Advanced, Low/Zero Emission Boiler Design and Operation

Quarterly Technical Progress Report

Reporting Period from October 1st, 2003 through December 31st, 2003

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ABSTRACT

This document reviews the work performed during the quarter October – December 2003. Task 1 (Site Preparation) had been completed in the previous reporting period. In this reporting period, one week of combustion parameters optimization has been performed in Task 2 (experimental test performance) of the project. Under full-oxy conditions (100% air replacement with O_2-enriched flue gas) in 1.5MW_{th} coal-fired boiler, the following parameters have been varied and their impact on combustion characteristics measured: the recirculated flue gas flow rate has been varied from 80% to 95% of total flue gas flow, and the total oxygen flow rate into the primary air zone of the boiler has been set to levels ranging from 15% to 25% of the total oxygen consumption in the overall combustion. In current reporting period, significant progress has also been made in Task 3 (Techno-Economic Study) of the project: mass and energy balance calculations and cost assessment have been completed on plant capacity of 533MW_e gross output while applying the methodology described in previous reporting periods. Air-fired PC Boiler and proposed Oxygen-fired PC Boiler have been assessed, both for retrofit application and new unit. The current work schedule is to review in more details the experimental data collected so far as well as the economics results obtained on the 533MWe cases, and to develop a work scope for the remainder of the project. Approximately one week of pilot testing is expected during the first quarter of 2004, including mercury emission measurement and heat transfer characterization. The project was on hold from mid-November through December 2003 due to non-availability of funds. Out of the ~$785k allocated DOE funds in this project, $497k have been spent to date ($480 reported so far), mainly in site preparation, test performance and economics assessment. In addition to DOE allocated funds, to date approximately $330k has been cost-shared by the participants, bringing the total project cost up to $827k ($810k reported so far) as on December 31st, 2003.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

The present report summarizes the work performed by the participants from September 1, 2003 through December 31st, 2003 (Q4 2003, Q5 of the project).

In the previous quarters (Q1, Q2 & Q3 2003), the site preparation (Task 1) of the experimental test campaign had been completed and the final configuration of the pilot boiler described. The test performance task (Task 2: "Combustion and Emission Performance Optimization task") had been initiated and two weeks of tests performed as on September 30th, 2003, demonstrating the feasibility of air replacement with oxygen-enriched flue gas in $1.5MW_{th}$ boiler. Task 3 (techno-economic study) had also been initiated while specifying power plant characteristics to be assessed and describing the process simulation procedure and cost assessment methodology to be applied.

In the current quarter (Q4, 2003), an additional week of tests has been performed in the scope of Task 2, enabling combustion parameters optimization in full-oxy firing conditions. The parameters investigated are listed in the "Experiment" section of this document, while their impact on combustion performance is reported in the "Results and Discussion" section. In the scope of the Task 3, process simulations and cost assessment have been performed on a first selected plant capacity: $533MW_e$ gross power output. Both air-fired units with and without CO_2 capture option have been evaluated as a baseline in this study, and compared to the oxy-fired unit with flue gas recirculation. Further description of the methodology and references is provided in "Experimental" section, and results in term of capital cost, operating cost and overall cost of electricity are provided in the "Results and Discussion" section.

This report also provides an update of the project financial status and schedule.

EXECUTIVE SUMMARY

The main effort of this quarter (October – December 2003) was primarily dedicated to **Task 2 (Test performance) & Task 3 (Techno-Economic Study)** of the project. The main achievements resulting from current reporting period are the following:

Task 1 (Site Preparation), had been completed in the previous reporting period, and the final boiler configuration described, as available for testing.

In Task 2 (Test performance), one week of combustion parameters optimization has been completed, following two weeks of tests performed in the previous reporting period. In the previous quarter, the feasibility of 100% air replacement by O_2-enriched flue gas on a 1.5MWth coal-fired pilot boiler had been demonstrated, and the procedure to operate a smooth and safe switch from air to O_2/CO_2 conditions described. In current quarter, under same full-oxy conditions, the following parameters have been varied and their impact on combustion characteristics measured: the recirculated flue gas flow rate has been varied from 80% to 95% of total flue gas flow, and the total oxygen flow rate into the primary air zone of the boiler has been set to levels ranging from 15% to 25% of the total oxygen consumption in the overall combustion.

The preliminary conclusions of this combustion optimization under 100% oxygen and recirculated flue gas are the following:

- A stable flame has been obtained, with similar shape as in air-firing operation. From a visual judgment, the oxy-fired flame was colder than air-fired flame, presumably because of higher CO_2 specific heat.
- The air infiltration in the boiler under O_2-conditions has been reduced to a final level of approximately 5% of the overall stoichiometry, thus increasing the initial CO_2 content in flue gas from 15% in air-fired conditions to eventually 80% (corrected to 3% boiler exit oxygen concentration) in O_2-fired conditions. Alternative boiler operating procedures are expected to reduce even more the air infiltration to achieve higher CO_2 concentration in flue gas for further sequestration or reuse.
- The flue gas volume exiting the boiler has been reduced by 70% thus making easier any additional flue gas treatment which may be necessary before stack exhaust or CO_2 reuse or sequestration.
- As noticed during previous quarter, the NO_x emissions have been shown considerably lower in O_2-fired conditions than in air-baseline, the reduction rate averaging 70%. The baseline NOx emission range was 0.22 to 0.26lb/MMBtu (with low-NOx burner) and dropped to 0.07 to 0.08lb/MMBtu under oxycombustion conditions. NOx emissions is also impacted by oxygen flow rate into the primary air zone and by flue gas overall recirculation rate. This can be explained by higher flame temperature resulting from increased O_2 content in primary air zone or from lower flue gas flow. Such higher temperature in the reducing zone of the boiler promotes the conversion of recirculated NOx and devolatilized fuel nitrogen to molecular nitrogen.

- Furnace exit flame temperature (FEGT) and convection pass exit gas temperature (CPEGT) have been measured and compared in under oxy-firing than under air-firing conditions. While lower FEGT was measured under oxy-firing conditions, the CPEGT was generally higher. Further studies are required to address boiler heat transfer and steam generation characteristics.

The current work schedule is to review in more details the experimental data collected during the past three weeks of tests and to develop a work scope for the remainder of the project. Approximately one week of pilot testing is expected during the first quarter of 2004, including mercury emission measurement and heat transfer characterization

In Task 3 (Techno-Economic Study), a specific capacity has been selected for process and cost calculations. Based on the methodology described in previous reporting periods, process calculations, including mass and energy balance, and cost assessment have been completed on plant capacity of 533MW_e gross power output for air-fired pulverized coal (PC) units with and without CO_2 separation and oxygen-fired PC units with flue gas recirculation. Air-fired PC Boiler and proposed Oxygen-fired PC Boiler have been compared in both assumptions of retrofit applications or new unit.

The further work in the scope of task 3 will consider the economic analysis of air and oxygen process for different plant capacity. In addition, for OEC process, a second condenser, CO_2 compression and gas-liquid separation may be studied to remove the moisture and non-condensable gas in flue gas, to increase CO_2 concentration to 98% prior to sequestration, which is comparable to CO_2 purity from MEA process.

Task 4 (Boiler Design), will be initiated in 2004. The exact scope of this effort will be discussed and specified in Q1 2004.

The project was on hold from mid-November through December 2003 due to non-availability of funds. Out of the ~$785k DOE cost-share allocated in this project, $497k have been spent to date ($480 reported so far), mainly in site preparation (~$290k spent and reported), test performance (~$167k spent, ~$150k reported so far) and economics assessment (~$40k spent and reported). In addition to DOE allocated funds, to date approximately $330k has been cost-shared by the participants, bringing the total project cost up to $827k ($810k reported so far) as on December 31st, 2003.

EXPERIMENTAL

During this reporting period, the participants have completed an additional week of tests in Task 2 (Test performance) and have completed the first phase of Task 3 (Techno-Economic Assessment) of the project.

1 TASK 1: SITE PREPARATION

Task 1 has been completed in the previous reporting period. The resulting final configuration of the pilot boiler has been described and is shown in Appendix section of this report.

2 TASK 2: COMBUSTION AND EMISSIONS PERFORMANCE OPTIMIZATION

The following subsections describe the tests configuration as performed during this reporting period while the test results are reported and analyzed in the next section of this report "RESULTS AND DISCUSSION".

2.1 Test configuration and coal characteristics

The test configuration (burner, oxygen injection, overall boiler configuration) was the same than in previous reporting period. The low-sulfur sub-bituminous coal burned for those tests had been delivered at the beginning of the test campaign in August 2003 and its composition, already reported in previous quarter, is reminded in Table 1 below.

Moisture (As Received)	26.85 %
Ash (dry)	6.29 %
Volatile (dry)	47.20 %
Carbon (dry)	72.21 %
Hydrogen (dry)	5.00 %
Nitrogen(dry)	0.92 %
Sulfur (dry)	0.41 %
BTU (dry)	12,505 Btu/lb

Table 1: PRB Coal Analysis

2.2 Tests performed during the reporting period

One week of full-oxy combustion optimization tests has been performed in this quarter totaling 4 days of experimental data gathering.

In previous reporting period, the participants had demonstrated the feasibility of 100% air replacement by oxygen-enriched flue gas on the 1.5MW_{th} coal-fired boiler. The air infiltrations had been reduced to approximately 5% of the stoichiometry, enabling to reach around 70% of CO_2 in the flue gases. The NO_x emissions had been shown considerably lower in O_2-fired conditions than in air-baseline, the reduction rate averaging 70%.

During this reporting period, some **overall combustion characteristics** have been measured and the participants performed **optimization of the boiler parameters** to get maximum benefit of the oxygen/flue gas configuration. Two main testing parameters impacting the combustion characteristics have been investigated:

- The flue gas recirculation flow rate
- The oxygen flow rate through the primary air zone

The following sub-sections provide some description of the combustion performance parameters measured and of the optimization parameters varied. The experimental measurements resulting from these boiler setting variations are reported in the "Results and Discussion" section of this report.

2.2.1 Overall combustion characteristics

Specific flame characteristics under full-oxy conditions have been noticed. In addition, in-furnace gas temperature measurements were performed to access evaluation of heat transfer in boiler and convection pass in O_2/CO_2 conditions. Flue gas composition, including CO_2 content was also recorded, as well as pollutant emission levels.

2.2.2 Variation of Flue Gas recirculation rate

For retrofit applications, the flow rate of flue gas has to be optimized such that the oxy-combustion technology produces a positive or at least a minimal adverse effect on heat transfer and steam generation. To assess the impact of flue gas recirculation rate on the combustion performance, the mass flow rate of the recirculated flue gas has been varied from 80% to 95% of the overall flue gas flow rate.

2.2.3 Variation of oxygen flow rate in the primary air zone

In full-oxy conditions to a specific overall oxygen flowrate required to complete the combustion correspond many different primary/secondary/tertiary oxidants composition since the oxygen content in each of the three main types of oxidant can be varied almost independently: oxygen content in the primary air zone, oxygen content in the secondary air zone and oxygen content in the tertiary air zone are controlled by the flue gas recirculation rate in each of this zone and the oxygen injection methods (premixing or oxygen lancing)

In the tests, the oxygen to the secondary air and overfire air port was introduced through the Oxynator (premixing of oxygen and flue gas before injection). The switching of primary air to flue gas was initially performed with addition of oxygen only through a lance at the burner. After all primary air was substituted with flue gas, some oxygen was introduced in the primary air line with the remainder introduced at the burner via lance. With this arrangement we could **vary the overall oxygen concentrations of primary air zone**. Oxygen flow rates ranging from 15% to 25% of the overall oxygen injected into the boiler has been introduced in this primary air zone.

3 TASK 3: TECHNO-ECONOMIC STUDY

In the scope of the techno-economics task of the project, process calculation and economics assessment are performed to compare the Oxygen Enhanced Combustion (OEC) process for power generation to the baseline air blown PC units. Both new and retrofit coal-fired applications are considered. In this study, the OEC process refers to the oxycombustion process with flue gas recirculation.

In the previous reporting period, the various cases to be assesses (plant type, plant capacity, flue gas treatment technologies…) had been described, as well as the methodology to be applied for mass and energy balance calculation and cost assessment.

In the current reporting period, the power generation costs assessments have been performed for a specific plant gross capacity of 533 MWe. Plants burning PRB coal under oxygen-enhanced combustion (OEC) process and conventional air-blown PC were investigated.

3.1 Air-blown and Oxygen-Blown plant configuration

The conventional air blown power plant considered was equipped with a selective catalytic reduction (SCR) process for NOx reduction, an activated carbon injection (ACI) process for mercury removal, a lime spray dryer (LSD) process for SO_2 removal, and an MEA process for capturing CO_2.

The OEC process was equipped with LSD process and ACI process. The SCR system was not considered since the EPA limits for NOx emissions can be met with the OEC process. A CO_2 capture process was not considered for the OEC process. A wet and a dry recycle flue gas configurations were considered to further identify the optimum process configuration. In the wet recycle configuration, water vapor was recycled with flue gas without condensation. In the dry recycle configuration, a portion of the flue gas was subjected to a condensation process before it was recycled to the boiler as a make-up gas.

3.2 Process simulation: calculation of mass and energy balances

Data have been given in the previous quarterly reports describing the flow diagram and the detailed process areas to be simulated.

In the current quarter, the mass and energy flows were calculated based on a gross power output of 533 MWe.

A sub-critical steam cycle for power generation was assumed in all cases. The process was divided into three sectors: coal combustion, steam generation and flue gas cleaning. CHEMCAD software package was used for process simulation and calculations. Typical design and operation conditions for the OEC and conventional plants were adopted from the literature [1,2,8,9].

3.3 Auxiliary power calculation

The items consuming auxiliary power in power generating plants have been described in previous quarterly reports.

In the current quarter, the auxiliary power consumption were calculated for the selected 533 MWe gross power output units.

Most of the auxiliary power in plant, by pumps and fans, was calculated in the simulation according to the fluid flow rates and pressure drops. Auxiliary power included:

- Pumps and fans in flue gas recycle and flue gas drying in the OEC process
- Coal handling and pulverizing (power consumption was assumed to be linear with the coal feeding rate
- Other miscellaneous in-plant power use was linearly scaled from a DOE reference plant based on the mass flow rates or the plant capacity.
- Loss of power generation due to a large amount of steam extracted from the intermediate pressure (IP) turbine to the re-boiler of MEA regenerator in the PC plant with CO_2 capture. The reduced power use of condensate pump and cooling water pump due to steam extraction was also considered.
- Auxiliary power for flue gas cleaning systems such as LSD, SCR and ACI were available from the recent literature.

For the comparison purpose, compression of both the purified CO_2 from MEA and concentrated CO_2 from OEC prior to transportation was not considered in this study.

3.4 Cost assessment

The cost model used to complete this economics assessment has been described in details in previous quarterly reports. In the current quarter, this methodology has been applied to the selected 533MWe gross power output units. Some further methodology information are given in the following subsections while the results are provided in the “Results and Discussion” part of this report.

3.4.1 Cost for new plants

Cost assessment was carried out for the following six sections of a plant based on the data availability in the literature:

1) The basic systems of a plant including the boiler and turbine systems and the ESP,
2) SO_2 removal section,
3) NOx removal section,
4) Activated carbon injection section,
5) CO_2 removal section, and
6) ASU section and related specific components of gas recycle in an OEC process.

Cost of Basic power Plant System

Capital costs of the basic combustion and steam generation systems in a sub-critical power plant with a gross power output of 533 MWe were scaled from a 422 MWe reference plant [1,2]. The scaling was based on the material or energy flows specific to the equipment or system considered (such as the coal feed rate used for estimating the cost of coal pulverizer). In general, a scaling factor of 0.8 was adopted based on the available data. Because the plant size considered in this study is comparable to the reference, the error associated to the scaling-up approach is not significant.

Operating and maintenance (O&M) costs of a power plant mainly include the costs of labor and maintenance, and the costs of consumables. The labor requirement adopted was the same as the reference plant used in this study because labor requirement is roughly independent of the plant size. The maintenance cost was estimated as an annual percentage of installed capital costs. Factors used in EPRI guidelines were also used in this study. The costs of consumables were based on the results of mass flows from simulation studies. Their unit prices were obtained form recent literatures. The price of PRB coal delivered to the site was 20 $/ton.

Cost of Flue Gas Cleaning System

Given the fact that the flue gas cleaning systems including LSD, SCR, ACI and MEA were not covered in the reference plant, the methodologies recently developed by DOE, EPA and EPRI projects were used in the economic analysis. The economic impacts of reduced flue gas volume in the OEC process were also carefully investigated.

3.4.2 Costs for retrofit

In the cases of retrofit, the cost analysis will only consider those existing components in a plant to be modified, and other necessary new components in retrofit. These include the modifications of LSD flue gas desulphurization process and ACI process due to the change of flue gas flow rate, elimination of SCR process in the OEC plant due to reduced NOx emissions in oxygen combustion condition, new installment of MEA process in the conventional PC plant, and new installment of ASU and gas recycle system in the OEC plant.

RESULTS AND DISCUSSION

As described in the "Experimental" section of this report, an additional week of experimental tests has been performed in the current quarter (Task 2). The results are reported and discussed hereafter, providing trends and optimization of the oxygen-fired process with flue gas recirculation.

Results from process and cost calculations on air and oxy-fired units are also reported and discussed in this section, based on the 533MWe gross output case.

Finally project management update are provided in the following "Project Schedule" and "Financial Status" subsections.

1 TASK 2: COMBUSTION AND EMISSIONS PERFORMANCE OPTIMIZATION

As reported in the previous "EXPERIMENTAL" section, optimization tests have been performed in the current quarter under full-oxy combustion with flue gas recirculation. Those latest tests provide additional combustion characteristics of the O_2/CO_2 process, which will be very useful for further retrofit applications of the technology. Although still at small scale the 1.5MWth pilot-boiler used during this campaign features all components of an industrial full-scale PC boiler design.

The experimental measurements resulting from the boiler setting variations described in "Experimental" section are reported in the following subsections.

1.1 Overall Combustion characteristics in O_2/CO_2 environment

A stable flame has been obtained in full-oxy conditions with recirculation, attached at the throat, and flame shape was similar to air firing. The flame emissivity was not measured but the oxy-firing flame was colder (visual judgment) than air firing conditions, presumably because of higher specific heat of CO_2.

Flue Gas Exit Gas Temperature (FEGT) measurements were performed for base line air firing and oxy-firing while the overall mass flow rate was kept constant. Under oxy-firing conditions, the average FEGT was lower by 70 F than air firing. That could be a positive impact if a boiler is operating with above than normal FEGT. The convection pass exit gas temperature was measured for both oxy-firing and air, indicating 535 F and 486 F, respectively. This could be the result of convective surface deposits. Longer pilot-scale tests or site-specific boiler performance studies are required to address boiler heat transfer and steam generation.

1.2 Impact of Flue Gas recirculation rate

As explained previously, the flow rate of recirculated flue gas has to be optimized in oxycombustion technology for retrofit application in order to produces a positive or at least a minimal adverse effect on heat transfer and steam generation, when switching fron air to oxygen/flue gas operation. During these tests, the total flue gas recirculation has been varied and furnace exit gas temperature (FEGT) and convection pass exit gas temperature have been measured to provide insight to the amount of flue gas recirculation required. Figure 4 shows the effect of recirculated gas flow rate on NO_x emissions. The NO_x emission decreased to a minimum of 0.065 lb/MMBtu when the recirculated flue gas flow rate was 83% of normal air firing condition. Under this recirculated flue gas flow rate (83%), the overall mass flow rates through the boiler of air firing and oxygen firing conditions are similar. Figure 1 shows that NO_x emissions decrease as the recirculated flue gas flow rate decreases. This can be explained by the presence of a higher flame temperature with the lower flue gas flow which increases the NO_x destruction in the reducing zone of the burner.

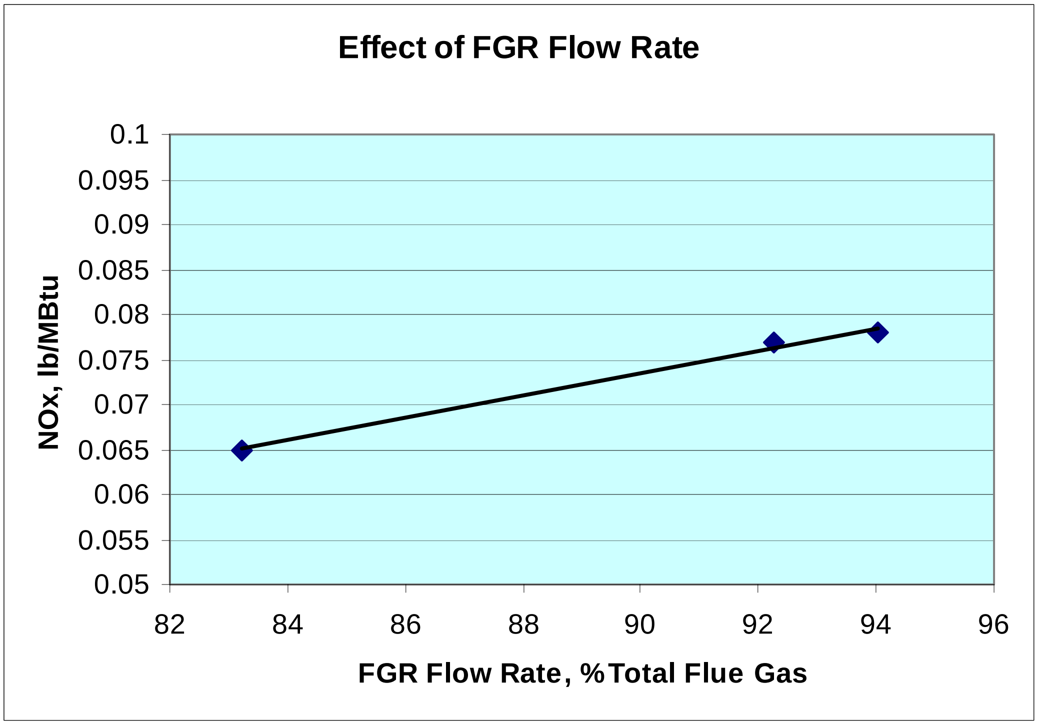

Figure 1: Effect of Recirculated Gas Flow Rate

1.3 Impact of oxygen flowrate in the primary air zone

Figure 2 shows the effect of primary zone oxygen concentration on the NO_x emissions. It should be mentioned that the oxygen concentration in the primary air line always was below 20%, and the balance was introduced by an oxygen lance. The baseline NO_x emission range was 0.22 to 0.26 lb/MMBtu (The commercial units typically generate 0.15 to 0.2 lb/MMBtu NO_x level with this burner) and reduced to 0.07 to 0.08 lb/MMBtu with oxygen enriched flue gas firing (the data was obtained at a burner stoichiometry of 0.83 to 0.89). This can be explained by higher temperature at the main flame zone where recirculated NO_x and devolatilized fuel nitrogen species can be converted to harmless molecular nitrogen.

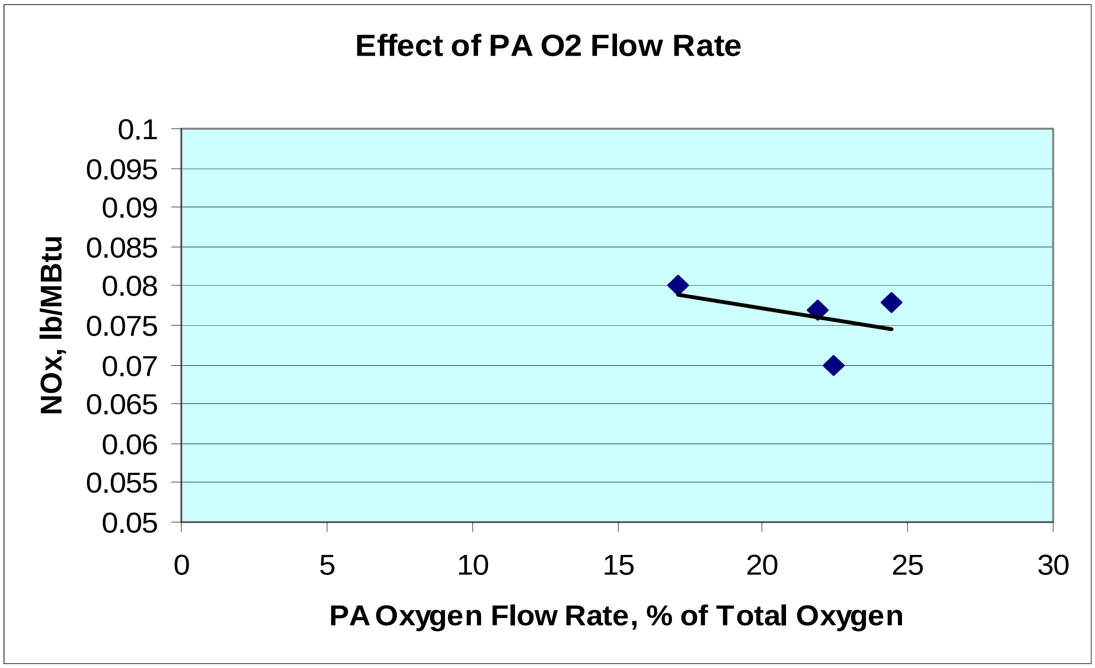

Figure 2: The Effect of Primary Zone Oxygen Concentrations

1.4 CO_2 content in flue gases

One area of concern was air infiltration into the flue gas line. During these tests the maximum CO_2 concentration was 80% (corrected to 3% boiler exit oxygen concentration). The infiltrated air was approximately 5% of the total boiler gas flow rate (air, oxygen, flue gas, coal). Air infiltration has been discussed as an issue for commercial application of this technology. The SBS boiler is balanced draft and operates under slightly negative pressure (-0.5 inch of water). During these tests decision of operation changes has been taken, and the furnace pressure has been increased to slightly positive to minimize air leaks in the boiler. The condensing heat exchanger (CH_x) is operating under slightly positive pressure, and no air leak is expected from it. Therefore, the main sources of air leaks are suspected to be the I.D. fan, baghouse, and scrubber that are operating under higher negative pressures. This level of air leakage is a good representation of potential air leaks in commercial boiler retrofits from the ESP, air heater, etc. There are alternative boiler operating procedures that could be employed to reduce the air leaks.

2 TASK 3: TECHNO-ECONOMIC STUDY

The following sub-sections report the simulation results and cost assessment obtained for 533MWe air-blown and oxygen-blown power plants as described in "Experimental" section of this document.

2.1 Process simulation: calculation of mass and energy balances

Table 2 shows the basic process parameters obtained from simulation studies of the OEC and conventional PC plants.

	Conv. PC W/O CO_2 Removal	**Conv. PC With CO_2 Removal**	**Wet OEC**	**Dry OEC**
Combustion				
Air/O_2 equivalent ratio	1.15	1.15	1.03	1.03
Air flow rate	4029474	4029474	n/a	n/a
O_2/Ar flow rate	n/a	n/a	851275	885740
Coal feed rate	524982	524982	504064	524472
Flue gas recycle ratio	n/a	n/a	71.60%	75.10%
Steam generation				
Hot reheat steam, lb/h	3022125	3022125	3022125	3022125
Superheat steam, lb/h	3422824	3422824	3422824	3422824
IP steam to MEA process	n/a	1470914	n/a	n/a
Steam condensate, lb/h	2802051	1331136	2802051	2802051
Main feedwater, lb/h	3321228	3321228	3321228	3321228
Heat duty of cooling tower, Mbtu/h	2178	1034	2178	2178
Flue gas for cleaning				
Flue gas volume	4526825	4526825	1331136	1154319
Flue gas temperature, ^oF	295	295	295	395
Composition: N_2, vol%	71.62%	71.62%	0.33%	0
O_2, vol%	2.49%	2.49%	1.80%	3.17%
CO2, vol%	14.55%	14.55%	53.74%	76.57%
H_2O, vol%	11.15%	11.15%	41.05%	15.39%
Ar_2, vol%	0	0	2.97%	4.27%
SO_2, vol%	0.0257%	0.0257%	0.0950%	0.1352%
NOx, lb/MMbtu	0.5	0.5	0.15	0.15
Fly ash flow rate, lb/h	22049	22049	21171	22028

Table 2: Main process parameters of OEC and conventional PC plants

2.2 Auxiliary power calculation

The power generation and auxiliary power use are summarized in Table 3.

	Conv. PC W/O CO_2 Removal	**Conv. PC With CO_2 Removal**	**Wet OEC**	**Dry OEC**
Gross Power (terminal), kWe	533230	434850	533230	533230
Auxillary load summary, kWe				
Coal handling	339	339	326	339
Pulverizer	2937	2937	2820	2934
Primary air fans	1212	1212	1264	1243
Forced Draft fans	1154	1154	1204	1184
Induced draft fans	5122	5122	1506	1306
Seal air blowers	46	46	48	47
Steam turbine auxiliaries	884	884	884	884
Condensate pumps	949	891	949	949
* Main feed pump	10938	10938	10938	10938
Circulating water pumps	4187	1989	4187	4187
Cooling tower fans	2367	1125	2367	2367
Ash handling	1424	1424	1367	1423
Miscellaneous	2411	2411	2411	2411
Transformer loss	1215	1215	1215	1215
ESP	1319	1319	388	336
LSD	3500	3500	1029	892
SCR	2750	2750	n/a	n/a
MEA: gas induced fan	n/a	15837	n/a	n/a
MEA pump	n/a	2980	n/a	n/a
ACI	99	99	29	25
OEC flue gas recycle fan	n/a	n/a	1874	1604
Dry OEC condenser pump	n/a	n/a	n/a	1214
ASU	n/a	n/a	73490	76465
Sub-Total	31916	47234	97358	101026

* Feed-water pumps are turbine driven, and not included in the subtotal auxiliary use.

Table 3: Summary of power generation and auxiliary use

2.3 Overall process performances

The overall process performances for the conventional and OEC power plants are presented in Table 4.

	Conventional PC Plant		OEC Process	
	Without CO_2 Removal	With CO_2 Removal	Wet OEC	Dry OEC
Coal Flow Rate (lb/hr)	524982	524982	504064	524472
Steam Turbine Power (MWe)	533.2	434.9	533.2	533.2
ASU Power (MWe)	0.00	0.00	73.49	76.46
Other Aux. Power (MWe)	31.9	47.2	23.9	24.6
Net Power (MWe)	501.3	387.6	435.9	432.2
Net efficiency, HHV (%)	37.0%	28.6%	33.5%	32.0%
CO_2 Removal, K ton/year	0	2,472	0	0

Table 4: Overall process performances of OEC and conventional PC plants

The results show that the amounts of coal used in different plants are comparable. Only a small reduction in coal use was observed for the wet OEC due to the reduced heat loss by flue gas. The conventional air blown PC without CO_2 removal had the highest net generation efficiency. The addition of the MEA process for CO_2 removal dramatically reduced the net efficiency of the PC plant. Both the wet and dry OEC processes exhibited higher generation efficiencies than the conventional plant with CO_2 removal. The wet OEC process had a slightly higher generation efficiency than the dry process.

2.4 Cost assessment

The cost model used to complete this economics assessment has been described in details in previous quarterly reports. In the current quarter, this methodology has been applied to the selected 533MWe gross power output units. Some further methodology information are given in the following subsections while the results are provided in the "Results and Discussion" part of this report.

2.4.1 Cost for new plants

As mentioned previously, for the following six sections of a plant were considered for the cost assessment: 1) the basic systems of a plant including the boiler and turbine systems and the ESP, 2) SO_2 removal section, 3) NOx removal section, 4) activated carbon injection section, 5) CO_2 removal section, and 6) ASU section and related specific components of gas recycle in an OEC process.

Cost of Basic power Plant System

The cost results of the basic systems of a power plant are presented in Table 5.

k$/year	**PC w/o CO_2 remvl**	**PC with CO_2 remvl**	**Wet OEC**	**Dry OEC**
Total Plant Cost				
(1) Coal & sorbent handling	29,218	29,218	28,283	29,195
(2) Coal & sorbent prep & feed	23,212	23,212	22,469	23,194
(3) Feedwater &misc. 80 P systems	36,402	36,402	36,402	36,402
(4.1) PC boiler & accessories	96,914	96,914	96,914	96,914
(4.2) boiler Bop	6,315	6,315	6,315	6,315
(5) ESP	22,500	22,500	8,451	7,541
(6) HRSG, ducting and Stack	25,642	25,642	9,632	8,594
(7) Steam turbine generator	80,661	80,661	80,661	80,661
(8) Cooling water system	29,289	16,149	29,289	29,289
(9) Ash/Spent sorbent handling system	20,795	20,795	20,130	20,779
(10) Accessory electric plant	30,585	30,585	30,585	30,585
(11) Instrumentation &control	17,143	17,143	17,143	17,143
(12) improvements to site	11,773	11,773	11,773	11,773
(13) Buildings and structures	57,926	57,926	57,926	57,926
subtotal	488,375	475,235	455,972	456,310
O&M cost				
1. Fixed O&M				
(1) Operation labor	9,108	9,108	9,108	9,108
(2) Maintenance labor	4,464	4,464	4,193	4,202
(3) Maintenance material	6,696	6,696	6,290	6,303
(4) Administration support labor	4,176	4,176	4,176	4,176
Subtotal	24,443	24,443	23,766	23,788
2. Variable O&M				
(1) Water making up	3,040	3,040	3,040	3,040
(2) Chemicals in water treatment	1,624	1,624	1,624	1,624
(3) Ash disposal	845	845	811	844
(4) Coal cost	32,223	32,223	31,222	32,442
subtotal	37,733	37,733	36,698	37,951

Table 5: Costs of basic components of a power plant

The impact of reduced flue gas volume on the ducting and stack was considered for the OEC process. In the case of the air blown PC equipped with CO_2 removal, a scenario in which a portion of the steam in the MEA process was withdrawn was considered. The impact on the sizing of downstream steam turbine loop, such as the cooling water tower, and the associated costs were estimated

Cost of SO_2 removal section

The LSD process for SO_2 removal was chosen for burning low sulfur PRB coal. A removal efficiency of 90% was assumed based on the general performance of this process. Mass and energy balances were calculated by CHEMCAD, and the cost estimation was conducted according to the detailed equations available in an EPA report [12]. The results are presented in Table 6.

k$/year	PC w/o CO_2 remvl	PC with CO_2 remvl	Wet OEC	Dry OEC
Total Plant Cost				
(1) reagent feed equipment	10,534	10,534	10,455	10,531
(2) SO2 removal equipment	19,856	19,856	7,572	7,043
(3) flue gas handling equipment	7,061	7,061	3,431	3,156
(4) waste handling equipment	1,471	1,471	1,637	1,698
(5) support equipment	11,182	11,182	7,266	6,940
Subtotal	50,104	50,104	30,360	29,368
O&M cost				
1. Fixed O&M				
(1)Operating Labor	1,277	1,277	631	573
(2)Maintenance labor& materials	705	705	427	413
(3)Administration&support labor	468	468	241	222
subtotal	2,450	2,450	1,299	1,208
2. Variable O&M				
(1) Lime reagent	861	861	833	860
(2) Waste disposal	471	471	455	470
(3) Fresh water	1	1	1	1
subtotal	1,333	1,333	1,289	1,332

Table 6: Costs of the Lime Spray Dryer (LSD) proces

Cost of NOx removal section

A hot side, high dust configuration was selected for the SCR process with a NOx removal efficiency 90%. Process simulations for the SCR were not carried out in this study. Cost estimation of the SCR process was adopted from a DOE report [13]. The estimation results are listed in Table 7.

k$/year	PC w/o CO_2 remvl	PC with CO_2 remvl	Wet OEC	Dry OEC
Total Plant Cost	30,313	30,313	N/A	N/A
O&M cost				
1. Fixed O&M	200	200	N/A	N/A
2. Variable O&M				
(1) NH_3 use	560	560	N/A	N/A
(2) Catalyst replace	481	481	N/A	N/A
subtotal	1,041	1,041	N/A	N/A

Table 7: Costs of the Selective Catalytic Reduction (SCR) process

Cost of activated carbon injection section

The cost estimation of the ACI process was adopted from a recent EPA study related to the applications of planning models [13]. Detailed cost models were developed for different coal sources and different configurations of ESP, FGD and SCR. A removal efficiency of 80% was adopted in this study. A unit price of 1 $/kg activated carbon was employed as recommended in the EPA study. Table 8 presents the cost results for mercury removal.

k$/year	PC w/o CO_2 remvl	PC with CO_2 remvl	Wet OEC	Dry OEC
Total Plant Cost				
(1) Sorbent injection system	1,848	1,848	834	760
(2) Sorbent disposal system	96	96	28	24
subtotal	1,943	1,943	862	784
O&M cost				
1. FOM	1,047	1,047	633	603
2. VOM				
(1) AC use	2,134	2,134	627	544
(2) AC sorbent disposal	70	70	21	18
subtotal	2,204	2,204	648	562

Table 8: Costs of the Activated Carbon Injection (ACI) process

The capital costs in the model include the water spray cooling, AC injection and disposal systems. However, in this study water spray cooling is not necessary because the ACI process can be installed downstream a LSD and upstream an ESP.

Cost of CO_2 removal section

The Fluor Daniel Economine MEA process was employed for capturing 90% of CO_2 in flue gas. The detailed simulation was carried out to estimate the heat duty and total costs of the process. The typical design conditions such as the lean MEA CO_2 loading, rich loading and MEA concentration were chosen from a recent DOE study [10]. The capital costs were scaled from a gross output of 498MWe plant reported in a DOE report [6] with a factor of 0.6. The O&M costs were based on the labor and maintenance requirement and the consumable demands such as the MEA, inhibitor, caustic and water. The unit prices of these chemicals referred to the literature [10]. Table 8 summarizes the estimation results. It should be noted again that the cost related to CO_2 compression is not included.

	PC w/o CO_2 remvl	PC with CO_2 remvl	Wet OEC	Dry OEC
Total Plant Cost	N/A	95,579	N/A	N/A
O&M cost				
1. FOM				
(1) Operating Labor	N/A	4,415	N/A	N/A
(2)Maintenance labor &materials	N/A	2,389	N/A	N/A
(3)Administration&support labor	N/A	1,611	N/A	N/A
subtotal	N/A	8,416	N/A	N/A
2. VOM				
MEA make-up	N/A	6,356	N/A	N/A
Inhibitor	N/A	1,271	N/A	N/A
Caustics NaOH	N/A	643	N/A	N/A
Activated Carbon	N/A	371	N/A	N/A
Waste disposal	N/A	61	N/A	N/A
Water	N/A	30	N/A	N/A
subtotal	N/A	8,733	N/A	N/A

Table 9: Costs of the Mono-Ethonal-Amine (MEA) process

Cost of ASU section and related specific components of gas recycle in an OEC process

The capital cost for the air separation unit (ASU) was calculated assuming the cost is 13,000/(ton/day oxygen). Power consumption for the oxygen production was calculated from a DOE/NETL report [19]. Capital cost of the condenser was obtained from literature [8]. The O&M cost was based on the assumptions that the total maintenance cost is 2.0% of the capital cost, maintenance labor is 40% of the total maintenance cost, the operating labor is 2 jobs/shift with a payment 15 $/hr, and the administration & support labor is 30% of the total labor. The detailed results are presented in Table 10.

	PC w/o CO_2 remvl	PC with CO_2 remvl	Wet OEC	Dry OEC
Total Plant Cost				
(1) ASU	N/A	N/A	113,785	118,392
(2) Condenser in OEC	N/A	N/A	N/A	3,750
subtotal	N/A	N/A	113,785	122,142
O&M cost				
1. Fixed OM				
(1) Operating Labor	N/A	N/A	4,415	4,415
(2)Maintenance labor& materials	N/A	N/A	2,276	2,368
(3)Administration&Support labor	N/A	N/A	1,598	1,609
Subtotal	N/A	N/A	8,288	8,392
2. Variable O&M				
(1) Water used in OEC condenser	N/A	N/A	N/A	920

Table 10: Costs of the Air Separation Unit (ASU) and condenser

Global Plant Capital an O&M costs

Table 10 summarizes the results of capital and O&M costs of different sections listed in Tables 4-9 (in 1999 $). Results show that the total capital costs for the OEC processes are about 8% higher than a conventional PC plant without CO_2 capture, but about 9% less than a conventional PC plant with CO_2 removal. The OEC process has much lower capital costs than the conventional PC plant for the flue gas cleaning and ducting/stack system, mainly due to the reduced volume of flue gas. The potential future stringent regulations on SO_2 control for the low sulfur coal will favor the economic competition of the OEC process.

Levelized cost of electricity

The levelized costs of electricity generation are also listed in Table 11.

The levelized factor for the total capital requirement (TCR) was 16.9% assuming the inflation rate of 4.1%, discount rate of 9.25% and 30-year life of plant. Levelization factor of 1.54 was adopted for all O&M costs except for coal, and 1 for coal.

The levelized cost of electricity for the conventional air-blown PC with CO_2 removal is about 27% and 30% higher than the dry OEC and wet recycle OEC, respectively. The cost for conventional air blown process without CO_2 removal is about 18% lower than the OEC with wet gas recycle. These quantities, however, could be subjected to the uncertainties associated with the cost estimation models and parameters used in this study. The cost estimation presented here indicates the economic attractiveness of the OEC technology for the new PRC coal-fired power plant.

	$*1000	**$/kW**	**$*1000**	**$/kW**	**$*1000**	**$/kW**	**$*1000**	$/kW
Total Plant Cost (TPC)	557,596	1,112	653,175	1,685	600,980	1,379	608,604	1,408
Capital investment								
Total cash expended	535,923		627,787		577,621		584,949	
AFDC	50,432		59,077		54,356		55,046	
Total Plant investment (TPI)	586,356	1,170	686,864	1,772	631,977	1,450	639,995	1,481
Royal allowance								
Preproduction costs	15,324	31	17,392	45	16,271	37	16,436	38
Inventory capital	10,836	22	12,298	32	11,505	26	11,622	27
Initial catalyst & chemicals								
Land cost	511	1	580	1	542	1	548	1
Total capital requirement (TCR)	613,026	1,223	717,134	1,850	660,296	1,515	668,600	1,547
O& M costs (1st year)	$*1000	mills/kWh	$*1000	mills/kWh	$*1000	mills/kWh	$*1000	mills/kWh
Fixed O & M	28,140	9.15	36556	15.38	33987	12.72	33991	12.83
Variable O&M	10,088	3.28	18821	7.92	7413	2.77	8322	3.14
Fuel cost (1st year)	32,223	10.48	32223	13.56	31222	11.68	32442	12.24
Levelized O&M costs								
Fixed O & M		14.11		23.70		19.60		19.76
Variable O & M		5.06		12.20		4.27		4.84
By-product credit								
Fuel		10.48		13.56		11.68		12.24
	$/kW-yr	mills/kWh	$/kW-yr	mills/kWh	$/kW-yr	mills/kWh	$/kW-yr	mills/kWh
Levelized capital costs	207	33.70	313	50.99	256	41.75	261	42.63
levelized cost of power		63.35		100.45		77.30		79.48
Levelized cost of power (1st year)		56.62		87.85		68.92		70.84

Table 11: Costs of Electricity for Conventional PC plants and OEC Processes

2.4.2 Costs for retrofit

As said in the "experimental" section of the report, the cost analysis for retrofit applications only consider those existing components in a plant to be modified, and other necessary new components in retrofit. These include the modifications of LSD flue gas desulphurization process and ACI process due to the change of flue gas flow rate, elimination of SCR process in the OEC plant due to reduced NOx emissions in oxygen combustion condition, new installment of MEA process in the conventional PC plant, and new installment of ASU and gas recycle system in the OEC plant.

The comparison results of these mentioned components are listed in Table 12.

In the conventional PC plant, retrofit of CO_2, SO_2, NOx and Hg removal installment increases the total capital cost by 96 million dollars while the OEC modification increases the capital cost of 63 M$ for wet OEC and 70 M$ for dry OEC. OEC retrofit also costs less than the MEA retrofit in terms of the O&M cost. The total O&M cost of OEC retrofit is about half of that of the MEA retrofit. These comparisons also indicate the economic competitiveness of OEC technology in the retrofit cases.

	PC w/o CO_2 removal		PC with CO_2 removal		Wet OEC		Dry OEC	
Net output, MW		501		388		436		432
Power generation, KWh		3074059574		2376860248		2672767642		2650276138
Total Plant Cost	K$	$/KW	K$	$/KW	K$	$/KW	K$	$/KW
ASU&OEC					113,785	261	122,142	283
MEA			95,579	247				
ACI	1,943	4	1,943	5	862	2	784	2
SCR	30,313	60	30,313	78				
LSD	50,104	100	50,104	129	30,360	70	29,368	68
Total	82,360	164	177,939	459	145,007	333	152,294	352
O&M cost	K$	mill/KWh	K$	mill/KWh	K$	mill/KWh	K$	mill/KWh
1. FOM								
ASU&OEC					8,288	3.10	8,392	3.17
MEA			8,416	3.54				
ACI	1,047	0.34	1,047	0.44	633	0.24	603	0.23
SCR	200	0.07	200	0.08				
LSD	2,450	0.80	2,450	1.03	1,299	0.49	1,208	0.46
subtotal	3,697	1.20	12,113	5.10	10,221	3.82	10,203	3.85
2. VOM								
ASU&OEC							920	0.35
MEA			8,733	3.67				
ACI	2,204	0.72	2,204	0.93	648	0.24	562	0.21
SCR	1,041	0.34	1,041	0.44				
LSD	1,333	0.43	1,333	0.56	1,289	0.48	1,332	0.50
subtotal	4,579	1.49	13,311	5.60	1,937	0.72	2,813	1.06
Total O&M cost	8,275	2.69	25,424	10.70	12,158	4.55	13,016	4.91

Table 12: Comparison for Retrofit of Power Plants

3 PROJECT SCHEDULE

The current status of the project tasks and sub-tasks is displayed below, followed by a short description of the work to be performed in the next quarter (Jan-Mar 2004).

3.1 Status of the project tasks and sub-tasks

The sub-tasks completed in previous reporting periods **(bold & black)**, completed in the current reporting period (**bold & blue**), currently in progress or soon to be ongoing, together with their deadlines, are:

		Deadline		Status
Task 1: Site Preparation				
Task 1.1:	List of required modifications	March 30, 2003	-	**Completed**
Task 1.2:	Conceptual design of SBS adaptations	April 15, 2003	-	**Completed**
Task 1.2:	Technical design of SBS adaptations	April 30, 2003	-	**Completed**
Task 1.3:	Implementation of SBS adaptations	July 30, 2003	-	**Completed**
Task 1.4:	System shake-down	August 1, 2003	-	**Completed**
Task 2: Test Performance				
Task 2.1:	Test matrix definition	Sept. 15, 2003	-	**Completed**
Task 2.2:	Tests performance	Dec. 15, 2003	-	**13 days completed** 1 week tests scheduled in 2004.
Task 2.3&2.4:	Test analysis & Report	March 15, 2004	-	In Progress
Task 3: Techno-Economic Study				
Task 3.1:	Cases Specification	Sept. 15, 2003	-	**Completed**
Task 3.2:	Methodology Definition	Aug. 30, 2003	-	**Completed**
Task 3.3:	Process Simulation & Cost Estimation	March 30, 2004	-	**Half of the study completed**. Second part to be started in 2004.
Task 3.4:	Results analysis & Report	June 30, 2004	-	Future
Task 4: Preliminary Boiler Design				
Task 4.1:	Task specification	Mar. 30, 2004	-	Future
Task 4.2:	Design performance	Sep. 30, 2004	-	Future
Task 4.3:	Results analysis & Report	Dec. 31, 2004	-	Future

Table 13: Project Schedule

3.2 Next quarter sub-tasks

During the next quarter (January 1st to March 31st 2004), the following activities will be performed:

- Tests Performance (task 2) will be completed thanks to additional funds allocation. Approximately one week of tests will be performed to finalize the optimization of the combustion characteristics in O_2/CO_2 environment, to compare the measurements of mercury emission in air-fired or O2-fired conditions, and to characterize the heat transfer in O_2 conditions as compared to air conditions.
- In the techno-economical study (task 3), phase 2 will be initiated based on the results obtained in phase 1 of the task. The exact content of phase 2 will be specified by the participants, along with the updated corresponding schedule.
- The boiler design task (task 4) will be initiated, starting with the specification of these task objectives.

4 FINANCIAL STATUS

Tables 7 and 8 show the financial status of the report to-date. An amount of ~$267k has been spent by the main contractor in the reporting period (Q_4, 2003), including ~ $24k of direct labor, ~$3.5k in travel, ~ $3.5k of material & equipment related to oxygen, $190k of contractual ($150k tests and $40k economics) and ~ $46k of indirect charges. To date, $809k have been spent and reported in the project. $300k has been reimbursed by DOE-NETL. The project proceeds according to the planning, in the limit of available funds. Due to funds non availability and "on hold" status of the project after Mid-October 2003, some sub-tasks in experimental and economics tasks have been postponed to 2004.

10. Transactions:	I Previously Reported	II This Period	III Cumulative
a. Total outlays	$ 541,861.63	$ 267,155.12	$ 809,016.75
b. Recipient share of outlays	$ 541,861.63	- $ 32,844.88	$ 509,016.75
c. Federal share of outlays	$ 0	$ 300,000.00	$ 300,000.00
d. Total unliquidated obligations			$ 0
e. Recipient share of unliquidated obligations			$ 0
f. Federal share of unliquidated obligations			$ 0
g. Total Federal share (Sum of lines c and f)			$ 0
h. Total Federal funds authorized for this funding period			$ 485,268.00
i. Unobligated balance of Federal funds (Line h minus line g)			$ 185,268.00

11. Indirect Expense				
a. Type of Rate (Place "X" in appropriate box)	☐ Provisional	☒ Predetermined	☐ Final	☐ Fixed
b. Rate	c. Base	d. Total Amount	e. Federal Share	
see attachment	**see attachment**	**$ 185,019.86**	**$ 0**	

Table 14: Financial situation to-date.

Indirect Expenses	**Rate**	**Base**		**Indirect expense charged to the project**	**Federal share for indirect expense**
Labor Overhead	87.94%	Total Direct Labor Costs	$ 124,032.00	$ 109,073.74	$ 0
General&Administrative	10.36%	Total Direct Project Costs and Overhead Costs	$ 733,070.63	$ 75,946.12	$ 0
Total Indirect Expenses				**$ 185,019.86**	**$ 0**

Table 15: Indirect Expenses (details)

5 TASK 5: PROJECT MANAGEMENT & REPORTING

The sub-contract between American Air Liquide and Babcock and Wilcox has been finalized in June 2003.

The sub-contract between American Air Liquide and ISGS has been finalized November 3, 2003.

CONCLUSION

At the end of the first budget period (October 1, 2002 extended through December 31, 2003), the Site Preparation (Task 1) is completed, three weeks of tests have been performed (Task 2) and half of the Techno-Economic Study (Task 3) has been performed.

As far as the 2003 milestones of the project, the three first ones have already been completed as per the initial schedule:

- ✓ On **August 2003**, **the Site Preparation (Task 1)** of 5 million Btu/hr B&W's Small Boiler Simulator (SBS) enabling delivery of recycled flue gas and oxygen to the boiler to allow oxygen-enhanced combustion tests has been completed, along with the boiler equipment with appropriate sensors and controls. The entire system has been shakedown mid August 2003 enabling Task 2 initiation.
- ✓ On **September 2003**, the **Test Definition** including oxidant streams a specification has been completed, and the analyses of a representative sample of PRB coal for testing performed.
- ✓ On **December 2003**, the **Test Performance** milestone has been achieved: three weeks of tests have been completed, including optimization of full-oxy combustion tests with flue gas recirculation. The feasibility of 100% air replacement by O_2-enriched flue gas has been demonstrated on 1.5MWth coal-fired boiler. Air infiltrations have been reduced to approximately 5% of the overall stoichiometry, thus increasing the initial CO_2 content in flue gas from 15% in air-fired conditions to eventually 80% in O_2-fired conditions Alternative boiler operating procedures are expected to reduce even more the air infiltration to achieve higher CO_2 concentration in flue gas for further sequestration or reuse. The NO_x emissions have been shown considerably lower in O_2-fired conditions than in air-baseline, the reduction rate averaging 70%, and the final NOx level reaching 0.07 to 0.08lb/MMBtu. Impact of flue gas recirculation rate and oxygen injection location on boiler temperature and on NOx emissions have been investigated and reported.

The first part of the **Techno-Economic Study** (Task 3) has been completed in December 2003. A detailed description of the methodology to be applied has been provided, along with basic references and overall selection of plant capacity and equipment to be evaluated. Process simulation and cost assessment of 533MWe gross power output air-fired and oxygen-fired (with flue gas recirculation) pulverized coal (PC) units have been performed. The resulting capital and operating costs, as well as cost of electricity have been reported for both retrofit and new unit applications.

The current work schedule is to review in more details the experimental and economics data collected during the first budget period and to develop a work scope for the remainder of the project. Approximately one week of additional experimental tests are scheduled in Q1 2004, including mercury emission measurement and heat transfer characterization. The Techno-Economic will be extended to a wider range of plant capacity. Task 4 (boiler design) will be initiated in the next quarter and will first have to be specified in more details.

REFERENCES

List of published reports that will be used for performing the **techno-economic analyses** (estimation of auxiliary powers and costs associated with various process areas):

1 CONVENTIONAL PC POWER PLANT

(1) Gilbert/Commonwealth Inc., Clean Coal Reference Plants: Pulverized Coal Boiler with Flue Gas Desulfurization, DE-AM21-94MC311 66, September 1995

(2) Office of Fossil Energy, US DOE, Market Based Advanced Coal Power Systems, DOE/FE-0400, May 1999

(3) United Engineers & Constructors Inc, Total Generation Cost: Coal and nuclear Plants, DOE EY-76-C-02-2477, February 1979

(4) EIA, Electric plant cost and power production expenses 1988, DOE/EIA-0455, August 1990

(5) DOE/EIA , Steam-electric plant construction cost and annual production expenses, 1977

2 CO2 REMOVAL PROCESS

(6) EPRI, Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal, Interim Report 1000316, December 2000

(7) EPRI, Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO2 Removal, Interim Report 10004483, December 2002

(8) Henrik Birkestad, Separation and Compression of CO2 in O2/CO2-Fired Power Plant, master thesis, Chalmers University of Technology, Sweden, 2002

(9) D. Singh, E. Croiset, P. L. Douglas and M. A. Douglas, Techno-economic study of CO2 Capture from an Existing Coal-Fired Power Plant: MEA Scrubbing vs. O2/CO2 Recycle Combustion, Energy Conversion and Management, 44(19), 2003: 3073-3091

(10) Edward S Rubin and Anand B Rao, A Technical, Economic and Environmental Assessment of Amine-based CO2 Capture Technology for Power Plant Greenhouse Gas Control, Annual Technical Process Report, DE-FC26-00NT40935, Oct. 2002

3 FGD PROCESS

(11) United Engineers and Constructions, Inc., Economic Evaluation of Flue Gas Desulfurization Systems, EPRI GS-7193, February 1991

(12) Srivastava R K, Controlling SO2 Emissions: A review of the Technologies, EPA/600/R-00/093, November 2000

4 SCR PROCESS

(13) Foerter D and Jozewicz W, Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-fired Boilers, EPA/600/R-01/087, October 2001

5 MERCURY REMOVAL PROCESS

(14) US EPA, Mercury Study Report to Congress, Vol. VIII: An Evaluation of Mercury Control Technologies and Costs, EPA-452/R-97-010, December 1997

(15) U.S. EPA clean Air Markets Division, Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, EPA-68-D7-0081, March 2002

6 IGCC PLANT

(16) Scott Chen, Subhash Bhagwat, Massoud Rostam-Abadi, Techno-Economic Studies of Illinois Coal in Future Power production processes. ICCI Project No: 01-1/2.3C-1, October, 2002

(17) Destec Gasifier IGCC Based Cases, PED-IGCC-98-003, Prepared by EG&G, Sept. 1998, revised June 2000.

(18) Economic Assessment of the Impact of Plant Size on Coal Gasification-Combined Cycle Plants, Prepared by Fluor Engineers, Inc. EPRI Report, AP-3084, May 1983.

(19) NETL of DOE, Destec gasifier IGCC Base cases, PED-IGCC-98-003, June 2000

LIST OF ACRONYMS AND ABBREVIATIONS

AAL	American Air Liquide
BSR	Burner Stoichiometric Ratio
B&W	Babcock and Wilcox
CHx	Condensing Heat Exchanger
COE	Cost of Electricity
DOE	Department of Energy
EPA	Environmental Energy Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FD Fan	Forced Draft Fan
FEGT	Furnace Exit Gas Temperature
FG	Flue Gas
FGD	Flue Gas Desulfurization
FGR / RFG	Flue Gas Recirculation / Recycled flue gas
Hg	Mercury
HMI	Human Machine Interface
HRSG	Heat Recovery Steam Generator
ID Fan	Induced Draft Fan
IGCC	Integrated Gasification Combined Cycle
ISGS	Illinois State Geological Survey
LOI	Lost On Ignition (Unburned Carbon in Ash)
MEA	Mono ethanol-amine
NETL	National Energy Technology Laboratory
OEC	Oxygen Enriched Combustion
O&M	Operating And Maintenance
PA	Primary Air
PACI	Pulverized Activated Carbon Injection
PC	Pulverized Coal (Boiler)
PO	Primary Oxidant
PRB	Powder River Basin
SA	Secondary Air
SBS	Small Boiler Simulator
SCR	Selective Catalytic Reduction
SNCR	Selective Non Catalytic Reduction
SO	Secondary Oxidant
TA	Tertiary Air
TBD	To be defined
TCR	Total Capital Requirement
TO	Tertiary Oxidant
TPC	Total Plant Cost

TPI	Total Plant Investment
UBC	Unburned Carbon in Ash

APPENDICES

Appendix A. SBS (Small Boiler Simulator) in an Oxygen Firing Mode

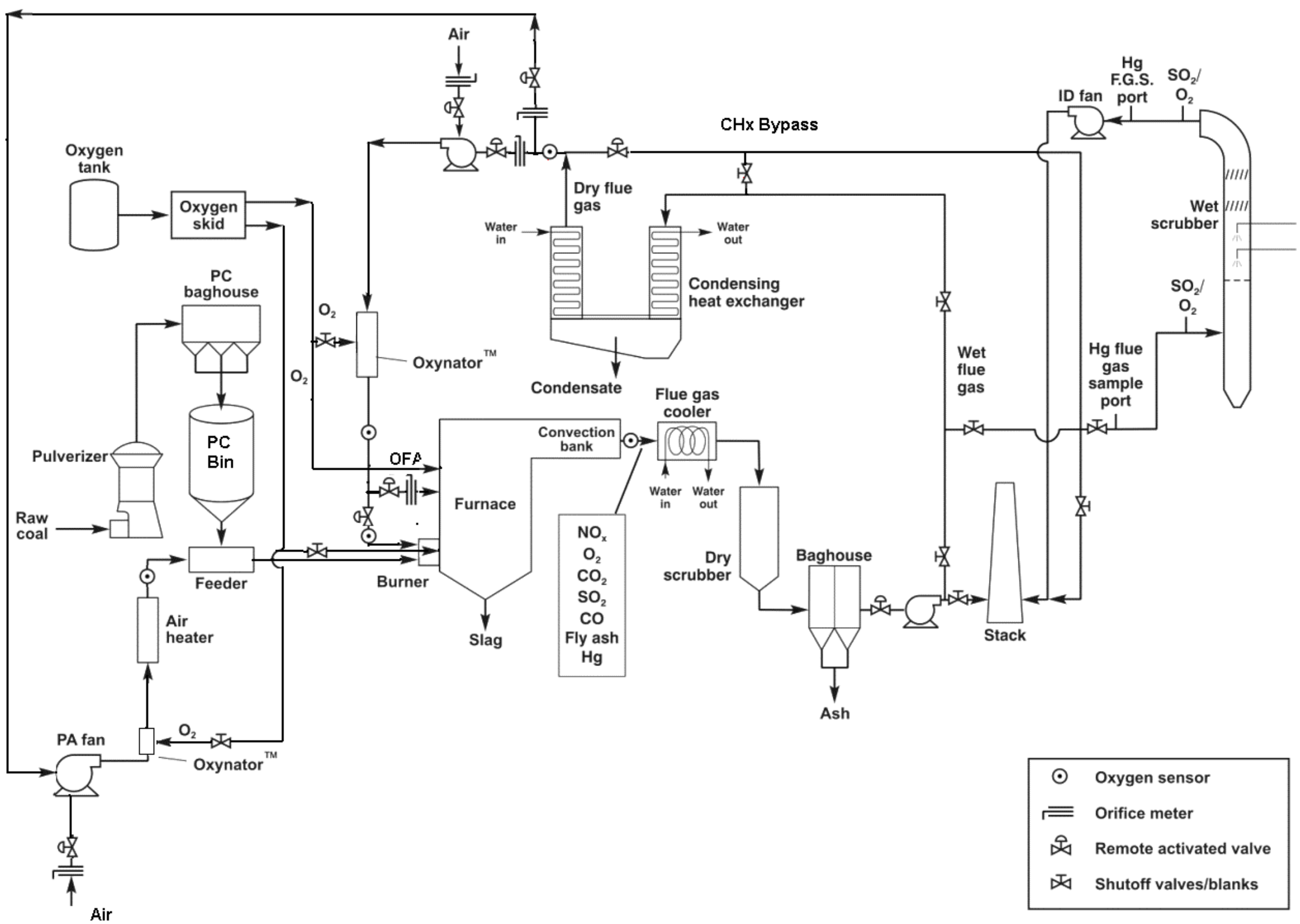

Figure 3: SBS (Small Boiler Simulator) schematics

Appendix B. New equipment and duct work (in red) installed on the SBS

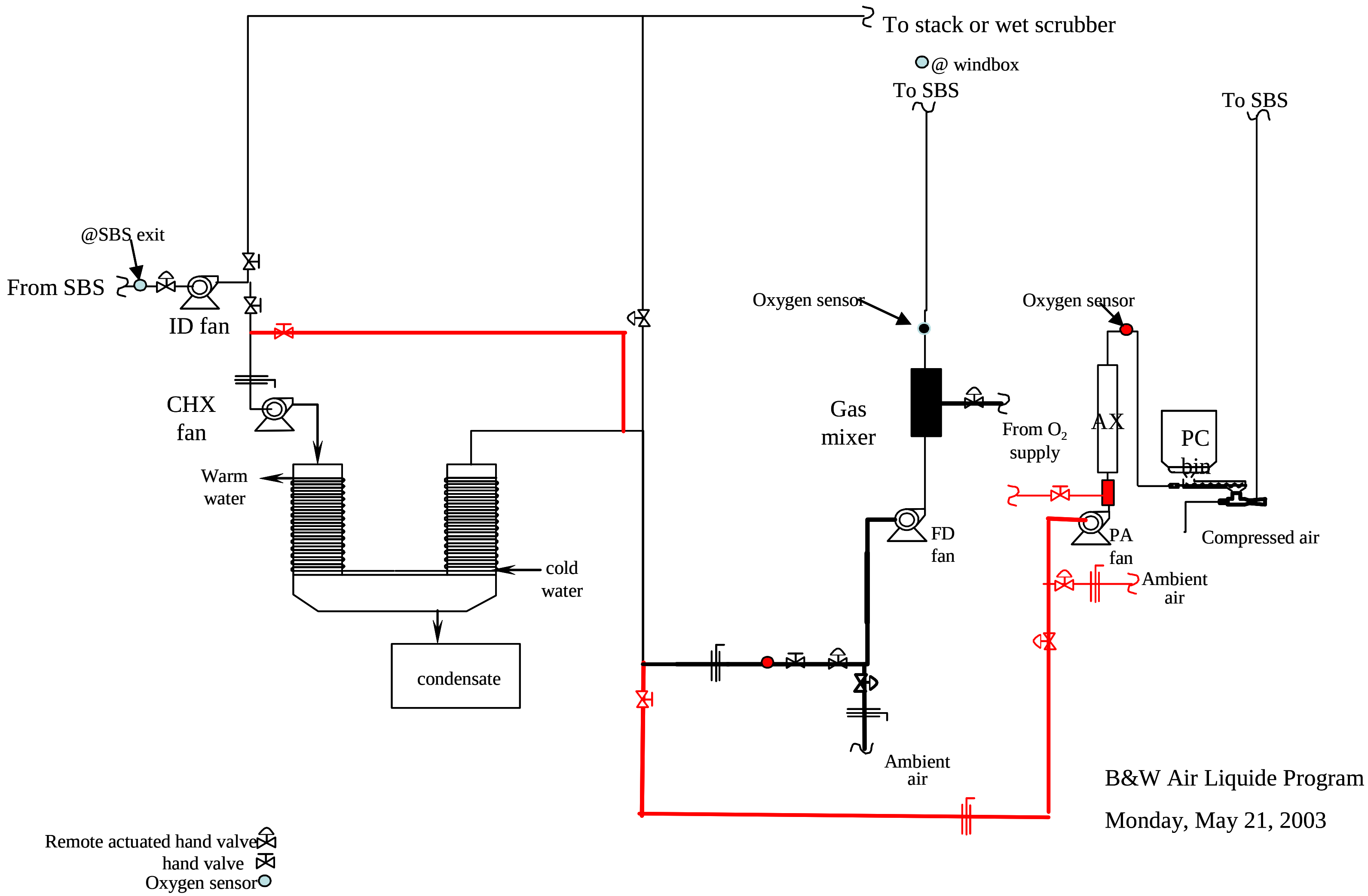

Figure 4: New equipment and duct work installed on the SBS

Appendix C. UPDATED MODIFIED OXYGEN SKID

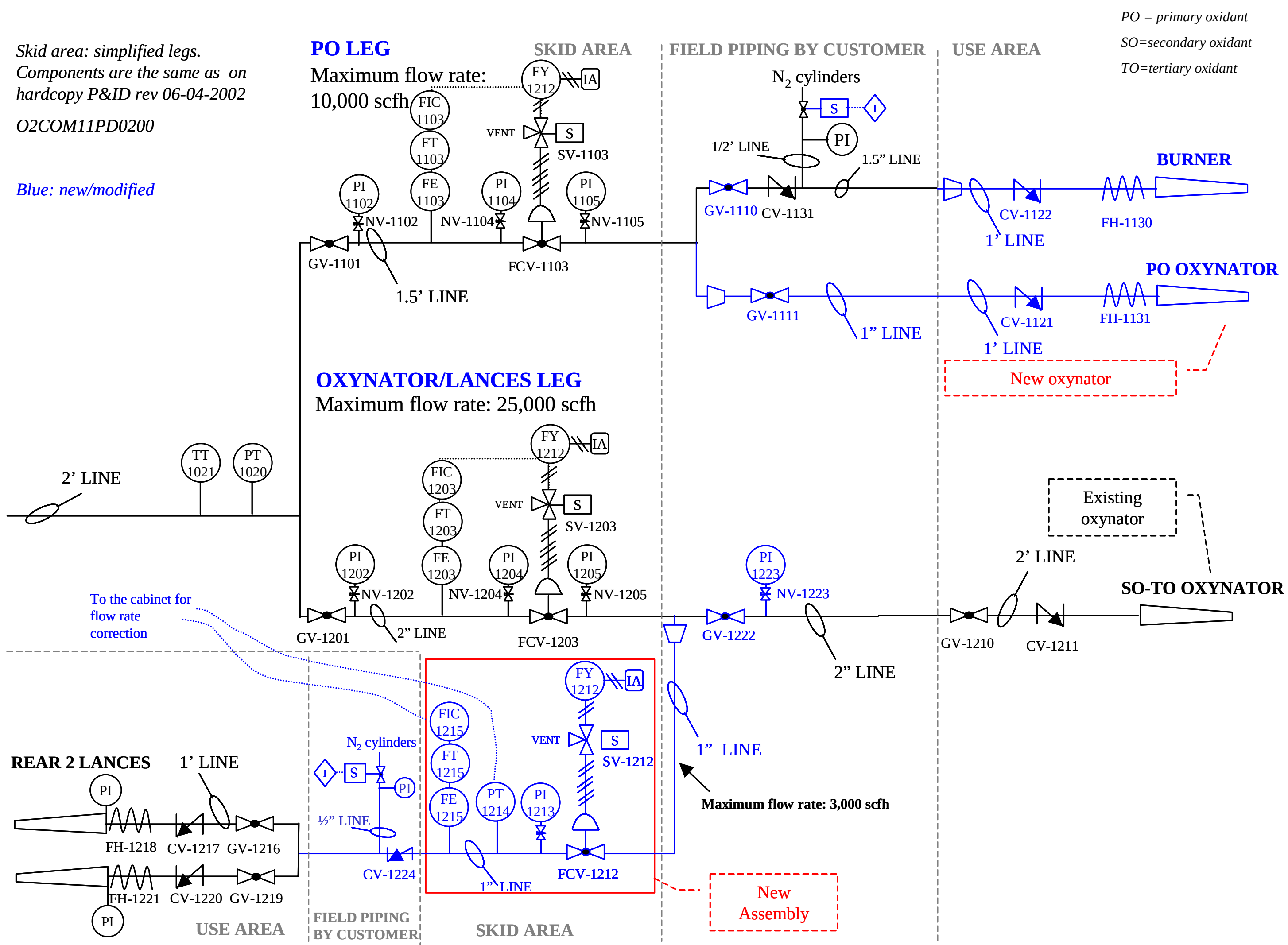

Figure 5: Updated modified Oxygen Skid