Conceptual Design Report

A Supercritical CO_2 Power Cycle / Pressurized Fluidized Bed Combustion System Integrated with Energy Storage:

Compact, Efficient and Flexible Coal Power

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1. Business Case

Introduction

The proposed coal power technology for this project is an indirect-fired supercritical CO_2 (sCO_2) power cycle integrated with a pressurized fluidized bed oxy-combustion system at nominal 100 MW_e net size. This section describes the circumstances around the current coal power marketplace and how the proposed technology will be designed to respond to varying market scenarios. Factors include:

- Coal type(s)
- CO_2 constraint and/or price
- Domestic and/or international market applicability
- Estimated cost of electricity (and ancillary products) that establishes competitiveness
- Market advantage of the concept
- Natural gas (NG) price
- Renewables penetration

The current marketplace for coal power varies widely on a regional basis, but in all cases, one or more of the following drivers impact its future viability:

- **Competition against other power sources –** In some regions, coal remains a low-cost generator, while in others, NG-based power is typically more economical due to the availability of low-cost NG (e.g., in the U.S., NG is about half the cost of elsewhere).
- **Drive towards low carbon –** 179 countries have signed the Paris Accord, whose goal is to reduce greenhouse gas (GHG) emissions (typically, countries have pledged to reduce CO_2 emissions on the order of 20–40% from 2012 levels). While the U.S. has not signed the accord, multiple states have enacted low-carbon initiatives including several that have committed to 80% reductions by 2040. Coal, as a fossil fuel, and one that produces double the CO_2 per MWh than NG does, is therefore a bigger target related towards reducing CO_2.
- **Energy security –** In some regions, coal is an abundant natural resource, representing energy security and reducing the need for reliance on fuels or energy from foreign countries. Finding ways to use it more effectively can be critical for these regions.
- **Environmental regulations –** Coal emission regulations – CO, NO_X, hazardous air pollutants, mercury, particulate matter, and SO_X – vary globally, but coal universally remains a tougher permitting challenge than NG.
- **Financing –** Financing is becoming more challenging for larger plants as the future power market has significant uncertainties, especially around carbon. Coal power plants are a particular challenge (30 banks have stopped financing coal). Smaller plants are thought to be lower risk since they require less capital, and hence have a better opportunity for financing.
- **Meeting a changing market –** The energy market is changing, largely due to the growth of variable renewable energy (VRE). Intermittency requires grid protection provided by dispatchable sources, which largely comes from fossil-based units. In the U.S., some coal power plants are providing such grid support, requiring them to operate more flexibly than they were designed for, which is deleterious to performance. Such operating behavior will likely also occur in other regions as renewables grow, reducing the need for base-load fossil power, while putting extra importance on their ability to provide grid resilience.

United States
New coal power has stagnated in the U.S., where coal is often not competitive with NG, or presents significant future environmental risk. There are few known coal power projects advancing in the U.S. and some utilities have back-burnered coal or pledged to eliminate it. Several things are likely needed for a significant resurgence in new coal:

- **Increase in the relative price of NG compared to coal –** While this has not been forecasted, it remains a possibility, especially as the demand for NG grows internationally.
- **Larger value for CO_2 either by regulation or for utilization –** If a significant market for CO_2 develops, this could help drive new coal power with carbon capture and storage (CCS). Enhanced oil recovery (EOR) remains the primary form of utilization and tapping into this market will likely be a necessity for any new coal plants with CCS in the short term. Governmental programs like 45Q provide a value for captured CO_2 as well, which aids in the overall project economics. In general, the worth of capturing CO_2 must be greater than the cost, which is not the case in most circumstances. Hence, the value must increase (perhaps by regulation) and/or the cost must decrease for coal CCS projects to be viable.
- **Regulatory certainty –** Uncertainty in future regulations increases risk, which makes coal power projects difficult to finance and generators more reticent to build them. Recent revisions to the Clean Air Act section 111(b) have been proposed to alter the definition of best system of emission reduction for new coal units to the most efficient demonstrated steam cycle in combination with best operating practices, instead of requiring partial CCS as was the case in the previous version. Getting this in place and adding certainty around the low-carbon future may be important for growth in coal power.

Outside the U.S.
Outside the U.S., different regions have different appetites for coal. A summary is given below.

- **China –** China is the largest coal producer and consumer in the world and coal accounts for 70% of its total energy consumption. Although China anticipates coal capacity growth of about 19% over the next five years, this comes at a time of slowing electricity demand. As a result, many coal plants have been operating at reduced capacity factors. Due to this, and growing environmental concerns, the Chinese government has announced it will postpone building some coal plants that have received approval and halt construction of others. However, there is still a need for new power, especially in the west, and a large supply of coal exists in China. Coal plants that are efficient (a key criterion) and smaller will likely be of appeal. CO_2 utilization for EOR and enhanced gas recovery are also growing possibilities.
- **Europe –** In Western Europe, following the Paris Accord, several countries announced plans to end coal-fired generation within their borders or set in place emissions reductions targets that would effectively require an end to coal without CCS: France by 2023, the United Kingdom and Austria by 2025, the Netherlands by 2030, and Germany by 2050. This makes new coal power difficult in the region. In Eastern Europe, there is more potential for new coal as brown coal resources are abundant and cheap. Efficiency and cleanliness will be keys in this region. CCS may be a challenge, however, as underground storage is not popular, although Norway is developing a potential sink for CO_2 in the North Sea.
- **India –** India has large domestic coal reserves and recently had the largest growth in coal use of any country. India's draft National Electricity Plan indicates that the 50 GW of coal capacity in construction is sufficient to meet the country's needs for the next decade, but new coal remains a possibility. Most new coal plants proposed are supercritical units as India has

imposed a carbon tax on coal, which is about \$6.25/tonne-CO_2, making efficiency important in the region. India has also championed fluidized-bed technology to be able to burn India's lower-quality, higher-sulfur coals. Work has also been done to locate reservoirs for CCS.

- **Japan –** As of 2018, Japan had over 44 GW of coal plants in operation, with over 6 GW permitted or in construction. Japan's climate pledge is to reduce GHG emissions by 26% from 2013 levels by 2030, so improving efficiency and potentially performing CCS are important factors in Japan. Smaller-scale plants are also likely, in part because space is an issue. Japan is very interested in novel coal power cycles, including sCO_2 power cycles.
- **Korea –** Coal produces over 40% of Korea's power and the country still has plans for additional coal power, despite having a climate pledge with a 30% reduction in GHG emissions by 2030. Efficiency is also important in Korea, and they have strong interest in sCO_2 power cycles, having invested in the Department of Energy's (DOE) STEP program.
- **Others –** Coal is growing in some regions in Africa (e.g., Kenya and Zimbabwe) and Southeast Asia (e.g., Indonesia and Vietnam), which presents opportunities, although low-cost coal power will be critical in these areas. Smaller-scale plants will be a definite plus.

Advantages of the Proposed Technology

- This system can be made smaller (100 MWe net or less) and still maintain high efficiency and flexibility. This reduces the financing hurdle and makes the system a better fit for niche locations that lack a low-cost NG supply, where power demands are typically lower.
- Pressurized oxy-combustion is one of the highest-efficiency and least-cost technologies for CO_2 capture. Typical improvements in efficiency, compared to atmospheric oxy-combustion or post-combustion capture (PCC), are on the order of 4–6% points. Converting from a steam-Rankine to a sCO_2 power cycle can improve efficiency by another 2–4 % points.
- The pressurized fluidized-bed technology being used for the oxy-combustion can burn any type of coal, including high-sulfur variants. This characteristic extends the applicability of the technology into regions with poor coal quality. The technology can also burn biomass, providing further fuel flexibility and the potential for a renewable, ultra-low (or even negative) carbon power down the road, if needed.
- Indirect-fired sCO_2 power cycles have been factory-tested[1], lowering the risk of the technology. The first commercial installation of an sCO_2 power system by Siemens using Echogen technology was recently announced[2], and is scheduled to begin operation in 2021.
- Indirect-fired sCO_2 power cycles are heat-source agnostic. Lessons learned and technology derived from this project on the power island will be directly relevant to other applications, included coal power without CO_2 capture. This is important since the proposed technology uses pressurized oxy-combustion, which requires a need for CO_2 to be captured, but could readily be replaced with another similar non-CCS technology such as pressurized air-combustion.
- This technology is well designed for thermal energy storage, which can be readily integrated using a system based on concept already being studied under a separate ARPA-E grant.

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[1] Held, T. J., 2014, "Initial Test Results of a Megawatt-Class Supercritical CO_2 Heat Engine," *The 4th International Symposium - Supercritical CO_2 Power Cycles*, Pittsburgh, Pennsylvania.

[2] TransCanada, 2019, "Capturing the Power of Hot Air" [Online]. Available: https://www.transcanada.com/en/stories/2019/2019-02-28-capturing-the-power-of-hot-air/. [Accessed: 21-Mar-2019]

Energy storage is growing in importance as the penetration of VRE increases, as it could allow the coal unit to operate near continuously, putting power on the grid when needed and storing energy when not. This allows the unit to run more often at its design conditions, avoiding ramping and turndown, which have negative impacts on efficiency, emissions output on a per MWh basis, and unit lifetime. Moreover, if this unit captures CO_2 for utilization (e.g., EOR), it may be required to operate near continuously, either to deliver an agreed-to amount of CO_2 or to improve the overall economics. With energy storage, the plant can provide CO_2 continuously while allowing power to be provided to the grid when needed. In short, energy storage can have a significant impact on the unit's competitiveness.

- In addition to the potential for integrated energy storage, the proposed cycle will have improved operational flexibility characteristics, meeting those specified by DOE. Mainly this is due to the sCO_2 cycle turbomachinery being significantly smaller on a relative basis compared to that of steam-Rankine cycles, which lends itself to improved flexibility. The flexibility provided by the technology, particularly lower turndown and faster startup times, could be key in the future marketplace even if energy storage is included, and provides the ability to not include energy storage for cases where the cost-benefit analysis is not positive.

Things That Must Be Addressed on the Proposed Technology

- Advancement of the technologies and components that are at lower technology readiness levels must be achieved, including in particular the fluidized-bed heater that joins the pressurized oxy-combustion system with the sCO_2 power cycle.
- Assessment of the most beneficial duration and size of energy storage for the overall system.
- Development of an optimal plant layout and integration that balances efficiency with cost aimed at producing an economically viable solution for the marketplace.
- Evaluation of how the air separation unit (ASU), which provides the O_2 for oxy-combustion, can operate flexibly. This may require liquid air storage.

What Is Needed for the Technology to be Competitive?

DOE performed a techno-economic analysis for coal power plants using Powder River Basin (PRB) coal with and without CCS, as shown in the table below, with total plant cost (TPC), levelized cost of electricity (LCOE), and CO_2 captured cost adjusted to 2019 $ by EPRI.

Technology	Case	Size, MWe	Efficiency, % HHV	TPC, $/kW	LCOE, $/MWh	CO_2 Captured Cost, $/tonne
Oxy-combustion (atmospheric, supercritical)	S12F	650	31.0	4084	169.0	51
PC without CCS (supercritical)	S12A	650	38.8	2406	94.2	---
PC with CCS (supercritical)	S12B	650	27.0	4243	181.4	52

Also of relevance in the U.S., DOE calculated that a 727-MWe net NG power plant had TPC of $780/kW and $1984/kW and LCOE of $59.3/MWh and $110.4/MWh without and with CCS and CO_2 captured cost of $103/tonne-$CO_2$. Based on these data from DOE, EPRI determined:

- The NG price to make the NG with CCS LCOE equal to coal (at $2.2/MBtu) with CCS COE must go from $4.4/MBtu to $11.6/MBtu (2 ½ times increase)
- TPC for the proposed technology to equal the LCOE of coal with CCS is $3914/kW

- TPC for the proposed technology to get the cost of CO_2 captured to $40/tonne is $2926/kW

Note that these numbers are all for larger-scale power plants and hence do not account for any diseconomies of scale when reducing to 100 MWe. SaskPower's Boundary Dam Unit 3 installed PCC for EOR in 2014. The resulting unit produces 110-MWe net. The CCS retrofit cost ~$C800M and $C500M was used to upgrade steam conditions to 124 bar and 565°C. Add to this the cost of the original components, estimated to be $C200M, and the capital cost for a new build is roughly $10,200/kW. While this number should be taken with a grain of salt (SaskPower has stated that the next CCS unit will be 65% cheaper), it acts as a cautionary tale, illustrating the higher cost of CCS at smaller scales for more conventional technology.

Another example of importance is the most recent coal power plant built in the U.S.: an 84-MWth combined-heat-and-power plant at the University of Alaska Fairbanks for $248M, which equates to a TPC of ~$8000/kW. Annual fuel costs for the plant were about $5M for coal and $20M for NG. In such areas where NG supply is not available or is inconsistent, if coal can be delivered cheaply, smaller-scale coal plants have an opportunity. For the proposed technology, to account for the risk associated with less mature technology, a TPC of ~$6000/kW would be appealing. EOR opportunities will also be important in such cases.

Based on this high-level review, for the proposed system to be competitive, beyond achieving the performance characteristics that have been set for this project, the table below provides cost targets for the technology in various regions and scenarios.

Case	Region	Scenario	Competition	Cost Targets
1	U.S.	NG not available, coal and EOR / 45Q available	Small coal (100 MWe)	TPC < $6000/kW
2	U.S.	NG < $4.4/MBtu (coal $2.2/MBtu) and no CO_2 value	NG with CCS	LCOE < $59/MWh
3	U.S.	NG < $4.4/MBtu (coal $2.2/MBtu) and CO_2 value of $50/tonne	Coal or NG with CCS	TPC < $3000/kW; CO_2 cost < $40/tonne
4	Africa, Asia, Europe	NG > $11.6/MMBtu (coal $2/MBtu)	Coal with CCS	LCOE< $160/MWh; TPC < $39000/kW
5	Anywhere	CO_2 value of $50/tonne	Any CCS	CO_2 cost < $50/tonne
6	Anywhere	Non-base load operation with CCS	Coal FIRST technologies	TPC < $3900/kW; CO_2 cost < $50/tonne; value for energy storage

The first 5 cases in the table assume a base-load unit with 85% capacity factor and ~1M tonnes of CO_2 captured annually. The $50/tonne value for CO_2 is roughly a summation of EOR with 45Q credits (or 45Q credits for storage only). Option 2, with low NG price and no value for CO_2, is not a competitive option for this technology. <u>So, the cost targets for the technology are TPC = $3900/kW, LCOE = $160/MWh, and CO_2 cost = $50/tonne, with stretch goals of TPC = $3000/kW, LCOE = $120/MWh, and CO_2 cost = $40/tonne</u>. Several additional comments:

- One of the short-term markets will be niche areas where NG supply is limited or unavailable without significant infrastructure investment, where coal can be supplied. In the U.S., this is largely in the west. Opportunities may also exist in Mexico. These applications will be small, perhaps smaller than 100 MWe net (which is doable with this technology). In these cases, the capital costs must be lower than $8000/kW. The other potential short-term market is in regions where there is an EOR play, e.g., Texas and Wyoming. Generally, EOR projects must provide ~1M tonnes of CO_2 annually to be considered, which is about what 100 MWe net produces. This size is likely a better fit in oil & gas markets than larger plants.

- In regions where NG is more expensive (e.g., Africa, Asia, and Eastern Europe), or if NG prices should rise in North America, the technology will be competing directly with more established PCC systems for coal. In these cases, the proposed technology must have capital costs and COE that are comparable, and preferably superior (given it might be perceived to be higher risk), to this option.
- Several caveats are that since this system utilizes a fluidized bed, it may be more likely to handle poorer fuel qualities (e.g., as in China), including biomass, which may provide opportunities; also, in regions where there is more explosive projected VRE growth (e.g., Korea), the inherent energy storage of this system may provide additional opportunities.
- Another factor is if the value of CO_2 is increased (either by a CO_2 price or value) in comparison to the cost of CO_2 captured, then this proposed CCS technology will have more opportunities. On the flip side, since this current system has inherent CCS, if the region does not have a significant CO_2 policy or utilization opportunities (e.g., India or South Africa), or is not focused on low carbon but rather just cheaper power production (e.g., developing nations like Kenya), this technology likely will not be an option at least in the short term.

2. Plant Concept, Description and Important Traits

Integrated Plant Concept

Echogen, Gas Technology Institute (GTI). and Electric Power Research Institute, Inc. (EPRI) have partnered to design an advanced technology coal-fired power plant, integrating three innovative technologies to deliver the key characteristics of compactness, efficiency, modular construction, and operational flexibility: supercritical CO_2 (sCO_2) power cycles, oxygen-fired pressurized fluidized-bed combustion (Oxy-PFBC), and electrothermal energy storage (ETES). This combination, shown in Figure 1, offers a coal-fired power plant favorable attributes that will allow better competitiveness in the future energy market. The plant will have a base peak power output of 94.4 MW_e with an additional generation of up to 20 MW_e for 10 hours available through the energy storage system giving the plant a maximum generation capacity of 114.4 MW_e. The proposed plant is expected to achieve the DOE targets for ramp rates and efficiency including 35.2% plant efficiency with up to 98% CO_2 capture and 44.4% without. The estimated installed cost of the sCO2 power cycle and oxy-PFBC is approximately \$5,031/MW_e and the predicted of the energy storage system has a levelized-cost-of-storage of \$100/MW_e-hr to \$125/MW_e-hr.

Firstly, sCO_2 power cycles offer substantial benefits over conventional and even advanced steam-Rankine cycles; foremost among these is higher efficiency. It has been shown that sCO_2 cycles are up to 4% points higher on an "apples-to-apples" when compared with steam cycles integrated with atmospheric oxy-combustion, chemical looping combustion and air fired pulverized coal heaters (DE-FE0025959). While direct comparisons with an Oxy-PFBC integrated with a steam Rankine cycle were not completed as part of this study, we would expect similar results.

Secondly, sCO_2 power cycles offer a potential cost advantage over comparable steam-Rankine cycles. The high fluid density of sCO_2 greatly reduces the physical size of its turbomachinery.

And because the condensing pressure of CO_2 is well above atmospheric pressure, vacuum systems are unnecessary, and air infiltration is eliminated, which also removes the need for components such as deaerators and condensate polishers. This same high condensing pressure increases the vapor density by four orders of magnitude (decreasing the volumetric flow rate requirement of the condenser by the same) compared to steam, making air-cooled condensers a much more practical and cost-effective alternative to water-cooled condensers that dominate steam-based systems.

To take full advantage of sCO_2 power cycle's smaller physical size, a more compact coal combustion technology is needed. The Oxy-PFBC design developed by GTI is 1/3 the size of atmospheric-pressure combustors and half the cost. The compact size is achieved by operating above atmospheric pressure, which reduces gas volume and hence the size of components, and by using in-bed heat exchangers. Additional cost benefits can be achieved through enhanced manufacturing efficiencies since at the proposed scale, the Oxy-PFBC is small enough for factory fabrication rather than field assembly.

Finally, the ramp rate and turndown capabilities of the system will be significantly improved through the addition of a flexible energy storage system that can capture and store excess thermal energy and excess electrical power generation capacity in a set of thermal reservoirs that can be discharged when power demand exceeds baseload capacity. Echogen has been developing a CO_2-based ETES system that integrates well with both electrical and direct thermal energy storage, which are both used in this concept.

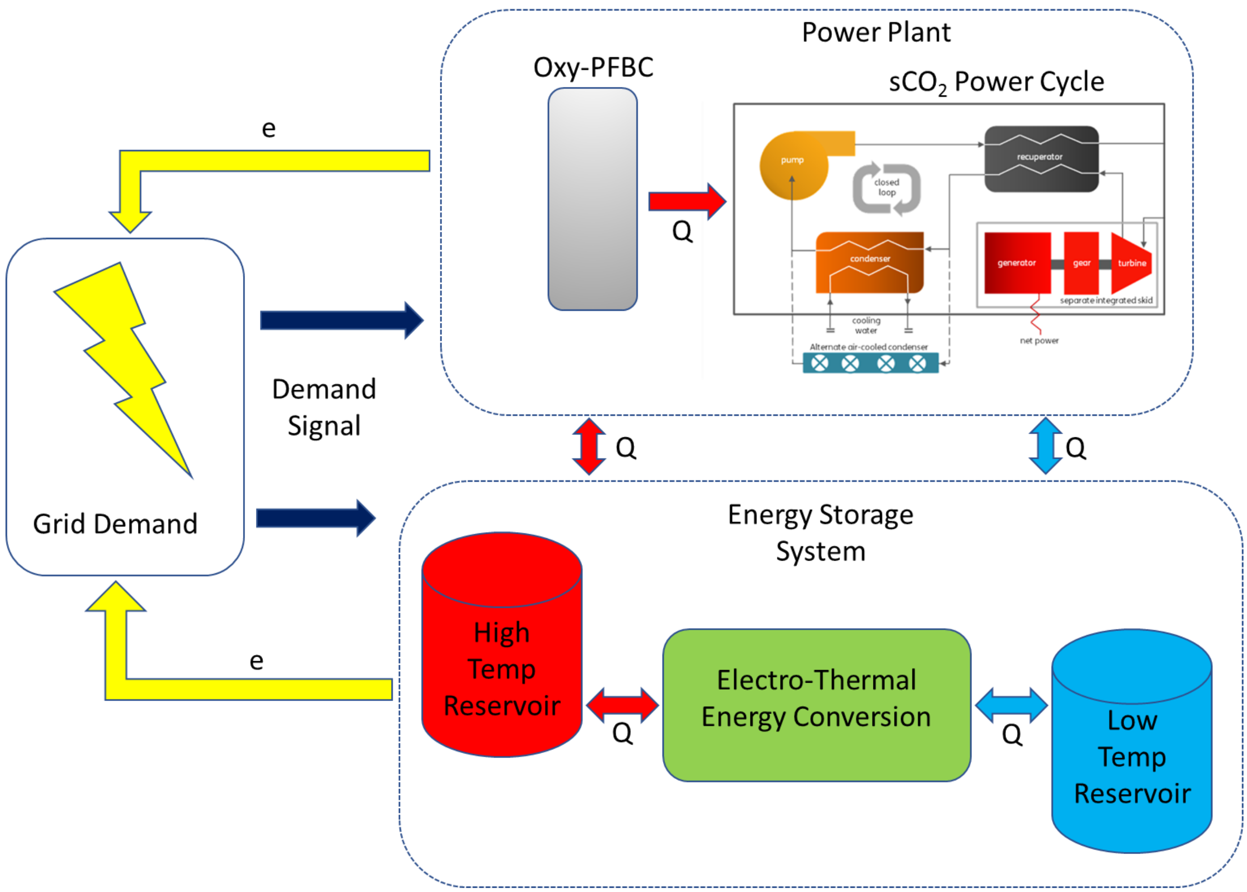

Figure ***Error! Reference source not found.*** *Oxy-PFBC / sCO_2 / ETES plant concept*

The plant is being designed using the site characteristics defined in Appendix B, Exhibit 1 of the Performance Work Statement. While the PFBC can burn a variety of coals and other solid fuels, for this study the fuel type was assumed to be bituminous Illinois No. 6. The process flow diagram and heat-and-mass balance for the integrated sCO_2 power cycle and Oxy-PFBC are shown in Figure 9.

sCO_2 Power Cycle

sCO_2 power cycles were first proposed in the 1960s[3,4] and studied extensively during the past decade due to their potential for delivering transformational improvements in efficiency. The compact nature of sCO_2 turbomachinery also offers potential capital cost and footprint advantages, and the water-free power cycle can significantly reduce operation and maintenance costs over traditional steam-Rankine systems. sCO_2 power cycles for waste heat recovery and gas turbine combined cycle power plant applications are commercially available from Echogen in the 1–10 MWe range, and larger units are planned. A substantial body of design literature has been developed over the past 20 years[5], with numerous ongoing R&D programs under private, U.S. Department of Energy (DOE). and non-U.S. governmental funding.

The basis for the sCO_2 power cycle is the recuperator bypass cycle (RBC), shown in Figure 2. The RBC cycle employs two compressors in parallel. The low-temperature compressor (LTC) receives low-temperature, high-density CO_2 from the cooling/condensing heat exchanger (CHX). The high-temperature compressor (HTC) receives comparatively high-temperature, low-density CO_2 that bypasses the CHX. Via the CHX bypass, the HTC flow avoids heat rejection to the extent that it optimizes recuperation (internal heat exchange). The cycle includes a low-temperature recuperator (LTR) and a high-temperature recuperator (HTR) to pre-heat the sCO_2 entering the primary heat exchanger (PHX; the Oxy-PFBC), which transfers heat from the thermal resource to the sCO_2 working fluid. Heated sCO_2 flows to three turbines. Two are drive turbines (DT), powering the LTC and HTC. The largest turbine is the power turbine (PT), which produces electrical power via a synchronous generator.

Initial optimization of the design point was completed based on preliminary design values for key parameters including net power (100 MWe), maximum CO_2 pressure (30 MPa), maximum CO_2 temperature (760°C), CO_2 pressure drop in the PHX (0.7 MPa), and ambient temperature (15°C). Details of the CO_2 pressure drop calculation are described in the Oxy-PFBC section.

The RBC configuration provides the highest cycle efficiency due to its high recuperation. As a result, the temperature of the CO_2 entering the PHX is over 500°C. While this is beneficial from a cycle perspective, this high temperature limits the exhaust gas cooling and would be problematic for downstream equipment and suboptimal for the efficiency of the thermal resource (the Oxy-PFBC). To optimize the overall plant design, modifications can be made to the RBC cycle.

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[3] Feher, E. G., 1968, "The Supercritical Thermodynamic Power Cycle," Energy Convers., **8**, pp. 85–90.

[4] Angelino, G., 1968, "Carbon Dioxide Condensation Cycles for Power Production," ASME J. Eng. Power, **90**(3), pp. 287–296.

[5] Brun, K., Friedman, P., and Dennis, R., eds., 2017, *Fundamentals and Applications of Supercritical Carbon Dioxide (SCO2) Based Power Cycles*, Elsevier Ltd.

The modified recuperator bypass cycle (mRBC), shown in Figure 3, is an RBC variant that incorporates low-grade heat addition using a second primary heat exchanger (PHX-2) installed in the exhaust ducting downstream of the radiant section of the Oxy-PFBC (PHX1). This variation was developed and optimized by Echogen under DOE funding (DE-FE0025959) in a collaborative project led by EPRI, which included contributions from The Babcock & Wilcox Company, GE-Alstom, Howden, Siemens, and Doosan Heavy Industries. Adding low-grade heat to the power cycle presents an efficiency tradeoff. Low-grade heat addition to the working fluid improves the efficiency of the thermal resource by extracting more heat from the exhaust gas. However, low-grade heat addition simultaneously penalizes the thermal efficiency of the sCO_2 power cycle by reducing the average temperature of the heat available to the CO_2 in the PHX and by limiting amount of heat available for internal recuperation.

The efficiency and cost tradeoffs were evaluated using a parametric study of the Oxy-PFBC PHX-2 exhaust gas boundary conditions. The integrated Oxy-PFBC sCO2 power cycle was considered for this study. sCO2 power cycle costs were estimated based on previous work that considered a 90 MWe plant with an air fired pulverized coal heater operating with turbine inlet conditions of 730°C and 27.5 MPa (DE-FE0025959). Tracked costs in the power cycle included turbomachinery, compressors, heat exchangers (ACC and recuperators) and turbine valves. The remaining power cycle costs were scaled as a percentage of the tracked costs versus the total installed cost.

GTI provided costs for the Oxy-PFBC and required auxiliaries. These costs were in 2011 dollars and were scaled on heat input using typical scaling exponents. A summary of costs for the sCO2 power cycle and Oxy-PFBC is shown in Table 1.

Shown in Table 2**Error! Reference source not found.** are the key parameters considered for this study. Other PHX-2 boundary conditions include the exhaust gas flow (which is defined by the thermal resource) and the CO_2 flow and temperatures (which are optimized for maximum cycle efficiency under the given constraints). Based on previous experience (including DE-FE0025959), the CO_2 temperature entering PHX-1 was also constrained to a minimum approach of 30°C below the gas temperature leaving PHX-1 and entering PHX-2.

Results of the parametric study indicated that exhaust gas temperatures of 550°C and 275°C (entering and leaving PHX-2, respectively) produced a balance of low plant cost (Figure 4) and high net plant efficiency (Figure 5). Plant costs were normalized in *Figure 4*, with the design point shown at $5,031/$MW_e$. Note, the net plant efficiency recorded in the plots does include the compression work associated with pressurizing the captured CO_2 to pipeline pressures. The resulting debit from net plant efficiency would be approximately 2% points.

At 275°C, the exhaust gas leaving PHX-2 is at the maximum temperature allowed by the downstream equipment. Reducing this temperature further would come at a greater cost to sCO_2 power cycle efficiency than it would benefit the thermal resource (Oxy-PFBC) efficiency, resulting in a net reduction in overall net plant efficiency. The exhaust gas entering PHX-2 is not constrained by material limits. However, changing the temperature from 550°C does not present an overall benefit to the plant. Marginal improvement of one metric (plant efficiency or plant cost) would be exchanged for marginal deterioration of the other.

Table 1 Plant cost summary – 2019 Dollars

Equipment	Total Installed Cost ($K)	Cost per kW_e
sCO2 Power Cycle		
High-Temperature CO2 Compressor	2,141	23
Low-Temperature CO2 Compressor	1,384	15
High-Temperature CO2 Recuperator	11,485	122
Low-Temperature CO2 Recuperator	16,048	170
CO2 Air-Cooled Condenser	7,531	80
CO2 Power Turbine	12,128	128
Compressor CO2 Turbines	4,407	47
System Piping	9,102	96
CO2 System Foundations and Auxiliary Equipment	5,307	56
Oxy-PFBC		
Coal Handling System	13,487	143
Coal Prep & Feed Systems	13,783	146
PFBC	75,640	801
DCC System	27,061	287
ASU (99% purity)	117,990	1250
Flue Gas Clean Up	53,245	564
CO2 Removal & Compression	35,974	381
Heat Recovery, Ducting and Stack	25,449	270
Cooling Water System	36,760	389
Ash/Spent Sorbent Handling	6,011	64
Total Cost of sCO2 Power Cycle and Oxy-PFBC	**473,941**	**5,031**
ETES System		
Total Installed Cost (20 MW_e – 10 Hours)	29,631	1,482

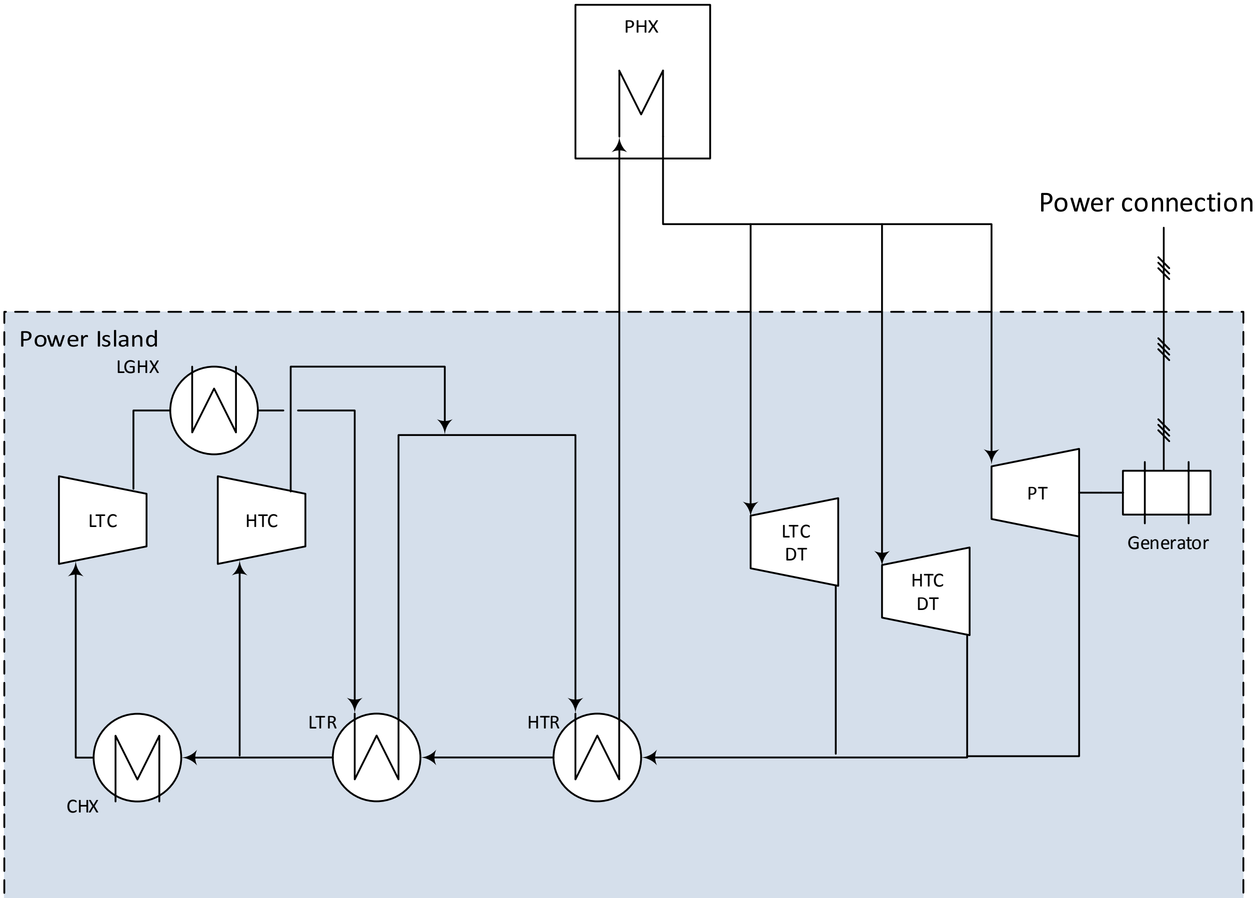


Figure 2 RBC cycle with a single PHX

Table 2. PHX-2 boundary conditions for parametric study.

Parameter	**Value**	**Notes**
Exhaust Gas Flow	131 kg/s	PFBC combustion byproduct
Exhaust Gas Temperature In	500–600°C	Obtain via PHX-1 sizing
Exhaust Gas Temperature Out	200–300°C	Obtain via PHX-2 sizing
CO_2 Flow	Optimized for each case	
CO_2 Temperature In	Optimized for each case	
CO_2 Temperature Out	Optimized for each case	

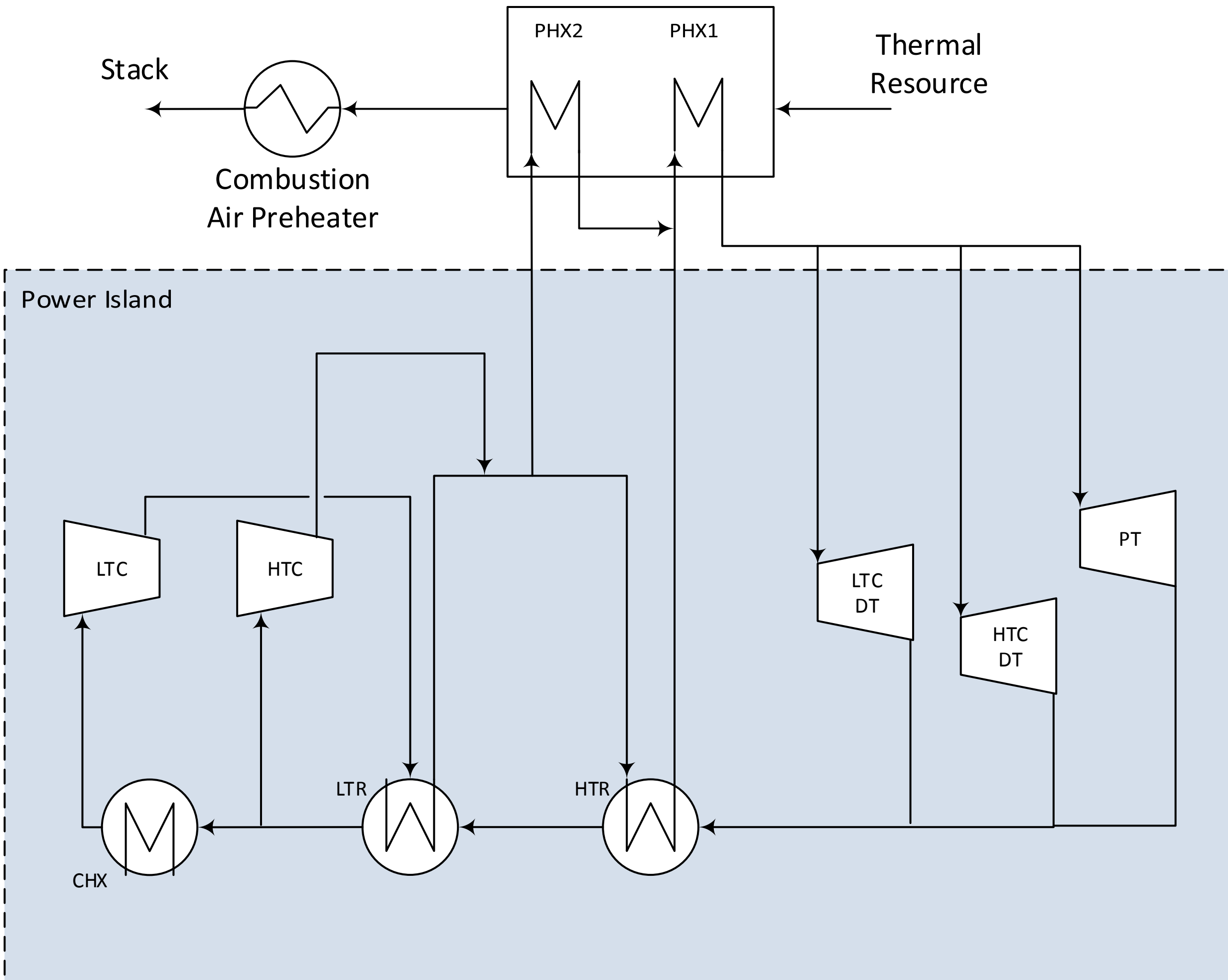


Figure 3 mRBC cycle with PHX-2 added for low-grade heat addition.

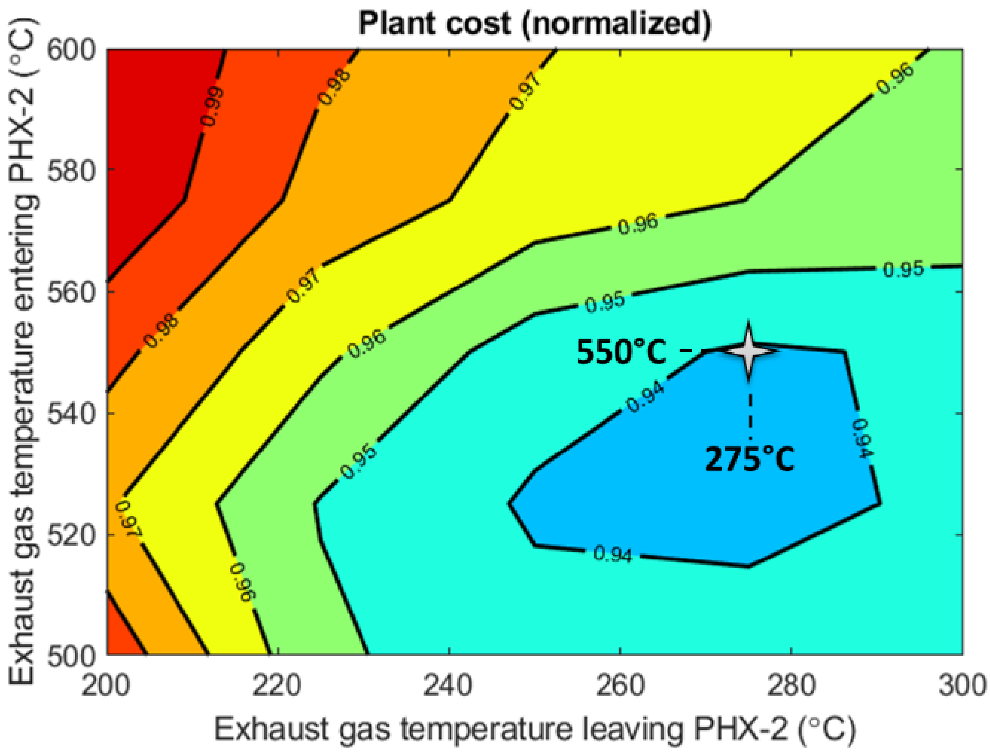


Figure 4 Normalized plant cost as a function of the combustion gas temperature boundary conditions around PHX-2.

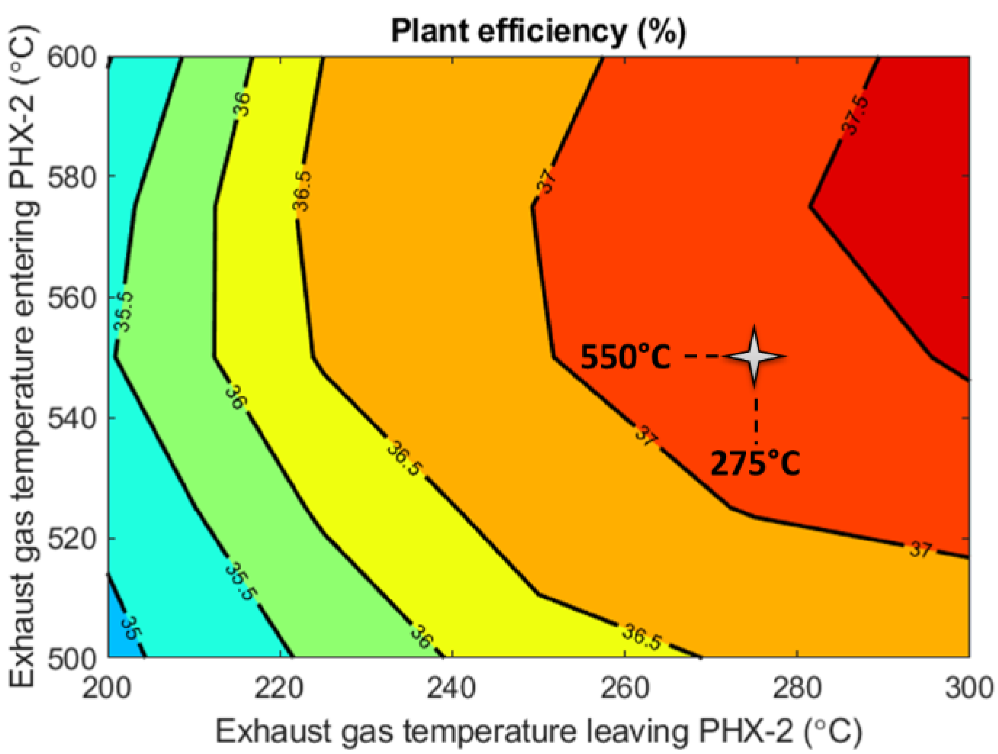


Figure 5 Net plant efficiency as a function of the combustion gas temperature boundary conditions around PHX-2.

Oxy-Pressurized Fluidized-Bed Combustor

The GTI Oxy-PFBC system is an advanced compact combustor technology with inherent CO_2 capture. Innovative aspects of the Oxy-PFBC include the use of oxy-combustion combined with a fluidized bed and high pressure to significantly reduce the cost of carbon capture. Elevated pressure contributes to faster reactions and reduced reactor size, while the fluidized bed increases the heat transfer coefficient for a smaller and less expensive heat exchanger. This results in a combustor that is 1/3 the size of a comparable atmospheric-pressure combustor at less than half the price. Similarly, the cost of the ASU and CO_2 purification unit (CPU) is significantly less expensive than post-combustion amine-type CO_2 capture systems. Previous studies[6] of 550 MWe systems show that Oxy-PFBC is projected to reduce total plant cost (TPC) by 24.6% compared to NETL Case 12 which is a pulverized coal combustor with post combustion carbon capture as shown in Figure 6. The figure shows a 10.5% improvement due to oxy-combustion at atmospheric pressure which can be seen by comparing DOE Case 5A for atmospheric oxy-combustion to Case 12 for PC with CO_2 capture. An additional 14.2% improvement in TPC is predicted for the GTI Oxy-PFBC relative to Case 5A due primarily to pressurization. This can be seen by the difference in combustor cost (labeled PC Boiler).

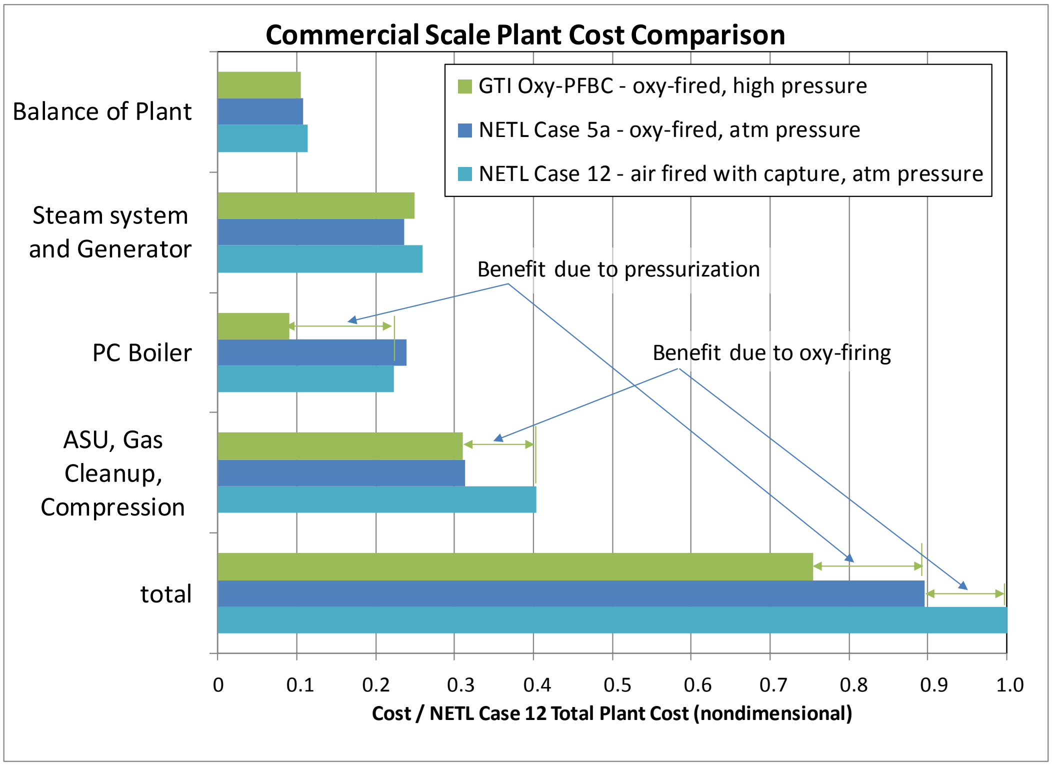


Figure 6 Oxy-PFBC cost savings are combination of high-power density and an innovative gas cleanup system which combines a high efficiency ASU with a low-cost back-end purification system

[6] Technology Engineering Design and Economic Analysis Report of the Aerojet Rocketdyne Oxygen Fired Pressurized Fluidized Bed Reactor and Regenerative Rankine Steam Cycle Power Plant with Heat Integration, Fitzsimmons, M., et. al., submitted to the DOE/NETL on June 27, 2013.

The combustor utilizes a high-aspect-ratio, bubbling fluidized bed of dolomite particles, with finer pulverized coal (PC) flowing through and elutriated out of the bed to particle filters as fly ash (see Figure 8). Dolomite particles are used to capture sulfur within the combustor, including both larger particles that remain in the bed and smaller ones that are injected with the coal and elutriate out to the filters. An oxygen/recycled flue gas mixture is used as the oxidant and as the fluidizing transport medium. Local bed temperature is controlled both by the rapid mixing of the fluidized bed and with in-bed heat exchangers, which balance heat removal with heat release of the burning fuel. Coal is injected in stages at different axial locations to provide additional local temperature control, with stage design determined by coolant properties and fuel burning characteristics. The resultant flue gas is processed by a CPU to produce a pipeline quality stream of CO_2 for storage or use.

The Oxy-PFBC and gas cleanup systems were tested at a 1-MWth pilot scale (DE-FE0009448). The Oxy-PFBC design heritage is based on a 2m x 2m atmospheric-pressure air-fired fluidized-bed combustor that also used coal and limestone with elutriated fly ash removal, and a very similar in-bed heat exchanger that demonstrated long life. The DCC and LICONOX technologies were demonstrated by Linde at Vattenfall's Schwarze Pumpe oxyfuel plant in Schwarze Pumpe, Germany, prior to demonstration at the 1-MWth pilot. They are also suitable for use with air-firing in addition to oxy-firing. The DeOxo reactor was demonstrated during the 1-MWth pilot scale testing. The pilot program demonstrated PFBC operation with air- and oxy-firing, and gas polishing technologies with simulated flue gas. All performance targets, including sulfur capture, excess oxygen removal, combustor acid dewpoint, combustor heat removal, and bed-temperature management, were achieved except carbon conversion. The carbon conversion was not achieved due to temperature sensors that became insulated by bed material. The measurement defect led to erroneous calculations for gas velocity in the combustor, leading in turn to much higher gas velocities than intended, thus reducing fuel residence time and carbon conversion. More details on this are provide later in this report.

The pilot Oxy-PFBC unit consisted of a fluidized-bed combustor, an in-bed heat exchanger, convective heat exchangers, and a bed-ash removal system as shown in Figure 8. The combustor and heat exchangers were housed within two pressure vessels filled with inert CO_2 blanketing gas. Below the main Oxy-PFBC vessel, was a valve train required to depressurize and remove ash from the bottom of the bed. The combustor, free board, and first convective heat exchanger, which were exposed to the hottest temperatures, all resided in a refractory-lined column. At the bottom of the column was the recycle/fluidizing gas injection assembly. This area contained the recycle flue gas inlet duct, a windbox, and tuyeres. The windbox functioned as a manifold, distributing gas flow evenly between the tuyeres and out through the bubble caps. Located above the tuyeres, but before the first set of in-bed heat exchanger tubes, was the fuel/sorbent injector. The injector was a stainless-steel conveying line and relied upon jet penetration of the coal/sorbent mixture into the bed to provide proper mixing of the combustibles. Conveying gas kept the metallic injector parts cool. A natural-gas burner provided preheat to the bed, allowing for warm up of the bed, refractory, and the cooling system. The combustion section of the bed contained the in-bed heat exchanger, which not only regulates bed temperature, but the presence of the tubes help break up bubbles and mitigate bed chugging. The heat exchanger consisted of thirty-six rows of tubes. Flue gas leaving the bed was cooled in the convective heat exchangers. The gas then flowed to the filter vessel where candle filters separated ash and dolomite for removal.

Linde's CPU provides a cost-effective method for CO_2 purification (99+% purity) and heat recovery compared with traditional cryogenic CPUs. In the pilot Oxy-PFBC system, Linde's approach used a DCC for complete HCl removal, a LICONOX® to remove SOx and NOx by 95% and 90% respectively, and a De-Oxo reactor that can reduce the O_2 below 100 ppm, while increasing net efficiency by heat integration with the power cycle. The DCC performed as expected, with the column completing over 120 hours of cooling of flue gas from the Oxy-PFBC, with flue gas from coal and oxygen based combustion, as well as air/natural gas and air/coal-based combustion. During these campaigns, the DCC was run with flue gas flow rates between 200–400 kg/hr, flue gas inlet temperatures of 190–220°C, and pressures between 4 and 8 bara. The flue gas outlet temperature was reduced to between 45 and 55°C, depending on the water circulation rate. The discharge pH of the condensate was maintained close to neutral with the addition of caustic as needed. The CPU underwent independent tests in 2018 without the Oxy-PFBC using a synthetic flue gas mixture of CO_2 and air, with trace amounts of contaminants SO_2 and NO. The CPU completed an extended duration test in October 2018, where it ran without interruption for over 3 full days. Inlet NO and SOx concentrations varied between 500–1000 ppmv and inlet SO_2 between 500–750 ppmv. Test results demonstrated that a significant amount of SOx and NOx were removed in the DCC before target SOx and NOx removal was achieved after the LICONOX. Simulated tests of the DeOxo also demonstrated stable performance with natural gas fuel, achieving removal of 2 mol% oxygen with an average oxygen slip below 100 ppmv.

Analysis of fluid bed operability with high temperature working fluid

The high working fluid temperatures necessary to achieve high cycle efficiency were determined to be within the operating limits of the Oxy-PFBC. The primary concern with high working fluid (SCO_2) temperatures of 730°C relative to previous designs for steam at 550°C, is that it could push up the combustor operating temperatures into regimes with ash melting and slag formation, which is detrimental to fluid bed behavior. During the Oxy-PFBC Phase II program (DOE-FE0009448), Penn State University developed an agglomeration model. It was validated with publicly available data and then used to analyze the GTI Oxy-PFBC as shown in Figure 7, below. The analysis found that there is 200°C operating margin at the planned bed operating temperature of 900°C. The blue line is consistent with Oxy-PFBC operating conditions with pressures of 8 bar and a bed composed primarily of limestone. The analysis found that the presence of limestone in the bed changes the chemistry in the combustor. This increases the onset of slag formation from 900°C (the red line) to 1200°C (the blue line). This is consistent with pilot test data that did not experience slag formation at normal operating temperatures. Since the maximum working fluid of 730°C is well below the 900°C operating bed temperature, it is expected that the combustor can be operated at 900°C as planned, with 200°C of margin.

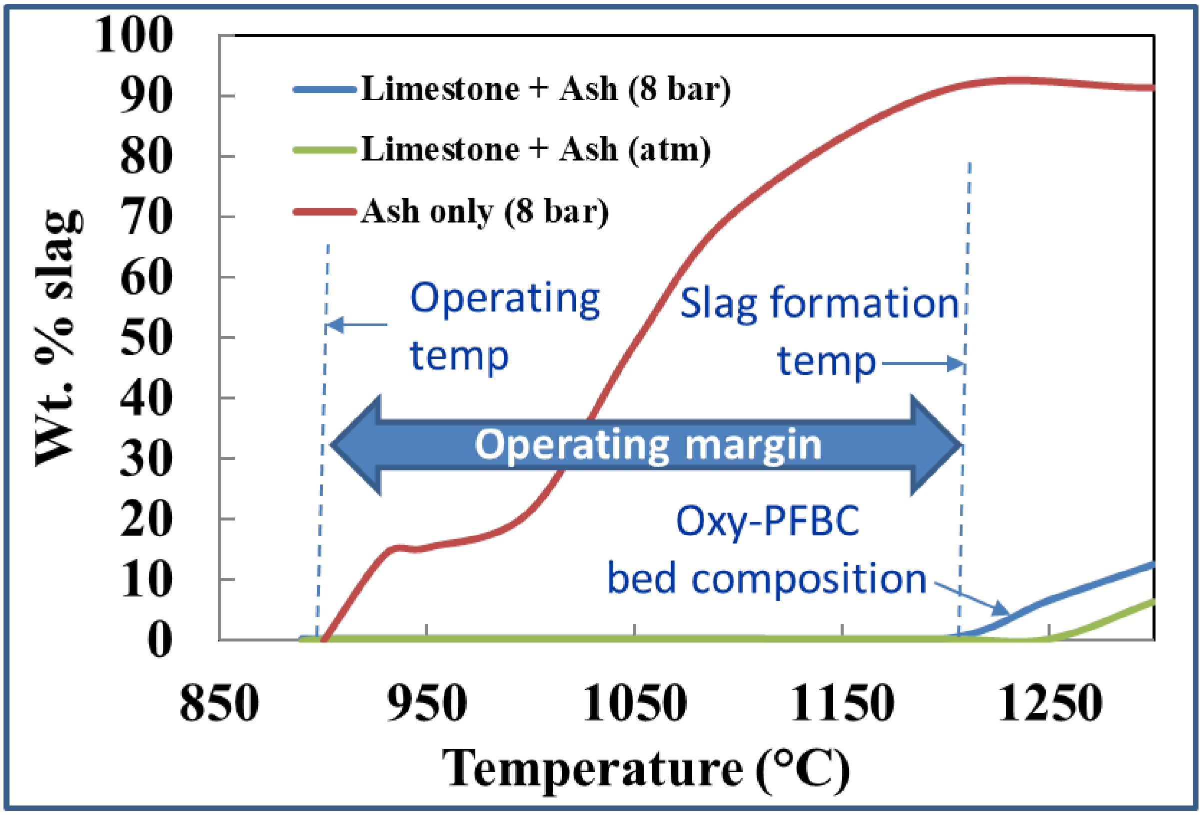


Figure 7 The Oxy-PFBC is designed with 200°C operating margin to insure robust operation
Oxy-PFBC ramp rate and start up time strategies

The Oxy-PFBC is expected to be able to achieve a 4% ramp rate since it is well within the state of the art for current technology coal plants, which can achieve up to 8% ramp rates.[7,8] More detailed analysis is necessary to quantify the ramp rate and understand the items that will constrain it due to thermal growth or other issues. The requirement for achieving a warm start in less than 2 hours is also considered feasible for the Oxy-PFBC if the bed material and combustor can be kept sufficiently warm. Achieving a cold start in less than two hours is more challenging and may require a significant improvement in the current state of the art, since typical cold start times for coal combustors are 6 hours or more, while ASU startup time can be 36 hours. The

[7] *Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables*, Miguel Angel Gonzalez-Salazar, Trevor Kirsten, Lubos Prchlik, Renewable and Sustainable Energy Reviews, Volume 82, Part 1, February 2018, Pages 1497-1513

[8] *Operating Flexibility of Power Plants with CCS*, IEA GHG ref number 2012 /June 6, Ferrari, Mancuso and Davidson IEA GHG 2012

detailed analysis activity necessary to quantify ramp rates and start times is planned for the pre-FEED study phase. Strategies to address these are summarized in Table 3 below.

Table 3 Strategies to address the ramp rate and startup time requirements in the pre-FEED phase of the project

Requirement			
Warm start (2 hrs)	Cold start (2 hrs)	4% ramp rate	Strategy
x	x	x	System design: Utilize the energy storage to augment the Oxy-PFBC start time and ramp rate
x	x	x	System design: Utilize energy storage to reduce/eliminate need for Oxy-PFBC shutdowns and restarts
	x		Size the system preheater to heat the Oxy-PFBC mass quickly enough meet cold start requirements
x		x	Store excess bed material in insulated container to minimize heat loss
x			Keep combustor bed material (and possibly excess bed material) warm through use of periodic heating
x	x		System design: Use heaters to warm the SCO2 system at the same time as the Oxy-PFBC to reduce start time
x	x	x	Work with vendor to deliver 4% ramp rate with ASU, or provide oxygen storage to augment ASU ramp rate
x			Keep ASU at temperature by periodically restarting it
x	x	x	Use state of the art digital control system to accelerate ramp rate capability
x	x	x	Utilize stockpiled coal to decouple ramp rate of feed system from Oxy-PFBC
x	x	x	Reduce material thickness of items found to constrain ramp rate, i.e. could use double wall pressure vessel made of two thinner walls rather than one thick wall

Heat exchanger design to reduce pressure drop

The Oxy-PFBC heat exchanger designs were modified relative to the Oxy-PFBC steam application baseline to achieve the Echogen target pressure drop of 0.7 MPa. This was achieved and there is potential to achieve further reductions in pressure drop and associated efficiency gains.

The primary design challenge was that the proposed cycle has significantly higher SCO_2 volumetric flows when compared to steam mass flows associated with a steam Rankine cycle. This resulted in a large pressure drop (2.9 MPa) which has a large impact on efficiency. As a result, the manifold design for the heat exchangers was modified to allow more parallel flows of working fluid compared to the steam Rankine design with negligible impact on hardware costs.

This reduces the fluid velocities and significantly reduces the pressure drop through the heat exchanger. It also allows the heat exchanger tube design within the fluidized bed to remain unchanged. This insures that development work done on the Oxy-PFBC can be applied to both steam Rankine and SCO_2 designs, without significant concerns about changes in fluidized bed and combustor behavior.

In the baseline design, the flow through the heat exchangers is sequential, meaning that all the flow entering the first heat exchanger portion sequentially flows through all subsequent portions of the heat exchanger. A trade study was run to determine how many parallel flows would be required to achieve Echogen's target pressure drop and SCO_2 outlet temperatures. It was found that adding a second parallel path for the coolant was sufficient to reduce the fluid velocity by half and the pressure drop by approximately a factor of four, to achieve the 0.7 MPa pressure drop target. The SCO_2 outlet temperatures were predicted to be essentially unchanged with this new configuration. If a third or fourth parallel path were to be added, the pressure drop could be further reduced to 0.3 MPa or 0.2 MPa, respectively.

Oxy-PFBC Benefits

The Oxy-PFBC design offers key advantages over conventional coal-combustion technology:

- **Compact size:** The Oxy-PFBC operates at a pressure of approximately 0.7 MPa, which allows for a significantly higher volumetric heat release rate compared to conventional coal boilers or fluidized bed combustors.
- **High heat transfer coefficients:** The combination of high fluid density and the in-bed heat exchangers within the fluidized bed environment allows for a substantial reduction in required heat transfer area, which in turn could result in significant heat exchanger cost savings.
- **Modularity:** The Oxy-PFBC reactor is very compact, enabling factory assembly and shipping via truck for reactor sizes up to 275 MWth. Higher power ratings can be achieved by parallel installation of multiple combustion systems.
- **Low emissions:** The Oxy-PFBC pilot testing of the CPU exceeded all design targets and demonstrated the ability to meet pipeline purity specs for CO_2 emissions for all tested items including NOx (90 ppm), SOx (0.75 ppm) and oxygen (53 ppm). The combustor demonstrated the ability to capture 99% of the sulfur in the combustor. The remaining SOx and NOx are eliminated in the flue gas polishing step utilizing demonstrated Linde gas cleanup technologies. The Linde DCC cools the flue gas and removes some SOx, while mercury and particulate matter are removed in candle filters and the DCC. The LICONOX system removes NOx and remaining SOx. Emissions of criteria pollutants including SOx, NOx, particulate matter and mercury are all projected to be significantly less than current regulatory requirements. The DeOxo reactor removes oxygen.

The Oxy-PFBC design has been optimized for carbon capture. With an ASU, a CO_2 recycle loop for the combustor, and CO_2 deoxidation and compression equipment, the Oxy-PFBC can achieve up to 98% carbon capture. The captured CO_2 would be available for sequestration or use, depending on the host site.

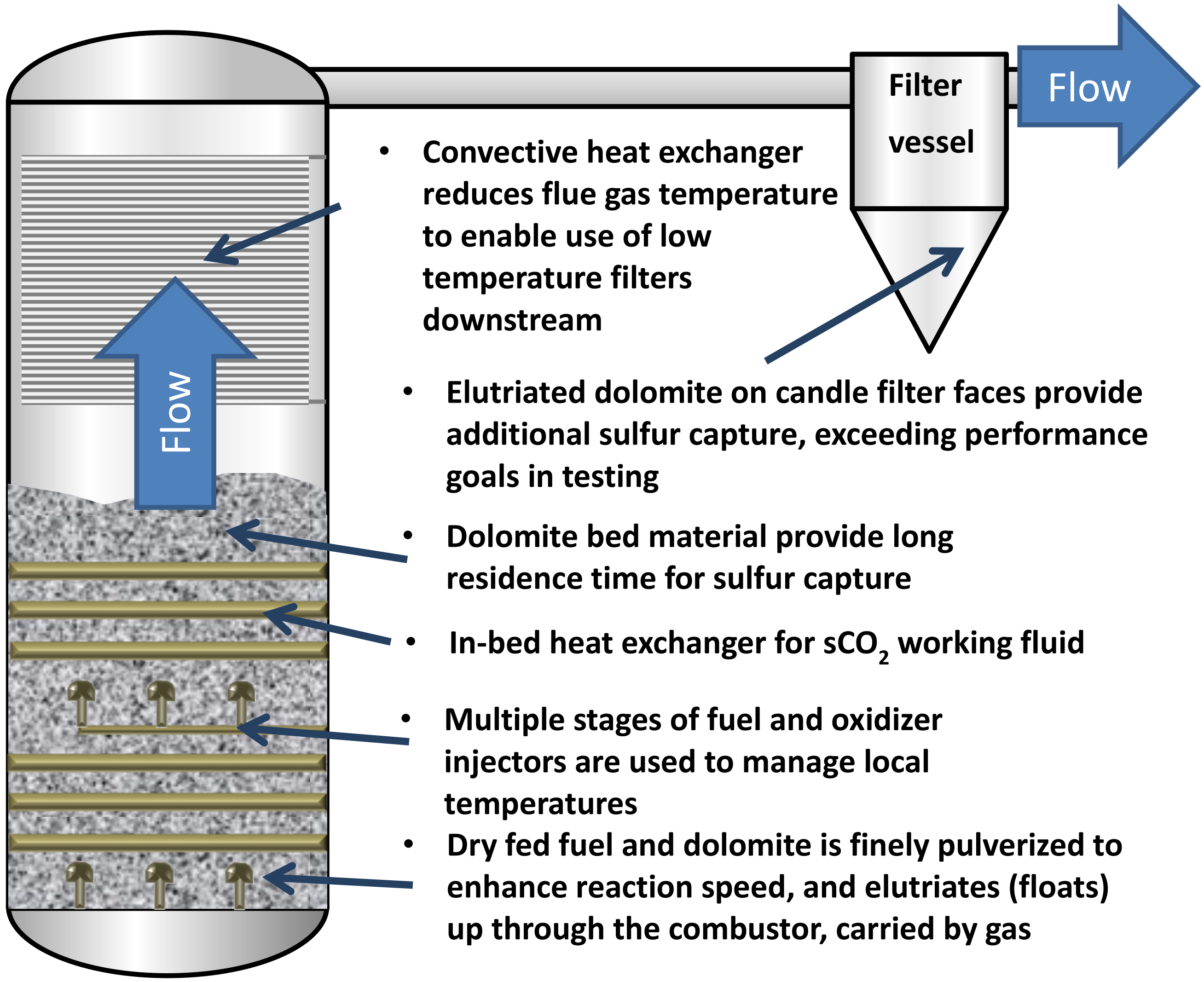


Figure 8 Oxy-PFBC design overview

Energy Storage

Echogen is developing an electrical energy storage technology, known as ETES, that leverages its expertise in sCO_2 power cycle technology. In its electrical storage-only configuration, a CO_2-based, electrically driven heat pump cycle transfers thermal energy from a low-temperature reservoir (LTRe) to a high-temperature reservoir (HTRe), thus converting electrical energy into potential thermal energy (the temperature difference between reservoirs). To recover this stored energy, an sCO_2-based power cycle is used to convert the temperature difference back into electrical power. Echogen has used its thermodynamic cycle design process to produce a flexible model of the ETES process and perform initial techno-economic analysis of the system. For the purposes of this study, a combination of a simple recuperated heat pump cycle and recuperated power generation cycle with 2-stage expansion and heat rejection are assumed, with HTRe limit temperatures of 325 and 83°C, and a water / 8% propylene glycol solution / ice LTRe with a freezing point of -2°C. Note for the purposes of modeling the two stage-expansion is shown as separate flow diagrams. This is functionally equivalent.

A primary performance metric of an energy storage system is the round-trip efficiency (RTE), defined as the ratio of energy discharged during the "generating" cycle to that used in the "charging" cycle. For the ETES system, this can be conveniently defined as the product of the heat pump cycle coefficient of performance (COP, Qh/Wchg) and the generating cycle efficiency (η_{gen}, Wgen/Qh). A thermodynamically perfect ETES system would have generating efficiency and charging COP equal to the Carnot limits ($1-T_c/T_h$ and $(1-T_c/T_h)^{-1}$ respectively), and therefore an RTE 100% independent of the reservoir temperatures. In practice, turbomachinery inefficiency, piping and heat exchanger pressure drops, and finite heat exchanger temperature approach values lead to lower RTE. These non-idealities also result in excess thermal energy in the HTRe, which must be "disposed" or otherwise utilized. Echogen has an innovative cycle design that maximizes the utilization of this "waste" heat by effectively dividing the generating cycle into two sub-cycles, one that operates between the HTRe and LTRe, and the other that operates between the HTRe and the environment.

The generation system was sized to 20 MWe net generation rating with a storage capacity of 10 hours. Based on an initial RTE estimate of 57.5%, a net storage power rating of 35 MWe is required to provide a charging time of 10 hours. The cycle diagram and state points for the charging and generating cycles are shown in Figure 11and Figure 12 respectively.

As ETES inherently stores energy in a thermal reservoir, the potential for integration of additional thermal resources into the system was explored. For this purpose, a simplified model of the ETES system and integration strategy was created. The baseline configuration is simple electrical charging of the system during periods of low electrical demand, with the storage system providing peak generation capacity added to the plant base load rating during periods of high demand.

Potential thermal integration resources were then surveyed by inspection of the base plant process flow diagram. These resources fall into three main categories:

1) **Low-grade heat that does not impact cycle performance (true waste heat):** The primary sources of such energy are the DCC water cooler (18 MWth at 140°C), and ASU waste heat. This heat is introduced to the charging cycle between the recuperator outlet and the compressor inlet. The charging cycle thus reaches the desired HTRe temperature at a lower compressor pressure ratio, thus improving charging COP and system RTE.
2) **Low-grade heat from the sCO_2 power cycle:** Several potential sources were considered—the most promising appeared to be the heat between the HTR and LTR. Extracting heat from this region affects the primary power cycle power output and efficiency. Therefore, curves of cycle power and efficiency, and the temperature of the heat extracted, were created as a function of heat extracted and used to estimate the overall system response.
3) **Higher-grade heat from the sCO_2 power cycle:** The turbine discharge temperature is high enough to permit direct heating of the HTRe material. The elevated HTRe temperature then allows for a higher efficiency of the generating cycle, and therefore an improved ETES system RTE.

When utilizing low-grade thermal resources, the heat is added during the charge cycle, between the recuperator and compressor inlet. This allows the same compressor discharge temperature to be reached at a lower pressure ratio, thus reducing the required compressor power to store the same amount of thermal energy. This effect manifests as higher $\mathrm{COP_h}$, lower $\mathrm{COP_c}$, higher RTE and lower compressor power used to achieve the same net energy storage capacity.

High-grade thermal resources (>350°C) are added directly to the HTRe. These have no direct impact on the charging cycle—rather, the generation efficiency values are increased due to the higher available turbine inlet temperature. In addition, the amount of compression work that is required during the charging cycle is reduced, as a significant fraction of the total heat stored is obtained directly from the high-grade resource.

These integration scenarios were simulated by assuming a 100-MWe base-load plant, with 10 hours of ETES charging time and 10 hours of ETES generating time. The baseline net plant efficiency is 37.3% HHV basis. During the charging process, 35.0 MWe of electrical power is used to charge the ETES system, giving a net power output of 65.0 MWe, and an effective net efficiency of 24.2% HHV. During the generating process, the plant generates a total of 114.4 MWe net, with an effective net efficiency of 44.7% HHV.

Under all studied scenarios, the plant efficiency during ETES generation is the same, as the system is sized for 20 MWe generating capacity. Therefore, the scenarios can be compared based on the net plant efficiency during the charging process. For example, the DCC water waste heat adds a maximum of 11.4 MWth during the charging process (limited by the temperature of the heat source relative to the minimum CO_2 temperature at the point of heat addition). To charge the system in the 10 hours allotted, the charge compressor work decreases from 35 MWe to 33.6 MWe, which increases the plant efficiency during charging to 24.7%.

The results of other two cases are shown in Figure 9. As heat is extracted from the base plant (not including the ETES system), the net output of the base plant decreases from 100 MWe to lower values, while the ETES charging electrical power also decreases. As the same amount of fuel is being consumed as heat is being extracted, the resulting net output is directly reflected in the net plant efficiency.

The results of this study can be summarized as follows:

- Utilization of true "waste heat" (such as the DCC water) has a modest improvement in the overall plant performance.
- Low-grade heat addition has an overall detrimental effect on plant performance at any potential level. The decrease in ETES charging power is more than offset by the decrease in base plant output. Note that the maximum amount of low-grade heat that could be extracted from the base plant was approximately 14 MWth, at which point the temperature at the studied state point has been reduced below the CO_2 temperature in the ETES cycle.
- High-grade heat addition improves the overall plant performance significantly, as the reduction in base plant performance is more than offset by the reduction in ETES charging power.

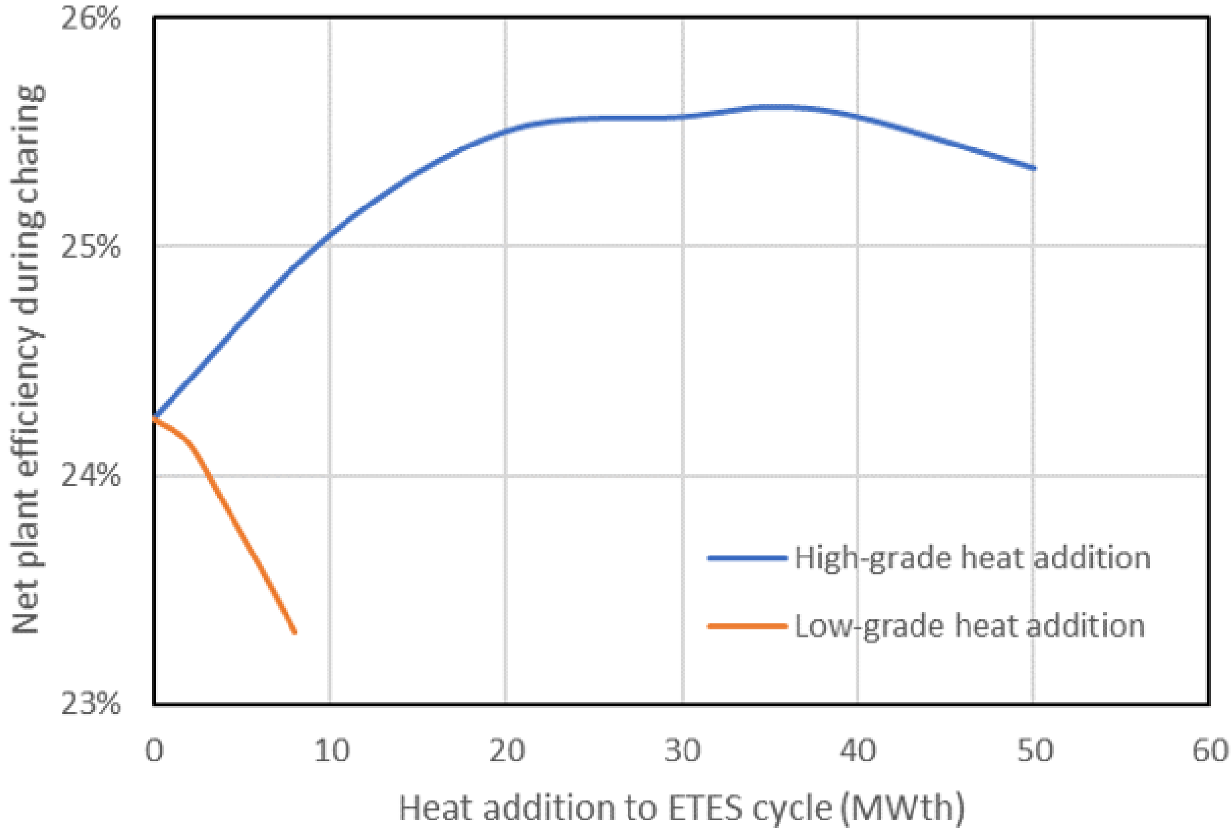


Figure 9 Effect of heat extraction for energy storage charging on net plant efficiency

System Summary

A summary of the system's ability to meet design criteria is presented below.

- **Greater than/equal to 4% ramp rate:** The system is expected to achieve the 4% ramp rate. The strategies for achieving a 4% ramp rate for the combustor portion of the plant are detailed in the Oxy-PFBC section and include keeping bed material warm, addressing possible ASU limitations, and leveraging energy storage. . Due to the compact nature of the sCO_2 power cycle and associated equipment (turbines and internal heat exchangers), the system can change power output and ramp quickly as compared to the Oxy-PFBC. If heat exchangers (recuperators and cooling sink) are sized properly, turbine and pump bypass valves can be used to adjust power down at rates above 4%. If the energy storage block is considered, 20 MWe can be brought on from cold metal in less than 30 minutes (potentially adding 0.67% to the overall ramp rate of the plant).
- **Cold/Warm start – less than 2 hours:** The system exceeds the warm start requirement by delivering full power in 60 minutes (~30 minutes to heat the bed material to coal ignition temp and get the 1st stage operating at full temperature with 33% power, and another 30 minutes to get stages 2 and 3 operating to get to 100% power). This is achieved through keeping the combustor and ASU at appropriate temperatures to support rapid start. With the ETES system cold start can achieve partial power (20 MW_e) in 30 minutes, with full power in 4-6 hours through multiple approaches on the Oxy-PFBC portion of the plant including stored oxygen to bypass the ASU during startup,

appropriately sized heaters, and reduced thickness parts where possible to reduce thermal stresses.

- **5:1 turndown with full environmental compliance:** The system can meet the 5:1 turndown requirement by ramping the oxy-PFBC down by 3:1 (achieved by shutting down two of the three fuel injection stages) and by using the excess power (up to 38 MW_e) to the charge ETES system. The minimum turndown can be maintained for up to 10 hours before other actions are needed such as bypassing flow for power generation which reduces plant efficiency.

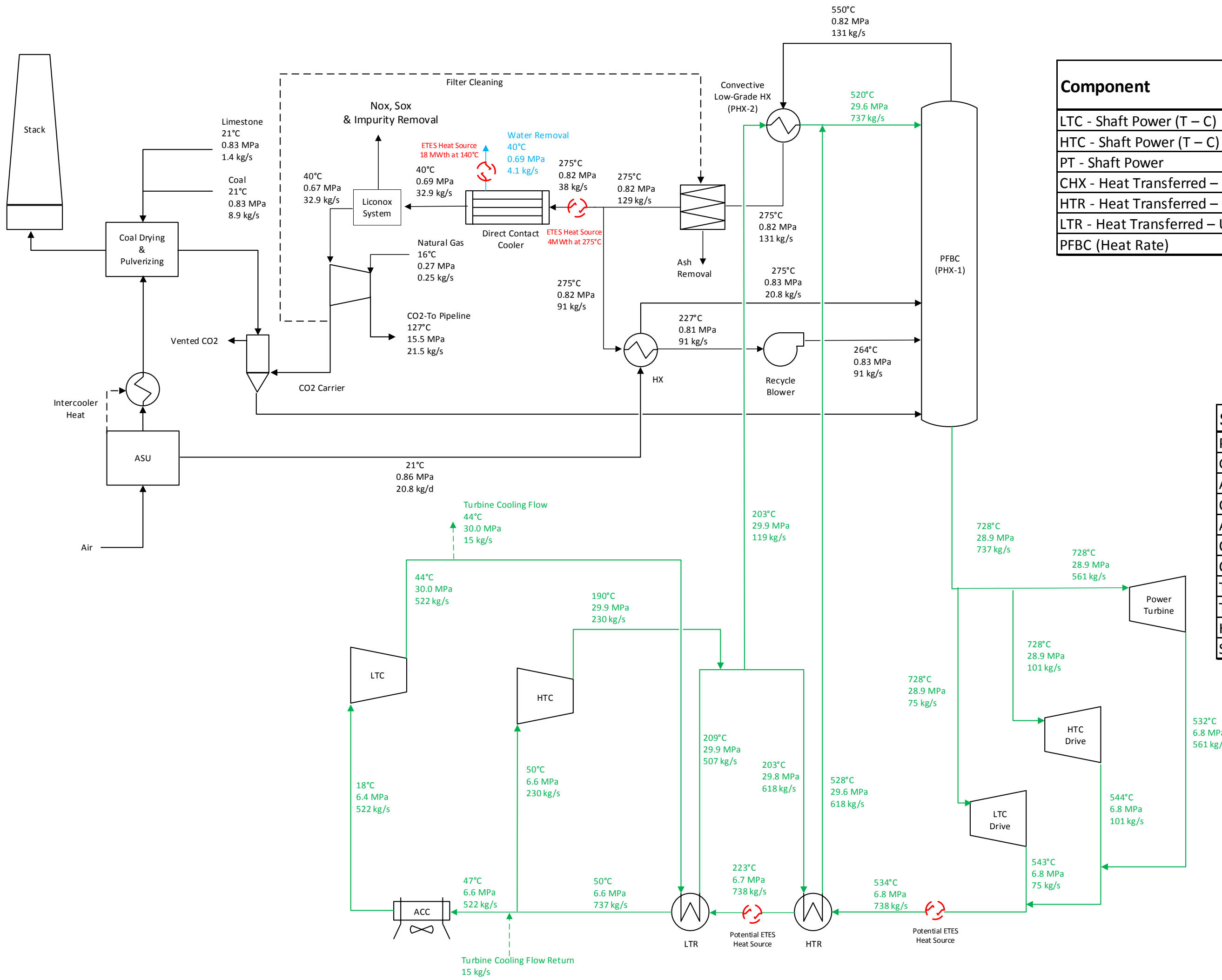
- **CO_2 capture ready:** The Oxy-PFBC was chosen and has inherent carbon capture built in, which can achieve up to 98% capture. The system can provide CO_2 at conditions required for enhanced oil recovery. If CO_2 capture was not required, an air-fired PFBC could be utilized and the ASU, CO_2 recycle blower, and DeOxidation (DeOxo) reactor would not be installed, while an air compressor upstream of the PFBC would need to be installed.

- **Zero liquid discharge:** The sCO_2 power cycle utilizes dry cooling (air) and hence requires no water for operation or cooling. The ETES system, while utilizing an ice slurry and air cooling for cold storage and cooling sink, does not discharge any liquids. The Oxy-PFBC has liquid discharge from the direct-contact cooling (DCC), which will have sulfur and mercury present, as well as water from the DeOxo reactor. The proposed system has a very low liquid discharge of 4.7 kg/s which is an 80% reduction to a typical coal fired steam Rankine power plant.

- **Solids disposal that is mostly salable with limited landfill:** The system will have solids that have potential for sale. The Oxy-PFBC has solids discharge from two locations: a mixture of fly ash and fine dolomite from the fly ash filter, and larger dolomite bed material particles discharged from the bottom of the combustor (without significant ash). Coal ash can be sold for the production of concrete and cement. While dolomite is used as an aggregate in cement, there is a risk that the small size of the dolomite present in the fly ash may make this less valuable for this process. However, it may be suitable as soil amendment. The dolomite removed from the bottom contains sulfur and there is a risk that this could reduce its value on the market. Typical applications for dolomite include soil conditioner, acid neutralization in the chemical industry, and as a source of MgO for livestock feed. If the dolomite could be sold for the same price at which it was purchased, the cost of electricity could be reduced by up to 1%. The value and usability of the solids will be explored in greater detail during the pre-front-end engineering and design (pre-FEED) study.

- **Dry bottom and fly ash discharge:** As discussed in the previous section, the Oxy-PFBC will have a dry bottom discharge of dolomite, and a dry fly ash discharge mixed with fine dolomite that has elutriated from the bed.

- **40% net plant efficiency for maximum load range w/out carbon capture:** The proposed plant exceeds the requirement by achieving 44.4% efficiency without carbon capture, and 35.2% with carbon capture by operating in oxy-fired mode.



Component	Duty (kW – kW/°C)	Efficiency / Effectiveness
LTC - Shaft Power (T – C)	16,252	86.1% - 88.0%
HTC - Shaft Power (T – C)	21,889	85.9% - 85.7%
PT - Shaft Power	130,105	91.8%
CHX - Heat Transferred – UA	108,522 - 17,700	95.0%
HTR - Heat Transferred – UA	263,836 - 15,023	98.0%
LTR - Heat Transferred – UA	155,077 - 22,931	98.0%
PFBC (Heat Rate)	268,310	-

SYSTEM PARASITICS	Loss (kW_e)	Power (kW_e)
PT Shaft Power		130,105
Generator Losses	(1,665)	
ACC Fan Loads	(2,917)	
Coal Handling and Conveying	(90)	
Air Seperation Unit (ASU)	(20,391)	
CO2 Compression	(5,600)	
CO2 Recycle Blower	(3,946)	
Turbine Auxiliaries	(156)	
Transformer Losses	(440)	
House Loads	(500)	
System Net Power		94,400

Figure 10 Integrated flow sheet and heat-and-mass balance - sCO_2 power cycle and Oxy-PFBC heater

Component	Duty (kW – kW/°C)
Charge Compressor - Shaft Power	38,094
Charge Compressor Drive Turbine - Shaft Power	4,417
HTX - Heat Transferred	67,012
LTX - Heat Transferred	33,973
RCX - Heat Transferred – UA	17,967 - 4,821

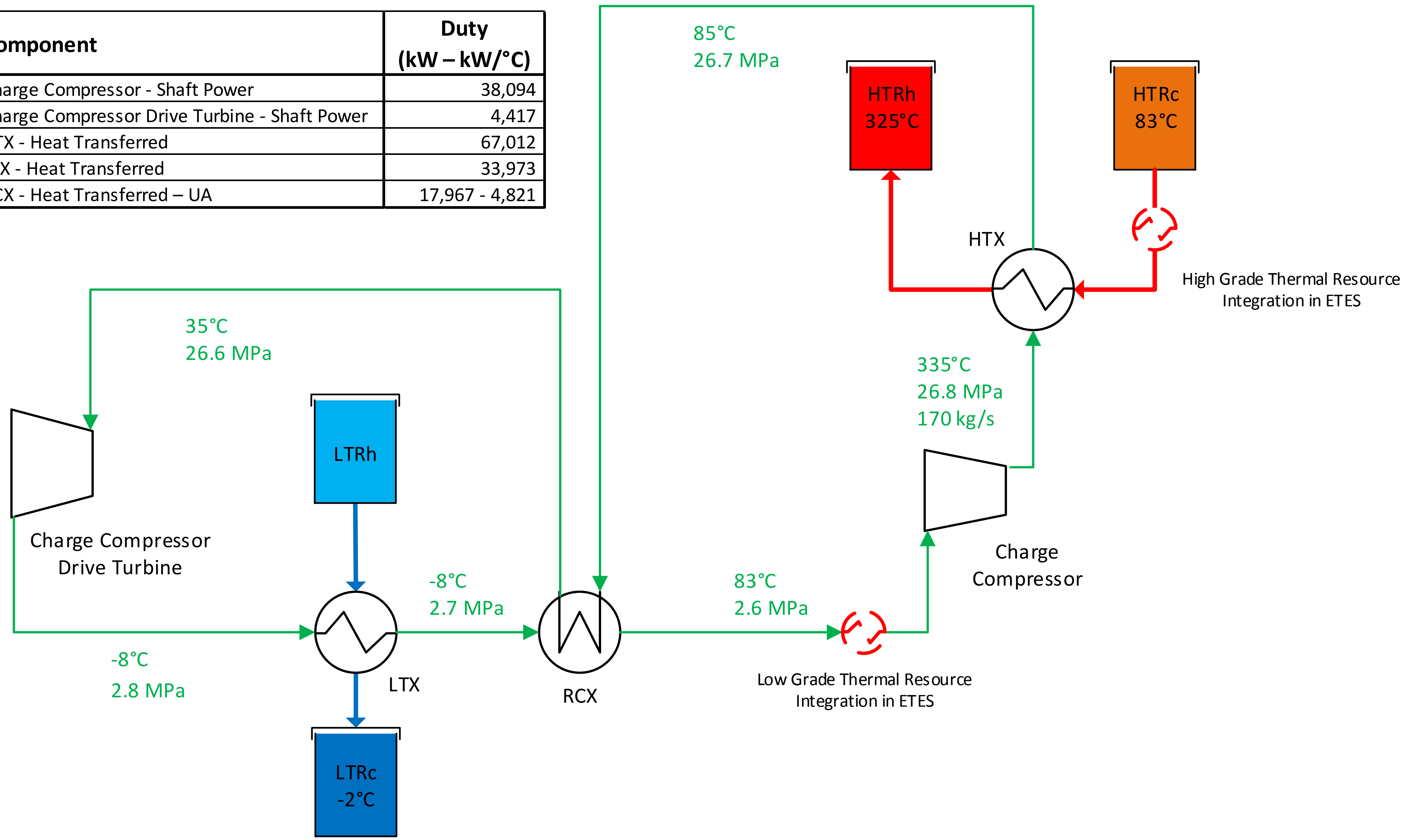


Figure 11 ETES charging cycle flow sheet and heat-and-mass balance

Component	Duty (kW)
Generating Pump	4,479
Generating Compressor	1,649
High Pressure Turbine	23,214
Low Pressure Turbine	3,707
HTX - Heat Transferred	73,202
LTX - Heat Transferred	35,422
RCX - Heat Transferred	15,976
QRX - Heat Transferred	16,982

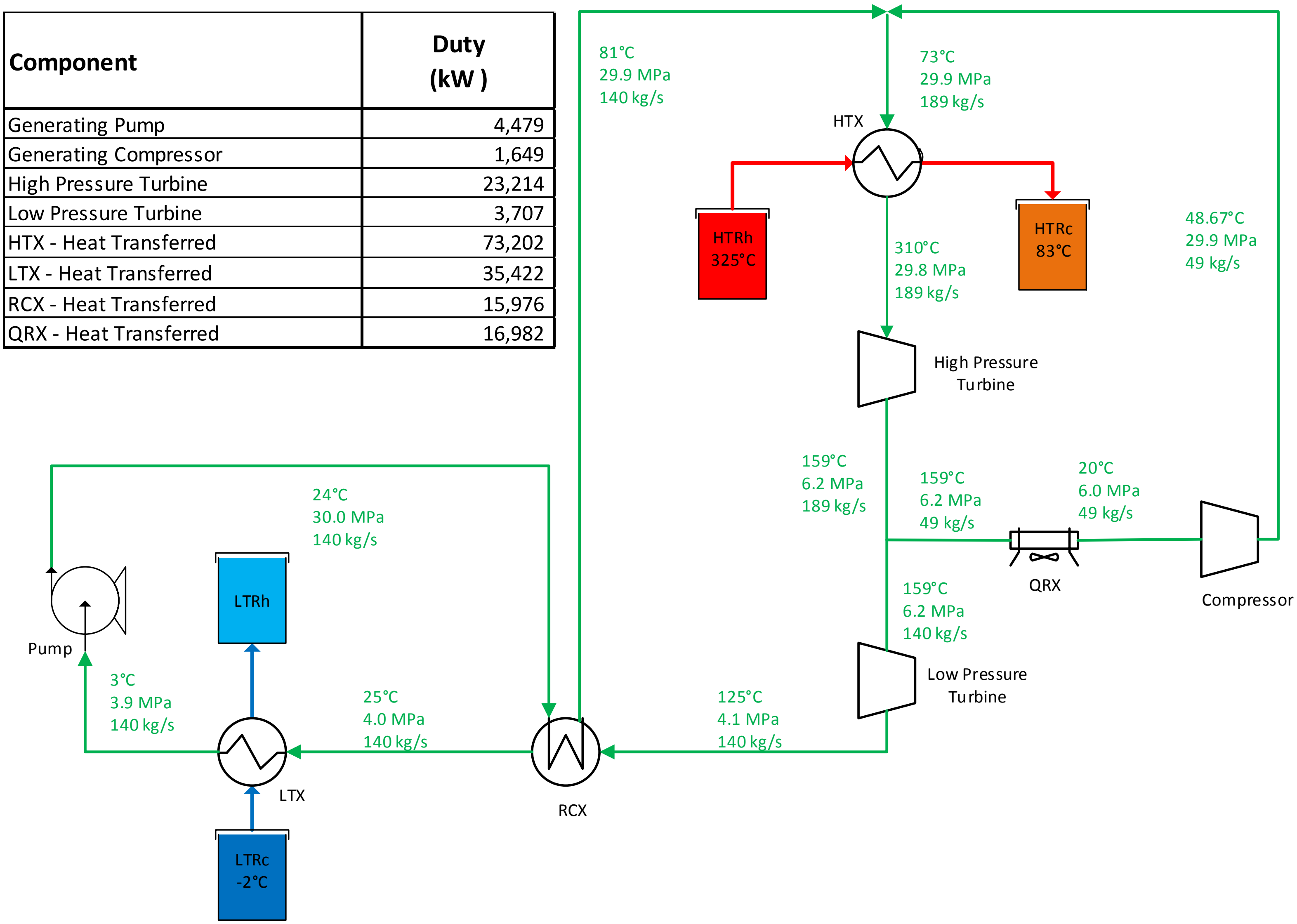


Figure 12 ETES Generating cycle heat and mass balance

3. Technology Development Pathway

Current State-of-the-Art

This section provides a comparison to relevant state-of-the-art coal-based systems with CCS and discusses their key challenges. Candidates, which are at different technology readiness levels (TRLs)—as assessed by EPRI—are:

- Integrated gasification combined cycles (IGCCs) with pre-combustion capture
- Oxy-combustion (Allam Cycle, atmospheric, and pressurized)
- PC with PCC

A high-level summary of relevant characteristics of each system is given in the table below.

Type	TRL	Size, MWe net	Efficiency, % HHV net	Total Plant Cost, $/kW	Flexibility
IGCC with Pre-Combustion Capture (B1B, B5B)	8	250–550	32.0–33.0[9]	5100–6200[1]	Medium
Oxy-Combustion (Allam Cycle)	5	300–562	37.7[10]	3663[2]	Good
Oxy-Combustion (atmospheric, super-critical, S12F)	7	30–550	31.0[1]	4084[1]	Medium
Oxy-Combustion (pressurized)	6	300–550	36.7[11]	---	Good
PC with PCC (sub-critical, B11B)	8	100–650	30.0[1]	3756[1]	Medium
PC with PCC (super-critical, B12B)	8	300–650	31.5[1]	3800[1]	Medium

IGCCs with Pre-Combustion Capture

IGCCs gasify coal to produce a synthetic gas (syngas) primarily consisting of CO and hydrogen, which is then used as a fuel in a combustion turbine tied to a steam-Rankine bottoming cycle to generate power. When pre-combustion capture is added, a shift conversion process is included to convert CO and steam to hydrogen and CO_2. The CO_2 is subsequently removed at pressure in a physical or chemical-based solvent system, yielding a high-concentration hydrogen syngas as the fuel. IGCC plants are relatively flexible, although they are limited by the air separation and gas purification systems, but adding pre-combustion capture should not adversely impact this.

IGCCs have been successfully installed in multiple locations and over a dozen are still operating. Recent IGCC experience in the U.S. has not been positive as several high-profile projects had significant cost overruns, but new-build IGCCs are still being contemplated elsewhere,

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[9] Based on recent DOE studies with cases noted in parentheses. IGCC (over a range of gasifiers) and PC data use Illinois #6 at net outputs of 550 MWe and 650 MWe, respectively. Oxy-combustion data use PRB at 550 MWe net. As the oxy-combustion report was from 2007, the cost number was adjusted to 2019 $ to match the others.

[10] "Performance and Cost Assessment of a Coal Gasification Power Plant Integrated with a Direct-Fired sCO_2 Brayton Cycle," NETL-PUB-21435, 2017. Illinois #6 was used on a 562 MWe net unit. Note that 8 Rivers, who is developing an Allam Cycle, has published higher efficiencies and lower cost numbers

[11] Based on Washington University in St. Louis' pressurized oxy-combustion system on Illinois #6 at 550 MWe net.

especially in Asia. IGCC with pre-combustion capture has been tested at up to 524-MWe scale at Southern Company's Kemper. The 170-MWe net Osaki CoolGen IGCC unit in Japan is the closest in size to the proposed technology. Pre-combustion capture is planned for the unit with testing scheduled to start circa 2020. The net efficiency of CoolGen is 40.8% HHV—with CCS added, based on data from the DOE studies, it is expected to drop to 30–32% HHV. TPC for this system are unknown, but the costs for IGCC with pre-combustion capture shown in the table are likely representative.

Challenges for IGCC with pre-combustion capture lie mainly with their complexity and potential for high cost in general. A more efficient way to produce oxygen and reducing the size and structure height of the gasifiers would reduce cost. Reliable hydrogen-based turbines also require development and testing.

Oxy-Combustion

Oxy-combustion performs combustion using oxygen cryogenically separated from air mixed with recirculated flue gas to produce a stream of principally CO_2 and water, thereby greatly simplifying CO_2 capture. Oxy-combustion can be done at atmospheric pressure or at elevated pressure, which improves efficiency by allowing recovery of latent heat of condensation from the flue gas at a temperature that is useful to the power cycle and reduces costs as equipment can be made smaller. Allam Cycles are a special type of pressurized oxy-combustion, which utilize a direct-fired sCO_2 power cycle, improving power cycle efficiency, but requiring front-end gasification of the coal. The pressurized oxy-combustion plants in particular should have good flexibility; Allam Cycles are purported to have low turndowns and high ramp rates.

The largest operational (atmospheric) oxy-combustion plant was CS Energy's 30-MWe Callide Unit 4, which operated for over 15,000 hours. The demonstration project was a retrofit to an existing unit, which cost about $130M. The estimated net efficiency for this sub-critical unit with oxy-combustion was ~22% HHV. FutureGen 2.0 developed a design for retrofitting atmospheric oxy-combustion to an existing sub-critical unit, producing a 100-MWe net unit with a net efficiency of 21.5–22.5% HHV, compared to 31.5% HHV net when air firing. The overall projected cost of the FutureGen 2.0 project was $1.65B, but this included operations and a significant pipeline for storage. Still, these two examples show the large cost increases at smaller scales compared to the costs shown in the table for oxy-combustion.

Pressurized oxy-combustion systems are still relatively immature. NET Power has built a 50-MWth Allam Cycle, which is operational, but uses natural gas. Developing a syngas version will take more time and funding. Pressurized oxy-combustion developers are driving towards constructing a DOE-funded 10-MWe sized pilot within the next five years, but in all cases, commercial-scale pressurized oxy systems likely won't be ready until 2030 at the earliest. More accurate estimates on cost won't be available until these technologies get closer to the finish line.

Challenges for atmospheric oxy-combustion include high-cost air separation, back-end CO_2 purification systems that are still relatively untested, issues with air inleakage and corrosion, and relatively low efficiencies compared to more novel oxy-combustion technologies. Challenges for pressurized oxy-combustion add developing low-cost, durable, and reliable pressurized components including in particular the oxy combustor, potential materials issues, and testing at scale. For the special case of Allam Cycles, challenges include high-pressure combustor operation, high-temperature heat exchanger durability, sCO_2 turbine performance, control system effectiveness, potential corrosion, and overall system complexity.

PC with PCC
PCC captures CO_2 from the PC flue gas after NO_X, SO_X, and particulate matter have been sufficiently removed. Typically, an amine-based solvent is used that chemically captures the CO_2, then releases it under temperature, generally supplied by steam from the cycle (or from a standalone island). Membranes that are selective to CO_2 can also be used for PCC, but are less mature. One advantage of PCC is that it can be retrofitted to existing PC units.

Two commercial PCC systems have been retrofitted to PC units: SaskPower's Boundary Dam's Unit 3 and NRG's WA Parish's Unit 8. Boundary Dam, at 110-MWe net with CCS, is comparable in size to the proposed technology. Its CCS retrofit (which also included SO_2 capture) cost ~$600M, which is roughly a $5450/kW adder. While this project was likely more expensive because it was first-of-a-kind, this is significantly higher than the number shown in the table, potentially showing the impacts of economies of scale. Another study done by EPRI for a 100-MWe net PC unit at sub-critical conditions without CCS showed a net efficiency of 33% HHV with PRB and TPC of ~$3000/kW. Based on data from the DOE, adding CCS to this unit would likely reduce the net efficiency to ~23% HHV and add at least another $1745/kW to the cost, resulting in a TPC of ~$4745/kW.

Challenges for PC with PCC include solvent degradation, potential amine and amine byproduct emissions, potential corrosion, increased water use, and a large footprint, along with its inherent cost and energy penalty. Adding PCC also impacts the overall flexibility of the unit, adding to the startup time and likely limiting ramp rates and turndown.

Summary
Based on this summary of state-of-the-art coal-based CCS systems, the proposed technology has several potential advantages:

- **Better flexibility.** With integrated energy storage, the proposed technology will be able to meet flexible market demands than the other technologies.
- **Higher efficiency at the nominal 100 MWe size.** As shown in the various examples, none of the other technologies, save potentially the Allam Cycle, will be able to compete with 40% net HHV. Some will be significantly lower, especially those that will need to use sub-critical steam-Rankine cycles at this size (IGCC and PC).
- **Lower costs.** sCO_2 power cycles scale down better than steam-Rankine cycles with less economies-of-scale impacts. The target TPC for the proposed technology of $3000–3900/kW is lower than what has been seen for comparably sized units from the set of current technologies, in some cases significantly.

Key Technical Risks and Technology Gaps

sCO_2 power cycles are the subject of numerous DOE- and privately-funded programs, which have addressed many of the existing technical and cost challenges. Echogen has been at the forefront of the development and testing of sCO_2 power cycles, with key work done by them and others listed below.:

- The first commercial sale of an EPS100, Echogen's flag ship product, recently announced by Trans-Canada, will provide operational, performance, and reliability data on equipment very similar to what would be deployed in this plant.
- The DOE has recently funded (DE-FE0031585) a detailed FEED study of an sCO_2 power cycle integrated with a coal-fired stoker heater under the Large-Scale Pilot Program. The

proposed plant will be 10 MWe net output and operate at turbine inlet temperatures of 600°C. From the power cycle perspective, the cycle architecture and equipment technologies would be the same (only scaled) of what is proposed here. The principal difference would be the primary heater.

- The DOE-funded STEP program that GTI is leading will address the use of high-temperature materials (>700°C) and heat exchanger testing.

These programs will expand upon the knowledge base in these primary areas:

1) **High-temperature materials:** The high temperatures required for high-efficiency power cycles are challenging for today's materials and limited long-duration experience in sCO_2 environments represents a technical risk. Significant laboratory-scale autoclave experiments have helped provide indications of potential material compatibility issues at elevated temperatures, but practical experience is limited. Recently, under a DOE SunShot-funded program, Southwest Research Institute (SwRI) and GE operated a subscale turbine for several hours at inlet temperatures > 700°C, providing the first operational data at these conditions. DOE's Large-Scale Pilot Program will provide designs and operation at turbine inlet temperatures up to 600°C and the DOE STEP program is expected to permit extended operational experience at turbine inlet temperatures exceeding 700°C.

2) **RBC operability:** Many of the current sCO_2 test loops utilize either a simple recuperated or cascade-type cycle architecture with a single low-temperature compressor. The recompression Brayton cycle uses two compressors in parallel, which can cause operability issues if not controlled properly. While the fundamental principles of parallel compressor operation are well-known, little experience exists in the context of a closed-loop power cycle.

3) **Axial turbine testing:** To date, most operating sCO_2 turbines have been single-stage radial turbines. At the larger scales of this program, multi-stage axial turbines are expected to provide an efficiency and generator speed-matching benefit. While limited axial turbine testing was included as part of the DOE SunShot-funded program at SwRI, it was at a small scale and under unloaded conditions. The proposed large-scale pilot plant and planned STEP facility will include testing of a multi-stage axial turbine at more practical scales (>10 MWe).

The main technical risks on the combustion and PHX side lie within the Oxy-PFBC. The auxiliary equipment required for operation are commercially available and have been used in similar applications. The Oxy-PFBC needs to complete pilot testing to validate carbon conversion predictions. All other performance goals of the pilot test program were met including CPU performance, SOx capture in the combustor, and heat transfer in the in-bed heat exchanger. The Oxy-PFBC completed a pilot test but did not meet carbon conversion goals due to issues described below. Plans to address this have been developed.

The Oxy-PFBC was undergoing pilot testing in October 2017 when the combustor experienced unexpectedly high temperatures that caused hardware damage and coal ash melting (slag) that clogged the combustor. Low bed density and poor carbon conversion also occurred throughout the test campaign. The root cause was found to be that some heat exchanger tubes were too close to the combustor wall, leading to bed material collecting on top of the heat exchanger tubes near the wall and insulating temperature sensors there. The resulting low temperature readings, which are used to regulate combustor gas velocities, led to significantly higher gas velocities than planned. The higher gas velocities caused reduced coal residence time, poor carbon conversion, burning in the freeboard region and ultimately to hardware damage. This must be addressed by increasing the gap between the wall and the heat exchanger tubes, and by adding temperature probes with thermowells that extend away from the wall to avoid potential insulation by stagnant bed material. A revised design will be evaluated in cold flow testing at the GTI lab in Agoura Hills, CA with testing expected to start in August 2019.

The root cause analysis was conducted by reviewing all available data from the hot fire tests, as well as data from design, construction, and cold flow tests. In late January 2018, findings were reviewed by a team of non-advocate experts, while DOE personnel were present. The review team found that there were not any problems identified that indicated there were inherent problems with the technology. There was general consensus on the root causes of the problems identified and the set of corrective actions. Technology gaps previously identified by the TIDD program include issues with gas turbine durability. This was because the TIDD plant was a direct cycle, where the flue gas from the combustor went through high temperature filters and into the gas turbine. TIDD reported numerous problems with failures of the high temperature filters, which resulted in ash and particulates getting to the turbine and causing issues with reduced life through erosion and corrosion of the turbine. The proposed approach eliminates this issue through the use of an indirect cycle. Our filters operate at a much lower temperature so they are not susceptible to failure, and if they do fail, a turbine will not be impacted.

Echogen has been developing the ETES system for 24 months. The main system components (turbines, recuperators, and generating compressor), except for the high- and low-temperature heat exchangers and the high-temperature charge compressor, have been tested in the test program that led to Echogen's commercial EPS100 sCO_2 power cycle, greatly reducing component risk.

Presently Echogen is under contract with ARPA-E (DE-AR0000996) to develop the high- and low-temperature reservoirs and heat exchangers, verify cycle operability, and performance at the lab scale. As part of this program, hot oil, sand, and concrete high temperature thermal reservoirs and their associated heat exchangers are being considered. Each of the three thermal media and their associated heat exchangers are being considered separately with the goal of down selecting to the most cost effective solution. While the use of sand, concrete. or other solid media as thermal energy storage systems has been considered previously, there has not been widespread implementation to date. The single largest technical challenge with the sand-based systems is the sand-CO_2 heat exchanger design, performance, and cost. The use of concrete structures at temperature above 300°C entails a certain technical / economic risk, as durability and long term performance are still being evaluted. The ongoing program is centered around development of design, performance, and cost predictions for these key elements.

Development Pathway

Echogen is a leading developer of sCO_2 power cycle technology, with over 10 years of experience in designing, building, and operating systems ranging from laboratory-scale to multi-megawatt commercial systems. Echogen is initially marketing the technology as a bottoming cycle for 5–50 MW combustion turbines, an application in which the conventional steam-Rankine cycle suffers from dis-economies of scale. The prototype power plant fielded by

Echogen is the state-of-the-art in sCO_2 power cycle technology, and the recently announced TransCanada project represents the first commercial sale and deployment of an sCO_2 power system through Echogen's licensing partner, Siemens.

The RBC cycle architecture proposed for this project (see Figure 3) shares many of the same components and configurations as Echogen's commercially available heat-recovery cycle. The Echogen cycle uses two primary heat exchangers and turbines to maximize the temperature drop through the heat source and minimize the exergy loss in the LTC. The proposed mRBC cycle also uses two primary heat exchangers, along with two compressors that serve to minimize LTC exergy loss. The RBC cycle utilizes a smaller fraction of the available heat source enthalpy, but the residual enthalpy is recycled back to the heat source (for the coal-fired case, as air preheating). The heat recovery cycle is used in applications where there is not a simple or economic way to utilize the residual enthalpy, such as gas turbine combined cycle plants.

The next logical step in progression will be a pilot scale demonstration of the sCO_2 mRBC. Echogen's involvement in DOE's Large Scale Pilot Program will address this and if the program is funded through Phase III, the sCO_2 power cycle and it systems and components will all have reached a TRL of 7. This will be a necessary step prior to commercial deployment.

The primary equipment around combustion and coal heating that requires research and development (R&D) is the Oxy-PFBC which is currently at TRL 4-5. Pilot-scale testing is required to demonstrate that it can achieve carbon conversion targets and to demonstrate sustained operation. Future pilot testing should provide integrated testing of the CPU with the Oxy-PFBC to get the system to TRL 6. The development plan is to spend 1.5 years to repair the 1 MWth pilot rig and complete testing. This will be followed by a 3.5 year large scale pilot effort at the 15-30 MWth scale. At the end of this 5 year effort, the technology will be ready to scale up to the 100 MWe commercial scale.

Echogen is presently working under an ARPA-E program to develop high-temperature heat exchangers for the ETES system. At the completion of this work, several of the highest risk components will have advanced to TRL 4. Apart from the ARPA-E funded work, Echogen also has proposals in for the development and testing of the high-temperature charge compressor under DE-FOA-0002064. Echogen is also actively pursuing a large-scale pilot demonstration of the ETES system (10 MWe with storage of 4 to 8 hours) that, upon completion, would bring the ETES system TRL to 7. It is expected that this larger-scale demonstration will be operational 24 months after full funding has been obtained.

To reduce risk to a level where financing would be possible the following will have to be completed:

- Complete small-scale testing of the Oxy-PFBC at the 1 MW_{th} size.
- Complete pilot scale testing the Oxy-PFBC using CO_2 as the working fluid at scale 15 – 30 MW_{th} scale.
- Demonstrate the sCO2 power cycle at the pilot 10 MW_e scale.
    - This is proposed under DE-FE0031585
- Complete pilot plant testing of the ETES system at the 5 – 10 MW_e scale with storage times of 4 – 8 hours.

Technology Original Equipment Manufacturers (OEM)

sCO_2 Power Cycle

Many of the required components for the sCO_2 power cycle are commercially available today.

- **LTC –** This would be like boiler feed water pumps provided by several potential suppliers including Ebara and Flowserve. Alternately, a custom-designed solution based on Echogen's EPS100 turbine-LTC could be explored.
- **HTC –** For this application, two commercially available technologies could be considered: an integrally geared compressor from MAN Turbomachinery, Siemens, or Howden) or a standard centrifugal compressor from Dresser-Rand or Atlas Copco.
- **Recuperators –** At present, there are two suppliers that could provide printed circuit heat exchangers at the scale required for this program: Vacuum Process Engineering and Heatric.
- **Air-Cooled Condenser –** Air cooled condensers for similar service are sold into chemical, oil, gas, and power industry applications today. Potential suppliers include Kelvion, GEA, and Air-X Limited.
- **Turbines –** Conceptual sCO_2 turbine designs have been developed by Siemens and Doosan Heavy Industries for plant sizes of 90 MWe and 550 MWe, respectively under DE-FE0025959.

Other required equipment and systems (valving, control system, piping, and inventory control) would be considered catalog items and are available from multiple suppliers.

Oxy-PFBC, Environmental Control System

Linde will provide commercial equipment for use with the Oxy-PFBC and environmental control system. These include the ASU to provide oxygen for combustion with the coal in the Oxy-PFBC, DCC to cool the flue gas and remove contaminants such as HCl, NOx, and SOx, the LICONOX that further removes NOx, SOx, mercury, and particulates, and the DeOxo to reduce O_2 levels in the final output gas. The ASU, DCC, and LICONOX are commercial offerings available from Linde and are well developed products with little inherent risk. The Linde DeOxo is currently under development and will require some R&D effort.

Macawber will provide commercial feed system equipment to convey coal and dolomite from feed hoppers into the Oxy-PFBC. These have been used in pilot testing and experience has been gained in their operation. A commercial natural-gas burner manufactured by Fives North America will be used to heat up the Oxy-PFBC. Fives North America has developed burners for many years with demonstrated reliability.

A recycle blower will need to be procured to recycle flue gas into the bed for fluidization. From the pilot testing, GTI has experience using a blower manufactured by Spencer Turbine, but other possible vendors that produce suitable blowers also include Atlas Copco, Schutte & Koerting, GEA Process Engineering, Process Barron, Linde, Howden, Mayekawa, and Dresser-Roots (now GE). The candle filters in the flue gas filter vessel that removes ash and dolomite particles will need to be procured. Possible vendors include Pall, Porvair, Tri-Mer, and GKD. Valves that regulate lock-hopper flow of ash and dolomite from the bed and filter vessel will be commercially supplied by Everlasting Valves as GTI has experience with these valves from the pilot testing.

GTI is collaborating on the Oxy-PFBC technology with KEPCO (Korean Electric Power Company) and Hyundai to develop a large-scale pilot (15-30 MW_{th}). GTI and KEPCO signed a joint development agreement where KEPCO is funding basic design for an Oxy-PFBC pilot located at their Donghae power plant, with a decision gate in 2020 for moving forward with the plant FEED and construction activities. In addition, GTI, KEPCO and Hyundai will sign an MOU on July 16, 2019 at the Donghae site to formalize the interest and collaboration between the three organizations for this technology.

Energy Storage

Many of the required components for the ETES system are commercially available or have been developed through the commercialization of Echogen's waste heat recovery power cycle. Some of the equipment is nearly identical to that used in the sCO2 power cycle with similar vendors. Components that are unique include:

- **High-Temperature Heat Exchanger Reservoir –** Three potential suppliers are being considered. Solex is developing a packed, moving-bed sand-to-CO_2 heat exchanger, Tu-Wein is developing a fluidized-bed sand-to-CO_2 heat exchanger, and Westinghouse Electric Corp. is developing a concrete-based thermal storage system using hot oil as the heat transfer medium between the concrete and CO_2.
- **Low-Temperature Heat Exchanger and Reservoir –** Echogen is working with Liquid Ice Technologies on the design of a lab-scale ice slurry generator, using CO_2 as the refrigerant. Standard brazed-plate heat exchangers will be used to transfer heat between the CO_2 and ice-slurry mixture.