530°C and 10.6 MPa, were provided based on design work done for a site where such a power plant was intended to be built in the past and escalated to June 2017 dollars.

Test Case 1

The capital costs for Test Case 1, a 550-MW oxy-coal power plant utilizing a sCO_2 power cycle with turbine inlet conditions of 593°C and 24.1 MPa, have unique costs for the fired heater and sCO_2 power cycle that were developed, while the other costs around these primary components were scaled off of the corresponding base cases, in this case Base Case 1.

Test Case 2

The capital costs for Test Case 2, a 550-MW oxy-coal power plant utilizing a sCO_2 power cycle with turbine inlet conditions of 730°C and 27.6 MPa, have unique costs for the fired heater and sCO_2 power cycle that were developed, while the other costs around these primary components were scaled off of the corresponding base cases, in this case Base Case 2.

Test Case 3

The capital costs for Test Case 2, a 550-MW LCL-C™ coal power plant utilizing a sCO_2 power cycle with turbine inlet conditions of 593°C and 24.1 MPa, have unique costs for the fired heater and sCO_2 power cycle that were developed, while the other costs around these primary components were scaled off of the corresponding base cases, in this case Test Case 3.

Test Case 4

The capital costs for Test Case 4, a 550-MW LCL-C™ coal power plant utilizing a sCO_2 power cycle with turbine inlet conditions of 730°C and 27.6 MPa, have unique costs for the fired heater and sCO_2 power cycle that were developed, while the other costs around these primary components were scaled off of the corresponding base cases, in this case Test Case 4.

Test Case 5

The capital costs for Test Case 5, a 90-MW air-fired coal power plant utilizing a sCO_2 power cycle with turbine inlet conditions of 593°C and 24.1 MPa, have unique costs for the fired heater and sCO_2 power cycle that were developed, while the other costs around these primary components were scaled off of the corresponding base cases, in this case Base Case 5.

Test Case 6

The capital costs for Test Case 5, a 90-MW air-fired coal power plant utilizing a sCO_2 power cycle with turbine inlet conditions of 730°C and 27.6 MPa, have unique costs for the fired heater and sCO_2 power cycle that were developed, while the other costs around these primary components were scaled off of the corresponding base cases, in this case Base Case 5.

Summary

The following section provides a summary of the cost results presented in a format where comparisons can more easily be made.

Capital Costs Summary

A listing of the capital costs for each account for each case is shown side-by-side in Table 11.

Table 11
Comparison of Capital Costs for All Cases

Account	Case 1		Case 2		Case 3		Case 4		Case 5		Case 6
	Base	Test	Base	Test	Base	Test	Base	Test	Base	Test	Test
1	$53,595	$51,828	$50,490	$47,355	$58,114	$55,515	$53,951	$51,907	$18,873	$16,359	$15,102
2	$18,649	$17,998	$17,506	$16,357	$22,244	$21,203	$21,030	$20,197	$9,218	$7,924	$7,281
3	$93,684	$6,221	$84,627	$6,000	$106,888	$6,625	$91,750	$6,455	$13,936	$1,464	$1,418
4	$914,421	$897,608	$1,082,782	$1,070,829	$350,389	$372,557	$443,201	$453,415	$68,567	$162,971	$211,939
5	$156,532	$145,899	$147,373	$133,168	$159,832	$155,145	$148,326	$134,497	$26,446	$23,089	$21,402
5B	$120,332	$116,367	$113,455	$106,433	$119,437	$114,002	$110,137	$106,405	$0	$0	$0
6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	$100,420	$96,876	$85,580	$82,071	$47,193	$45,749	$45,021	$44,121	$10,272	$9,421	$8,978
8, 8B	$165,086	$381,813	$198,002	$416,144	$176,064	$428,807	$279,894	$402,867	$48,664	$67,434	$83,334
9	$42,593	$0	$35,285	$0	$58,989	$0	$51,737	$0	$578	$0	$0
10	$20,742	$20,124	$19,655	$18,552	$37,766	$36,397	$35,369	$34,399	$4,844	$4,259	$3,963
11	$91,745	$91,689	$87,950	$85,433	$97,734	$99,737	$93,931	$94,831	$18,553	$19,116	$18,091
12	$29,434	$29,428	$29,050	$28,784	$30,278	$30,505	$29,806	$29,908	$8,815	$8,920	$8,726
13	$17,585	$18,050	$17,613	$18,305	$18,485	$18,746	$18,777	$18,779	$8,365	$8,948	$9,247
14	$69,377	$80,929	$69,025	$92,875	$73,198	$30,416	$73,870	$30,788	$22,033	$27,428	$29,223
Total	**$1,894,195**	**$1,954,831**	**$2,038,394**	**$2,122,304**	**$1,356,613**	**$1,415,403**	**$1,496,801**	**$1,428,569**	**$259,165**	**$357,332**	**$418,703**
% Dif		**3.2%**		**4.1%**		**4.3%**		**-4.6%**		**37.9%**	**61.6%**

Key observations on the capital costs:

- In general, the sCO_2 test cases are incrementally more expensive than their corresponding steam-Rankine base cases. The only exception is Case 4 where the sCO_2 cycle is 4.6% cheaper than the steam-Rankine cycle. However, given the level of accuracy of the Class 5 estimate, this analysis basically shows that the capital costs are more or less the same between these two systems at identical operating conditions.
- Test Case 5 is not an apples-to-apples comparison to Base Case 5 given that the turbine inlet conditions were not matched. Also, Base Case 5 takes advantage of shared resources at the site the plant was designed for, further reducing its costs. Hence, Test Case 5 being 37.9% more expensive than Base Case 5 is not unexpected since raising steam temperatures by 60°C in a steam-Rankine cycle can cause comparable cost increases.

O&M Costs Summary

First-Year Power Costs and LCOE Summary

Figure 10 compares the first-year power costs, broken down into their components, for the base and test cases. Capital and fuel costs (driven by efficiency) are the primary drivers for the differences between the corresponding base and test cases, with capital cost having the largest impact. The sCO_2 cases have higher capital costs than their respective base cases save for Case 4, where the sCO_2 plant is cheaper than its steam-Rankine counterpart—which added to the fact that Test Case 4 is more efficient than Base Case 4, resulted in its first-year power cost being lower by $6.3/MWh than for Base Case 4. The other first-year power costs between corresponding base and test cases are nearly indistinguishable.

Note that comparing Test Case 5 or 6 with Base Case 5 directly is not an exact comparison given their different turbine inlet conditions.

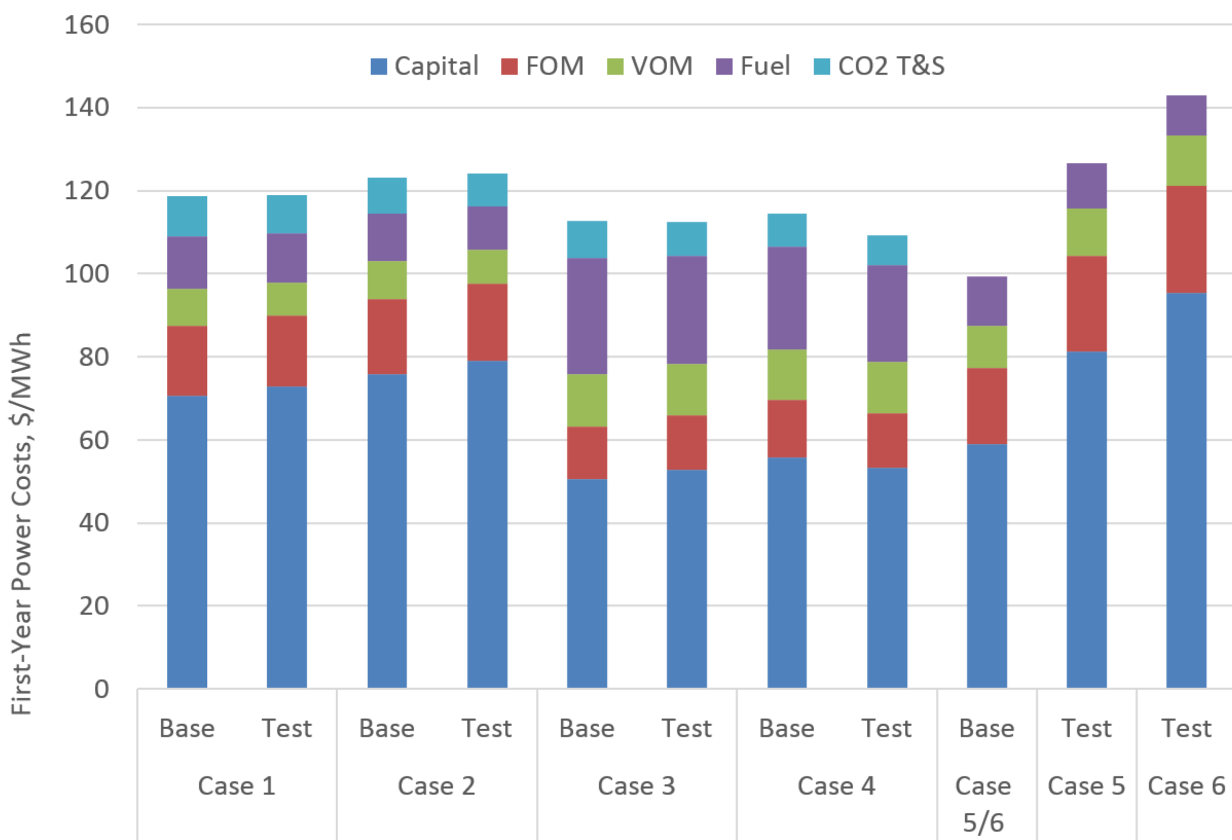


Figure 10
First-Year Power Costs for All Cases

Figure 11 compares the LCOE for the base and test cases. Similar conclusions can be drawn to those for the first-year power costs as the relative differences between base and tests and differing technologies are similar.

Note that similarly to first-year power cost, LCOE for Test Case 5 and 6 is not a direct comparison to Base Case 5 due to the different operating conditions. That said, if a company desired to build a 90-MW net coal-fired power plant, they likely would not choose a system that has significantly higher LCOE, as is the case for either Test Case 5 or 6 in comparison to Base Case 5, despite its ability to achieve higher efficiency. The high cost of the fired heater for the sCO_2 cases for Test Cases 5 and 6 is likely a deal killer, unless it can be lowered by redesign.

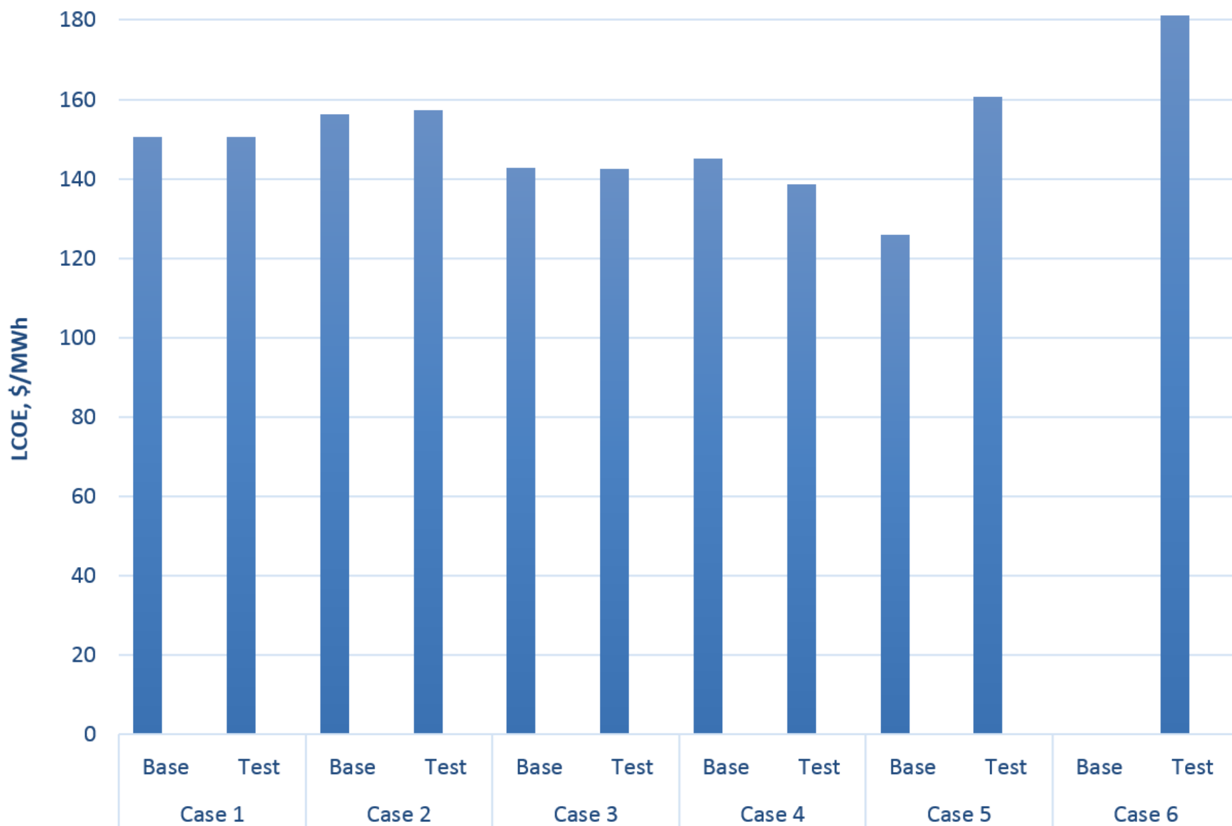


Figure 11
LCOE for All Cases