"Power Generation with 100% Carbon Capture and Sequestration"

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ABSTRACT

Clean Energy Systems (CES), of Sacramento CA, has developed and demonstrated a technology which will enable construction and operation of efficient, zero emission power plants. The enabling technology has been tested under a Vision 21 program, co-funded by DOE/NETL. The CES gas generator, combined with a modern gasification technology and current turbine technology, will make possible zero atmospheric emission operation of coal fired power plants at costs comparable to IGCC plants with partial (85%) carbon sequestration. In addition to explaining the basic CES generating concept, this paper presents the accumulated test results and performance evaluations of the gas generator tested under the Vision 21 program completed in the first quarter of 2003. Also included are examples of applications of the new technology, in conjunction with current and higher performance steam turbines, resulting in substantially higher plant efficiencies. Plant economics and net plant efficiencies for various configurations in the Near Term (5 years) and the Long Term (10 years) are presented in comparison with combined cycle plants of similar output. Demonstration projects that are under development are also discussed. The CES technology permits essentially 100% carbon dioxide separation and capture at an estimated US$9 per metric ton, compared to US$32 per metric ton for combined cycle plants. These costs include the transport costs (pumping) from the generating source to the sequestration site.

THE CES PROCESS

Clean Energy Systems, Inc. (CES) has developed zero-emission fossil-fueled power generation technology, integrating proven aerospace technology into conventional power systems. The core of CES' process involves replacing steam boilers and flue gas cleaning systems with "gas generator" technology adapted from rocket engines. The gas generator burns a combination of oxygen and any gaseous hydrocarbon fuel to produce a mixed gas of steam and carbon dioxide (CO_2) at high temperature and pressure, which can power conventional or advanced steam turbines. A simplified schematic diagram of the process is shown in Figure 1.

Efficiencies higher than any current or planned power systems are obtainable for utility-sized power plants. The gas generator can operate on a range of fuels including natural gas, syngas from coal or biomass, or methane from landfills, and the power cycle is a net producer of water, most of which is recycled to the combustor.

From the turbines, the exhaust gas enters a condenser/separator where the drive gas is cooled, separating into its components, water and CO_2, with the CO_2 either sold or sequestered. The gas generator technology has been used successfully in aerospace applications for decades, including in the Space Shuttle main engines, where hydrogen and oxygen are combusted to produce steam at high temperature 816 C (1500 °F) and pressure 34.48 MPa (5000 psia). Likewise, high-temperature 1427 C (2600 °F), moderate-pressure turbines 2.76 MPa (400 psia) have been used successfully in aerospace applications. Every other component in the CES process is commercially proven and is standard in power generation or other industries.

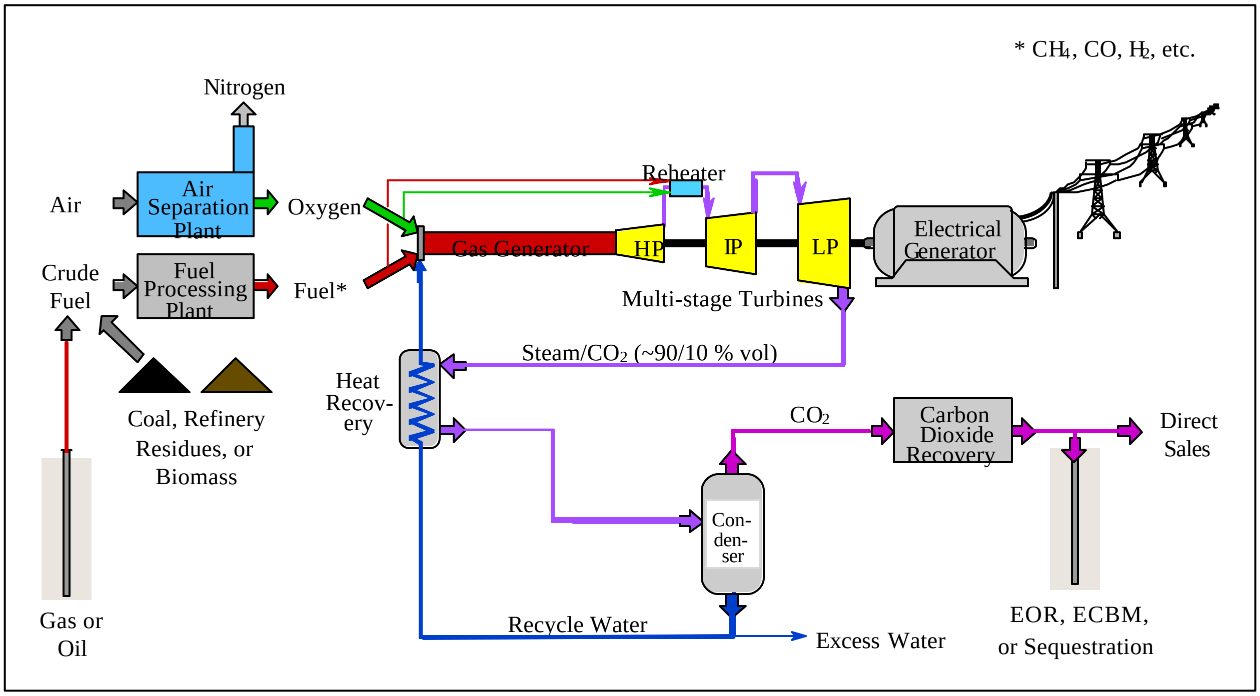

Figure 1. The CES Process

CES' approach has been e to apply gas generators and high-temperature, high-pressure turbines from aerospace applications to power generation, much like the process by which aircraft jet engines were adapted for aero-derivative gas turbines in conventional power plants.

CES technology works with today's turbines to produce power without pollution. The first generation power plants will have energy cost structures below those of other clean energy sources, such as wind and solar power. Since the CES process will be less efficient than conventional combined-cycle plants until the commercial availability of higher-temperature, higher-pressure steam turbines, the initial target markets will be those where a premium is placed on clean energy. With the introduction of advanced turbines (which have been held back by historical boiler steam temperature constraints), it is expected that power plants based on CES technology will operate at efficiencies equal to or above those achievable with combined cycle plants. At the same time, CES power plants would capture and compress the CO_2 to sequestration conditions.

There are no exhaust gases to be cleaned, and no emissions of sulfur oxides, nitrogen oxides, or other pollutants. On a long-term basis, power plants based on CES technology, including all costs associated with obtaining oxygen, will be cost-competitive with comparable combined-cycle technology. In re-powering situations, the CES gas generator could replace a conventional boiler and eliminate the emission of regulated pollutants. This is an important application in those markets with severe air pollution and transmission constraints, such as most large U.S. urban zones.

TECHNOLOGY DEVELOPMENT

In 1999 CES built a test bench and operated a lab-scale gas generator at temperatures up to 1482 C (2700 °F) and pressures up to 2.07 MPa (300 psia). The gas generator operated repeatedly, reliably, and stably during more than 75 starts, with individual test durations up to 48 minutes. This program experimentally established the "proof of principle" for a new method of producing clean, high-energy drive gases for the generation of electrical power from fossil fuels. Funding was provided in part by the California Energy Commission under an Energy Innovation Small Grant (EISG Grant 99-20).

In 2000, the DOE/NETL awarded CES a jointly funded program under the Vision 21 Program to fabricate and test a 20 MW_t ($10MW_e$) gas generator. This program produced a utility scale gas generator which was tested in Santa Clarita CA, during 2002 and early 2003. The program goals were to demonstrate a non-polluting gas generator at temperatures up to 1649 C (3000 °F) at 10.34 MPa (1500 psia), and to demonstrate resulting drive gas composition comprising steam and carbon dioxide, that is substantially free of pollutants. The principal objectives called out in the agreement of this program were to design, fabricate and test a prototype gas generator to demonstrate the non-polluting aspects of the concept, evaluate performance, and verify operational characteristics.

The test unit has a nominal size of $10MW_e$ (1361 kg/hr (3,000 lb/hr) of methane), assuming a plant efficiency of 50%. The prototype has been built and tested. It burned methane with oxygen, and deionized water was used to cool the combustor, produce the drive gas, and control the exhaust gas temperature. Parametric data was collected to characterize the operational performance. Post-test inspection and assessment of the device confirmed no significant material degradation, and the gas generator can be used for future testing.

THE 20 MW GAS GENERATOR TEST RESULTS

The NETL/CES Gas Generator program has proceeded through design, fabrication, and testing. Testing of the complete gas generator began in September 2002 at National Technical Services' facilities in Santa Clarita, CA. Final extended-duration testing, with gas sampling, was concluded in February 2003, and the Final Report will be delivered in May 2003. All the stated objectives of the program have been attained except for the analysis of gas samples during steady-state operation, which is discussed below. The igniter for the gas generator had been previously tested successfully at Aerojet–General facilities in Sacramento CA, during the period of September-October 2001. Testing of the 20 MW_t gas generator was performed, with only minor adjustments, in accordance with the DOE program approved Test Plan.

A summary of the planned tests versus those completed is shown in matrix form in Table I. The upper portion of the table is relevant to component and assemblies and non-firing tests only except for the igniter. The components and assemblies tested include:

(1) the igniter,
(2) igniter/main injector assemblies,
(3) cooldown chamber/diluent injector assemblies, and
(4) main injector/combustion chamber assemblies.

The types of tests conducted on most of these components or assemblies included:

(1) static proof tests to pressures near 20.69 MPa (3000 psia),
(2) leak tests using gaseous nitrogen,
(3) flow calibration of contained flow circuits to define flow rates versus differential pressures using fluids O_2, CH_4 (methane), or H_2O, as appropriate,
(4) valve timing tests to establish the times from actuation signals to the achievement of prescribed pressure or flow responses at downstream points,
(5) pattern checks of the various injectors to assure they produce the desired distributions of the fluids, and
(6) hot-fire testing of the stand-alone igniter at Aerojet

All planned tests of components and subassemblies were completed. The results of these tests were judged satisfactory and the hardware was deemed acceptable for hot-fire testing.

The gas generator configurations to be tested included:

(1) the uncooled copper chamber with injector design "A,"
(2) the uncooled copper chamber with injector design "B,"

(3) fully cooled gas generator with injector "A," and
(4) fully cooled gas generator with injector "B."

The types of hot-fire tests conducted on these configurations of the gas generator included:

(1) tests of the igniter only installed within the combustion chamber,
(2) low-fire (nominal 20 % of rated full power) gas generator tests,
(3) high-fire, full power (~ 20 MW_t) gas generator tests of various durations:
    (a) short duration (up to ~ 10 sec),
    (b) extended durations (up to ~ 1 min.),
    (c) extended duration with gas sampling (up to ~ 3 min.)

The test durations were limited by the high-pressure feed supplies of the test facility and the high demands for fuel, oxygen and water at the 20 MW_t power level. All but two of the originally planned sets of hot-fire tests described above were completed. The extended duration tests of the fully cooled chamber with injector "B" were not conducted because, in the course of three tests of the uncooled copper chamber with the injector "B", that injector suffered extensive damage and as a consequence was judged to be an unsuitable design and unfit for further testing. Thus, the only extended duration hot-fire tests were done with limited gas sampling on the fully cooled gas generator with injector "A".

SUMMARY OF GAS GENERATOR TESTS AND SIGNIFICANT RESULTS/FINDINGS

A summary of all 20 MW_t gas generator testing is presented in Table I. That summary describes the types of tests conducted, the number of valid tests in each category, the cumulative test time and maximum test duration (where applicable), and the corresponding significant results and/or findings derived from those tests.

Tests demonstrated that the igniter operates successfully over the prescribed ranges of pressure and mixture ratios, is repeatable, and reliable through more than 80 ignitions. Injector "A" has been operated successfully at both low power (~ 20 % of rated power) and at rated power (~ 20 MW_t) in more than 60 valid tests and 700 sec. of cumulative operation. Injector "B" was tested but exhibited extensive damage after only two low-fire and one high-fire tests and ~ 10 sec. of operation. This indicates that injector "B" is an unacceptable design. The uncooled gas generator configuration (no diluent injectors or cooldown chambers installed) has produced drive gases at temperatures in excess of 1649 C (3000 °F) and greater than 10.69 MPa (1550 psia). The fully cooled gas generator configuration with cooldown chambers and injector "A" operated continuously to the duration limits of the test facility (more than three minutes) at pressures in the range from 7.59 MPa (1100 psia) to 10.62 MPa (1540 psia) and produced drive gases with temperatures in the range of 316 C (600 °F) to 982 C (1800 °F).

These tests demonstrated the gas generator to be capable of producing steam-rich turbine drive gases at very high pressures and at temperatures ranging from a high of greater than 1649 C (3000 °F) to as low as 316 C (600 °F). Such drive gases can re-power existing power plants and convert them to near-zero emissions facilities, or be used to power advanced turbines in efficient, near-zero emission power plants.

In November testing revealed the need to modify the gas generator to separate the water-cooling and water-injection circuits to the combustion chamber and thereby better assure positive water-cooling of all components exposed to the combustion gases during the critical start transient. Relatively minor hardware modifications to accomplish the separation of water-cooling and water-injection circuits were implemented in December 2002.

The final series of tests, involving longer duration tests and gas sampling, was restarted in January 2003 and was completed in February 2003. These latter tests proved the hardware modifications to be acceptable and beneficial. Test durations up to the limit of the test facilities (approximately 3 minutes) and gas sampling were accomplished.

Table I
Summary of 20 MW_t Gas Generator Tests

Type of Test	Valid Tests	Accumu. Time, sec.	Max. Dur.,sec.	Significant Results/Findings
Tests Conducted at Aerojet				
Igniter only	17	130	25	Demonstrated satisfactory operation over prescribed ranges of pressures and mixture ratios
Tests Conducted at NTS				
Leak tests	2	NA	NA	Assembled complete gas generator (two configurations) and passed leak tests
Water flow tests	7	NA	NA	Measured flow rates versus ΔP's to define orifice sizes to properly balance flow circuits
CH_4 flow tests	4	NA	NA	Measured flow rates versus ΔP's to define restrictors to properly balance flow circuits
O_2 flow tests	2	NA	NA	Measured flow rates versus ΔP's to define restrictors to properly balance flow circuits
Valve timing	7	NA	NA	Measured valve actuation and line fill times to define appropriate valve sequencing
Igniter in GG	8[1]	69	7	Demonstrated repeatable operation in assembled gas generator at NTS test facility
Uncooled Chamber with Injector "A"				
Low-fire tests	5	8	3.4	Demonstrated successful main chamber ignition and combustion at 20 % of full power
Full power tests	8	22	7.4	Demonstrated full power gas generator operation at rated pressure (≥ 1550 psia)
Uncooled Chamber with Injector "B"				
Low-fire tests	2	8.2	4.1	Demonstrated successful main chamber ignition and combustion at 20 % of full power
Full power tests	1	1.8	1.8	Successful operation at full power and pressure but injector suffered damage
Cooled Chamber with Injector "A"				
Low-fire tests	24[2]	13.1	1.1	Demonstrated successful main chamber ignition and combustion at 20 % of full power
Full power tests	37	664	181	Demonstrated full power gas generator operation at pressures of 1100 to 1650 psia. Incorporated beneficial hardware modifications. Performed 3-minute test. Sampled gases.

[1] 21 additional prior tests (10 ignitions and 11 non-ignitions) were required to detect, find, and resolve a facility problem, a failed diaphragm in a fuel pressure regulator.
[2] An additional 37 "low-fire" test operations accompanied the 37 full-power tests.

Data from a typical extended-duration firing of the gas generator (Run # 56, 10/2/02) with an uncooled copper chamber and injector "A" indicated that the gas generator, operated in the low-fire condition (20 % of rated full power) for approximately 1 sec., then ramped rapidly and smoothly to full power and a very stable operating pressure of 10.79 MPa (1564 psia). The calculated gas temperature was 1593 C (2900 °F). The test was conducted essentially at stoichiometric ratio to form H_2O and CO_2 (O_2 to CH_4 equivalence ratio of 1.003). The gas generation rate was 14,966 kg/hr (33,000 lb/hr) at 10.79 MPa (1564 psia) and 1593 C (2900 °F) or 18.6 MW_t LHV.

Data from a typical extended-duration firing of the gas generator (Run # 115, 11/5/02) with a cooled chamber and injector "A," and four cooldown chambers with diluent injectors, indicated that when this gas generator configuration operated in the low-fire condition (approximately 20 % of rated full power) for approximately 1 sec., then ramped rapidly and smoothly to full power, the steady-state operating pressure was 9.62 MPa (1395 psia) and produced drive gases at 660 C (1220 °F) near the exit of the third cooldown chamber and 579 C (1075 °F) near the exit of the last (fourth) cooldown chamber. The test was conducted slightly above the stoichiometric ratio to form H_2O and CO_2 (O_2 to CH_4 equivalence ratio of 1.03). The gas generation rate was 23,583 kg/hr (52,000 lb/hr) at 9.62 MPa (1395 psia) and 579 C (1075 °F) or 18.5 MW_t LHV.

APPLICATION OF CES TECHNOLOGY IN COAL POWER PLANTS

Currently and for the near future, coal provides a substantial portion of the world's supply of electric energy. Pollution from coal-fired power plants is a pressing environmental problem and the emission of carbon dioxide is of increasing concern in regard to global warming. The CES technology allows economical production of electricity from virtually any gaseous fossil, or biomass fuel with zero atmospheric emissions. The CES approach, which was described in detail in previous conferences[1, 2], involves oxygen-blown gasification of coal. The resulting gaseous syngas is cleaned of corrosive components and burned with oxygen in the presence of recycled water in a gas generator. The combustion produces the drive gas composed almost entirely of steam and CO_2. This gas drives turbines/electric generators to produce electricity. The turbine discharge gases pass to a condenser where water is captured as liquid and gaseous CO_2 is pumped from the system. The CO_2 can be economically conditioned for enhanced recovery of oil or coal-bed methane, or for sequestration in a subterranean formation.

The performance and cost of the power plants are based on the use of syngas obtained from Illinois No.6 coal using a Texaco gasification process. Table II presents the operating conditions for turbines in the anticipated time period of the emerging technologies. Studies of further cycle optimization, with ASU-power cycle integration, indicate that significant improvements in efficiency of four to six percentage points are possible.[3]

Table II
Operating Conditions of Turbines for Various Technologies

Turbine technology	**Current technology**	**Near-term (5yr) technology**	**Advanced (10 yr) technology**
Inlet conditions	Press. - Temp., MPa - C	Press. - Temp., MPa – C	Press. - Temp., MPa - C
High-press. Turbine	10.34 - 649	10.34 – 816	10.34 - 816
Interm.-press. Turbine	2.62 - 566	2.62 – 1427	2.62 - 1649
Low-press. Turbine	0.31 - 566	0.31 – 1427	0.31 - 1649
Plant efficiency (no syngas plant losses)	40%	56%	60%
Plant efficiency (with syngas plant loss)	32%	48%	53%

For purposes of calculating plant efficiency, the compressed CO_2 is assumed to be compressed to a pressure typically ranging from 10.00 MPa to 24.82 MPa (1450 to 3600 psia) for sequestration into subterranean oil strata, coal seams, or aquifers.

The overall plant efficiency is based on several technologies that will be discussed in more detail in the next section of this paper, related primarily to the development of steam turbines that operate at higher temperatures than current steam turbines, and to the reduction of the air separation plant capital costs and power consumption. The turbine operating pressures and temperatures of CES plants at various development stages are shown in Table II, while the performance characteristics and efficiencies for CES plants and combined cycle plants are listed in Table III.

The advanced air separation technology uses ion transfer membranes (ITM). This technology is projected to have lower capital costs and lower power consumption than those of current cryogenic plants. It is expected that ITM plants will have a capital cost of 73 to 85 % of the cost of cryogenic plants and power requirements that range from 55 to 70% of cryogenic plants.[4] These modest improvements were not included in this study. However, the use of ITMs could reduce the cost of electricity by about 4% for combined cycles and 8% for CES plants.

In Table III, the CES power plants produce no atmospheric emissions and have efficiencies ranging from 32 to 53 % depending upon the state of turbine development, while the combined cycle plants with no CO_2 control and partial CO_2 control have efficiencies of 46 and 37 %, respectively.

Table III
Comparative Electricity Cost for 400 MW_e Plants Using Syngas, and Operating on CES and Combined Cycle Technologies

Plant Operating Factors	**CES[3]**			**Combined Cycle[5, 6]**	
Turbine Technology	***Current***	***Near-Term***	***Advanced***	***Current Technology***	
Plant Thermal efficiency, (With Syngas Plant)	32	48	53	46	37
ASU plant type	Cryo	Cryo	Cryo	Cryo	Cryo
ASU Plant Size, Metric Ton/Day	8774	5849	5297	2118	2633
Capital Cost, US$/$kW_e$	1872	1412	1318	1457	1865
Coal cost, US$/GJ (LHV)	1.19			1.19	
Emissions of NO_x, kg/MWh_e	0.00			0.03	0.04
Emissions of CO_2, kg/MWh	***0.00***			***745***	***139***
	Unit Costs, $				
Capital Unit Cost, $/kWh	0.040	0.030	0.028	0.031	0.040
Fuel Cost, $/kWh	0.013	0.009	0.008	0.009	0.012
Maintenance Cost, $/KWh	0.008	0.006	0.005	0.006	0.008
Cost of Electricity, $/kWh	***0.061***	***0.045***	***0.041***	***0.046***	***0.060***
CO_2 Seq. Cost, $/Metric Ton	***6.3***	***4.6***	***4.2***	***NA***	***29.1***
Carbon Seq. Cost, $/Metric Ton	***23.2***	***17.0***	***15.5***	***NA***	***107***

The CES near-term plant technology is expected to become commercially available in less than one decade. When this technology is available, the cost of electricity of a CES plant with ***full*** exhaust gas sequestration is comparable to the cost of electricity of a combined cycle plant with ***no*** exhaust gas sequestration. Table V shows that the cost of sequestration per metric ton of CO_2 in CES plants, ranges from $4.2 to $6.3/metric ton versus $29.1/metric ton CO_2 for a combined cycle plant. These values are based on energy required to separate and compress CO_2 from turbine exhaust pressure to 14.48 MPa (2100 psia). For this task, CES plants require 102 kWh/metric ton and a combined cycle plant, using an exhaust absorption/endothermic stripping process, requires approximately 485 kWh/metric ton CO_2.[5] The ideal minimum energy required to isothermally (27 C (80 °F)) compress CO_2, over this specified pressure range, is 74 kWh/metric ton CO_2. Also, an additional cost of $3.0/metric ton, for transporting (pumping) the CO_2 from the generating station to the oil field, was used by Ruether *et al.*[7] and Wallace.[8] Using these values, the total cost for conditioning and transporting CO_2 to the injection site is approximately $7-9/metric ton for CES plants and the $32/metric ton for combined cycle plant.

BASES FOR COST AND PERFORMANCE DETERMINATIONS

A method for assessing the economics of a power plant is to calculate the unit cost of electricity (COE) produced by the plant.[9] To determine this cost, the following information is used:

A - Unit capital cost, ($/kWh)
B - Plant net thermal efficiency
C - Fuel cost, ($/kWh)
D - Operating and maintenance cost, ($/kWh).

If income from plant by-products is excluded to simplify the calculations, the cost of electricity is given by: COE = A + C + D, where C is a function of B, and where D is conservatively estimated to be D = 0.15 x (A + C). Plant capital cost was based on 85% utilization, 20-year life span, and 15% capital recovery cost.

The comparative electricity costs for various CES plants versus various types of combined cycle plants are listed in Table V. Table V shows that the cost of electricity for CES plants ranges from $0.041/kWh to $0.061/kWh. This variation of 33 % illustrates that the unit capital cost (67%) dominates the cost of electricity, while plant efficiency and fuel cost (20%) have a secondary effect. Others report similar results.[10]

Assessment of the other integrated gasification combined cycle (IGCC) plants listed in Table V shows that the cost of electricity varies from a low of $0.046/kWh with no exhaust gas sequestration to approximately $0.060/kWh with sequestration. This latter cost is approximately one third higher than the corresponding electricity cost of CES plants using near-term steam turbine technology. CES plants using current steam turbine technology have electricity costs comparable to combined cycle plants that sequester CO_2, but with 100% carbon capture versus 85% to 90% for conventional IGCC with post?-combustion carbon capture.

An advantage of the CES technology over combined cycle technology is the lower cost to condition CO_2 for sequestration of US$4.2-6.3/metric ton versus $29.1/metric ton. This lower CO_2 conditioning cost could provide additional revenue for CES plants where the CO_2 could be used for enhanced oil or coal bed methane recovery, or could be sold as an industrial by-product.

REQUIRED STEAM TURBINE IMPROVEMENT

The economic studies, summarized in Table V, show the cost benefits of improved steam turbine technology over today's designs that operate at 566 C (1050 °F). The goal for the near-term high-pressure turbine is 816 C (1500 °F). The near-term technology has been set at approximately 816 C (1500 °F) to eliminate blade cooling when using high-temperature nickel alloys such as: IN 718, IN 617, IN 625, Waspaloy or Haynes 230. With modest cooling requirements, existing low cost stainless steel steam turbine materials could be used.

The near-term technology has been demonstrated in the DOE/Solar program[11] by design analysis per ASME Boiler Code and by tests of 105 hrs. The space shuttle fuel turbo pump has operated repeatedly over a twenty-year period at temperatures of 760 C (1400 °F) and at a pressure of 47.9 MPa (6950 psia), which is substantially higher than the 10.34 MPa (1500 psia) pressure that could be used in the high-pressure turbine.

The near-term intermediate pressure turbine that operates at approximately 1427 C (2600 °F) will require the transfer of existing aero-derivative cooling technology while using warm 227 C (440 °F) steam rather than air as the blade coolant. For the more advanced, long-term goal of 1649 C (3000 °F) the latest land-based gas turbine technology developed under DOE's Advanced Turbine Systems program by Siemens-Westinghouse and General Electric would need to be stretched. These turbines required closed-loop steam cooling rather than compressor discharge air to achieve the high turbine efficiency goal of 60%. Cascade testing on turbine blades in Japan[12] using steam at 1700 C (3092 °F) demonstrated operation on model size stator and rotor blades. The blade heights were 71 mm (2.8 in.) and the test pressure was 2.81 MPa (408 psia) for the stator and 3.53 MPa (512 psia) for the rotor. Test times at rated temperatures were 24 minutes and 22 minutes respectively for stator and rotor tests. The stator and rotor blades were made of FSX-414 and CMSX-4 respectively. Both were coated with thermal barrier coating (TBC) of ZrO_2 – 8% Y_2O_3. Since steam cooling has more than twice the cooling capacity of air, it may be possible to use existing low-cost steam turbine materials for the intermediate and low pressure turbines without incurring excessive cooling losses – at least for near-term designs. CES is preparing a paper specifically addressing the required development path for advanced steam turbines. Preliminary results indicate that current aeroderivative and industrial gas turbines can be driven by a mixed gas of steam and carbon dioxide with few modifications.

USE OF HYDROGEN-DEPLETED COAL SYNGAS

A key attribute of the coal gasification process is the ability to co-produce hydrogen and other high-value liquid fuels from the synthesis gas. Different technologies are available for processing the syngas into separate streams, ranging from the production of essentially pure hydrogen and carbon dioxide following a shift reaction and separation process, to extracting a portion of the hydrogen, leaving a hydrogen-depleted syngas for power generation purposes. This latter option may be particularly attractive if the objective is to produce hydrogen for offsite uses, such as future transportation applications, while still providing a fuel source for onsite power generation, other than the hydrogen itself, which represents a high-value product. All of the performance and cost figures presented above are based on all of the coal syngas being available for power production, without any separation or extraction of hydrogen for offsite uses.

While further analysis is required, 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 by condensing the steam component of the drive gas. Under this scenario, CES technology could be a key component to fulfill FuturGen objectives. The high-value hydrogen is available for offsite use, and the "low value" residual comprising CO_2,carbon monoxide and/or hydrogen is used for onsite power production. Further optimizations include the ability to shift hydrogen and oxygen production to off-peak periods, providing the flexibility to produce more electricity during peak hours.

NEXT STEPS – A 500 KW DEMONSTRATION PLANT

In December 2001, the California Energy Commission awarded CES a $2 million grant for co-funding a small (500 kW) demonstration power plant, to be located in Antioch, California. This proposal was jointly developed with Air Liquide and Mirant Corporation. Basic engineering has been completed, all permits have been obtained, and the steam turbine has been purchased and overhauled for this project. The project team is currently procuring the plant control system, and will conduct additional operational tests simulating typical power plant operating conditions.

The gas generator will be operated over a range from 0.5 to 5 MW_e (1.5 to 15 MW_t) and independently controlled by the plant digital control system. Testing will include full load, part load, and transient conditions. Temperature, pressure, and mass flow rates will be individually varied while other parameters are held constant to evaluate the system's robustness and response to simulated steam turbine throttling. Fuel quality and excess oxygen set-points will also be varied. This testing is scheduled to take place the summer and fall of 2003, with plant startup occurring in 2004. The plant, once on line, is planned to operate continuously for two years to obtain durability data on the gas generator.

In addition, CES is working on projects in the 20 MW_e to 70 MW_e range, primarily in California. Discussions are also being held with industrial partners for possible projects in the Netherlands and Norway. Other potential applications of the technology are being explored, but are not at sufficient levels of development to warrant public discussion.

DEVELOPMENT OF A NATIONAL ZERO-EMISSION POWER PLANT TEST FACILITY

CES has been working with Lawrence Livermore National Laboratory (LLNL) and others to develop a 5-10 MW test facility based on CES technology. Initial efforts focused on locating the facility at LLNL to take advantage of a neighboring oil field. The purpose of the facility would be to provide a test bench for advanced turbine and materials development, to allow optimization of the basic gas generator technology, and to provide a field demonstration of enhanced oil recovery in fractured and immiscible oil fields.

As an alternate location for a national test facility, CES identified an idled biomass plant in Southern California, which has unique characteristics to serve as a potential long-term test facility. The plant was shut down due to its inability to meet permitted air emissions, yet the basic power cycle infrastructure is in very good shape. CES is currently developing this project to serve as a small-scale national test facility for oxy-combustion technologies with carbon sequestration. While still in an early development stage, LLNL has expressed interest in supporting these studies, along with a major industrial company and the California Energy Commission.

The project site, located near Bakersfield, California, is located within five miles of major oil fields, both operating and abandoned. Additional fields within ten miles or the project site offer the capability to conduct sequestration studies in abandoned gas fields, and injection into the Central Valley saline aquifer system can be conducted directly at the plant site.

The first phase envisions re-powering the existing steam cycle to produce approximately 4 MW of net electrical output, and approximately 100 tons per day of carbon dioxide. The quantities are not sufficient for large-scale or commercial sequestration projects, but should prove adequate for pilot and demonstration purposes. The operating conditions of the existing 6 MW steam turbine will support "upstream" installation of a high-pressure, high-temperature advanced steam turbine, such that the new turbine discharge can match the existing steam turbine's inlet conditions. This second phase will provide a test bed for advanced steam turbine development and durability testing, and will also improve the test facility operating efficiency.

Concurrent with the second phase, or subsequently in a third phase, an existing extraction steam line can be used to feed a reheater, similar to the one developed by DOE/NETL and described elsewhere[13, 14]. This reheater, in turn, can drive an advanced, high-temperature, intermediate pressure turbine incorporating gas turbine technology into a steam turbine application. All of the above testing would be performed at a 1 to 5 MW range, which is small enough to keep program costs manageable, but large enough to demonstrate these technologies as being ready for the first commercial demonstration plants.

Another attribute of this particular site is the possibility to gasify coal or biomass products in support of the zero-emission coal plants described earlier in this paper. With rail access and existing material handling infrastructure, a small-scale zero-emission coal plant could be added as yet another project phase.

Given the significant flexibility to be a component and product test site, as well as the near-ideal location for supporting multiple carbon sequestration studies, CES will collaborate with interested parties on the development of this facility. Initial ROM costs to re-power the facility and install the basic carbon compression and transport system are estimated at \$10 to \$12 million.

SUMMARY and CONCLUSIONS

A ten-year effort to develop and demonstrate near-zero emission oxy-combustion has resulted in the testing of a 20 MW_t gas generator and a high-temperature, intermediate pressure reheater. A small demonstration plant is under development and is expected to be online in 2004. Also, a potential long-term test facility incorporating carbon sequestration projects has been identified and is under development.

Using existing steam turbine technology, power plants based on CES technology can be built in the 20 MW to 70 MW range that are comparable in cost to other "green and clean" energy technologies, in particular windpower. With improvements in turbine technology that are achievable in the near-term, efficiencies in the range of 50% are possible with nearly 100% carbon capture.

CES technology, when integrated with conventional coal gasification technology, can utilize the clean syngas directly for power generation, with post-combustion carbon capture. If hydrogen production is desired for offsite uses, the hydrogen-depleted fuel gas can be used in a CES power plant with full carbon capture. Future papers will address cycles using hydrogen-depleted syngas fuel sources and the technical requirements for advanced turbines operating on a mixture of steam and CO_2.

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