

AN OVERVIEW OF TURBINE AND COMBUSTOR DEVELOPMENT FOR COAL-BASED OXY-SYNGAS SYSTEMS

Keith Pronske, Larry Trowsdale, Scott Macadam, and Fermin 'Vic' Viteri

Clean Energy Systems, Inc., Rancho Cordova, CA

Frank Bevc and Dennis Horazak

Siemens Power Generation, Inc.

Orlando, FL

ABSTRACT

Coal combustion technology is required that is capable of: (1) co-producing electricity and hydrogen from coal while; (2) achieving high efficiency, low capital cost, low operating cost, and near-zero atmospheric emissions; and (3) producing a sequestration-ready carbon dioxide stream. Clean Energy Systems, Inc. (CES) and Siemens Power Generation, Inc., are developing this technology that would lead to a 300 to 600 MW, design for a zero emissions coal syngas plant, targeted for the year 2015. CES and Siemens received awards on September 30, 2005 from the U.S. Department of Energy's; Office of Fossil Energy Turbine Technology R&D Program. These awards are designed to advance turbines and turbine subsystems for integrated gasification combined cycle (IGCC) power plants. Studies have shown [1-4] that replacing air with nearly pure oxygen and steam in a turbine's combustion chamber is a promising approach to designing coal based power plants with high efficiency and near-zero emissions. Siemens will combine current steam and gas turbine technologies to design an optimized turbine that uses oxygen with coal derived hydrogen fuels in the combustion process under a DOE Turbine Development Project [5]. CES will develop and demonstrate a new combustor technology powered by coal syngas and oxygen under a DOE Combustor Development Project [6]. The proposed programs build upon twelve years of prior technical work and government-sponsored research to develop and demonstrate zero-emission fossil fuel power generation. The planned system studies build upon previous work conducted by private, public, and foreign organizations, including CES [7-9], DOE's National Energy Technology Laboratory (NETL) [10-12], Air Liquide (AL)

[1,13], Lawrence Livermore National Laboratory (LLNL)[2], Fern Engineering, Inc. [14], and Japanese investigators [15,16]. Other pertinent data related to coal gasification, advanced air separation unit (ASU), plant integration and plant systems optimization, etc., can be found in references [17-23].

Introduction

The prior work indicated that current and future coal-based oxy-fuel systems could produce electricity with cycle efficiencies ranging from 32% to 57% depending primarily on the assumptions used for state points for turbine operating temperatures, the type of oxygen-production technology deployed, and the level of system integration. A key conclusion from these studies is that even under current technology scenarios, oxy-fuel cycles can produce coal-based power without pollution at costs comparable to IGCC plants with carbon capture today.

However, the previous studies [1-3, 9] did not fully optimize the systems nor go into sufficient detail to integrate the main process components, e.g. coal gasifier, air separation unit (ASU), gas turbine compressor, nitrogen driven auxiliary turbine, etc.. This project is intended, among other objectives, to address this shortfall, with the expectation that cycle efficiencies in the 45% to 57% range can be identified and then used to define the design parameters for the advanced technology combustors, turbines, ASU and gasifier.

CES OXY- FUEL ZERO EMISSION POWER PLANTS

Recent test programs by CES and DOE/NETL have successfully demonstrated the enabling combustion technologies of an oxy-fueled natural gas generator at 1089 K, 10.34 MPa (1500 °F, 1500 psia)[7,8] and an oxy-fueled natural gas reheater at, 1478 K, 1.00 MPa (2200 °F, 145 psia) [10 -

12]. A simplified schematic diagram of a CES power plant that incorporates these components is shown in Fig. 1.

CES power plants use the Rankine power cycle and consist of four basic systems as described below. Also, there are other alternative cycles that use CES technology and two of the many possible concepts are included as Fig. 2 & 3.

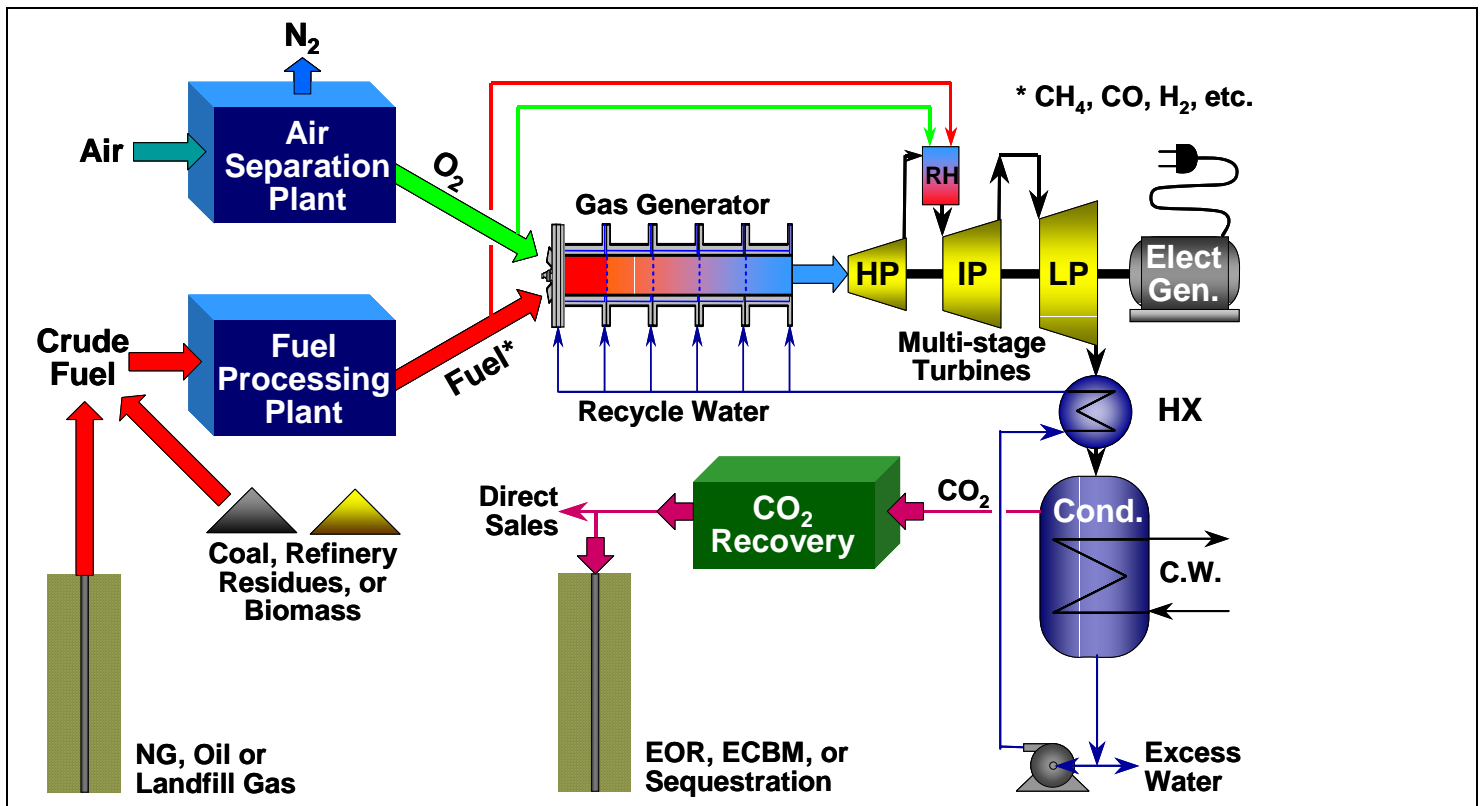


Figure 1. THE BASIC CES ZERO-EMISSIONS POWER PLANT (ZEPP)

1. FUEL PROCESSING AND GAS COMPRESSION:

Gaseous fuel, derived from virtually any organic source, e.g., natural gas, gasified coal, biomass or refinery residue, is processed by cleansing any undesirable substances (e.g. sulfur, nitrogen, etc.) and compressed to the combustor injection pressures. Solid fuels require gasification.

2. AIR SEPARATION AND OXYGEN COMPRESSION:

Nearly pure oxygen (> 95 %) is derived from large cryogenic air separation units (ASU) and compressed to the combustor injection pressure. As future ASU's incorporate ion transport (ITM) membrane technology the projected reduction in power requirement of approximately 37% [23] and a similar reduction in capital costs [23] will also benefit CES plants.

3. POWER GENERATION (POWER-TRAIN):

The power generation system includes steam turbines in series (usually three)

driven by high temperature gases consisting of approximately 85 %v steam, 15 %v CO₂ and a small amount of oxygen and trace amounts of nitrogen and Argon. The excess oxygen suppresses CO₂ dissociation and drives the combustion reaction to completion. Part of the condenser water is removed as excess, and of the remainder, part is heated to produce low temperature steam ~500 K (440 °F) for turbine cooling. The remaining recirculated water is unheated and injected into the gas generator for wall cooling and reducing the combustion gas temperature ~3589 K (6000 °F) to approximately 2033 K (3200 °F). Subsequent water/steam injection stages cool the drive gas to inlet temperatures of 867 – 1089 K (1100 -1500 °F) for the high pressure turbine (HPT) or 1478-2033 K (2200-3200 °F) for the intermediate pressure turbine (IPT). These turbines, in turn, drive an electric generator through a common or multiple shaft system, depending upon the selected plant configuration

4. CO₂ SEPARATION AND CONDITIONING: This subsystem cools the turbine exhaust in a condenser at atmospheric or sub-atmospheric pressure (depending on the type of cycle used) to condense the steam and separate the carbon dioxide (CO₂), with no energy penalty. Most of the condensed water is preheated in feed-water heaters located at the turbine exhaust to recover any residual heat before

recirculation back to the gas generator and turbine for cooling. The separated humid CO₂ exiting the condenser is extracted and compressed to approximately 15.17 MPa (2200 psia) with multi-stage compressors. Intercoolers and absorbers, between stages, remove the remaining water vapor and condition the CO₂ (remove impurities, e.g. excess oxygen, nitrogen and argon) for ultimate sequestration.

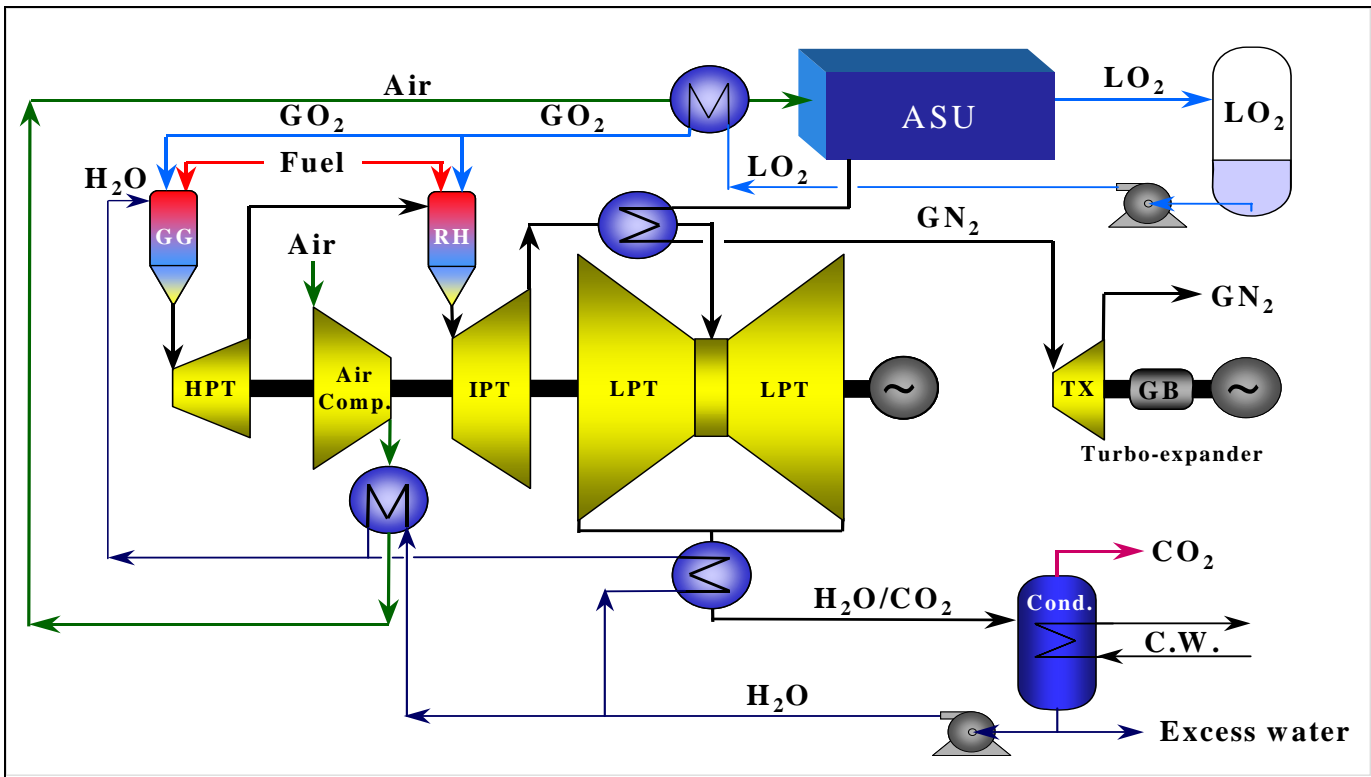


Figure 2. SCHEMATIC OF AN INTEGRATED CES RANKINE CYCLE WITH SUB-ATMOSPHERIC PRESSURE CONDENSER

The CES plant concept illustrated in Fig. 2 consists of a high pressure 10.34 MPa (1500 psia) gas generator (GG) feeding a high pressure 839 – 1033 K (1050-1400 °F) steam turbine (HPT); an intermediate pressure reheater (RH) 1.93 MPa (~280 psia), 1422 – 2033 (2100–3200 °F) feeding an industrial gas turbine (IPT); and a gas turbine compressor. All units are mounted on a common shaft that drives a generator. The compressor supplies air to the ASU and the IPT exhaust supplies the drive gas to a low-pressure steam turbine (LPT) 0.10 MPa (~15 psia), 839 – 1033 K (1050 – 1400 °F), driving a second generator. An expander-type turbine using heated

nitrogen drives a second auxiliary generator. The nitrogen is supplied by a high pressure ASU and heated by the IPT exhaust gases. The heated nitrogen is also used to modulate the LPT inlet temperature. A liquid oxygen storage tank provides oxygen for plant start-up and peaking power. The liquid oxygen is pumped to GG injector pressure level and gasified by the ASU incoming air supply. The CO₂ conditioning subsystem, described earlier, is considered standard off-the-shelf commercial equipment. This configuration is considered applicable for medium size 100 MW to large 600 MW plants.

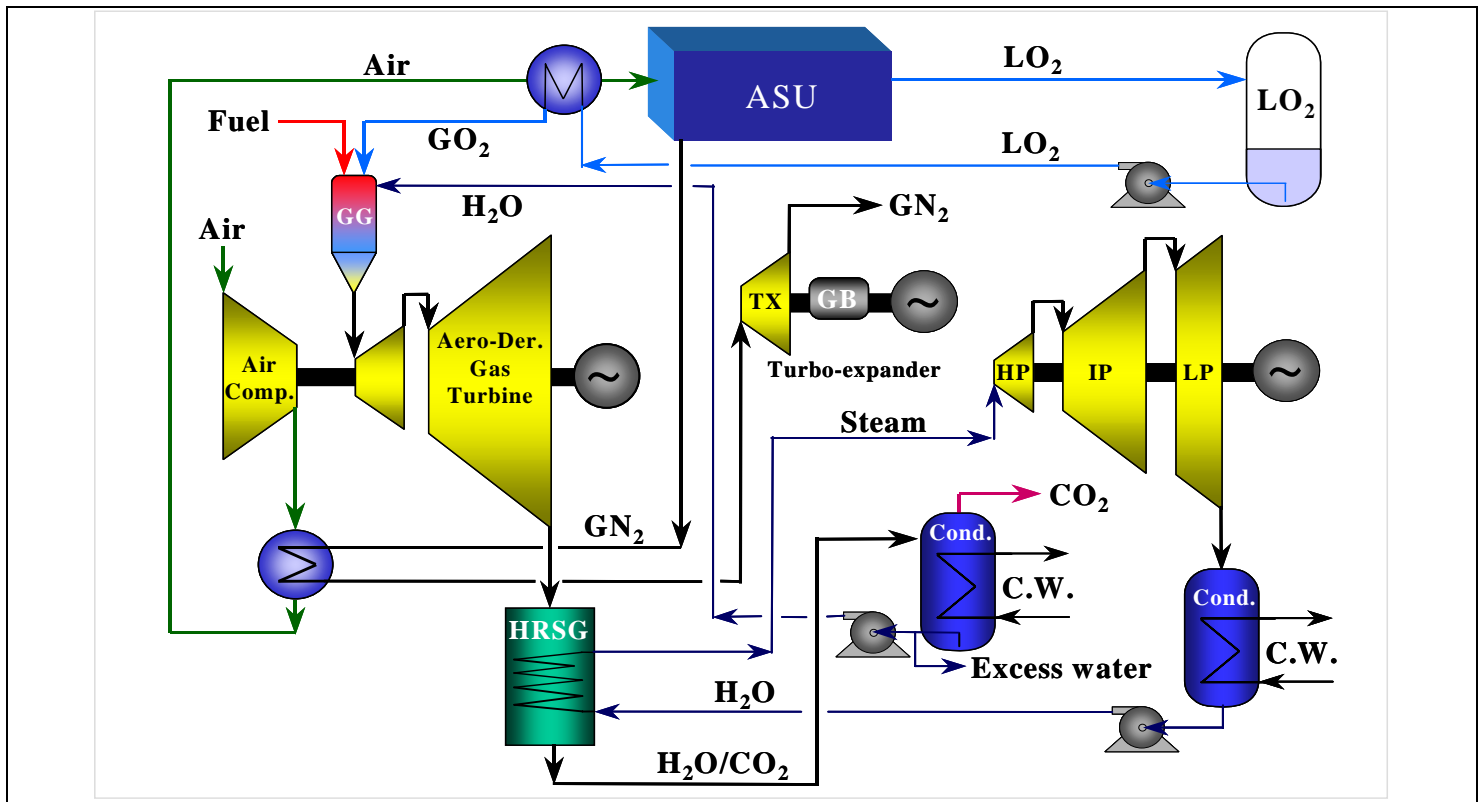


Figure 3. SCHEMATIC OF AN INTEGRATED CES COMBINED RANKINE CYCLE WITH AN ATMOSPHERIC PRESSURE HEAT RECOVERY STEAM GENERATOR (HRSG) AND PURE STEAM BOTTOMING CYCLE

The CES plant concept illustrated in Fig. 3 consists of an intermediate pressure gas generator (GG) 2.07 – 4.14 MPa, (300 - 600 psia), 1422 – 2033 K (2100–3200 °F) feeding an aero-derivative or industrial high temperature turbine (HTT) coupled to a compressor. The drive gases exiting the HTT then drive the low temperature turbine (LTT) coupled to a generator. The exhaust of the LTT is used to raise steam in a heat recovery steam generator (HRSG) and the steam is used to drive a commercial high-pressure 8.28 – 30.00 MPa (1200 - 4350 psia), 840 – 1033 K (1050 – 1400 °F) conventional or Ultra Super Critical (USC) steam turbine, with multiple reheats (not shown), that drive a second generator. An expander-type turbine, fed by heated nitrogen, drives a third auxiliary generator. The nitrogen is supplied by the high pressure ASU and heated by the compressor discharge air or some other heating source, e.g. coal syngas from the gasifier. This configuration is also considered applicable for medium

size 100 MW (aeroderivative turbines) to large 200 - 600 MW industrial turbines) plants.

BACKGROUND

In addition to combustor development and testing, it is necessary to develop turbines capable of operating on a steam/CO₂ mixture at temperatures of up to 2033 K (3200°F)(DOE's goal). Previous work by CES and Fern Engineering [14] (funded by the U.S. DOE/NETL) examined the feasibility of using gas turbine technology for CES oxy-fuel. These studies used an existing computer performance and heat transfer model of an aeroderivative gas turbine. By substituting CES's gas generator hot gas properties into the model, a comparison in performance and heat transfer characteristics was made. This comparison is summarized in Tables 1 and 2.

Table 1 – COMPARISON OF MODELING RESULTS FOR AN AERODERIVATIVE GAS TURBINE

	Base Flow, kg/hr	Base Temp. K	Base Press. MPa	CES Flow, kg/hr	CES Temp, K	CES Press. MPa
Compressor Inlet	268,969	296	0.0965	277,455	296	0.0965
Compressor Discharge	257,094	764	2.095	277,455	770	2.095
HP Turbine Inlet	245,566	1551	2.032	173,053	1553	1.759
HP Nozzle Cooling	16,602	764	2.095	18,602	518	1.933
HP Rotor Cooling	5,161	651	1.217	6,765	494	1.390
LP Turbine Inlet	267,780	1100	0.418	198,419	1132	0.377
LP Nozzle Cooling	2,652	523	0.589	2,590	458	0.537
LP Rotor Cooling	4,013	494	0.492	4,550	458	0.537
LP Turbine Exhaust	272,967	799	0.0965	205,559	884	0.0965

¹HP rotor speed was increased to its design limit in order to better match the nozzle jet velocity to the blade velocity ratio to increase efficiency and power output for the CES case.

Table 2 – ADDITIONAL MODELING RESULTS

	Base Case	CES Case
HP Turbine 1 st stage nozzle metal temp. K	1144	983
LP Turbine 1 st stage nozzle metal temp. K	813	796
HP Turbine speed, rpm	9680	10,050²
LP Turbine speed, rpm	3600	3600
LP Turbine shaft power, kW	25,753	27,208

Results of the Fern study [14] provides valuable insight into some of the technical challenges facing CES and Siemens engineers, e.g., at the design “firing temperature” of 1553 K (2335 °F), the CES cycle yields:

- **Slightly higher power output (6%)**
- A lower overall turbine pressure ratio (18.2 vs. 21.1)
- Much lower mass flow of working fluid
- **Significantly cooler HP turbine nozzle metal temperature due to steam cooling, -161 K (-290 °F)**
- Slightly lower power turbine inlet pressure
- **Slightly hotter LP turbine inlet temp., 32 K (58 °F)**
- **Cooler LP turbine nozzle metal temperature due to steam cooling, -17 K (- 31 °F)**
- Smaller turbine jet velocity ratios => slightly lower turbine efficiencies
- **Hotter LP turbine exhaust temp. , 85 K (153 °F)**

The final item noted above indicates that as CES gases expand, the temperature drop is smaller than those of gas turbines because of the specific heat ratio of 1.21 for CES gases versus the gas turbine value of 1.32. This effect will require slightly better materials and/or more cooling for the later turbine stages. However, this should not be a serious concern because water and low temperature steam are

excellent coolants as shown by the HP 1st stage nozzle metal temperature, Table 2. Also, transpiration cooling (which is considered the most efficient type) can be readily used at the leading and trailing edges of the nozzles/rotor blades, or other critical areas in the turbine hot section, since both fluids are available in abundance when using CES type cycles.

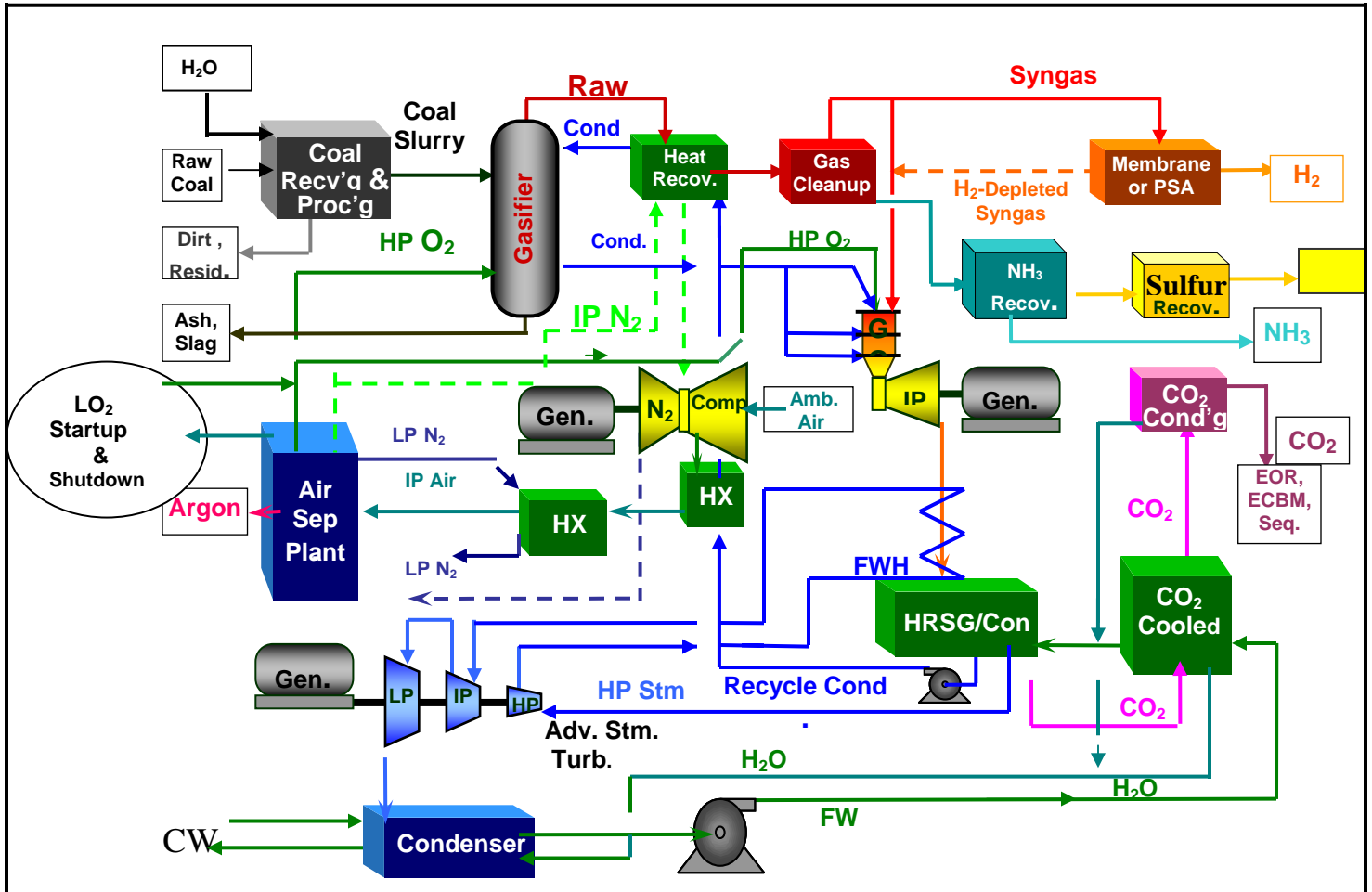


Figure 4 - INTEGRATED GASIFICATION CES COAL SYNGAS PLANT CONCEPT

A highly integrated gasification CES coal plant (IGCES) is illustrated in Fig. 4. The ASU, the ASU air supply compressor and nitrogen driven turbine are gas-coupled (heated nitrogen) to the coal gasifier and can operate independently of the CES GG and the Siemens HTIPT for start-up and shut-down operation. This setup may not be optimum for all plants, but is shown only as an example of the type of plants CES and

Siemens will be evaluating during the systems study phase. This phase will down select from 50 plant concepts to approximately eight. These eight most promising plants will be further evaluated based on performance, cost, operability and equipment availability while using syngas and hydrogen depleted syngas.

BENEFITS OF THE CES CYCLE

A strong attribute of an oxy-fuel combustor is the ability to easily operate on low calorific value fuels, such as depleted hydrogen coal syngas. In the CES combustor, or gas generator, water is used as a diluent to control combustion zone temperature, so the transition from natural gas to coal syngas is primarily a matter of adjusting the amount of water injected as a diluent and changing the mixture ratio of fuel and oxygen to maintain stoichiometric combustion. Practically all of the prior development work conducted on natural gas will be directly transferable to operations with coal syngas. Relevant technical issues are hydrogen content, flame speed, mixing chamber lengths, and heat transfer.

ECONOMICS

When applying the expected cost savings from CES technology to the U. S. domestic market, assumptions are required with respect to market penetration and timing. Forecasts for global gasification market growth prepared by Booz/Allen/ Hamilton [24], in a DOE/NETL/GTC funded study, indicated a gasification market penetration ranging between 12% and 50% in the timeframe of 2010 to 2025, depending largely on gas prices, multi-pollutant regulation, and whether or not carbon regulation comes into effect. This represents between 34 GW to 164 GW of new coal-fired gasification power plants. Based on a preliminary economic analysis conducted previously by CES, Air Liquide and others, utility scale zero-emission coal plants using CES technology will be cost competitive with IGCC in the near term as shown in Table 3.

**Table 3
COMPARATIVE COST OF ELECTRICITY FOR 400 MWe PLANTS USING SYNGAS,
AND OPERATING WITH CES AND COMBINED CYCLE TECHNOLOGIES**

Plant Operating Factors	IGCES			IGCC	
	Near-Term(1)	Advanced (1)	Advanced (1)	w/o CO ₂ Capture	w CO ₂ Capture
Net Plant Thermal Efficiency, (Including Syngas Plant)	47 [1](2)	51[1](2)	57 [1][23](2)	45 [4]	39 [4]
ASU Plant Type	Cryo	Cryo	ITM	Cryo	Cryo
ASU Plant Size – Tonne/Day	5974 (3)	5428 (3)	4857 (3)	2165 (4)	2498 (4)
Capital Cost, US \$/kW	1481	1400	1210 [23](5)	1210 [4]	1642 [4]
Coal Cost –\$/GJ/(\$/MMBtu) (LHV)	1.38(1.45)			1.38(1.45)	
Emissions of NO_x – kg/MWh	0.00			0.11 [4]	0.13 [4]
Emissions of CO₂ – kg/MWh	0.00			718 [4]	83 [4]
	<i>Unit Costs</i>				
Unit Capital Cost - \$/kWh	0.039	0.037	0.032	0.032	0.044
Unit Fuel Cost - \$/kWh	0.011	0.010	0.009	0.011	0.013
Unit Maintenance Cost - \$/kWh	0.008	0.007	0.006	0.010	0.012
Cost of Electricity - \$/kWh (6)	0.058	0.054	0.047	0.053	0.069
CO₂ Seq. Cost - \$/Tonne	6.0 (7)	5.6 (7)	4.8 (7)	NA	19.7[4](8)

- (1) Turbine inlet temperature: Near-Term, 1700 K (2600 °F); Advanced, 2033 K (3200 °F).
- (2) Efficiency Includes Turbine Cooling Losses of 2% Points.
- (3) O₂ Separation Power (99.5% purity): 906 kW/kg/sec (412 kW/lb/sec) Cryogenic; ITM ~ 63 % Cryogenic power [23]; and O₂ compression power assumes 85% compressor efficiency.
- (4) O₂ Separation Power (95% purity): 770 kW/kg/sec (350 kW/lb/sec),
- (5) ITM capital cost ~ 2/3 of cryogenic ASU plant cost [23].
- (6) Based on 20 year life, 60% Utilization Factor (5256 hrs/year) and capital recovery at 14%/year interest rate.
- (7) Assumes 103 kWh/tonne: CES CO₂ compression, 0.10 to 15.17 MPa (14.7 psia to 2200 psia).
- (8) Assumes 285 kWh/tonne [4]: IGCC MEA (Monoethanolamine) Absorption Process, 0.10 to 15.17 MPa. (14.7 psia to 2200 psia)

FUTURE MARKETS

The marketing of CES technology will focus on two key markets: Large, utility-scale plants (300 to 600 MW) in lieu of IGCC processes, and smaller, niche opportunities for plants in the 50 MW to 100 MW size, taking advantage of waste or low value coal (Lignite/Brown Coal) and/or biogas. The larger plants would most likely use current gasification technology marketed by ConocoPhillips, General Electric, Shell, and others, whereas the smaller plants would rely on technology developed by alternative gasification technology such as that using pyrolysis or plasma arc gasification.

Of particular importance is the fact that the CES process does not materially affect the gasification process. Instead, the efficiency and capital cost differences are centered on the power block. So instead of 'IGCC' plants, the alternative would be "IGCES" plants at a comparable cost but with zero or near-zero emissions. These IGCES plants would use many existing power block components found, such as steam turbines and compressors. Given that the cost structures of the IGCC, and IGCES plants are comparable, even in the near-term, it is reasonable to assume modest market penetration initially, followed by an increasing market share resulting from the superior environmental performance of IGCES technology. Following market acceptance, further improvement in turbine technology will result in zero-emission coal plants that are both more economical and cleaner than IGCC.

A key attribute of the coal gasification process is its ability to co-produce hydrogen and other high-value fuels from synthesis gas. Different technologies are available for processing the syngas into separate streams, ranging from the production of essentially pure hydrogen and carbon dioxide from a shift reaction and separation process, to extracting only a portion of the hydrogen, leaving a hydrogen-depleted syngas for power generation purposes. The latter option may be particularly attractive if the objective is to produce hydrogen for offsite uses, such as fuel cells or future transportation applications, while still providing a fuel source for onsite power generation, other than high-value hydrogen. While further analysis is required and will be conducted under this project, the CES process appears to be ideally suited to use with a hydrogen-depleted syngas, offering the possibility for nearly 100% carbon capture through post-combustion separation of carbon dioxide when condensing the steam component of the drive gas.

FUTURE DEVELOPMENT WORK

TURBINE DEVELOPMENT CHALLENGES

In the ideal case of an oxy-fueled turbine, hydrocarbon fuel ($\text{CH}_4 + \dots + \text{C}_x\text{H}_y$) is burned with pure oxygen (O_2) to produce a NO_x -free mixture of water vapor and carbon dioxide, which is used to produce power and is then separated

into potable water and disposable CO_2 . With operating pressures around 10.34 MPa (1500 psia) and temperatures around 1922 K (3000°F), the oxy-fueled turbine appears to be within existing technological limits for steam turbines and gas turbines, respectively. Challenges emerge, however, when this ideal concept is embodied in a real turbine.

In reality, fossil fuels also contain nitrogen and other impurities, separated oxygen contains residual nitrogen and argon, and the resulting working fluid also contains a small amount of excess oxygen. Existing steam turbines operate at temperatures that are considerably cooler than oxy-fueled turbines, existing gas turbines operate at considerably lower pressures, and neither steam nor gas turbines have operated over extensive periods with this working fluid. In areas where condensation takes place, the dissolved CO_2 and water will form carbonic acid (H_2CO_3). Carbonic acid is a weak colorless acid formed only with water and CO_2 in solution. Components exposed to this fluid are usually made of relatively low cost stainless steels, e.g. SS 316, 316L etc., or titanium. In areas where carbonic acid can form due to condensation, especially after shutdown, warm dry nitrogen purging will be required to evaporate any remaining corrosive fluid.

Expanding on the concerns identified by Fern Engineering, the main technical challenges to oxy-fueled turbine design are: providing sufficient air to the ASU; integrating the combustor with the turbine frame; aerodynamic design; blade path materials development; turbine cooling; and integrated system controls. The technical approach will involve combining the concepts and technologies of both the steam turbine and gas turbine within the same cycle. For the first time, a turbine will use a mixture of superheated steam and CO_2 as its working medium with temperatures as high as at 1922 K (3000° F) requiring cooled vanes and blades (as in advanced gas turbines), thus taking advantage of both steam and gas turbine technologies.

PROVIDING AIR TO THE ASU

High-temperatures inlet conditions notwithstanding, the oxy-fueled turbine will likely be more similar to a high-pressure steam turbine than to a gas turbine, including the presence of a full-admission "steam" inlet before the first row vanes, *and the absence of a mechanically connected compressor*. Air for the ASU would be provided by a separate compressor, allowing the ASU and gasifier to be started and shut down independently from the rest of the plant, and eliminating the need for extensive redesign of a gas turbine compressor to allow the extraction of all of its compressed air.

INTEGRATION OF COMBUSTOR INTO TURBINE FRAMEIn the current conceptual design for the oxy-fueled turbine, the combustor is located directly in the turbine frame. This close

coupling eliminates the need for expensive piping between the combustor and turbine, and locates the combustor near sources of cooling steam. In this regard, the high temperature turbine will have characteristics of the land-based gas turbines. Of course, this arrangement requires that the combustor and turbine be synchronized during startup, shutdown, load changing, and base load operation.

AERODYNAMIC DESIGN

Since the turbine's aerodynamic design depends primarily on the properties of the working fluid, the unusual mixture of steam and CO₂ presents a new challenge. Relative volumes of steam and CO₂ may vary, but a working estimate of approximately 85%v steam and 15%v CO₂ has been selected as a baseline. Because of the need for high cycle efficiencies, the blade flow path will be designed based on the most advanced turbine design principles.

Current steam properties used by the power generation industry, including accurate supercritical steam properties, were developed by international agreement [25], and are sufficient for the operating range of the anticipated oxy-fuel baseline cycle. The properties of carbon dioxide (CO₂), however, are another matter. The widely used properties of air and combustion products are published by JANAF [26] contain properties in the form of numerical data as a function of temperature. However, the JANAF CO₂ properties are only valid at a pressure level of 0.10 MPa, requiring further investigation into these properties at pressures greater than 1 bar. Finally, the property characteristics of steam and CO₂ will be combined, including reconciliation of reference temperature differences between the ASME Steam data and the JANAF data, to reflect dependence on varying proportions of H₂O and CO₂ in the several cycles at various temperature levels, including various degrees of H₂O condensation.

The gas path temperatures of the oxy-fueled turbine are typical of modern military aircraft gas turbine engines that operate at temperatures from 1700 K to 1922 K (2600 °F to 3000 °F). The key to obtaining hot section flow path hardware that can operate continuously for up to 50,000 hours at such high temperatures is the implementation of advanced material and cooling technologies.

BLADE PATH MATERIALS DEVELOPMENT

Blade and vane materials development can be characterized as the resolution of conflicting requirements for higher strength materials despite their lack of ductility, stress corrosion resistance in a less-than-pure steam environment, and resistance to thermal-mechanical fatigue (TMF) cracking during typical modern duty cycles where the number of startups per year has increased dramatically along with the pressure to shorten startup times from a variety of hot, warm and cold starts. Also, the low oxygen content in the working medium means that the passive oxide protecting coating that normally forms on steam, turbine blades will need to be

replaced by an advanced coating system that operates on different principles.

Scaling up designs for a new higher power output designs and applying the scaling rules for stresses and loadings are theoretically easy. The real challenge comes in the process of manufacturing the scaled-up designs and handling those parts in production. In the high temperature turbine, the necessity to provide high levels of cooling will challenge the material scientists to come up with novel ways of cooling the blades and vanes that may involve casting double-walled parts to minimize high-temperature gradients that would normally occur in single-walled parts. These complex designs, which utilize the cooling medium several times before it is discharged, are significant challenges to our casting suppliers and can only be considered because we have long term development programs in place that allow concurrent engineering of complex new prototype parts to extend the boundaries of manufacturability.

Currently, Siemens is working with North Carolina State University under a DOE Cooperative Agreement [27] to develop materials for Ultra Super Critical (USC) conditions of 30 MPa (4350 psia) and 1033 K (1400 °F). The results produced by this program, along with results from ongoing gas turbine material and coating technology development, will be applied to develop materials and cooling technologies for the working temperatures required by the oxy-fueled turbine.

TURBINE COOLING

The success of the oxy-fueled turbine system requires controlling the temperature levels of nozzle vanes, rotor blades, and their adjacent structures. Kizuka [16] and others have indicated that closed cooling systems utilizing water to cool stationary components and steam to cool rotating components was an optimum combination for a 1978 K (3100 °F) turbine. For the oxy-fueled turbine, steam will be considered for the cooling of rotating components but both water and steam will be considered for the cooling of stationary components.

The application of cooling, especially for rotors and casings, will allow the use of gas turbine-type designs with thinner walled components that are not currently used in modern steam turbine designs. Cooling and the judicious use of thermal barrier coatings (TBCs) are expected to further reduce the cost of materials for the major component groups.

INTEGRATED SYSTEM CONTROL

Subsystem process interactions in an IGCES plant are different than in a conventional IGCC plant, including significant control differences associated with the turbine. In an IGCES plant, the ASU feeds both the gasifier that produces syngas and the gas generator that burns syngas, so the control requirements for the ASU, gasifier, and gas generator are more

complex than their counterparts in a conventional IGCC plant. Also, as mentioned previously, the gas generator is likely to be closely coupled with the turbine, requiring synchronization between gas generator and turbine during startup, operation, and all forms of plant shutdown.

The design of integrated plant controls will require consideration of the operational requirements, dynamic characteristics, and thermal inertias associated with each of these subsystems so that the plant can be operated safely and without equipment damage under all circumstances.

CONCLUSIONS

Successful execution of the current CES and Siemens projects will demonstrate key components needed for zero emission coal-fueled power plants, paving the way for commercial power plants using this technology within a decade. The CES cycle will play a significant role in the United States' energy future. Such a power plant has negligible environmental impact and can be located wherever power is needed. In many cases these locations will be places at which traditional power generation systems could not be licensed because of their environmental impacts. CES technology removes one of the biggest obstacles – *pollution* – to the development of new coal-fired power plants, and does so at an economical cost. This project will make a significant contribution to the advancement of the administration's clean coal goal for a more secure energy future that is reliant upon coal rather than imported fuels such as LNG.

Under the scenario described in this paper, CES technology could be a key component to fulfill future near-zero emissions power plant objectives. The high-value hydrogen would be available for offsite use, and the "low value" residual gas consisting of carbon monoxide, some hydrogen, and some carbon dioxide would be used for onsite power production. Further optimizations include the ability to shift hydrogen oxygen production to off-peak periods, providing the flexibility to produce more electricity during peak hours.

NOMENCLATURE

Arg – Argon
 Aspen-Plus® – Power Plant Design Software
 ASU– Air Separation Unit
 Btu – British thermal unit
 CEC – California Energy Commission
 CES - Clean Energy Systems, Inc
 COE – Cost of Electricity
 Comp. – Compressor
 Cond – Condenser or Steam Condensate
 CH₄ – Methane
 CO₂ – Carbon Dioxide
 CO – Carbon Monoxide
 Cryo - Cryogenic
 CS – Coal Syngas
 CW – Cooling Water

DOE – Department of Energy
 EOR – Enhanced Oil Recovery
 ECBM – Enhanced Coal Bed Methane Recovery
 FW – Feedwater
 °F – Degrees Fahrenheit
 GB – Gearbox
 Gen. – Generator
 GW – Gigawatt (1000 MW)
 GG - Gas Generator
 GO₂ – Gaseous Oxygen
 GN₂ – Gaseous Nitrogen
 H₂ – Hydrogen
 HP – High Pressure (Turbine)
 HHV – Higher Heating Value
 H₂O – Steam or Water
 HPT- High Pressure Turbine
 HRSG – Heat Recovery Steam Generator
 HST- High Speed Turbine
 HTIPT – High Temperature IPT
 HTT- High Temperature Turbine
 HX – Heat Exchange
 IGCC – Integrated Gasification Combined Cycle
 IP – Intermediate Pressure (Turbine)
 ITM – Ion Transport Membrane
 K – Degrees Kelvin
 kW - Kilowatt
 kWh – Kilowatt Hour
 kWt – Kilowatt – thermal input power
 kWe – Kilowatt – electric output power
 LHV – Lower Heating Value
 LLNL – Lawrence Livermore National Laboratory
 LN₂ – Liquid Nitrogen
 LNG – Liquefied Natural Gas
 LO₂ – Liquid Oxygen
 LP - Low Pressure (Turbine)
 LPT- Low Pressure Turbine
 LST – Low Speed Turbine
 LTT – Low Temperature Turbine
 MWt – Megawatt, thermal input power
 MEA - Monoethanolamine
 MPa – Megapascal (145.04 lbf/in²)
 N₂ – Nitrogen
 NG – Natural Gas
 NH₃ - Ammonia
 NOx – Nitrogen Oxides
 O₂ – Oxygen
 psia – pounds per square inch, absolute
 RH- Reheater
 SOx – Sulfur Oxides
 Stm.- Steam
 TBC – Thermal Barrier Coating
 TMF – Thermal-Mechanical Fatigue
 TX – Turbo-Expander
 USC – Ultra Super Critical
 ZEPP – Zero Emission Power Plant

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