# ECONOMICS AND FEASIBILITY OF RANKINE CYCLE IMPROVEMENTS FOR COAL FIRED POWER PLANTS

**FINAL REPORT**

**SUBMITTED BY**

**ALSTOM POWER INC.**
**POWER PLANT LABORATORIES**
**2000 DAY HILL ROAD**
**WINDSOR, CT 06095**
**(860) 688-1911**

**Project Manager:**
**Mark Palkes**

**Principal Investigators:**
**Richard E. Waryasz**
**Gregory N. Liljedahl**

**PREPARED FOR**

**NETL AAD DOCUMENT CONTROL BLDG. 921**
**US DEPARTMENT OF ENERGY**
**NATIONAL ENERGY TECHNOLOGY LABORATORY**
**P.O. BOX 10940**
**PITTSBURGH, PENNSYLVANIA 15236-0940**
**(COOPERATIVE AGREEMENTT NO. DE-FCP-01NT41222)**

**REPORT SUBMITTAL DATE: SEPTEMBER 8, 2004**
**PERFORMANCE PERIOD: OCTOBER 1, 2001 – FEBRUARY 28, 2004**

**PPL REPORT NO. PPL-04-CT-03**

## DISCLAIMER

## ACKNOWLEDGMENTS

The authors appreciatively acknowledge the following people for their contributions to the successful performance of the work presented herein:

- John Marion, John Ferguson, Roland Tetreault, Ray Chamberland, Mike Rini, Maurus Herzog, Brendon Scarlin, Richard Skowyra, Raymond Hickey, Diane Calkin, Glen Jukkola, Srivats Srinivasachar, and Larry Cellilli of ALSTOM Power Inc. for their contributions as follows:

  - John Marion: For providing overall project leadership.
  - John Ferguson: For proving design guidance and cost calculations for the CMB™ Boiler Islands.
  - Roland Tetreault: For providing design graphics services.
  - Ray Chamberland: For providing economic analyses for all cases.
  - Mike Rini: For providing performance and cost information for wet FGD systems and FDA systems used for flue gas sulfur removal.
  - Maurus Herzog and Brendon Scarlin: For providing performance and cost information for the steam cycles.
  - Richard Skowyra: For providing general consultation on Circulating Fluidized Bed boilers.
  - Raymond Hickey: For providing general consultation on all boiler designs.
  - Diane Calkin: For providing cost estimating of Pulverized Coal and Circulating Fluidized Bed Boiler Islands.
  - Glen Jukkola: For providing general consultation on Circulating Fluidized Bed and Circulating Moving Bed Boilers.
  - Srivats Srinivasachar: For providing information on mercury removal from boilers.
  - Larry Cellilli: For providing contract administration.

- William McMahon of Parsons Energy and Chemical Group, Inc., of Wyomissing, Pennsylvania: For providing complete design and cost information for the material handling systems (Coal, Limestone, and Ash).

- Barry Brederstorff of American Electric Power, Inc., of Columbus, Ohio: For providing general project consultation, economic assumptions, and design and cost information for balance of plant equipment for the Repowering Case.

The financial support of this project by DOE National Energy Technology Laboratory (Contract No DE-FCP-01NT41222), and ALSTOM Power Inc. is also appreciatively acknowledged.

## PUBLIC ABSTRACT

ALSTOM Power Inc.'s Power Plant Laboratories (ALSTOM) has teamed with the U.S. Department of Energy National Energy Technology Laboratory (DOE NETL), American Electric Company (AEP) and Parsons Energy and Chemical Group to conduct a comprehensive study evaluating coal fired steam power plants, known as Rankine Cycles, equipped with three different combustion systems: Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and Circulating Moving Bed (CMB™). Five steam cycles utilizing a wide range of steam conditions were used with these combustion systems.

The motivation for this study was to establish through engineering analysis, the most cost-effective performance potential available through improvement in the Rankine Cycle steam conditions and combustion systems while at the same time ensuring that the most stringent emission performance based on CURC (Coal Utilization Research Council) 2010 targets are met.

- > 98% sulfur removal
- < 0.05 lbm/MM-Btu $NO_x$
- < 0.01 lbm/MM-Btu Particulate Matter
- > 90% Hg removal

The final report discusses the results of a coal fired steam power plant project, which is comprised of two parts. The main part of the study is the analysis of ten (10) Greenfield steam power plants employing three different coal combustion technologies: Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and Circulating Moving Bed (CMB™) integrated with five different steam cycles. The study explores the technical feasibility, thermal performance, environmental performance, and economic viability of ten power plants that could be deployed currently, in the near, intermediate, and long-term time frame. For the five steam cycles, main steam temperatures vary from 1,000°F to 1,292°F and pressures from 2,400 psi to 5,075 psi. Reheat steam temperatures vary from 1,000°F to 1,328°F. The number of feedwater heaters varies from 7 to 9 and the associated feedwater temperature varies from 500°F to 626°F. The main part of the study therefore determines the steam cycle parameters and combustion technology that would yield the lowest cost of electricity (COE) for the next generation of coal-fired steam power plants.

The second part of the study (Repowering) explores the means of upgrading the efficiency and output of an older existing coal fired steam power plant. There are currently more than 1,400 coal-fired units in operation in the United States generating about 54 percent of the electricity consumed. Many of these are modern units are clean and efficient. Additionally, there are many older units in excellent condition and still in service that could benefit from this repowering technology. The study evaluates the technical feasibility, thermal performance, and economic viability of this repowering concept.

**Major conclusions**:

Primary results for both parts of the study are summarized in terms of thermal efficiency, environmental performance, investment costs, and cost of electricity (COE). For the ten Greenfield cases, the calculated thermal efficiencies (HHV basis) range from 37.02% to 43.55%. The effect of the increasing steam cycle parameters (Temperature and Pressure) is to increase plant efficiency. The highest efficiency is achieved for the ultra supercritical steam cycle 1,292°F/ 1,1328°F/5075 psi. With respect to thermal efficiency, for the same steam conditions, there is little difference when comparing among the combustion systems (PC, CFB, and CMB™) as would be expected. In general the thermal efficiency of the PC fired systems are about the same as for the CFB based systems. The CFB and PC systems thermal efficiency are about 0.1 percentage points higher than the CMB™ systems which is due to only partial sulfation in the CMB™ combustor.

The specific plant investment cost results for the Greenfield cases range from about 1,018 to 1,168 $/kW-net. For the same steam conditions, the CMB™ combustion system plants require the lowest investment costs as compared to PC or CFB plants. This cost advantage increases as steam cycle conditions (Temperature and Pressure) are raised. The CFB systems are about 70 $/kW lower in cost than the PC type combustion systems. This difference is primarily attributable to the differences in the costs for the gas cleanup system equipment.

The levelized cost of electricity (COE) results for the Greenfield cases range from about 3.4 to 4.0 Cents/kWh. These results indicate that the CMB™ case designed for the ultra supercritical steam conditions is the most economical from a COE basis. Compared to the PC case designed for the same ultra supercritical steam conditions, it requires significantly less weight of very expensive Ni alloy tubing. For the same steam conditions there is very little difference in the COE between CFB and CMB™ designs.

Similar to the investment cost results, the PC cases are about 7% higher than the CFB type combustion systems with respect to COE at the same steam conditions. The advantage of the CFB systems is attributable to the investment cost savings. Because of the additional reduction in investment cost associated with CMB™ based systems, the CMB™ combustion system offers a COE advantage as compared to PC of about 8-10% (greater advantage at higher steam conditions) and about 1% as compared to CFB type combustion systems.

The cost of electricity is directly related to the cost of fuel. As the cost of fuel increases, the cost of electricity increases also and at the same time the economics continue to shift towards the more efficient power plant systems. For example, at a coal price of $1.80 MM-Btu the COE is the lowest for the ultra-supercritical case among the PC power plant cases. The ultra-supercritical CMB case continues to offer the lowest COE among the power plant cycles analyzed.

There is direct correlation of $CO_2$ emissions and plant thermal efficiency. For example, the ultra supercritical PC case is about 18% more efficient than conventional subcritical PC case and it also emits about 18% less $CO_2$ per kWh of net output.

The study has also investigated the impact of potential taxes placed on $CO_2$ emissions. As expected, the COE increases significantly with the increase in the tax. The tax would become a major driver in utility companies' selection process of the power plant cycle parameters and the high efficiency plants would become the technologies of choice.

For the Repowering Case, CMB combustion technology was selected because of its economic advantage for high temperature cycles. The calculated thermal efficiency (HHV basis) is improved from 35.70% for the existing unit to 38.40%. The investment costs necessary for all the equipment required for this repowering project is 413 $/kW-net and the resulting incremental cost of electricity is calculated to be 0.47 Cents/kWh (2.76 - 2.29 Cents/kWh). Incremental cost is calculated relative to the unmodified existing unit. This difference may quickly disappear if the price of $NO_x$ credits continues to increase and/or a major capital investment is required to refurbish the existing boiler or if there is loss of availability caused by the aging equipment. $CO_2$ emissions are decreased from about 1.94 to 1.80 lbm/kWh, a reduction of about 8 percent.

In summary, from the results of the study the evaluated power plant systems fall either into the near term or long term category with respect to technology implementation. All combustion technologies can achieve low levels of pollutants and comply with the CURC 2010 air pollution targets. Technology is available today to facilitate construction of all the PC cycles, except for the ultra-supercritical steam conditions, and all the CFB steam cycles. Technology is being developed to enable market introduction of the ultra supercritical and CMB™ cycles in a 10 to 15 year timeframe. The very high steam temperatures of the ultra-supercritical steam cycle do not appear to be practical for conventional CFB technology where combustion temperature is generally limited to 1,550°F. CMB™ technology with the combustion temperature of 2000°F allows greater latitude in selecting the range of steam cycle parameters. The ultra-supercritical CMB™ design offers the prospect of the lowest COE.

The CFB power plants are the technology of choice for high sulfur coals. For low sulfur coals the PC power plants that don't require installation of the back end $NO_x$ and $SO_x$ control technologies would be favored. The supercritical CFB plants have the lowest cost of electricity and its cost continues to improve for higher steam conditions.

**Major recommendations:**

Building up on these results, the next step in the development effort of the Rankine power plant cycle is recommended. It should include a CFB design with steam conditions of 4,000 psi to 5000 psi and main and reheat steam temperatures of approximately 1,200°F. The potential plant efficiency improvement would be significant and the efficiency should be in the range of 41-42% (HHV basis). These steam conditions may require some CFB process modifications to enable the higher steam temperatures but would represent the upper limit for conventional boiler alloys. Such a design would fulfill the promise of high efficiency and low cost of the intermediate term (3 to 5 years) power plant cycle.

Based on reliability, investment costs, emissions and cost of electricity a coal fired steam power plant will continue to be a good investment for power plant owners especially compared to other options such as IGCC for coal powered electric power production. The thermal efficiencies of today's steam power plants with supercritical steam cycles are higher than today's IGCC plants. For power plants of the future, studies show that coal fired steam plants with ultra-supercritical steam cycles will maintain this efficiency advantage over future IGCC plants with advanced gas turbines.

## Table of Contents

## List of Figures

## List of Tables

# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| acfm | Actual cubic feet per minute |
| ANSI | American National Standards Institute |
| ASME | American Society of Mechanical Engineers |
| BI | Boiler Island |
| BOP | Balance of Plant |
| Btu | British Thermal Unit |
| CFB | Circulating Fluidized Bed |
| cfm | Cubic Feet per Minute |
| CMB | Circulating Moving Bed |
| $CO_2$ | Carbon Dioxide |
| COE | Cost of Electricity |
| CS | Carbon Steel |
| dB | Decibel |
| DCS | Distributed Control System |
| DOE/NETL | Department of Energy/National Energy Technology Laboratory |
| EPC | Engineered, Procured and Constructed |
| ESP | Electrostatic Precipitator |
| FBC | Fluidized Bed Combustion |
| FD | Forced Draft |
| FDA | Flash Dryer Absorber |
| FGD | Flue Gas Desulfurization |
| FOM | Fixed Operation & Maintenance |
| gpm | Gallons per minute |
| HHV | Higher Heating Value |
| HP | High Pressure |
| hp | Horse Power |
| hr | Hour |
| HT | High Temperature |
| HVAC | Heating, Ventilating and Air Conditioning |
| Hz | Hertz |
| ID | Induced Draft |
| in. $H_2O$ | Inches of Water |
| in. Hga | Inches of Mercury, Absolute |
| IP | Intermediate Pressure |
| ISO | International Standards Organization |
| kV | Kilovolt |
| kWe | Kilowatts electric |
| kWh | Kilowatt-hour |
| lbm | Pound mass |
| LHV | Lower Heating Value |
| LP | Low Pressure |
| LT | Low Temperature |
| MBHE | Moving Bed Heat Exchanger |
| MCR | Maximum Continuous Rating |
| MWe | Megawatt electric |

| | |
|---|---|
| $N_2$ | Nitrogen Gas |
| NPHR | Net Plant Heat Rate |
| O&M | Operation & Maintenance |
| PA | Primary Air |
| PC | Pulverized Coal |
| PFD | Process Flow Diagram |
| ppm | Parts per million |
| psia | Pound per square inch, absolute |
| psig | Pound per square inch, gauge |
| SA | Secondary Air |
| TGA | Thermo-Gravimetric Analysis |
| TPD | Ton Per Day |
| TPH | Ton Per Hour |
| TSA | Temperature Swing Adsorption |
| UBC | Unburned Carbon |
| VOM | Variable Operation & Maintenance |

## Executive Summary

Due to continued higher cost and scarcity of oil and natural gas, and no growth of nuclear power generation, attention has focused on coal as a major energy resource for the nation's future. However, in search of higher efficiency and lower emission, much of this attention has been directed toward second generation technologies such as coal gasification combined cycle and fuel cell systems that utilize hydrogen derived from coal gasification processes or natural gas fuel. Other advanced power plant systems that in addition to power generation may also generate chemical products have also been emphasized.

Less consideration has been given to potential improvements in conventional coal fired steam power plants, known as Rankine Cycles, that are also capable of high efficiency and lower emissions. These plants utilize pulverized coal or fluidized bed combustion systems.

In view of the possible near-term benefits, a U.S. Department of Energy/ALSTOM Power Inc. consortium has funded an assessment of Rankine Cycle power plants equipped with three different combustion systems: Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and Circulating Moving Bed (CMB™). Five steam cycles utilizing a wide range of steam conditions were used with these combustion systems. The purpose of this study is to establish through engineering analysis, the most cost-effective performance potential available through improvement in the Rankine Cycle steam conditions and combustion systems.

ALSTOM managed and performed the subject study from its US Power Plant Laboratories office in Windsor, Connecticut. Participating, as sub-contractors in this effort are Parsons Energy and Chemical Group, from its offices in Wyomissing, Pennsylvania and American Electric Power (AEP), from its offices in Columbus, Ohio. The US Department of Energy National Energy Technology Laboratory provided consultation and funding. ALSTOM provided cost share to this project.

This report discusses the results of a coal fired steam power plant project, which is comprised of two parts. The main part of the study was the analysis of ten (10) Greenfield steam power plants employing three different coal combustion technologies: Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and Circulating Moving Bed (CMB™) integrated with five different steam cycles. The study explores the technical feasibility, thermal performance, environmental performance, and economic viability of ten power plants that could be deployed currently, in the near, intermediate, and long-term time frame. For the five steam cycles, main steam temperatures vary from 1,000°F to 1,292°F and pressures from 2,400psi to 5,075psi. Reheat steam temperatures vary from 1,000°F to 1,328°F. The number of feedwater heaters varies from 7 to 9 and the associated feedwater temperature varies from 500°F to 626°F. The main part of the study therefore determines the steam cycle parameters and combustion technology that would yield the lowest cost of electricity (COE) for the next generation of coal-fired steam power plants. With respect to environmental performance, the Greenfield plants are designed to meet the following emissions performance based on CURC (Coal Utilization Research Council) 2010 targets.

- > 98% sulfur removal
- < 0.05 lbm/MM-Btu $NO_x$
- < 0.01 lbm/MM-Btu Particulate Matter
- > 90% Hg removal

Mercury control has not been considered in the investment costs or economic analysis for this study to simplify the analysis. New mercury control technology is currently being developed. It is believed that the investment and operating cost would be relatively small and approximately the same for PC, CFB, and CMB™ boiler technologies.

The second part of the study (Repowering) explores one means of upgrading the efficiency and output of an older existing coal fired steam power plant. There are currently more than 1,400 coal-fired units in operation in the United States generating about 54 percent of the electricity consumed. Many of these are modern units are clean and efficient. Additionally, there are many older units in excellent condition and still in service that could benefit from this repowering technology. The study evaluates the technical feasibility, thermal performance, and economic viability of this repowering concept.

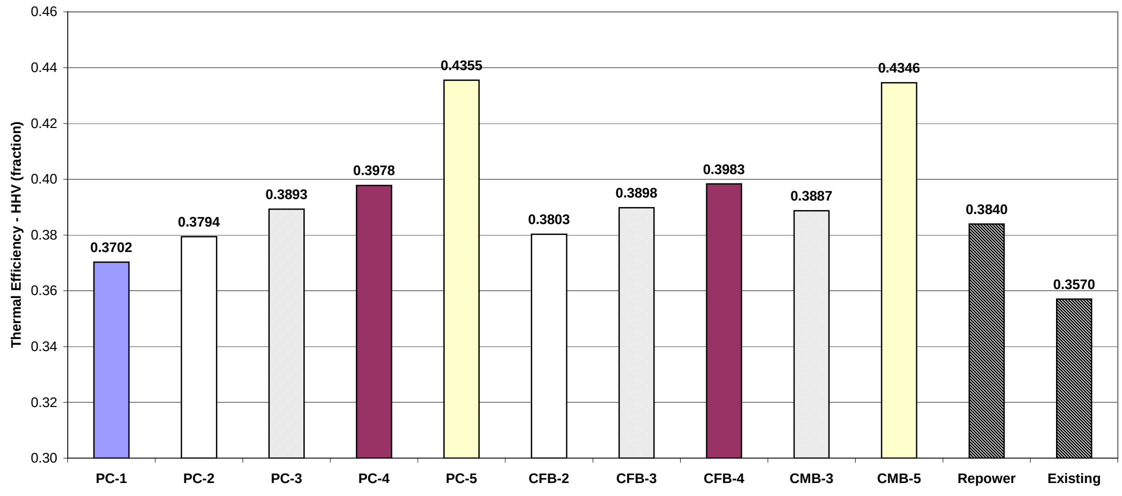
Primary results for both parts of the study are summarized in terms of thermal efficiency, environmental performance, investment costs, and cost of electricity (COE). The table shown below defines the case studies in terms of steam cycle parameters and combustion technology and the table and associated figures also summarize the thermal efficiency, investment cost, and COE results for all the cases.

**Primary Results Summary: Thermal Efficiency, Investment Costs, and Cost of Electricity**

| | | PC-1 | PC-2 | PC-3 | PC-4 | PC-5 | CFB-2 | CFB-3 | CFB-4 | CMB-3 | CMB-5 | Repower | Existing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Steam Cycle Parameters** | | | | | | | | | | | | | |
| Main Steam Pressure | (psia) | 2408 | 2408 | 3625 | 3915 | 5075 | 2408 | 3625 | 3915 | 3625 | 5075 | 4242 | 2015 |
| Main Steam Temperature | (Deg F) | 1000 | 1049 | 1049 | 1085 | 1292 | 1049 | 1049 | 1085 | 1049 | 1292 | 1292 | 1050 |
| Reheat Steam Temperature | (Deg F) | 1000 | 1112 | 1112 | 1148 | 1328 | 1112 | 1112 | 1148 | 1112 | 1328 | 1000 | 1000 |
| Feedwater Temperature | (Deg F) | 500 | 500 | 500 | 554 | 626 | 500 | 500 | 554 | 500 | 626 | 460 | 453 |
| Number of Feedwater Heaters | (no.) | 7 | 7 | 7 | 8 | 9 | 7 | 7 | 8 | 7 | 9 | 8 | 8 |
| **Efficiency and Output** | | | | | | | | | | | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8926 | 0.8926 | 0.8873 | 0.8816 |
| **Steam Cycle Efficiency** | (fraction) | 0.4442 | 0.4543 | 0.4650 | 0.4745 | 0.5161 | 0.4543 | 0.4650 | 0.4745 | 0.4650 | 0.5161 | 0.4604 | 0.4269 |
| | (Btu/kwhr) | 7683 | 7512 | 7339 | 7193 | 6613 | 7512 | 7339 | 7193 | 7339 | 6613 | 7413 | 7994 |
| **Generator Output** | (kw) | 696316 | 711278 | 736148 | 753937 | 821374 | 711278 | 736148 | 753937 | 736148 | 821374 | 203807 | 168604 |
| **Net Plant Output** | (kw) | 630526 | 646080 | 662936 | 677479 | 741615 | 647588 | 663823 | 678366 | 665552 | 744230 | 184887 | 156518 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5844 | 5844 | 1643 | 1496 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 9218 | 8997 | 8768 | 8580 | 7838 | 8976 | 8756 | 8568 | 8781 | 7853 | 8889 | 9561 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3702 | 0.3794 | 0.3893 | 0.3978 | 0.4355 | 0.3803 | 0.3898 | 0.3983 | 0.3887 | 0.4346 | 0.3840 | 0.3570 |
| **Costs and Economics** | | | | | | | | | | | | | |
| **Investment Costs** | ($/kWe net) | 1,139 | 1,126 | 1,109 | 1,098 | 1,168 | 1,051 | 1,038 | 1,039 | 1,018 | 1,039 | 413 | n/a |
| **Levelized Cost of Electricity** | (Cents/kWh) | 3.96 | 3.89 | 3.82 | 3.76 | 3.77 | 3.62 | 3.56 | 3.53 | 3.52 | 3.41 | 2.76 | 2.29 |

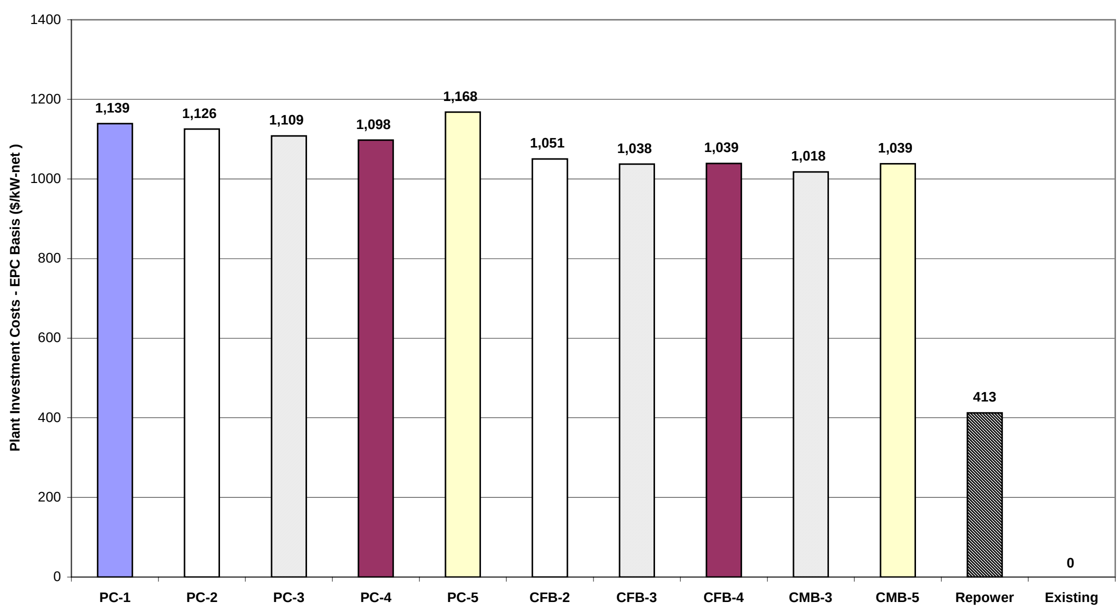
For the ten Greenfield cases, the calculated thermal efficiencies (HHV basis) range from 37.02% to 43.55%. With respect to thermal efficiency, for the same steam conditions, there is little difference when comparing among the combustion systems (PC, CFB, and CMB™) as would be expected. In general the thermal efficiency of the PC fired systems are about the same as for the CFB based systems. The CFB and PC systems thermal efficiency are about 0.1 percentage points higher than the CMB™ systems which is due to only partial sulfation in the CMB™ combustor. The effect of the increasing steam cycle parameters (Temperature and Pressure) is also clearly illustrated.

### Plant Thermal Efficiencies (HHV Basis) – All Cases




The specific investment cost results for the Greenfield cases are shown in the table above range from about 1,018 to 1,168 $/kW-net. For the same steam conditions, the CMB$^{TM}$ combustion system plants require the lowest investment costs as compared to PC or CFB plants. This cost advantage increases as steam cycle conditions (Temperature and Pressure) are raised. The CFB systems are about 70 $/kW lower in cost than the PC type combustion systems. This difference is primarily attributable to the differences in the costs for the gas cleanup system equipment.

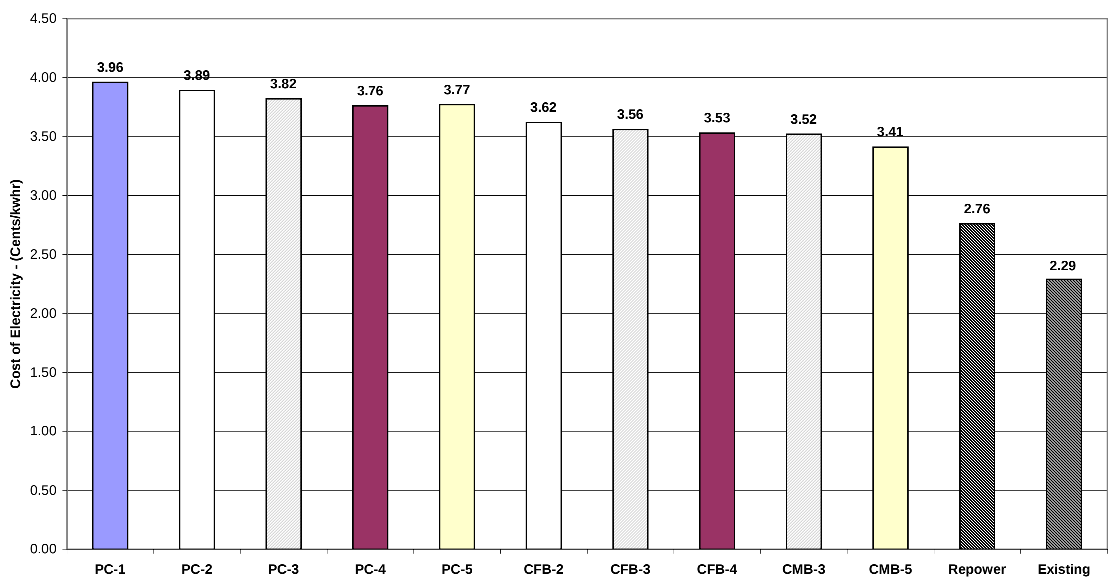
### Plant Investment Costs ($/kW - EPC Basis) – All Cases



The levelized cost of electricity (COE) results for the Greenfield cases shown in the table above range from about 3.4 to 4.0 Cents/kWh. These results indicate that Case CMB™-5 is the most economical from a COE basis. Compared to Case PC-5 it requires significantly less weight of very expensive Ni alloy tubing. The effect of increased steam conditions on COE is also shown in the graph below with the increased steam conditions offering a slight advantage. For the same steam conditions there is very little difference in the COE between CFB and CMB™ designs.

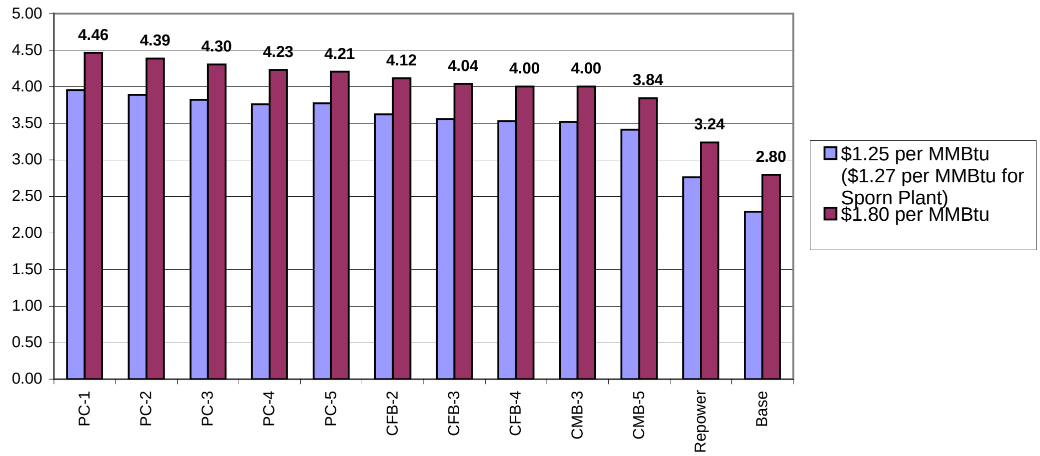
Similar to the investment cost results, the PC cases are about 7% higher than the CFB type combustion systems with respect to COE at the same steam conditions. The advantage of the CFB systems is attributable to the investment cost savings discussed above. Because of the additional reduction in investment cost associated with CMB™ based systems, the CMB™ combustion system offers a COE advantage as compared to PC of about 8-10% (greater advantage at higher steam conditions) and about 1% as compared to CFB type combustion systems.

**Cost of Electricity (Cents/kWh) – All Cases**



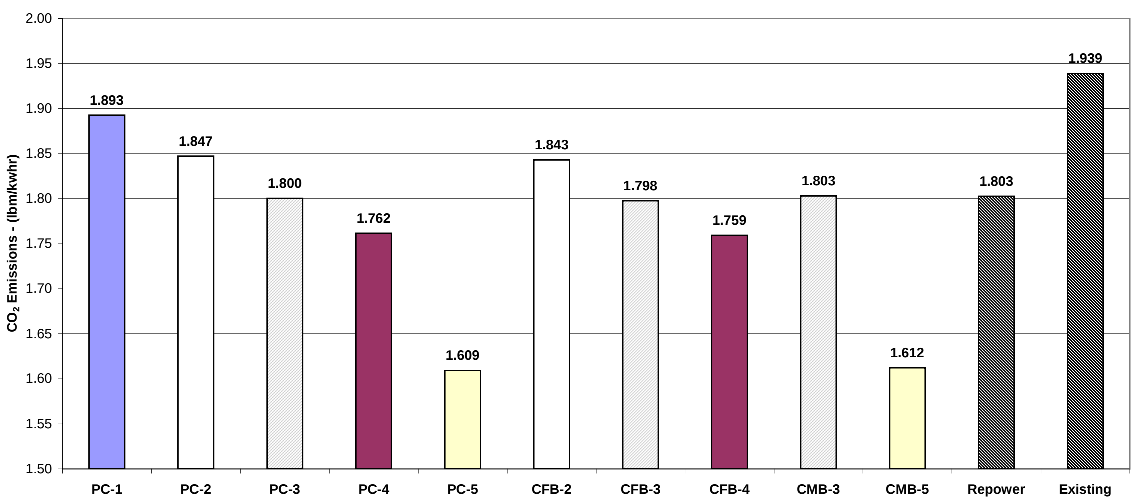

The cost of electricity is directly related to the cost of fuel. The above COE's are calculated for the price of fuel of $1.25/MBtu. As the cost of fuel increases, as shown in the figure below, the cost of electricity increases also and at the same time the economics continue to shift towards the more efficient power plant systems. For example, at a of coal price of $1.80 MM-Btu the COE is the lowest for the ultra-supercritical case PC-5 among the PC power plant cases. The ultra-supercritical CMB-5 continues to offer the lowest COE among the power plant cycles analyzed.

**Cost of Electricity Comparison for 1.25 and 1.80 $/MM-Btu Fuel Cost – All Cases**



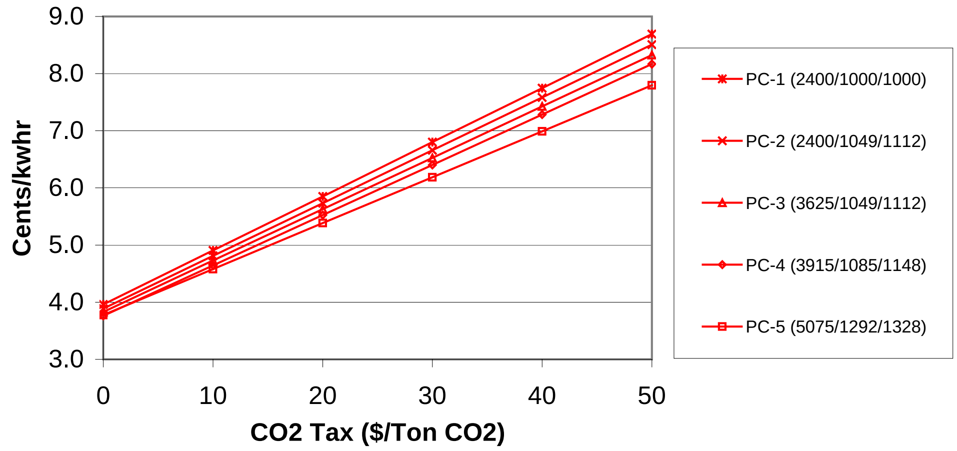

The following figure shows a comparison of specific $CO_2$ emissions (lbm/kWh) for all the cases. This figure, in combination with the thermal efficiency results shown above, shows the direct correlation of $CO_2$ emissions and plant thermal efficiency. For example, Case PC-5 is about 18% more efficient than Case PC-1 and it also emits about 18% less $CO_2$ per kWh of net output.

**$CO_2$ Emissions (lbm/kWh) – All Cases**




The study has also investigated the impact of potential taxes placed on $CO_2$ emissions. The figure below illustrates the changes in the COE as the potential tax increases for the PC power plant cases. As expected, the COE increases significantly with the increase in the tax. The figure also shows that the tax would become a major driver in utility companies selection process of the power plant cycle parameters and the high efficiency plants would become the technologies of choice.

**Cost of Electricity for PC Power Plant Cases For Different $CO_2$ Emissions Tax Rate**




For the Repowering Case, CMB combustion technology was selected because of its economic advantage for high temperature cycles. The calculated thermal efficiency (HHV basis) is improved from 35.70% for the existing unit to 38.40%. The investment costs necessary for all the equipment required for this repowering project is 413 $/kW-net and the resulting incremental cost of electricity is calculated to be 0.47 Cents/kWh (2.76 - 2.29 Cents/kWh). Incremental cost is calculated relative to the unmodified existing unit. This difference may quickly disappear if the price of $NO_x$ credits continues to increase and/or a major capital investment is required to refurbish the existing boiler or if there is loss of availability caused by the aging equipment. $CO_2$ emissions are decreased from about 1.94 to 1.80 lbm/kWh, a reduction of about 8 percent.

In summary, from the results of the study the evaluated power plant systems fall either into the near term or long term category with respect to technology implementation. All combustion technologies can achieve low levels of pollutants and comply with the CURC 2010 air pollution targets. Technology is available today to facilitate construction of all the PC cycles, except for the ultra-supercitical steam conditions of Case PC-5, and all the CFB steam cycles. Technology is being developed to enable market introduction of Case PC-5 and both CMB$^{TM}$ cycles in a 10 to 15 year timeframe. The very high steam temperatures of the ultra-supecritical steam cycle do not appear to be practical for conventional CFB technology where combustion temperature is generally limited to 1,550$^0$F. CMB$^{TM}$ technology with the combustion temperature of 2000$^0$F allows greater latitude in selecting the range of steam cycle parameters. The ultra-supecritical CMB$^{TM}$ design offers the prospect of the lowest COE.

The CFB power plants are the technology of choice for high sulfur coals. For low sulfur coals the PC power plants that don't require installation of the back end $NO_x$ and $SO_x$ control technologies would be favored. The supercritical CFB plants have the lowest cost of electricity and its cost continues to improve for higher steam conditions.

Building up on these results, the next step in the development effort of the Rankine power plant cycle is recommended. It should include a CFB design with steam conditions of 4,000 psi to 5000 psi and main and reheat steam temperatures of approximately 1,200$^0$F. The potential plant efficiency improvement would be significant and the efficiency should be in the range of 41-42% (HHV basis). These steam conditions may require some CFB process modifications to enable the higher steam temperatures but would represent the upper limit for conventional boiler alloys.

Such a design would fulfill the promise of high efficiency and low cost of the intermediate term (3 to 5 years) power plant cycle.

Based on reliability, investment costs, emissions and cost of electricity a coal fired steam power plant will continue to be a good investment for power plant owners especially compared to other options such as IGCC for coal powered electric power production. The thermal efficiencies of today's steam power plants with supercritical steam cycles are higher than today's IGCC plants. For power plants of the future, studies show that coal fired steam plants with ultra-supercritical steam cycles will maintain this efficiency advantage over future IGCC plants with advanced gas turbines. [MARION,10]

# 1. Introduction

Because of continued higher cost and scarcity of oil and natural gas, and no growth of nuclear power generation, attention has focused on coal as a major energy resource for the nation's future. However, in search of higher efficiency and lower emission, much of this attention has been directed toward second-generation technologies. These technologies include coal gasification combined cycles, fuel cells that utilize hydrogen derived from coal gasification or natural gas fuel, and other advanced power plant systems that in addition to power generation may also generate chemical products.

Less consideration has been given to potential improvements in conventional, pulverized, and fluidized bed coal fired steam power plants, known as Rankine Cycles, that are also capable of high efficiency and lower emission. A typical Rankine Cycle steam power plant configuration is shown in Figure 1.0.1.

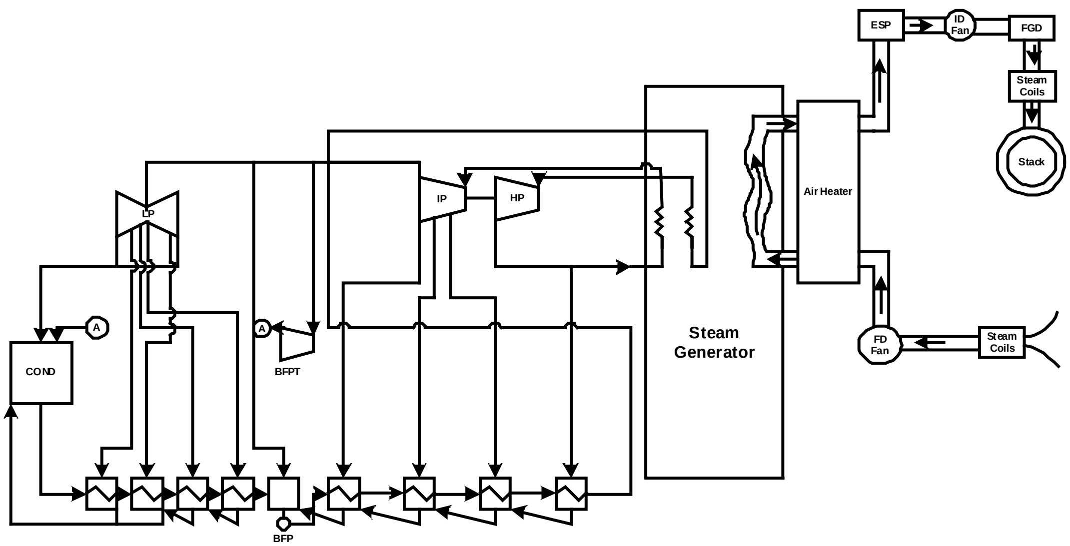



**Figure 1.0. 1: Simplified Diagram of a Rankine Cycle Steam Power Plant**

In view of the possible near-term benefits, a U.S. Department of Energy/ALSTOM Power Inc. consortium has funded an economic and technical feasibility assessment of a wide range of Rankine Cycles equipped with three different combustion systems: Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and Circulating Moving Bed (CMB$^{TM}$). The purpose of this study is to establish through engineering analysis, the most cost-effective performance potential available through improvements in the steam conditions of the Rankine Cycle.

Specific project objectives are listed below:

- Determine the thermal efficiency, investment costs, and economic improvements of the Rankine Cycle Steam Power Plant as a function of steam conditions.
- Identify state-of-the-art power plant systems, which are available in the market place today, in the near term, and long term future.
- Compare the economics of a nominal 700MW Rankine Cycle for the same steam conditions applying PC, CFB, and CMB$^{TM}$ combustion technologies.

The results of this study are based on a multi-step process that considers:

- Thermodynamic performance (Plant Thermal Efficiency)
- Equipment design, selection, and pricing (EPC basis)
- Economic Analysis (Cost of Electricity)

**Historical Experience:**
The modern Rankine Power Plant is the product of over 100 years of design developments and improvements. In 1900 typical steam conditions were 180 psig and 350°F with heat rates around 35,000 Btu/kWh. Reheat cycles were first used during the 1920's. During the 1940's steam conditions reached 1,500psig and 1,000/1,000°F. The 1950's saw the progress culminate with the introduction of double reheat utilizing 5,000psig throttle pressure and steam temperatures of 1,200/1,050/1,050°F at the Eddystone 1 unit of the Philadelphia Electric Company.

The throttle conditions at Eddystone 1 have been decreased somewhat due to material creep and coal ash corrosion problems, but the unit still maintains 4,700psig and 1,125°F throttle conditions, higher than any other unit in the US, after about 45 years of operation.

Since the early 1960's for a variety of reasons, advanced steam conditions have not been pursued in the domestic market. There was little motivation to continue lowering heat rates of fossil-fired plants because of the expected increase in nuclear power generation for base load application and the availability of relatively inexpensive fossil fuels.

However, due to recent increases in fuel prices and environmental concerns, plant heat rate is beginning to play a greater role in the utility companies' decision in selecting the most cost effective and environmentally friendly steam plant cycle. The corollary of higher efficiency is lower fuel consumption and lower emissions for the same unit of electrical output. It also means that for every pound of coal, which doesn't have to be burned, there is a pound of coal that doesn't need to be purchased, transported, stored and pulverized. If that coal is not burned it is not necessary to collect and dispose of combustion residues. As a direct function of efficiency, $CO_2$ emission, which is believed to be a contributor to global warming, is reduced in proportion to improved efficiency, as are $NO_x$ and $SO_x$ emissions, which are contributors to acid rain. Particulate matter, VOC, CO, and trace metal emissions are similarly reduced.

**Methodology and Design Parameters:**
This study is based on ALSTOM's previous work (Palkes, Liljedahl, Kruger, Weirich; 1999), which examined power plant parameters that would produce the lowest cost of electricity (COE) for the next generation pulverized coal-fired steam power plants. A total of 25 different design cases, each with 700 MWe nominal capacity were examined in the previous study.

The current study has updated the results of the previous work and expanded it to include an ultra-high steam conditions power plant cycle. Additionally, the current study also investigates three different coal combustion systems. The following list shows a comparison of the range of steam conditions and other plant parameters for the previous and current study.

| | Previous Study | Current Study |
|---|---|---|
| • Live steam pressure: | 2,408 - 3,915psi | 2,408 – 5,075psi |
| • Live steam temperatures: | 1,000°F - 1,090°F | 1,000°F - 1,292°F |
| • Reheater temperatures: | 1,000°F - 1,153°F | 1,000°F - 1,328°F |
| • Feedwater final temperatures: | 482°F - 572°F | 500°F - 626°F |
| • Reheater pressures between | 527 - 798psi | 703 – 1,054psi |
| • Number of feedwater preheaters: | 7 – 8 | 7 – 9 |
| • Combustion System: | PC | PC, CFB, CMB™ |

This project represents a coal fired steam power plant project, which is comprised of two main parts. The first part of the study is an analysis of ten (10) Greenfield plants utilizing a wide range of steam cycle parameters and three different combustion systems. The second part of the study (Repowering) explores one means of upgrading the efficiency and output of an older existing coal fired steam power plant.

**Greenfield Plants Study:**
The first part of the project, which represents the majority of the effort, is an assessment of ten (10) different Greenfield power plant systems with ~700-820 MWe generator output capacity. Although the generator outputs vary, the heat input to the steam cycles (i.e. boiler heat output) is the same for all cases. These ten plants encompass a matrix of plant designs incorporating a wide range of steam cycle parameters and three different combustion systems.

Five steam cycles are used among the ten Greenfield cases. Steam turbine design conditions for these five steam cycles (designated Steam Cycle 1-5) are shown below and range from conditions widely used today to conditions envisioned applicable for power plants of the future.

Steam Cycle Design Conditions:

- Steam Cycle #1; 1,000°F/1,000°F/2,408 psia
- Steam Cycle #2: 1,049°F/1,112°F/2,408 psia
- Steam Cycle #3: 1,049°F/1,112°F/3,625 psia
- Steam Cycle #4; 1,085°F/1,148°F/3,915 psia
- Steam Cycle #5; 1,292°F/1,328°F/5,075 psia

Each case selected utilizes one of the five steam cycles, listed above, integrated with one of three coal combustion systems: Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and Circulating Moving Bed (CMB$^{TM}$). The case identification acronym used for all the Greenfield cases is comprised of two or three letters, which identify the type of combustion system (i.e. PC, CFB, or CMB$^{TM}$), combined with a single number, which identifies the steam cycle used (i.e. 1, 2, 3, 4, or 5). For example, Case PC-3 indicates a pulverized coal combustion system combined with the # 3 steam cycle (i.e. 1,049°F/1,112°F/3,625 psia) as listed above.

Five of the ten Greenfield cases selected include pulverized coal (PC) fired steam generators equipped with low $NO_x$ tangential firing systems. These five PC cases utilize all five of the above identified steam cycles, which provide discretely different steam conditions, thermodynamic performance, and equipment design. Additionally three cases are selected with CFB and two cases are selected with CMB$^{TM}$ combustion systems.

The five Greenfield PC cases are listed below showing the design steam conditions.

- **PC-1**; 1,000°F/1,000°F/2,408 psia
- **PC-2**: 1,049°F/1,112°F/2,408 psia
- **PC-3**: 1,049°F/1,112°F/3,625 psia
- **PC-4**; 1,085°F/1,148°F/3,915 psia
- **PC-5**; 1,292°F/1,328°F/5,075 psia

Additionally, three Greenfield cases were selected with circulating fluidized bed (CFB) steam generators designed to produce the following steam conditions:

- **CFB-2**; 1,049°F/1,112°F/2,408 psia
- **CFB-3**; 1,049°F/1,112°F/3,625 psia
- **CFB-4**; 1,085°F/1,148°F/3,915 psia

The final two cases included in the first part of the study are two Greenfield cases with the following steam conditions selected for plants equipped with advanced circulating moving bed ($CMB^{TM}$) steam generators:

- **$CMB^{TM}$-3**; 1,049°F/1,112°F/3,625 psia
- **$CMB^{TM}$-5**; 1,292°F/1,328°F/5,075 psia

ALSTOM has been pursuing the development of $CMB^{TM}$ technology for the past few years. Significant progress has been made in understanding combustion and heat transfer processes unique to the $CMB^{TM}$ technology.

All power plant cases examined in the first part of the study are designed for several common parameters including the same boiler heat output, fuel analysis, limestone analysis, ambient conditions, condenser pressure, etc. These plants produce net plant outputs of about 630-750 MWe. The heat input into the steam turbines (i.e. heat output from the steam generators) is maintained constant for all cycles independent of the steam parameters to simplify thermodynamic and economic analyses. The resulting fuel heat input to the boilers is also nearly equivalent for all the Greenfield cases.

A number of major components and systems require design modifications due to changes in steam conditions. They are the steam turbine, generator, steam generator, high-pressure piping and fittings in accordance with pressure and temperature, feedwater pumps, high-pressure feedwater train, condenser and cooling water system, and the accessory electric plant. The designs also reflect differences between subcritical drum-type and once-through supercritical units, which employ different water treatment systems. A condensate polishing system is required for the supercritical plants.

Depending on the combustion technology employed, the steam generator designs and their auxiliary components will be different. The designs account for inherent differences in coal combustion, $NO_x$ particulate control, and sulfur control processes.

Environmental concerns are addressed in the designs also. With respect to environmental performance, the Greenfield plants are designed to meet the following emissions performance based on CURC (Coal Utilization Research Council) 2010 targets.

- > 98% sulfur removal
- < 0.05 lbm/MM-Btu $NO_x$
- < 0.01 lbm/MM-Btu Particulate Matter
- > 90% Hg removal

Mercury control has not been considered in the investment costs or economic analysis for this study to simplify the analysis. New mercury control technology is currently being developed. It is believed that the investment and operating cost would be relatively small and approximately the same for PC, CFB, and $CMB^{TM}$ boiler technologies.

**Repowering Study:**
The second part of the study (Repowering) explores one means of upgrading the efficiency and output of an older existing coal fired steam power plant. In this part of the study, one candidate case, Unit #4 of the Philip Sporn plant (~169 MWe gross output) owned and operated by American Electric Power (AEP), is being analyzed for a repowering scenario.

The proposed repowering concept uses a number of new plant components integrated with the existing plant components to the maximum extent practical. The repowered plant includes a new $CMB^{TM}$ boiler. It also includes a new topping steam turbine that expands steam from the new $CMB^{TM}$ boiler at 1,292°F/4,337psia to the steam conditions of 1,050°F/2,015psia, which match the throttle conditions of the existing steam turbine.

The scope of this second part of the study is to determine the overall thermal performance, investment cost, and incremental cost of electricity for repowering the plant to operate at these higher steam conditions. The incremental cost of electricity is incremental as compared to the unmodified Sporn Unit #4 Plant. For the repowering case, due to the limited framework of this study, it was agreed that no additional emission control system would be installed and at a minimum, the current air emission standards would be maintained. However, the CMB™ boiler produces inherently low $NO_x$ emissions. It is capable of 0.10 lbm/MM-Btu $NO_x$ emission without SNCR as compared to the existing unit emission of 0.57 lbm/MM-Btu. Since $NO_x$ emissions are a tradable commodity, particularly during the five-month ozone season when $NO_x$ emission is limited to 0.15 lbm/MM-Btu, the economic analysis (Section 4) includes $NO_x$ trade allowances.

# 2. Case Studies; Plant Performance, Design and Equipment

This section of the report provides detailed descriptions of all the study cases (Greenfield and Repowering), the design basis, and the various processes used for each of the cases analyzed. The equipment used for these processes is also described. Additionally, the overall plant performance of each case is also presented in terms of performance summary tables.

A total of eleven (11) case studies were analyzed in this two-part evaluation. The first part of the study, which represents the main effort of the study, is an evaluation of ten (10) Greenfield power plants. The second part of the study is a single case that evaluates the viability of repowering an existing coal fired steam plant to higher steam conditions.

The first part of the study evaluates ten (10) Greenfield cases ranging from ~700-820 MWe gross output. These cases are subdivided into three distinct groups, which utilize different Boiler Island systems for combustion of the coal. The first group includes five (5) cases, which utilize Pulverized Coal (PC) fired boilers and a wide range of steam conditions. The second group includes three (3) cases, which utilize Circulating Fluidized Bed (CFB) boilers and three of the same steam cycles used in the first group. The third group includes two (2) cases, which utilize advanced Circulating Moving Bed (CMB™) boilers and two of the same steam cycles used in the PC group. One of the steam cycles used in the CMB™ group is also common with one of the CFB group steam cycles. All of the steam cycles for these 10 cases require the same heat input from the boiler. To summarize the Greenfield case studies, a total of five steam cycles were used with three combustion systems. All five steam cycles were not used for each combustion system group. The selection of these cases allows a common basis comparison of both coal combustion system and steam cycle parameters.

The second part of the study evaluates a repowering scenario (~205 MWe gross output), which addresses the need for improved performance for the large fleet of existing older coal fired power plants. The Philip Sporn plant, owned by American Electric Power (AEP), is being analyzed to estimate the performance and cost of repowering the plant to operate at higher steam conditions. The steam conditions for the topping steam turbine are 4,242 psia / 1,292°F inlet and 2,016 psia /1,050°F exhaust. The topping turbine exhausts into the existing steam turbine inlet. The existing steam turbine has conditions of 2,000 psia, 1,050°F with reheat steam at 500 psia and 1,000°F. Because this case represents a site specific repowering evaluation, the results are not directly comparable to the ten Greenfield cases in the first part this study.

## 2.1 Plant Design Basis and Scope:

All of the plants designed for this conceptual level study, except for the repowering case, are assumed to be located on a common Greenfield site, and are assumed to be operated under common conditions of fuel, limestone, utility and environmental standards. This section is intended to describe the common parameters, the host site conditions, the scope of the cost estimate, and other items, which will be used as a common design basis for all these plants.

**Common Parameters:**
All of the Greenfield plants were designed for the identical coal and limestone analyses, ambient conditions, site conditions, etc. such that each case study provides results which are directly comparable, on a common basis, to all other cases analyzed within this work. Additionally, all cases (except for the repowering case) were designed for a constant heat input to the steam cycles (i.e. boiler heat output). The ambient conditions used for all material and energy balances were based on the standard American Boiler Manufacturers Association (ABMA) atmospheric conditions (i.e. 80 °F, 14.7 psia, 60 percent relative humidity). Many other items were common between cases such as the site, plant services, etc. as described below.

**Plant Site and Scope:**
The generic plant site, which is common to all study cases, is assumed to be located in the Gulf Coast region of southeastern Texas. The site consists of approximately 300 usable acres within 15 miles of a medium-sized metropolitan area, with a well-established infrastructure capable of supporting the required construction work force. The area immediately surrounding the site has a mixture of agricultural and light industrial uses. The site is served by a river of adequate quantity for use as makeup cooling water with minimal pretreatment and for the receipt of cooling system blowdown discharges.

A railroad line suitable for unit coal trains passes within 2-1/2 miles of the site boundary. A well-developed road network serves the site, capable of carrying AASHTO H-20 S-16 loads and with overhead restriction of not less than 16 feet (Interstate Standard).

The site is on relatively flat land with a maximum difference in elevation within the site of about 30 feet. The topography of the area surrounding the site is rolling hills, with elevations within 2,000 yards not more than 300 feet above the site elevation. The site is within Seismic Zone 1, as defined by the Uniform Building Code. The following list further describes the assumed site characteristics.

- The site is Greenfield with no existing improvements or facilities.
- The site is relatively clear and level with no characteristics that would cause any unusual construction problems.
- The structural strength of the soil is adequate for spread footings (no piling is required) at this site.
- No rock excavation is required on this site.
- An abundant sub-surface water supply is assumed available on this site.

The boundary limit for these plants includes the complete plant facility within the “fence line”. It encompasses all equipment from the coal pile to the busbar and includes the coal receiving and water supply systems and terminates at the high-voltage side of the main power transformers. The scope of supply is further defined by the following list.

- Site preparation and site improvements
- Foundations, buildings, and structures required for all plant equipment and facilities
- General support facilities for administration, maintenance, and storage
- Coal and limestone receiving, storage, and handling systems
- Boiler Island from coal feed through gas cleanup system including associated solids handling systems
- Power block, including steam turbine, heat rejection, and makeup water systems
- Plant electrical distribution, lighting, and communication systems
- High-voltage electrical system through step-up transformer
- Instruments and controls
- Miscellaneous power plant equipment

The electrical facilities within the plant scope include all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, foundations, and standby equipment.

Additionally, the following utilities are assumed to be available at the site boundary.

- Communication lines
- Electrical power for plant construction
- Potable water and sanitary sewer connections
- Electrical transmission facilities and lines

**Plant Ambient Design Conditions:**
Table 2.1.1 lists ambient and other relevant characteristic assumptions for this site. The ambient conditions used for all material and energy balances were based on the standard American Boiler Manufacturers Association (ABMA) atmospheric conditions (i.e. 80°F, 14.7 psia, and 60 percent relative humidity).

All steam cycles for the Greenfield cases used a condenser pressure of 2.5 inches of mercury (absolute) as shown in Table 2.1.1. The repowering case used a condenser pressure of 1.6 inches of mercury per actual site operating conditions. For equipment sizing, the maximum dry bulb temperature is 95°F, and the minimum dry bulb temperature for mechanical design is 20°F.

**Table 2.1. 1: Site Characteristics (Greenfield Cases)**

| Design Parameter | Value |
|---|---|
| Elevation (ft) | 500 |
| Design Atmospheric Pressure (psia) | 14.7 |
| Design Temperature, dry bulb ($^oF$) | 80 |
| Design Temperature, wet bulb ($^oF$) | 52 |
| Design Relative Humidity (percent) | 60 |
| Design Condenser Pressure (in Hga) | 2.5 |
| Ash Disposal | Off Site |
| Water Source | River |

**Consumables:**
Table 2.1.2 shows the design coal analyses (Ultimate, Proximate and Higher Heating Value) used for all Greenfield cases. The coal is classified as a medium volatile bituminous coal. Table 2.1.3 shows the design limestone analysis used for the PC, CFB, and CMB™ study cases.

Table 2.1.4 shows the design coal analyses (Ultimate, Proximate and Higher Heating Value) used for the Repowering case. The coal is classified as a high volatile bituminous coal. Limestone was not used in the repowering case except as part of a parametric economic analysis included in Section 4. For this case the limestone analysis was assumed as shown in Table 2.1.3.

**Table 2.1. 2: Design Coal Analysis (Medium Volatile Bituminous) for Greenfield Cases**

| Ultimate Analysis | | |
|---|---|---|
| Constituent | (Units) | |
| O2 | (wt. frac.) | 0.0316 |
| N2 | " | 0.0146 |
| H2O | " | 0.0399 |
| H2 | " | 0.0357 |
| Carbon | " | 0.6205 |
| Sulfur | " | 0.0234 |
| Ash | " | 0.2343 |
| **Total** | " | 1.0000 |
| | | |
| **Proximate Analysis** | | |
| Constituent | (Units) | |
| Fixed Carbon | (wt. frac.) | 0.5483 |
| Volatile Matter | " | 0.1775 |
| Moisture | " | 0.0399 |
| Ash | " | 0.2343 |
| **Total** | " | 1.0000 |
| | | |
| **HHV Coal** | (Btu/lbm) | **11074** |

**Table 2.1. 3: Design Limestone Analysis for Greenfield Cases**

| Constituent | (Units) | Value |
|---|---|---|
| $CaCO_3$ | (wt. frac.) | 83.71 |
| Moisture | " | 1.00 |
| Impurities | " | 7.08 |
| $MgCO_3$ | " | 8.21 |
| Total | " | 100.00 |

**Table 2.1. 4: Design Coal Analysis (High Volatile Bituminous) for Repowering Case**

| Constituent | (Units) | Value |
|---|---|---|
| O2 | (wt. frac.) | 7.12 |
| N2 | " | 1.49 |
| H2O | " | 7.55 |
| H2 | " | 4.58 |
| Carbon | " | 66.96 |
| Sulfur | " | 1.00 |
| Ash | " | 11.30 |
| **Total** | " | 100.00 |
| | | |
| **Constituent** | **(Units)** | **Value** |
| Fixed Carbon | (wt. frac.) | 49.15 |
| Volatile Matter | " | 32.00 |
| Moisture | " | 7.55 |
| Ash | " | 11.30 |
| **Total** | " | 100.00 |
| | | |
| **HHV Coal** | (Btu/lbm) | 12100 |

**Plant Services:**
The following services and support systems are available at the plant as a part of the balance-of-plant systems.

Auxiliary Power Systems:
- 7,200 V system for motors above 3,000 hp.
- 4,160 V system for motors from 250 to 3,000 hp.
- 480 V system for motors from 0 to 250 hp and miscellaneous loads.
- Emergency diesel generator (480 V) to supply loads required for safe and orderly plant shutdown. Instruments and controls and other loads requiring regulated (1-percent) 208/120 Vac power are supplied from this source.
- 250 Vdc system motors and, via static inverters, uninterruptible ac power for the integrated control and monitoring system, intercommunication.
- 125 Vdc system for dc controls, emergency lighting, and critical tripping circuits including the plant shutdown system.

Cooling Water:
- Cooling water (from the cooling towers) is available at between 20 and 30 psig, 90°F maximum temperature. The water is periodically chlorinated, and pH is maintained at 6.5 to 7.5. The cooling towers receive makeup water from the river.
- Auxiliary cooling water, which uses de-mineralized water treated for corrosion control, at 60 to 80 psig and 105°F, is available for small heat loads (e.g., control oil coolers). The pH is maintained at about 8.5.

Compressed Air:
- Instrument air filtered and dried to -40° dew point at 80 to 100 psig and 110°F (maximum).
- Service air at 80 -100 psig and 110°F (maximum).

Lube Oil:
- Lube oil from the conditioning system, with particulate matter removed to 10 μm or lower.

Hydrogen and Carbon Dioxide:

- $H_2$ and $CO_2$ for generator cooling and purging from storage.

Nitrogen:

- $N_2$ for equipment blanketing against corrosion during shutdown and lay-up.

Raw Water:

- Filtered river water. Additional water treatment will be included for potable water, etc.

**Structures and Foundations:**
Structures are provided to support and permit access to all plant components requiring support to conform to the site criteria. The structure(s) are enclosed if deemed necessary to conform to the environmental conditions.

Foundations are provided for the support structures, pumps, tanks, and other plant components. A soil-bearing load of 5,000 $lbm/ft^2$ is used for foundation design.

## 2.2 Steam Cycles for the Greenfield Cases

Five steam cycles were selected for the ten Greenfield cases. These cycles (~700-820 MWe gross output) have discretely different steam conditions, thermodynamic performance, and equipment design. Steam turbine design conditions for these five steam cycles are shown in Table 2.2.1 and range from conditions widely used today to conditions expected for the power plants of the future.

**Table 2.2. 1: Steam Cycle Conditions for Greenfield Cases**

| Steam Cycle Identification Number | Case Identification Acronym | Superheater Outlet Temperature | Reheater Outlet Temperature | Main Steam Pressure | Feedwater Temperature | Number of Feedwater Heaters |
|---|---|---|---|---|---|---|
| | | (Deg F) | (Deg F) | (psia) | (Deg F) | (no.) |
| **1** | **PC-1** | 1000 | 1000 | 2408 | 500 | 7 |
| **2** | **PC-2, CFB-2** | 1049 | 1112 | 2408 | 500 | 7 |
| **3** | **PC-3, CFB-3, CMB-3** | 1049 | 1112 | 3625 | 500 | 7 |
| **4** | **PC-4, CFB-4** | 1085 | 1148 | 3915 | 554 | 8 |
| **5** | **PC-5, CMB-5** | 1292 | 1328 | 5075 | 626 | 9(1) |

(1) This steam cycle includes a topping desuperheater in addition to the 9 feedwater heaters

### 2.2.1 General Steam Cycle Description

Each steam cycle starts at the condenser hot well, which is a receptacle for the condensed steam from the exhaust of the steam turbine. The condensate flows to the suction of the condensate pumps, which increase the pressure of the fluid and transport it through the piping system, and low-pressure feedwater heaters (LPFWH's) and enable it to enter the open contact heater, or deaerator. The condensate passes through a gland steam condenser (GSC) first, followed in series by four or five (depending on steam cycle) low-pressure feedwater heaters. Steam Cycle #5 utilizes five LPFWH's whereas all the other steam cycles use four. The heaters successively increase the condensate temperature by condensing and partially sub-cooling steam extracted from the LP steam turbine section. Each heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (now referred to as heater drains) is progressively passed to the next lower pressure heater, with the drains from the lowest heater draining to the condenser.

The condensate entering the deaerator is heated and stripped of non-condensable gases by contact with the steam entering the unit. The steam is condensed and, along with the heated condensate, flows by gravity to a deaerator storage tank. The boiler feedwater pumps take suction from the storage tank and increase the fluid pressure. Both the condensate pump and boiler feed pump are electric motor driven. The boosted condensate flows through three more high-pressure feedwater heaters, increasing in temperature and then enters the boiler economizer section. Each heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (drains) is progressively passed to the next lower pressure heater, with the drains from the lowest heater draining to the deaerator.

Within the boiler the feedwater is evaporated and finally superheated. The high-pressure superheated steam leaving the finishing superheater is expanded through the high-pressure turbine. The exhaust from the high-pressure turbine is reheated and returned to the intermediate pressure turbine. The reheated steam expands through the intermediate and low-pressure turbines before exhausting to the condenser. The condenser pressure used for all cases in this study was 2.5 in Hga.

These five steam cycles are shown schematically in Figures 2.2.1 – 2.2.5. All five of these cycles are used for the PC cases. Additionally, four of these steam cycles are also used in either the CFB and/or CMB™ cases as indicated in the table above.

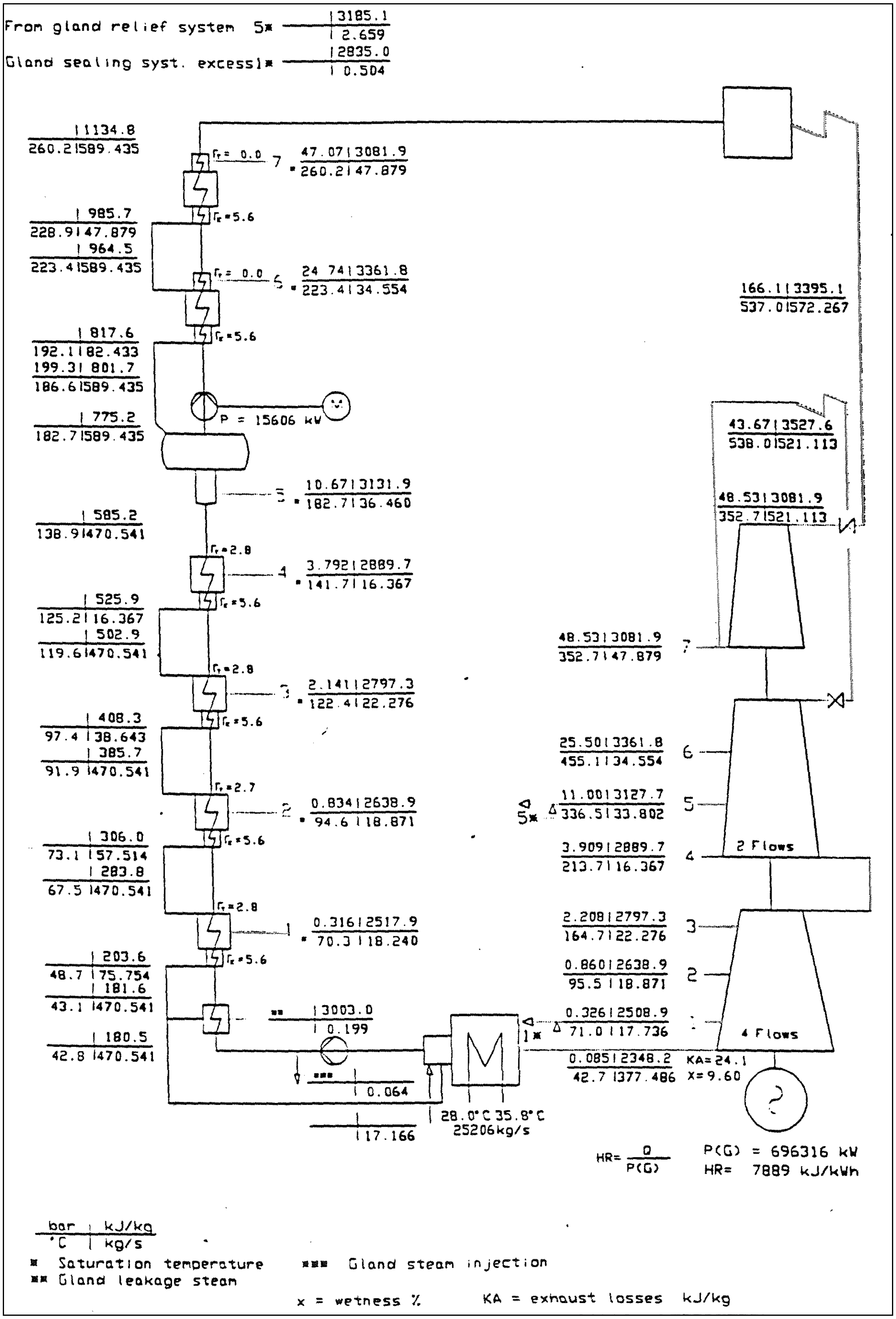



**Figure 2.2. 1: Steam Cycle #1 Schematic and Performance**

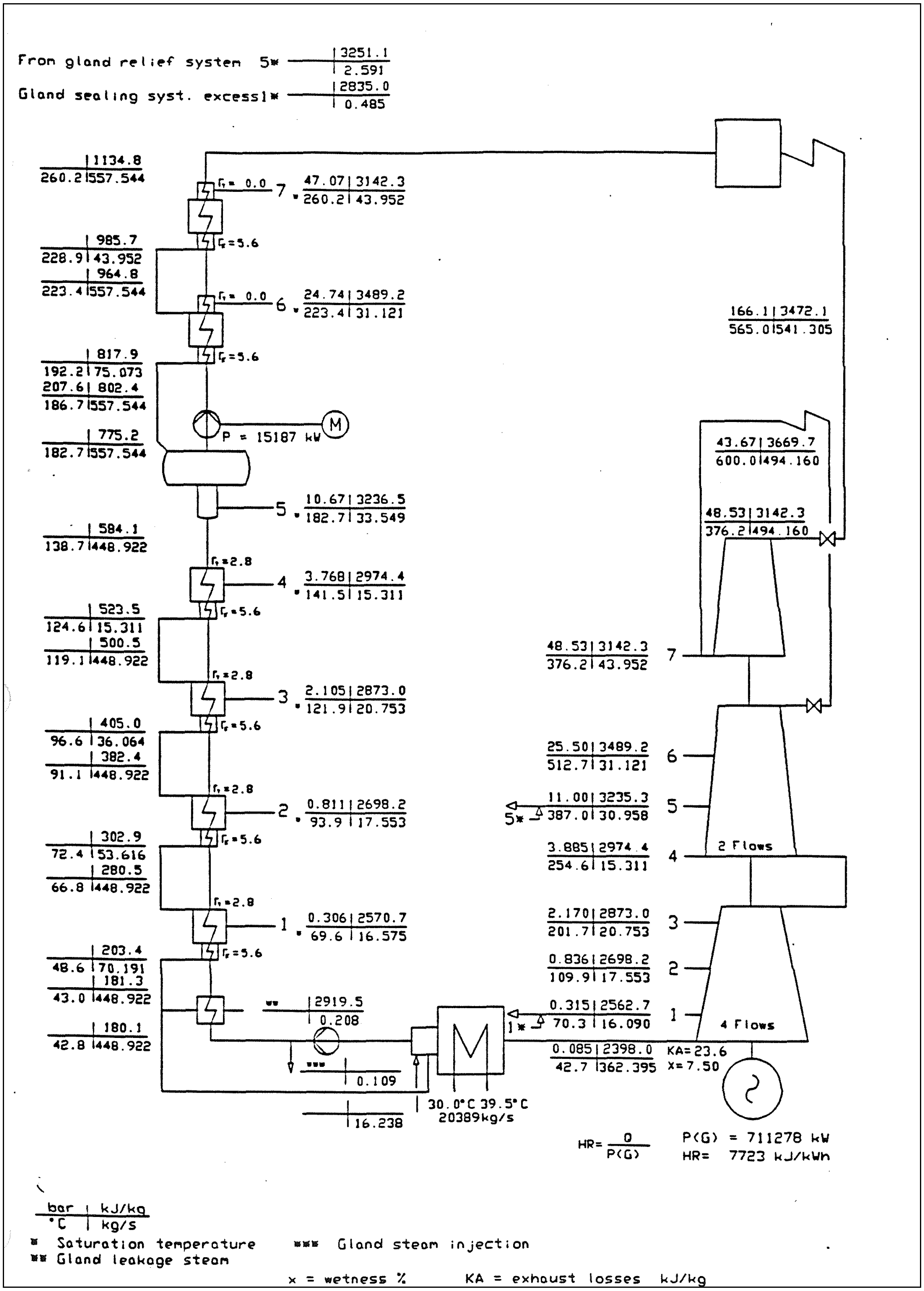



**Figure 2.2. 2: Steam Cycle #2 Schematic and Performance**

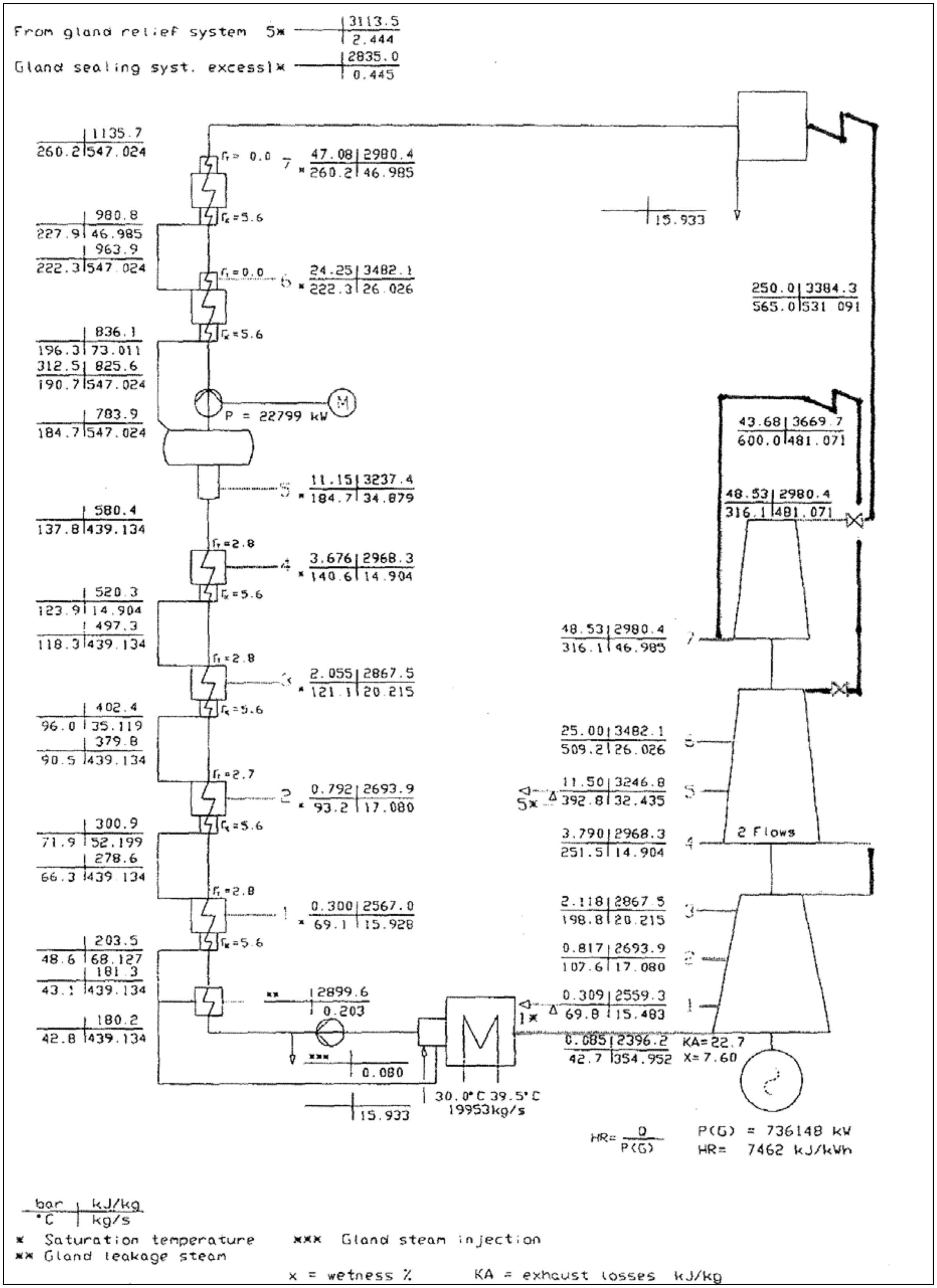



**Figure 2.2. 3: Steam Cycle #3 Schematic and Performance**

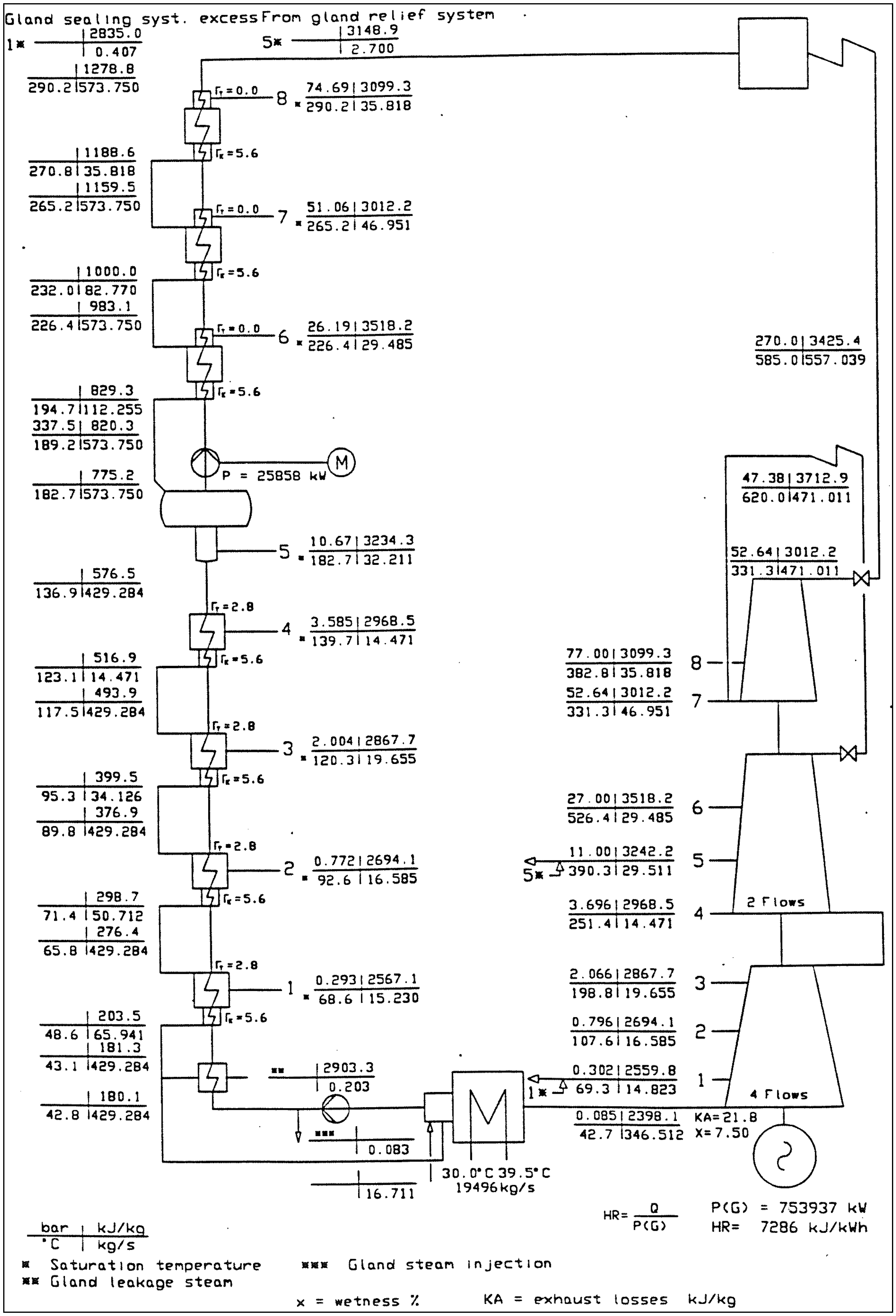



**Figure 2.2. 4: Steam Cycle #4 Schematic and Performance**

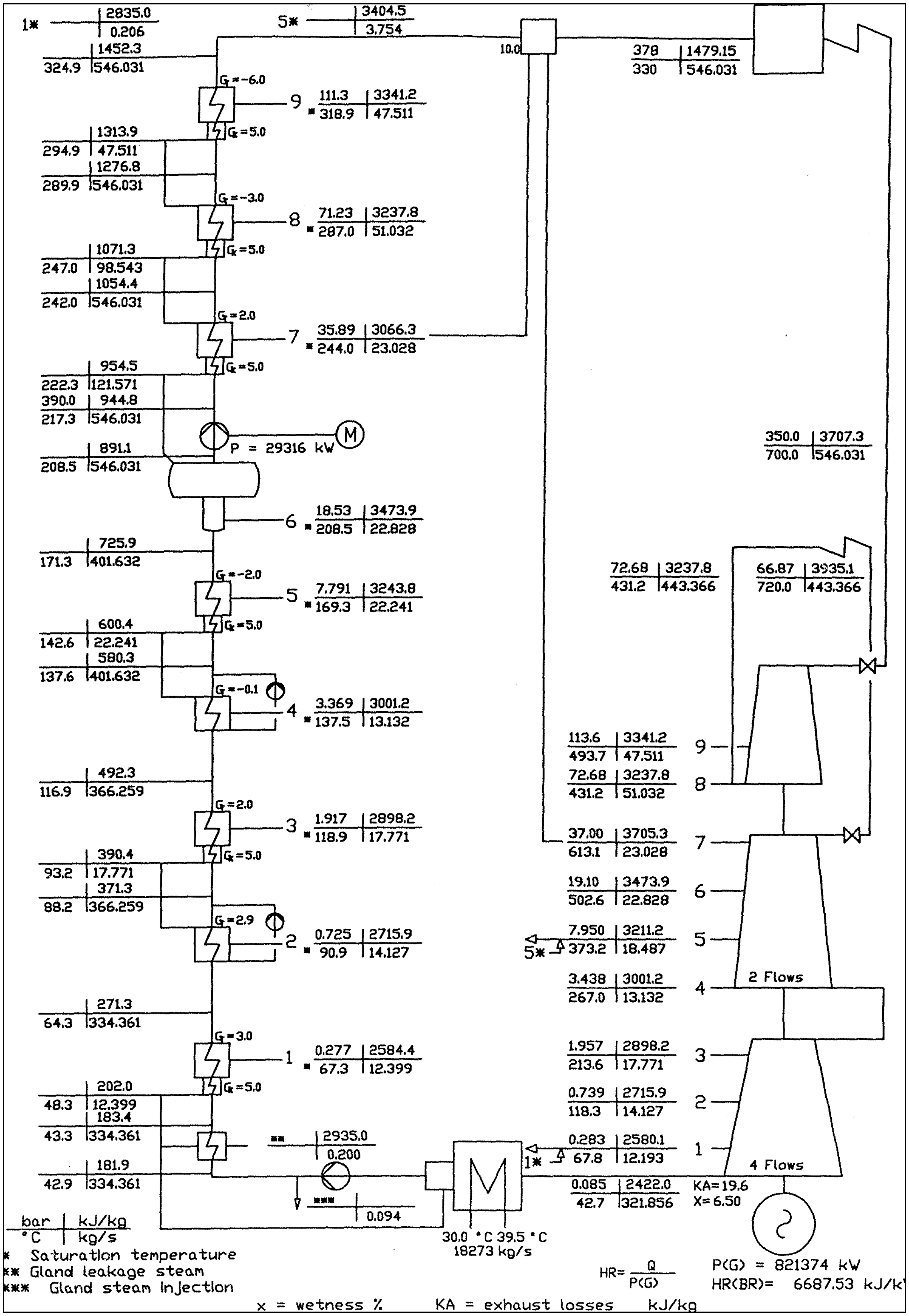



**Figure 2.2. 5: Steam Cycle #5 Schematic and Performance**

### 2.2.2 Steam Cycle Equipment

This section provides a brief description of the major equipment included with the steam cycle, including the steam turbine generator, the condensate system, and the feedwater system for these steam cycles.

#### 2.2.2.1 Steam Turbine Generators

The turbine consists of a high-pressure (HP) section, a double flow intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The reheated steam flows through the reheat stop valves and intercept valves and enters the IP sections. After passing through the IP sections, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is divided into two paths that flow through the LP section, exhausting downward into the condenser.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at variable inlet steam pressure (sliding pressure operation) over the entire load range.

#### 2.2.2.2 Condensate Systems

The function of the condensate system is to pump condensate from the condenser hot well to the deaerator, through the gland steam condenser and the low-pressure feedwater heaters. The system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four or five (depending on steam cycle) low-pressure heaters, and one deaerator with a storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line, discharging to the condenser, is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

#### 2.2.2.3 Feedwater Systems

The function of the feedwater system is to pump feedwater from the deaerator storage tank through the high-pressure feedwater heaters and to the boiler economizer. Two motor-driven boiler feed pumps are provided to pump feedwater through the three high-pressure feedwater heaters. Pneumatic flow control valves control the recirculation flow. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

The “once through” supercritical plants, compared to the drum type subcritical units, include a condensate polishing system. Subcritical designs have a steam drum installed for water steam separation. They also have water recirculation in the boiler waterwalls. For these designs, boiler water chemistry is controlled by chemical treatment in the drum and a periodic drum blowdown. Since the supercritical designs are of the once-through flow design and don’t have drums, boiler tubing and the steam turbine must be protected against potential corrosion due to contaminated feedwater that could result from leaking condensers. For this reason, once through designs require a condensate polishing system. Steam purity requirements are the same regardless of the type of boiler used.

## 2.3 Pulverized Coal (PC) Fired Cases

Five pulverized coal fired cases (PC-1, PC-2, PC-3, PC-4, and PC-5) with different steam conditions were analyzed for the Pulverized Coal (PC) fired group. Each case includes a selective catalytic reactor (SCR) for $NO_x$ emission control, an electrostatic precipitator for particulate removal, and a wet flue gas desulfurization (FGD) unit for sulfur capture. The five PC fired steam generators all fire the same amount of fuel and include low $NO_x$ tangential firing systems capable of reducing furnace $NO_x$ emissions to 0.25 lbm/MM-Btu. All five PC fired cases are identical with respect to the gas side energy and material balance. Figure 2.3.1 shows a simplified gas side process flow diagram for the five PC cases and Table 2.3.1 shows the associated inlet and outlet stream conditions.

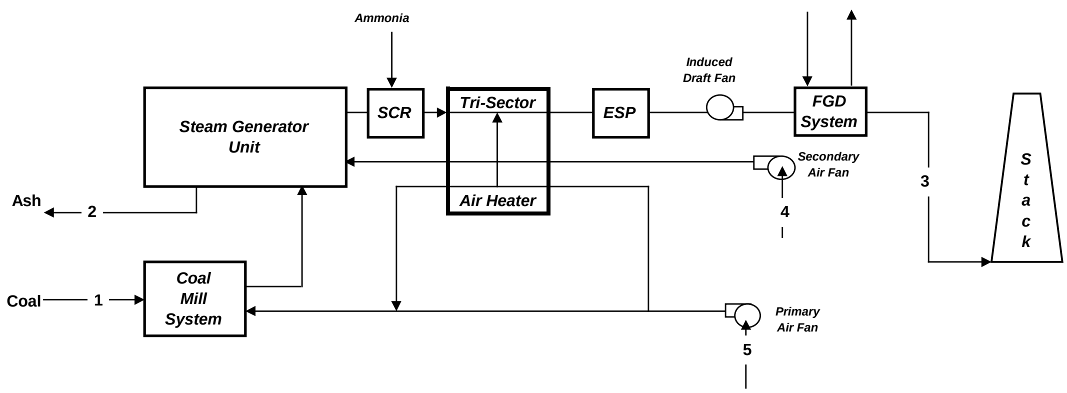



**Figure 2.3. 1: Simplified Gas Side Process Flow Diagram for the PC Cases**

**Table 2.3. 1: Gas Side Material and Energy Balance for the PC Cases**

| PC Cases | Units | Point 1<br>Coal<br>In | Point 2<br>Ash Cooler<br>Out | Point 3<br>ID Fan<br>Out | Point 4<br>PA Fan<br>In | Point 5<br>SA Fan<br>In |
|---|---|---|---|---|---|---|
| **Flow** | lbm/hr | 524,875 | 24,756 | 6,193,144 | 1,200,411 | 4,320,192 |
| **Temperature** | Deg F | 80 | 250 | 268 | 80 | 80 |
| **Gas Analysis** | | | | | | |
| N2 | % weight | n/a | n/a | 70.97 | 74.55 | 74.55 |
| CO2 | % weight | n/a | n/a | 19.33 | 0.04 | 0.04 |
| H2O | % weight | n/a | n/a | 4.20 | 1.30 | 1.30 |
| O2 | % weight | n/a | n/a | 5.00 | 22.84 | 22.84 |
| SO2 | % weight | n/a | n/a | 0.40 | 0.00 | 0.00 |
| Ar | % weight | n/a | n/a | 0.09 | 1.27 | 1.27 |

A brief performance summary for these five PC cases reveals the following information. The Case PC-1 subcritical plant produces a net output of about 631 MWe with a net plant heat rate and thermal efficiency of 9,218 Btu/kWh and 37.02 percent respectively. The Case PC-2 subcritical plant produces a net output of about 646 MWe with a net plant heat rate and thermal efficiency of 8,997 Btu/kWh and 37.94 percent respectively. The Case PC-3 supercritical plant produces a net output of about 663 MWe with a net plant heat rate and thermal efficiency of 8,768 Btu/kWh and 38.93 percent respectively. The Case PC-4 supercritical plant produces a net output of about 677 MWe with a net plant heat rate and thermal efficiency of 8,580 Btu/kWh and 39.78 percent respectively. Finally, the Case PC-5 ultra-supercritical plant produces a net output of about 742 MWe with a net plant heat rate and thermal efficiency of 7,838 Btu/kWh and 43.55 percent respectively. Detailed plant performance for the five PC cases is shown in Section 2.3.4.

### 2.3.1 Steam Cycles for the PC Cases

The steam generators and steam turbines for the five PC cases are designed for a wide range of steam conditions. Main steam pressure for these cases ranges from about 2,400 to 5,075 psia. Main steam temperature for these cases ranges from about 1,000 to 1,300°F while reheat steam temperature ranges from about 1,000 to 1,330°F. The steam conditions for the five PC cases are defined as listed below.

- **PC-1**: 1,000°F/1,000°F/2,408 psia
- **PC-2**: 1,049°F/1,112°F/2,408 psia
- **PC-3**: 1,049°F/1,112°F/3,625 psia
- **PC-4**: 1,085°F/1,148°F/3,915 psia
- **PC-5**: 1,292°F/1,328°F/5,075 psia

This wide range of steam cycle conditions within this group allows quantification of differences in performance, investment costs, and economics (cost of electricity) as a function of steam conditions. Several of these steam cycles are also used in the other combustion system groups (CFB and CMB™) which will provide a direct comparison of the effect of coal combustion system changes. For example, the steam cycle used for Case PC-2 is identical to that used for Case CFB-2 (Refer to Section 2.4). Other steam cycle commonalties between the three combustion system groups are explained later in Sections 2.4 and 2.5 respectively.

### 2.3.2 Steam Generator Designs for the PC Fired Cases

Five pulverized coal fired steam generators were designed for this study. Many components within the Boiler Islands were common among the cases since each of the five cases were designed for the same boiler heat input and output. With the same boiler heat output and with all five boilers designed for the same boiler efficiency, the gas side balance of plant equipment (draft system, and gas cleanup system) was identical. Similarly the solids handling equipment (coal, ash, and limestone) is identical for all five cases.

#### 2.3.2.1 Heat Transfer Surfaces and Arrangement for the PC Boilers

Heat transfer surfaces were sized for all five cases and metal temperature calculations were performed for most of the heat transfer surfaces. The materials were selected based on allowable stresses and oxidation limits of available alloys. No special provision was made in selecting tubing materials to combat increased potential for exfoliation and corrosion for very high temperature design cases. For each case, in addition to the heat transfer surfaces, estimates were made of the drum length for subcritical designs, header and connecting link sizes and materials, and the back-pass height, required to accommodate variations in back-pass installed heat transfer surfaces. All cases included selection of the circulation and start up systems. For these cases, detailed selection sheet packages were prepared for cost estimating purposes.

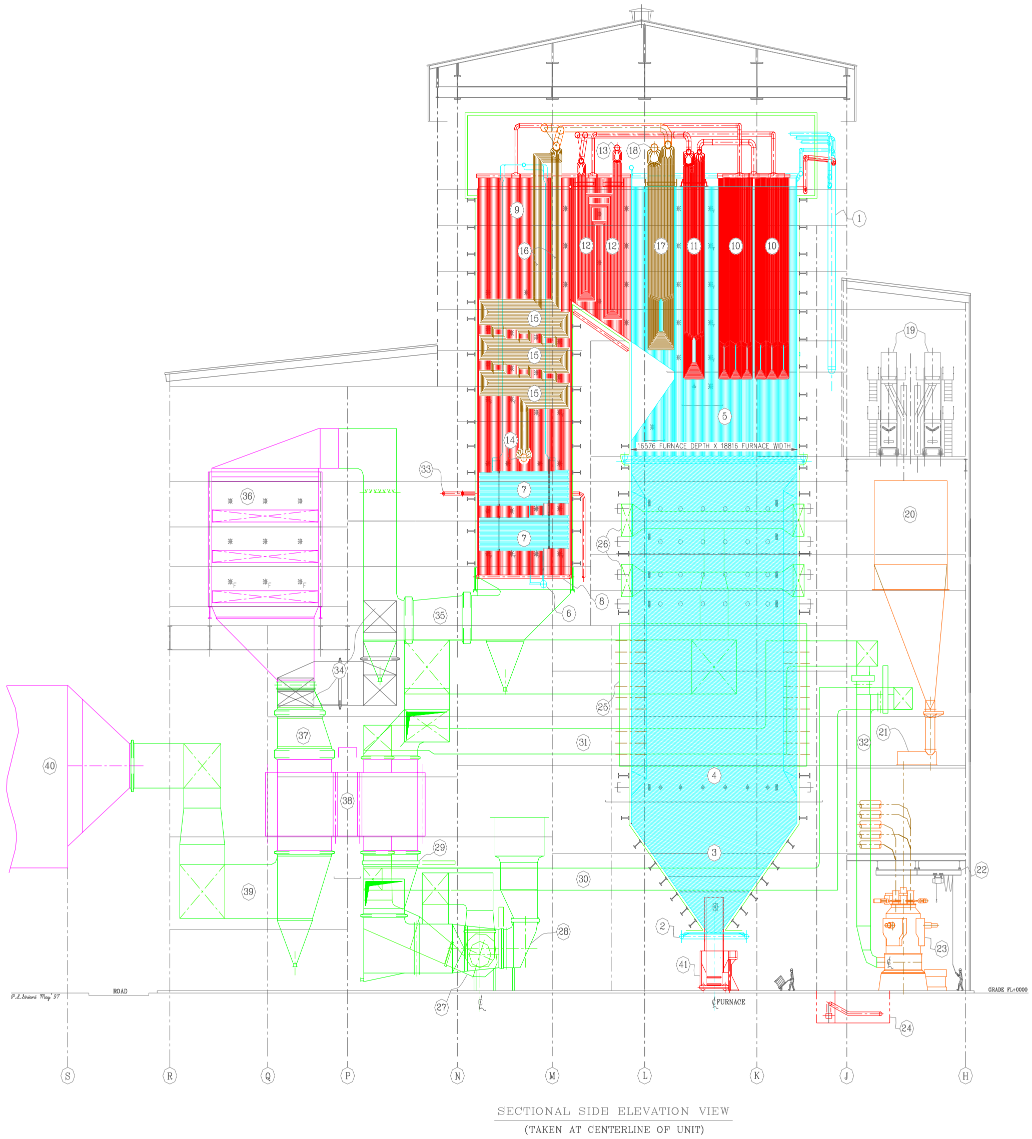
The study used a total pressure loss for the reheat systems of 10% of the turbine cold reheat pressure. Half of this pressure loss was made available for the boiler reheat system and the balance for the reheat piping system.

Since the heat input into the cycle is the same for all cases, the furnace size is fixed for all five designs. Heat liberated in the furnace is partially absorbed by the waterwall tubes forming the lower and upper chambers of the furnace.

Figure 2.3.2 illustrates a typical boiler arrangement of a once-through supercritical steam generator. It is a two-pass gas design with pendant heating surfaces located in the upper furnace and the horizontal heat transfer surfaces in the rear pass. (A Tower Type boiler configuration is feasible also but was not used in this study).

Combustion takes place in the lower furnace. After leaving the lower furnace, the flue gas enters the upper furnace where wide-spaced superheat division panels and superheat platens cool the gases. Downstream of the platens and above the arch, there is a finishing reheater followed by a finishing superheater pendant. To minimize the effect of a high radiant heat flux emitted by the combustion process in the furnace, the final superheat section is shielded from the furnace and is installed behind the final reheat section. In the backpass, there is a primary reheater followed by an economizer. The economizer is the last section within the steam generator and is located just ahead of the SCR and Ljungstrom® air heater. The location of the convective and radiant surfaces is determined by considering a proper balance between gas, steam, and tube metal temperatures.

Heat transfer surface arrangement for the ultra-supercritical design is the same except that an extra horizontal low temperature surface section is installed in the back-pass and ahead of the primary reheat section. In general, due to the high steam temperatures of the ultra-supercritical design the superheat and reheat surface quantities are significantly larger than for the more conventional steam temperature designs.




1. Separator
2. Furnace Lower Ring Header
3. Furnace Hopper Tubes
4. Furnace Spiral Waterwall Tubes
5. Furnace Vertical Waterwall Tubes
6. Economizer Inlet Header
7. Economizer Assemblies
8. Backpass Lower Ring Header
9. Backpass Sidewall Tubes
10. S.H. Division Panelettes
11. S.H. Platen Assemblies
12. S.H. Finish Assemblies
13. S.H. Outlet Header
14. R.H. Inlet Header
15. R.H. Horizontal Assemblies
16. R.H. Low Temp. Pendent Assemblies
17. R.H. Finishing Assemblies
18. R.H. Outlet Header
19. Tripper Conveyor
20. Coal Bunkers
21. Feeders
22. Mill Maintenance System
23. Pulverizers
24. Pyrites Removal System
25. Coal Nozzles & Windbox
26. Separated Overfire Air
27. Primary Air Fans
28. Forced Draft Fans
29. Steam Coal Air Heaters
30. Cold Primary Air Duct
31. Hot Primary Air Duct
32. Mixed Air Ducts to Pulverizers
33. Economizer Bypass Line
34. SCR Bypass Duct
35. Flue Gas Duct to SCR
36. SCR
37. Flue Gas Ducts to Air Heaters
38. Air Heaters
39. Flue Gas Outlet Ducts
40. Precipitators
41. Submerged Scraper Conveyor

**Figure 2.3. 2: Pulverized Coal Fired Sliding Pressure Supercritical Boiler**

Figure 2.3.3 shows a simplified high pressure main steam and reheat steam flow diagram for the supercritical designs. The feedwater is preheated in the economizer tubes. Vertical outlet tubes from the economizer terminate in an economizer outlet header from which connecting piping transports the water to the furnace wall inlet headers.

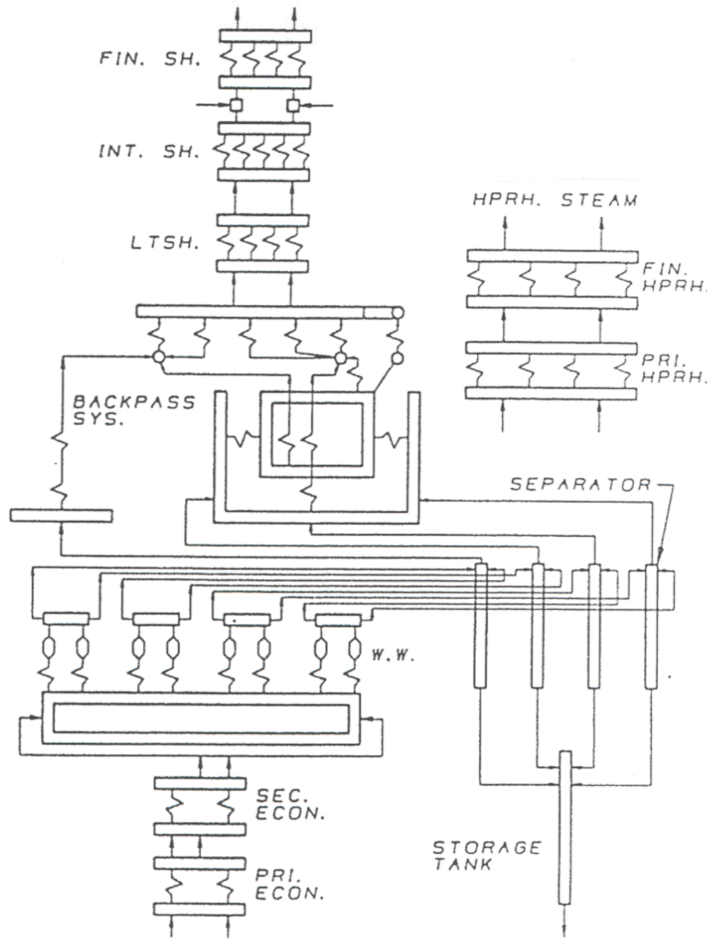



**Figure 2.3. 3: Boiler Water/Steam Flow Diagram for Supercritical Designs**

The fluid that flows up through the furnace tubes is collected at the waterwall outlet headers. From there, it passes through connecting tubes to the separators, and then to roof and rear wall tubes. The supercritical fluid then enters, in sequence, panels, platens and the superheat finishing section. Reheat steam enters the horizontally configured primary reheat section. The reheat steam exits through the rear pendant and continues into the finishing reheat pendant.

Surface arrangement for the two subcritical designs are configured slightly differently. The primary reheat is preheated in the radiant walls installed in the upper furnace region. The other major difference between the subcritical and supercritical designs is in the use of a steam drum that is not required for the supercritical units. The supercritical and ultra-supercritical boilers are equipped with start-up separators, which form an integral part of the start-up system discussed in the start-up system section of this paper.

The waterwall construction for subcritical and supercritical designs is similar. Both use a rifled tube, vertical wall configuration. The supercritical design, however, employs much smaller diameter tubes. The furnace wall construction for the ultra-supercritical design features a spiral wall design as illustrated in Figure 2.3.4. The principle of the spiral wound furnace is to increase the mass flow per tube by reducing the number of tubes required to envelop the furnace. Arranging the tubes at an angle such that they form a spiral pattern around the furnace accomplishes this.

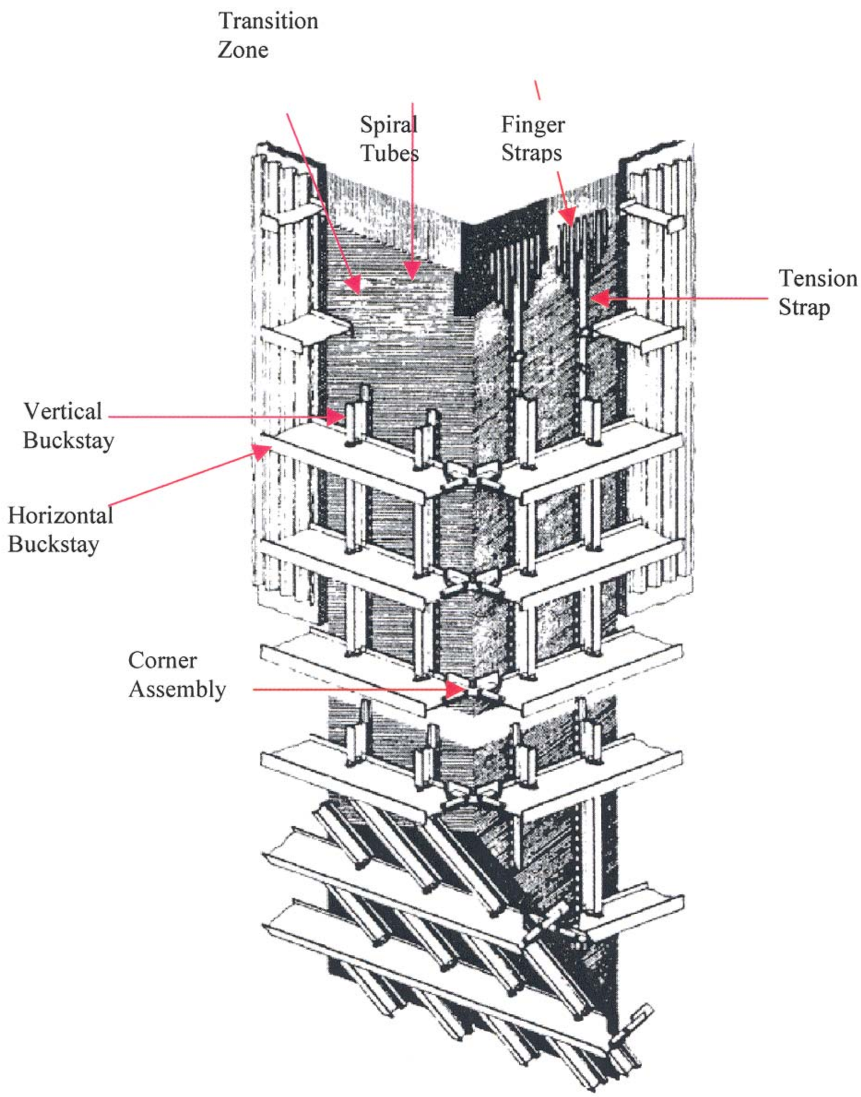



**Figure 2.3. 4: Spiral Wound Furnace Construction and Supporting Structure**

### 2.3.2.2 Materials for the PC Fired Boilers:

Typical materials of construction for steam generator tubing, headers and piping are carbon, ferritic, and austenitic steels. These steels are relatively inexpensive, have satisfactory strength, are easily fabricated, and are resistant to corrosion and oxidation from steam and furnace gases. For subcritical designs, the waterwalls are constructed of carbon steel 210C. The supercritical designs require application of conventional low chrome (Cr) ferritic steels T12 (1Cr-1/2Mo) and

T23 (2-1/4Cr-1/2Mo) in some critical areas of the upper furnace. Increasing cycle steam parameters depletes the design margin for tubes.

Compared to lower pressure steam conditions, ultra supercritical steam generation takes place at a higher temperature level. This is due to a number of factors; each one of them has a significant impact on the design of the waterwalls. The first factor is associated with the higher feedwater temperature at the economizer inlet and outlet. This leads to higher fluid temperature in the furnace walls. The second one is high operating pressure which requires thicker wall tubes. The third one pertains to reduced cooling flow that is associated with improved cycle efficiency. The effect of higher fluid temperature and pressure on the furnace walls must be mitigated by means of increased mass velocity and/or higher strength alloys for tubes or both.

For the ultra-supercritical case, primary materials of construction are the modified T22 alloy, HCM2S (T23) and a higher chromium steel (9%), T91, which is also used for the construction of the vertical tubes. Other 9-12% chromium steels such as T92, and HCM12A could be applied also instead of T91. These alloys are not as easy to work with and fabrication of the fusion or fin-welded panels requires post weld heat treatment. Therefore it was decided to use the more conventional alloys. The use of these higher strength materials, however, could enable higher fluid temperatures in the waterwalls. The vertical wall, which is less expensive than the spiral wall construction used may be feasible also.

Materials of construction for the superheat and reheat tubes are conventional steels for all designs except the ultra-supercritical. The use of low and high Cr ferritic alloys (T12, T22, T23, and T91) is maximized as much as it is practical. Above outside tube metal temperatures of 1175°F, the materials of choice are austenitic steels. The alloys used are TP304H (18Cr-8Ni), TP347H (18Cr-10NiCb), and Super 304H (18Cr-9NiNb). The extent of application of each alloy was governed by cost and pressure drop consideration. For the ultra-supercritical design, the austenitic alloys provide only a limited solution. As the metal temperatures increase, the limit of these steels is quickly reached and stronger materials are required. The primary materials of construction for the higher temperature superheat tubing are Super 304H, IN 617, Hayness 230, and IN 740. The latter three are nickel-based alloys and are currently being tested in Europe, Japan, and USA. Similarly, the reheat finishing section tubes require application of nickel-based alloys such as Hayness 230 and HR 120. Super 304H was also used for this section.

In the selection of headers and piping the following five parameters must be considered: (1) pressure drop, (2) flow distribution, (3) design temperature, (4) operating pressure and (5) mode of operation. For the subcritical and supercritical designs, low and high chromium ferritic alloy pipes P22 and P91 are used throughout. For the ultra-supercritical case, nickel-based alloys are required for the outlet headers and main steam piping. IN 617 is used for this purpose. For the intermediate headers and links, austenitic and high ferritic materials are applied. IN 617 is also employed for the finishing reheat outlet header and piping. The other Ni based alloys could be applied also.

#### 2.3.2.3 Firing Systems for the PC Boilers:

The firing system is designed to provide controlled efficient conversion of the chemical energy of the fuel into heat energy while minimizing pollutant formation. The heat energy produced is transferred to the heat absorbing surfaces throughout the steam generator. To accomplish this, the firing system introduces fuel and air for combustion, mixes the reactants, ignites the mixture, and distributes the flame envelope and the products of combustion. The firing system is comprised of several components or sub-systems including the windbox, the steam temperature control system, the ignition system, and the pulverizer system.

**Windbox:**

The fuel and air are introduced into the furnace through a device called a windbox. The windbox is a vertical stack of alternating fuel and air compartments with dampers associated with each compartment. One windbox is located in each corner of the rectangular furnace. Both the fuel and air are directed toward the tangent of an imaginary circle in the center of the furnace, thus the name “Tangential Firing”. The concept used for tangential firing is to form a single flame envelope within the furnace, which is controlled by the windbox assemblies. The windboxes are controlled on an elevation basis. For example, the top coal nozzles in each of the four windboxes are geometrically identical and operated as if they were one. The fuel piping is arranged such that all four coal nozzles are fed from the same pulverizer. As pulverizers are taken in and out of service, fuel flow to the furnace is increased or decreased from the same elevation within the windboxes. Thus the symmetry of the flame is maintained regardless of the number of pulverizers in operation needed to support the unit load. Because of the flame pattern symmetry, each furnace wall tube receives a predictable and repeatable heat flux for all loads and combinations of pulverizers in service.

The windbox also includes overfire air compartments for $NO_x$ control. The $NO_x$ emissions from the boiler are reduced to 0.25 lbm/MM-Btu.

The flame scanners require a separate cooling air source, which is provided by two dedicated booster fans. The booster fans receive air from the forced draft fan discharge.

**Steam Temperature Control System:**
For both the fuel and air, vertically adjustable nozzle tips are provided within the windbox to direct the fuel and air up or down from horizontal. The nozzles are capable of tilting up or down as much as 30 degrees from horizontal through the use of lever arms driven by pneumatic or electric drives. This allows the capability of raising or lowering the flame pattern within the furnace. When tilted down, more radiant heat is absorbed within the furnace and the gas temperature available to the superheater and reheater is reduced. When tilted up the reverse occurs.

This tilting capability therefore gives the operator (or control system) the ability to control superheater or reheater outlet temperature with the firing system and to use de-superheating spray for trim which minimizes the amount of de-superheating spray required. Thus the tilt capability allows compensation for the continuously changing conditions of the furnace walls due to ash deposition, wall-blower operation, load changes, and variations in ash composition.

**Ignition System:**
The High Energy Arc (HEA) igniter is designed for the capability of igniting fuels ranging from No. 2 to No. 6 fuel oil. The system uses an electrical capacitor discharge device for producing a high intensity spark. There is one elevation of HEA igniters for each elevation of light oil warm-up guns. The warm-up guns are used to light off the adjacent coal elevations.

**Pulverizer System:**
Six volumetric feeders provide the required flow rate of coal to each pulverizer. Each feeder is supplied from a dedicated coal silo. Each pulverizer feeds one windbox elevation of coal nozzles. The pulverizers are of the HP configuration and include Dynamic™ Classifiers and are designed to provide fine grind (85% through 200 mesh) pulverized coal for minimization of combustible losses.

The pulverizer dries and grinds the coal prior to transport to the furnace. The feed coal is discharged onto a revolving bowl. Centrifugal force causes the coal to travel to the perimeter of the bowl and through the grinding zone. Primary air is directed upward around the bowl where it entrains the pulverized coal. The coal/air mixture then enters the primary classifier where the large heavier particles are separated and returned to the bowl for further grinding. The lighter particles are carried to the dynamic classifier where secondary classification occurs. The rotational speed of the dynamic classifier determines the ultimate fineness. The coal leaving the dynamic classifier through the exhauster then enters the fuel piping system while oversized particles return to the bowl for additional grinding.

Any tramp iron or other dense difficult to grind foreign material drops from the bowl edge through the primary air stream to the mill bottom where it is scraped out of the pulverizer.

During the operation of pulverizers, conditions can arise where the potential for pulverizer fires or explosions exists. A fire extinguishing system is therefore provided on all pulverizers as required by code.

#### 2.3.2.4 Air Heater System for the PC Boilers

In all five cases the same high efficiency air heaters were installed. The air heater system is used for increasing the efficiency of the system by reducing the exit gas temperature leaving the boiler. Hot air leaving the air heater is used not only to provide oxygen for combustion of the coal but also for drying and transport of the coal. For these designs, two Ljungstrom horizontal tri-sector regenerative air preheaters are used. Air flow to and flue gas flow from the air heaters is provided from the Draft System (refer to Section 2.3.3.2).

The Ljungstrom bi-sector regenerative air preheater design is a very efficient and cost effective air heating system. The utilization of rotating modular elements with highly efficient heat transfer surface makes these air heaters extremely compact and cost effective for a large amount of heat transferred.

Sootblowers are used to clean the air heater heat transfer surfaces. The sootblower drive unit is located externally and can be serviced while the unit is in operation. The sootblowing medium (air or steam) pressures and flow rates are selected to achieve an optimum balance between duration of the cleaning cycle, energy consumption and element life.

#### 2.3.2.5 Start-up System for Supercritical and Ultra-Supercritical PC Boilers:

The function of the start-up system is to provide disturbance-free operation of the boiler during the start-up, shutdown, and low load operation in an economical manner. A simplified start-up system, shown in Figure 2.3.5, has essentially the same simplicity as the drum type Controlled Circulation® boilers which rely on circulating pumps to provide sufficient cooling flow for the furnace tubes. A once-through boiler operates in the normal operating range, as its name indicates, in a pure, once through flow sequence. In this mode, the boiler feed pump forces the water/steam flow through the economizer, furnace walls, and the superheater. The once-through operating mode applies in a load range from full load down to a minimum once-through load that is generally between 25 and 45%, depending on boiler design. Below this load the waterwall flow is kept constant. This is accomplished by water recirculation by means of a circulating pump to maintain satisfactory tube cooling. During the start-up, steam generated in the waterwalls must be separated from water at the waterwall outlet and dry saturated steam is piped to the first superheater section. A water separator is used to separate steam from water. This type of the start-up system is featured for all supercritical PC, CFB, and CMB™ designs in this study.

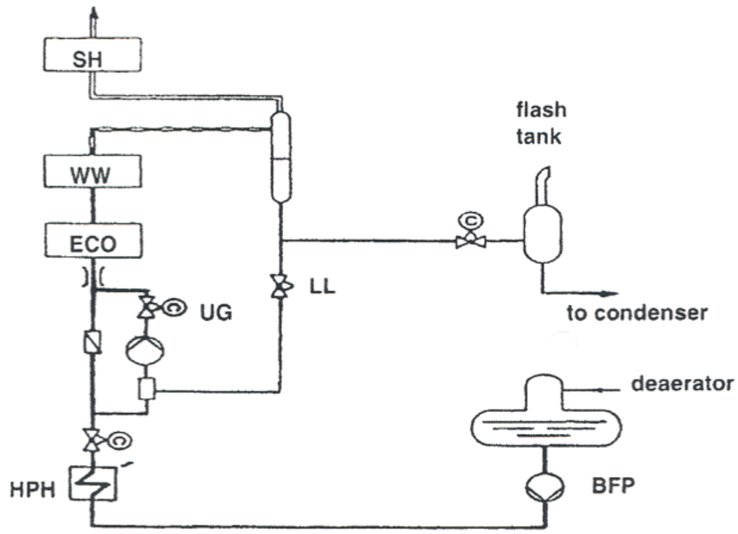



**Figure 2.3. 5: Start-Up System with Low Load Circulation Pump for Supercritical Boilers**

### 2.3.3 Balance of Plant Equipment for the PC Cases

The balance of plant equipment described in this section includes the gas cleanup system equipment and other BOP equipment. The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment, and miscellaneous BOP equipment. Refer to Appendix I for equipment lists and Appendix II for drawings.

#### 2.3.3.1 Gas Cleanup Systems for the PC Cases

The gas cleanup system for the PC cases, which is the same design for all five cases, includes all equipment necessary for the final stage of $NO_x$ reduction, particulate removal, and sulfur removal. Particulate removal is done with an electrostatic precipitator and sulfur ($SO_2$) is removed with a wet flue gas desulfurization (FGD) unit.

The selective catalytic reduction system uses a catalyst and a reductant (ammonia gas, $NH_3$) to dissociate $NO_x$ to nitrogen gas and water vapor. The SCR catalytic-reactor chamber is typically located between the economizer outlet and air heater flue-gas inlet (see Figure 2.3.6). This location is typical for steam-generating units with SCR operating temperatures of 575 to 750°F. Upstream of the SCR chamber are the ammonia injection pipes, nozzles, and mixing grid. Through orifice openings in the ammonia injection nozzles, a diluted mixture of ammonia gas in air is dispersed into the flue-gas stream. After the mixture diffuses, it is further distributed in the gas stream by a grid of carbon steel piping in the flue-gas duct. The ammonia/flue-gas mixture then enters the reactor where the catalytic reaction is completed.

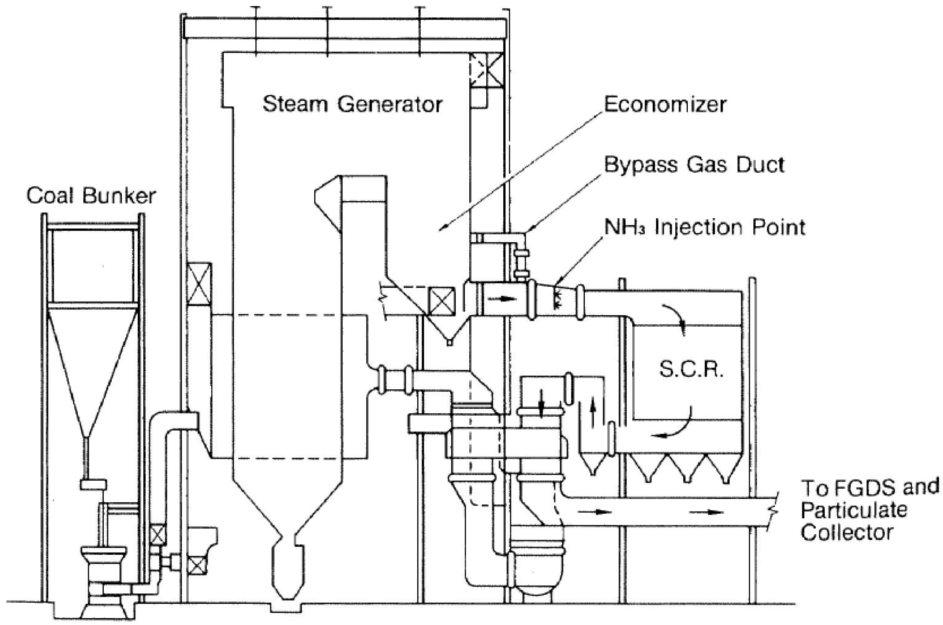



**Figure 2.3. 6: SCR Typical Arrangement Diagram**

Boiler flue gas enters the spray tower and is contacted by the absorbent slurry where the $SO_2$ is absorbed reducing $SO_2$ emissions by 98%. The spent sorbent drains to the scrubber effluent hold tank (reaction tank) where the dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone is added to regenerate the spent absorbent. The rate of additive feed is pH controlled. From the reaction tank the regenerated absorbent slurry is pumped back to the spray tower absorber. The slurry typically contains from 5-15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of flyash.

Figure 2.3.7 shows a simplified process flow diagram for the wet FGD system (Singer, 1991).

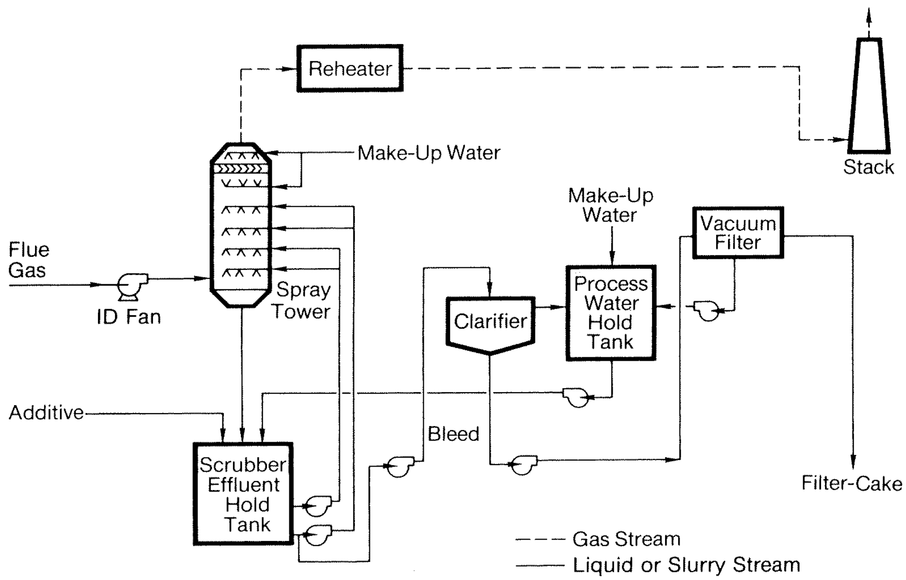



**Figure 2.3. 7: Simplified Process Flow Diagram for Wet FGD System**

To regulate the amount of solids a bleed stream is pumped to the clarifier for solid/liquid separation. Liquid is drawn off the top of the clarifier and returned to the scrubber loop. The clarifier underflow, containing from 25-45% solids, is further de-watered in a vacuum filter. The filtrate is returned to the scrubber loop. Make-up water is added to the system to replace evaporated water and water carried with the waste filter cake stream. The make-up water is added as mist eliminator wash at the top of the spray tower and also as the additive slurrying medium.

**Mercury Removal**

The power industry in the US is faced with meeting new regulations to reduce the emissions of mercury compounds from coal-fired plants. These regulations are directed at the existing fleet of approximately 1,400 existing boilers as well as additional new boilers. EPA's December 15, 2003 proposal to regulate mercury emissions from electric utility steam generating units includes several alternatives including prescriptive MACT standards and cap-and-trade options. In all of these versions, the EPA is proposing output-based limits for new units as shown in Table 2.3.2.

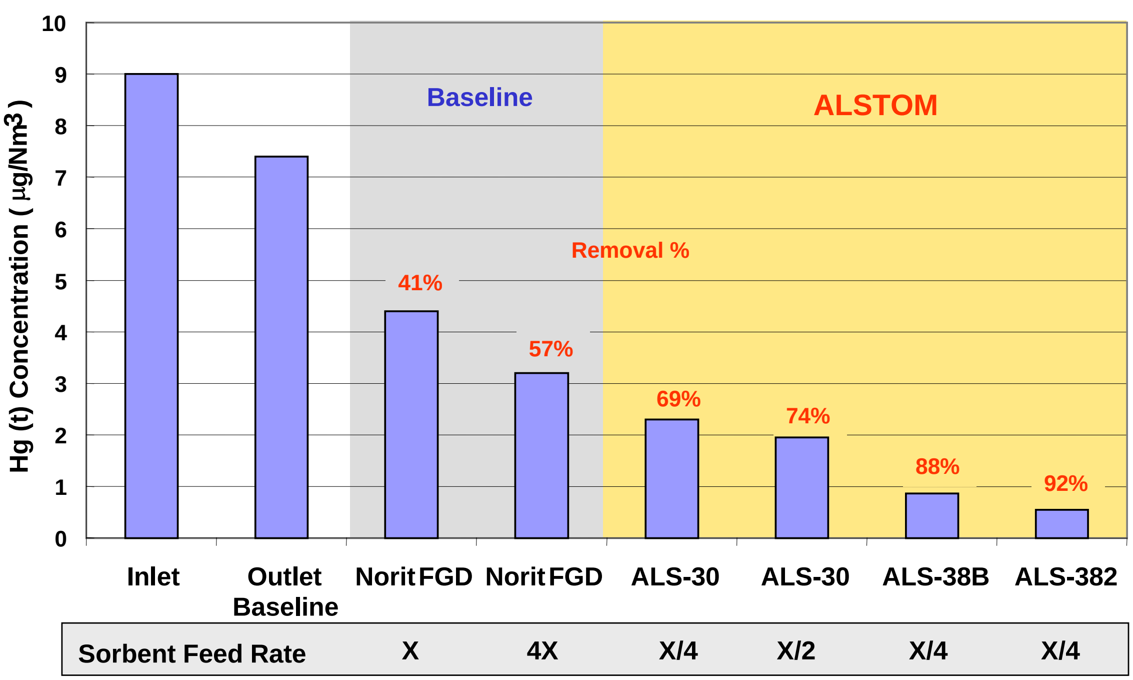
**Table 2.3. 2: EPA Proposed Mercury Limits**

| Unit Type | Hg($10^{-6}$ lbm/MWh) |
|---|---|
| Bituminous-fired | 6.0 |
| Sub-bituminous-fired | 20 |
| Lignite-fired | 62 |
| IGCC unit | 20 |
| Coal-refuse-fired | 1.1 |

Therefore, the industry needs mercury control technologies that can effectively meet regulations on a wide variety of coal characteristics. Recent full-scale and emerging pilot-scale testing indicate that activated carbon injection in the flue gas duct upstream of a particulate control device can be effective for mercury control. However, mercury removal is difficult for lignite and sub-bituminous coals compared to bituminous coals because of the high proportion of elemental mercury in the flue gas. A fabric filter captures mercury to a higher degree compared to an ESP due to enhanced gas-sorbent contact. However, it is capital intensive (~ \$30 - 50/kW$_e$). On the other hand, sorbent consumption is high for an ESP (factor of 5 to 10 vis-à-vis fabric filters). One of the approaches under development at ALSTOM (Mer-Cure) does not require installation of an additional fabric filter for mercury control. Capital costs with this approach are expected to be less than \$ 5-10/kW$_e$, and sorbent consumption is expected to be comparable to a fabric filter (~ 5 lbm/MM-acf). The Mer-Cure approach employs a sorbent preparation and injection system that enhances sorbent performance by changing the physical nature of the sorbent. In addition, process chemistry modifications and a unique injection methodology are used to further enhance mercury capture performance. It is anticipated that the long run cost of the enhanced sorbents used in our approach to be only marginally higher than the baseline activated carbon, given the low additive costs and simplicity of the sorbent preparation method.

The potential for mercury capture enhancement with the Mer-Cure technology is provided by recently concluded US-DOE funded tests at the University of North Dakota – Energy and Environmental Research Center. In these tests, the performance of this technology was compared to current industry standard: Norit Darco FGD$^{TM}$ sorbent injection. Results are presented in Figure 2.3.8 from the firing of a lignite coal with sorbent injection upstream of an ESP.

**Figure 2.3. 8: Pilot-Scale and Full Scale ESP Hg Removal Efficiencies as a function of Sorbent Injection Rate**



Comparison is also provided for standard sorbent injection in field units firing bituminous and sub-bituminous coals (Bustard et al., 2002). These data show that up to 90% mercury removal is possible at sorbent injection rates less than 10% of the standard sorbent with ALSTOM's technology, in contrast to less than 55 % removal with injection rates of the standard sorbent. The Mer-Cure technology is expected to be demonstrated at full-scale in fall 2004.

Mercury control has not been considered in the investment costs or economic analysis for this study to simplify the analysis. New technology is currently being developed. It is believed that the investment and operating cost would be small and approximately the same for PC, CFB, and CMB™ boiler technologies.

### 2.3.3.2 Other BOP Systems for the PC Cases

The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment, and miscellaneous BOP equipment. Refer to Appendix I for equipment lists.

**Draft System:**
The flue gas is moved through the boiler, the SCR, precipitator, scrubber, and other Boiler Island equipment with the draft system. The draft system is the same for all five PC cases. The draft system includes the primary and secondary air fans, the induced draft (ID) Fan, the associated ductwork and expansion joints, and the stack, which disperses the flue gas leaving the system to the atmosphere. The induced draft, primary air, and secondary air fans are driven with electric motors and controlled to operate the unit in a balanced draft mode with the furnace outlet maintained at a slightly negative pressure (typically, -0.5 inwg).

A forced draft primary air (PA) fan provides hot (temperature controlled) air to the pulverizers for pulverized coal drying and transport of the pulverized coal to the furnace. It is preheated in a steam coil air heater (during cold ambient conditions only) and a regenerative air preheater. Temperature control for the pulverizers is achieved by mixing cold air leaving the PA fan (which is bypassed around the air heater) with hot air leaving the air heater.

A forced draft secondary air (SA) fan provides an air stream that is preheated in a steam coil air heater (during cold ambient conditions only) and a regenerative air preheater, and is then introduced into the furnace as secondary air for combustion of the coal.

The flue gas exiting the furnace passes through the convection pass of the unit, flowing through the superheater, reheater, and, economizer sections. The flue gas leaving the convection pass flows through the SCR and regenerative air pre-heaters and then exits the unit and flows to the precipitator for particulate capture. The flue gas is drawn through the precipitator with the Induced Draft (ID) Fan and then flows through the sulfur removal system and is finally discharged to atmosphere through the stack.

The following fans are provided with the scope of supply of the steam generator:

- Primary air fans, which provides forced draft primary airflow. These fans are centrifugal type units, supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 1,322 kW for all five cases.
- Secondary air fans, which provides forced draft secondary airflow. These fans are centrifugal type units supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 1,589 kW for all five cases.
- Induced draft fans, centrifugal units supplied with electric motor drives and inlet dampers. The total electric power required for the electric motor drives is 8,950 kW for all five cases.

The total power requirement for the PC cases fans is 11,861 kW, which is about 46% of the power required for the CFB cases and about 50% of the power required for the CMB$^{TM}$ cases.

**Ducting and Stack:**
One stack is provided with a single FRP liner. The stack is constructed of reinforced concrete. The stack is sized for adequate dispersion of criteria pollutants, to assure that ground level concentrations are within regulatory limits. Table 2.3.3 shows the stack design parameters.

**Table 2.3. 3: Stack Design Parameters**

| Design Parameter | Value |
|---|---|
| Flue Gas Temperature (F) | 280 |
| Flue Gas Flow (lbm/hr) | 5,650,000 |
| Flue Gas Flow (acfm) | 1,737,000 |
| Particulate Load (gr/scf) | nil |

**Coal Handling and Preparation:**
All the cases included in this study, except the repowering case, use the exact same equipment for coal handling and preparation. This is possible because the heat output from the boiler is the same for all cases. The function of the coal handling and preparation system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the inlets of the prepared fuel silos.

The bituminous coal is delivered to the site by unit trains of 100-ton rail cars. Each unit train consists of 100, 100-ton rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal to two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6" x 0 coal from the feeder is discharged onto a belt conveyor (No. 1). The coal is then transferred to a conveyor (No. 2) that transfers the coal to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor (No. 3) that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3" x 0. The coal then enters a second crusher that reduces the coal size to 1/4" x 0. Conveyor No. 4 then transfers the coal to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the three silos.

**Technical Requirements and Design Basis**

- Coal burn rate:
  - Maximum coal burn rate = 524,000 lbm/h = 262 tph plus 10 percent margin = 288 tph (based on the 100 percent MCR rating for the plant, plus 10 percent design margin)
  - Average coal burn rate = 446,000 lbm/h = 225 tph (based on MCR rate multiplied by an 85 percent capacity factor)
  - Coal delivered to the plant by unit trains:
  - Five unit trains per week at maximum burn rate
  - Four unit train per week at average burn rate
  - Each unit train shall have 10,000 tons (100-ton cars) capacity
  - Unloading rate = 30 cars/hour (maximum)
  - Total unloading time per unit train = 11 hours (minimum)
  - Conveying rate to storage piles = 3,000 tph (maximum)
  - Reclaim rate = 1,000 tph
  - Storage piles with liners, run-off collection, and treatment systems:

- Active storage = 19,000 tons (72 hours at maximum burn rate)
- Dead storage = 160,000 tons (30 days at average burn rate)

**Table 2.3. 4: Coal Receiving Design Summary**

| Design Parameter | Value |
|---|---|
| Coal Receiving (TPH) | 288 |
| Active Storage (Tons) | 19,000 |
| Dead Storage (Tons) | 160,000 |

**Limestone Handling and Preparation System:**
The function of the balance-of-plant limestone handling system is to receive and store prepared limestone on an as-needed delivery basis. The system consists of a receiving station, unloading system with blowers, and silos to accommodate 3 days operation.

**Bottom Ash Removal:**
Bottom ash constitutes approximately two-thirds of the solid waste material discharged by the steam generator. This bottom ash is discharged through a submerged scraper conveyor (SSC). The steam generator scope terminates at the outlet stream of the SSC.

**Fly Ash Removal:**
Fly ash comprises approximately one-third of the solid waste discharged from the steam generator. Approximately 8 percent of the total solids (fly ash plus bottom ash) are separated out in the economizer and air heater hoppers; 25 percent of the total solids is carried in the gases leaving the steam generator en route to the baghouse. Fly ash is removed from the stack gas through an electrostatic precipitator.

**Ash Handling:**
The function of the ash handling system is to convey, prepare, store, and dispose of the flyash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the truck filling stations.

The flyash collected in the precipitator, economizer, and the air heaters is conveyed to the flyash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the flyash. Flyash is discharged through a wet un-loader, which conditions the flyash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is discharged to a drag chain type conveyor for transport to the bottom ash silo.

The silos are sized for a nominal holdup capacity of 36 hours of full-load operation. At periodic intervals, a convoy of ash hauling trucks will transit the unloading station underneath the silos and remove a quantity of ash for disposal.

**Circulating Water System:**
The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of two 50 percent capacity vertical circulating water pumps, a multi-cell mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of each condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load. The condenser cooling load varies significantly from case to case with Case PC-1 being the highest (2,808 x $10^6$ Btu/hr) and Case PC-5 being the lowest (2,480 x $10^6$ Btu/hr).

Although the cooling load varies among the cases, the design of the system is similar for all cases. Only capacity changes are required for the circulating water system equipment.

**Waste Treatment System:**
An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash to within U.S. Environmental Protection Agency (EPA) standards for suspended solids, oil and grease, pH, and miscellaneous metals. All waste treatment equipment is housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge de-watering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system with 50-ton lime silo, a 0 - 1,000 lbm/hour dry lime feeder, a 5,000-gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps.

**Miscellaneous systems:**
Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A 200,000-gallon storage tank provides a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

**Accessory Electric Plant:**
The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, all wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

**Instrumentation and Control:**
An integrated plant-wide distributed control and monitoring system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual with operator selection of modular automation routines available.

**Buildings and Structures:**
A soil-bearing load of 5,000 lb/ft$^2$ is used for foundation design. Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Pump house and electrical equipment building
- Fuel oil pump house
- Continuous emissions monitoring building

- Coal crusher building
- River water intake structure
- Guard house
- Runoff water pump house
- Industrial waste treatment building

**Plant Layout:**
The plants are arranged functionally to address the flow of material and utilities through the plant site.

### 2.3.4 Overall Plant Performance Comparison for the PC Cases

Table 2.3.5 shows a fairly detailed comparison of various plant performance parameters for the five PC cases including plant auxiliary power, steam conditions, generator output, net plant output, fuel heat input, net plant heat rate, and thermal efficiency. Figure 2.3.9 shows a comparison of thermal efficiency for the PC cases. This plot shows the effect of steam cycle parameters (temperature, pressure) on plant thermal efficiency.

**Table 2.3. 5: Overall Plant Performance Comparison for PC Cases**

| | | PC-1 | PC-2 | PC-3 | PC-4 | PC-5 |
|---|---|---|---|---|---|---|
| **Auxiliary Power Listing** | (units) | | | | | |
| Feedwater Pumps (mechanical) | (kw) | 15606 | 15187 | 22799 | 25858 | 29316 |
| Feedwater Pumps (electrical) | (kw) | 17340 | 16874 | 25332 | 28731 | 32573 |
| Main Condensate Extraction Pumps | (kw) | 1255 | 1197 | 1347 | 1317 | 1026 |
| Main Cooling Water Pumps | (kw) | 4799 | 4728 | 4627 | 4521 | 4237 |
| Secondary Cooling Water Pumps | (kw) | 202 | 199 | 234 | 228 | 214 |
| Closed Circuit Cooling Water Pumps | (kw) | 370 | 365 | 428 | 418 | 392 |
| Cooling Tower Fans | (kw) | 3300 | 3251 | 3182 | 3109 | 2914 |
| Forced Draft Fans | (kw) | 1589 | 1589 | 1589 | 1589 | 1589 |
| Primary Air Fans | (kw) | 1322 | 1322 | 1322 | 1322 | 1322 |
| Induced Draft Fans | (kw) | 8950 | 8950 | 8950 | 8950 | 8950 |
| Fluidizing Air Blowers | (kw) | n/a | n/a | n/a | n/a | n/a |
| Coal Handling | (kw) | 350 | 350 | 350 | 350 | 350 |
| Pulverizers | (kw) | 1949 | 1949 | 1949 | 1949 | 1949 |
| Ash Handling | (kw) | 2417 | 2417 | 2417 | 2417 | 2417 |
| Limestone Handling | (kw) | 741 | 741 | 741 | 741 | 741 |
| Electrostatic Precipitator | (kw) | 1400 | 1400 | 1400 | 1400 | 1400 |
| FGD or FDA System | (kw) | 13200 | 13200 | 13200 | 13200 | 13200 |
| SCR or SNCR Auxiliary Power | (kw) | 200 | 200 | 200 | 200 | 200 |
| Boiler Circulation Pumps | (kw) | 621 | 621 | n/a | n/a | n/a |
| Misc. Aux. Power (Controls, Lighting, HVAC, etc.) | (kw) | 3000 | 3000 | 3000 | 3000 | 3000 |
| Transformer Loss | (kw) | 2785 | 2845 | 2945 | 3016 | 3285 |
| **Total Auxiliary Power Consumption** | (kw) | 65790 | 65198 | 73212 | 76458 | 79759 |
| Fraction of Generator Output | (fraction) | 0.094 | 0.092 | 0.099 | 0.101 | 0.097 |
| Fraction of Generator Output (w/o BFP) | (fraction) | 0.070 | 0.068 | 0.065 | 0.063 | 0.057 |
| **Steam Cycle Parameters** | | | | | | |
| Main Steam Pressure | (psia) | 2408 | 2408 | 3625 | 3915 | 5075 |
| Main Steam Temperature | (Deg F) | 1000 | 1049 | 1049 | 1085 | 1292 |
| Reheat Steam Temperature | (Deg F) | 1000 | 1112 | 1112 | 1148 | 1328 |
| Feedwater Temperature | (Deg F) | 500 | 500 | 500 | 554 | 626 |
| Number of Feedwater Heaters | (no.) | 7 | 7 | 7 | 8 | 9 |
| **Efficiency and Output** | | | | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 |
| **Steam Cycle Efficiency** | (fraction) | 0.4442 | 0.4543 | 0.4650 | 0.4745 | 0.5161 |
| | (Btu/kwhr) | 7683 | 7512 | 7339 | 7193 | 6613 |
| **Generator Output** | (kw) | 696316 | 711278 | 736148 | 753937 | 821374 |
| **Net Plant Output** | (kw) | 630526 | 646080 | 662936 | 677479 | 741615 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 5812 | 5812 | 5812 | 5812 | 5812 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 9218 | 8997 | 8768 | 8580 | 7838 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3702 | 0.3794 | 0.3893 | 0.3978 | 0.4355 |

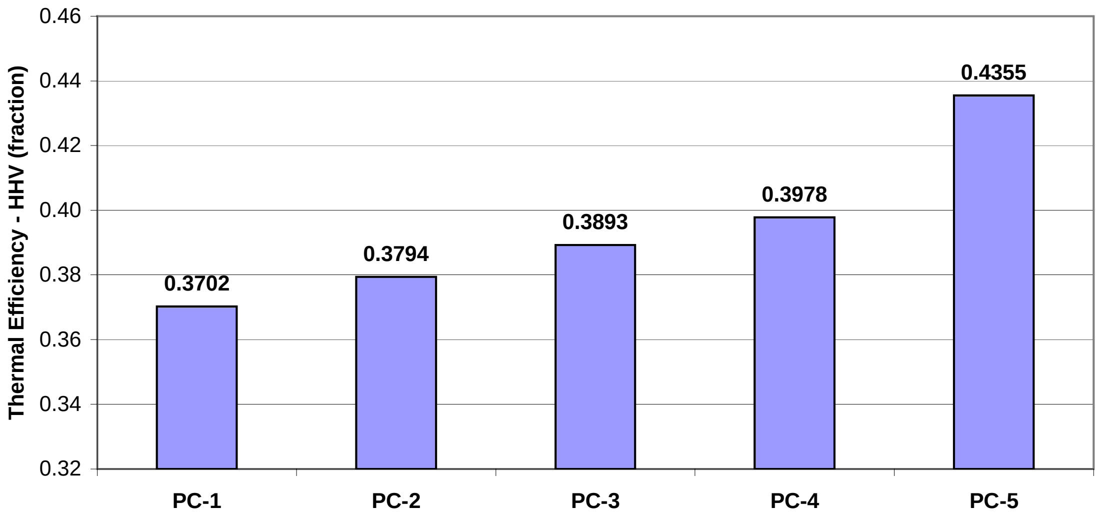



**Figure 2.3. 9: Thermal Efficiency for PC Cases (HHV Basis)**

In general, the transition from a subcritical plant with 2,400 psi main steam pressure to a supercritical plant with 3,625 psi, given constant fuel heat input and the same steam temperatures leads to an increase in net plant output, and efficiency, of approximately 2.9% (Case PC-3 vs. PC-2). The ultra high steam conditions case offers more than a 18% efficiency improvement over a conventional subcritical design (Case PC-5 vs. PC-1). This represents more than 6.5 percentage points in thermal efficiency improvement and an 18% reduction in $CO_2$ emissions.

## 2.4 Circulating Fluidized Bed (CFB) Cases

The three Circulating Fluidized Bed (CFB) steam generators (all ~700-750 MWe gross output) were designed to fire the same amount of fuel and produce the following steam conditions:

- **CFB-2**: 1,049°F/1,112°F/2,408 psia
- **CFB-3**: 1,049°F/1,112°F/3,625 psia
- **CFB-4**: 1,085°F/1,148°F/3,915 psia

The steam cycle used for Case CFB-2 is identical to that used for Case PC-2. The steam cycle used for Case CFB-3 is identical to that used for Case PC-3 and Case CMB$^{TM}$-3 (refer to Section 2.4). The steam cycle used for Case CFB-4 is identical to that used for Case PC-4. Thus there is good comparability from group to group allowing identification of advantages and disadvantages of one type combustion system as compared to another in addition to identification of the best steam cycle parameters.

Each CFB case includes a fabric filter baghouse for particulate removal integrated with a flash dryer absorber (FDA) system for sulfur capture. $NO_x$ emissions are inherently low with CFB boilers. The basic design of the furnace combined with high efficiency cyclones and intensive air staging results in $NO_x$ emissions of 0.20 lbm/MM-Btu. Additional reduction to 0.05 lbm/MM-Btu level is achieved by integration of the SNCR system with the furnace. All three CFB cases are identical with respect to the gas side energy and material balance. Figure 2.4.1 shows a simplified gas side process flow diagram for the three CFB cases and Table 2.4.1 shows the associated inlet and outlet stream conditions.

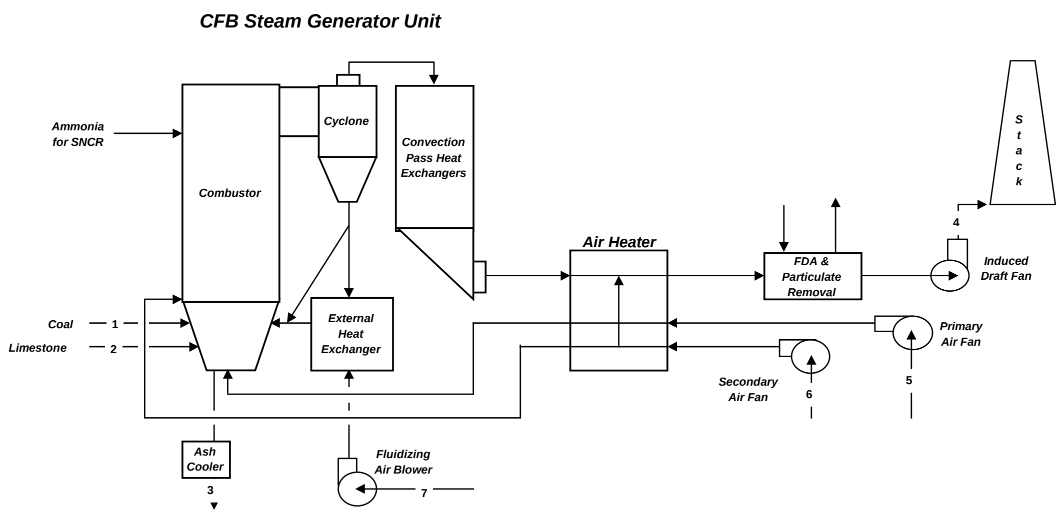



**Figure 2.4. 1 Simplified Gas Side Process Flow Diagram for the CFB Cases**

**Table 2.4. 1: Gas Side Material and Energy Balance for the CFB Cases**

| CFB Cases | Units | Point 1<br>Coal In | Point 2<br>Limestone In | Point 3<br>Ash Cooler Out | Point 4<br>ID Fan Out | Point 5<br>PA Fan In | Point 6<br>SA Fan In | Point 7<br>FA Fan In |
|---|---|---|---|---|---|---|---|---|
| **Flow** | lbm/hr | 524,875 | 64,128 | 58,298 | 6,045,094 | 2,987,042 | 2,196,779 | 388,016 |
| **Temperature** | Deg F | 80 | 80 | 250 | 268 | 80 | 80 | 80 |
| **Gas Analysis** | | | | | | | | |
| N2 | % weight | n/a | n/a | n/a | 71.04 | 74.55 | 74.55 | 74.55 |
| CO2 | % weight | n/a | n/a | n/a | 19.66 | 0.04 | 0.04 | 0.04 |
| H2O | % weight | n/a | n/a | n/a | 4.26 | 1.30 | 1.30 | 1.30 |
| O2 | % weight | n/a | n/a | n/a | 4.89 | 22.84 | 22.84 | 22.84 |
| SO2 | % weight | n/a | n/a | n/a | 0.06 | 0.00 | 0.00 | 0.00 |
| Ar | % weight | n/a | n/a | n/a | 0.09 | 1.27 | 1.27 | 1.27 |

A brief performance summary for these three CFB cases, each of which consumes fuel at the same rate, reveals the following information. The Case CFB-2 subcritical plant produces a net output of about 648 MWe with a net plant heat rate and thermal efficiency of 8,976 Btu/kWh and 38.03 percent respectively (HHV basis). The Case CFB-3 supercritical plant produces a net output of about 664 MWe with a net plant heat rate and thermal efficiency of 8,756 Btu/kWh and 38.98 percent respectively. Similarly, the Case CFB-4 supercritical plant produces a net output of about 678 MWe with a net plant heat rate and thermal efficiency of 8,568 Btu/kWh and 39.83 percent respectively. Detailed plant performance for the three CFB cases is shown in Section 2.4.4.

### 2.4.1 Steam Cycles for the CFB Cases

The steam cycles for the three CFB cases (CFB-2, CFB-3, CFB-4) are identical to three of the steam cycles used for the PC cases (PC-2, PC-3, PC-4) and the description is not repeated here. Additionally, the steam cycle used for Case CFB-3 is identical to that used for Case CMB™-3 (refer to Section 2.5). Refer to Section 2.2.1 for the description of these steam cycles.

### 2.4.2 Steam Generator Designs for the CFB Cases

Three CFB steam generator units of a nominal capacity of 700-750 MWe gross were designed for the three steam cycles described above. Each steam cycle requires the same boiler heat output. Although this size is significantly larger than any units built to date, the design procedure utilized for these units (described below) was developed to assure design parameters that fall within our proven experience and knowledge base. The three CFB units are directly comparable to the appropriate PC fired units that utilize the identical steam cycle. One of the CFB units (CFB-3) is also directly comparable to one of the CMB™ units (CMB™-3) described in Section 2.5.

#### 2.4.2.1 CFB Steam Generator Design Philosophy and Scale-up:

In designing a CFB unit, the parameters which affect the ability to meet performance requirements (emissions, Ca/S, and efficiency) are analyzed along with the fuel to be fired. Careful consideration is given to the geometry of the combustor as this impacts fuel, air, and sorbent mixing. In scaling-up CFB design from existing units, ALSTOM increases the combustor height only slightly to ensure the solids pressure profile, and therefore heat transfer to the waterwalls is within our proven experience and knowledge base.

The lower furnace design used by ALSTOM enables the fuel, air, and sorbent to mix in an area that is roughly one-half of the overall combustor plan area. As the unit size increases, the depth of the unit remains constant to ensure good mixing of fuel, air, and sorbent in the lower furnace. The width of the unit increases and cyclones are added as required to maintain gas velocities at optimum levels. Figure 2.4.2 illustrates this design philosophy. As units increase in size to a point where four (4) cyclones are required, the combustor design changes to a pant-leg style (see Figure 2.4.3).

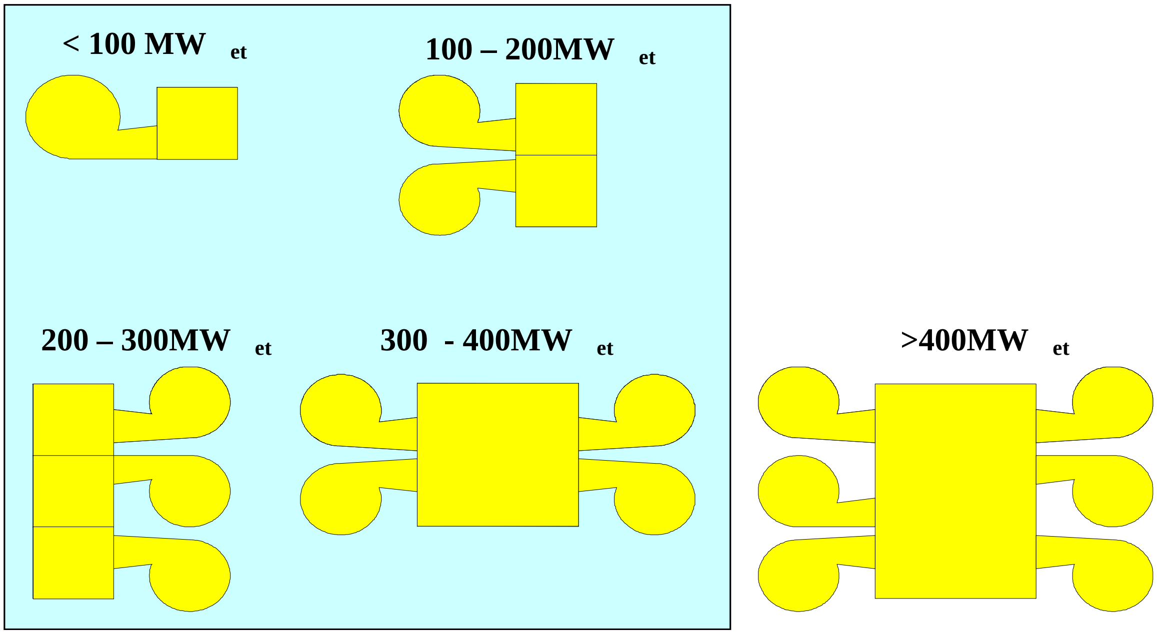



**Figure 2.4. 2: Cyclone Arrangements and Scale Up**

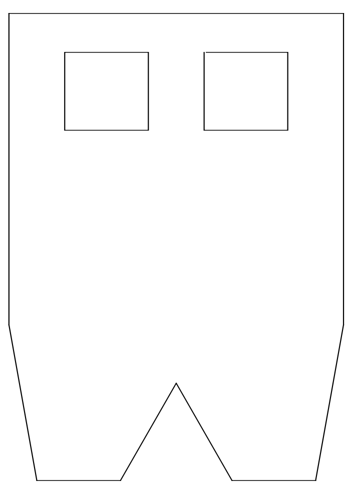


**Figure 2.4. 3: Pant Leg Style Combustor – Side View Schematic**

The combustion of the fuel, sulfur capture, and heat transfer to the combustor walls and other in-combustor surface are a result of fluidization of the bed. The bed material is fluidized by primary air, which is introduced into the combustor through a nozzle grid in the floor of the combustor. Primary air nozzles have been developed using pilot scale tests and computer modeling.

Properly designed nozzles allow for proper air distribution in the lower combustor region, which contributes to optimal residence time of the fuel, sorbent and ash in the primary loop. The location of the secondary air along the front and rear walls of the combustor aids in combustion as well as creates conditions to minimize $NO_x$ formation.

Cyclones in a CFB separate the entrained solid particles from the flue gas leaving the combustor and return the hot solids to the combustor. The resulting high recycle rate ensures a uniform temperature in the combustor. The efficiency of the cyclone impacts the capture rate of the fines fraction of the solids entering the cyclone. This in turn affects limestone utilization and carbon burn-up. Scale-up to larger size cyclones has been gradual. Optimization of the cyclone collection efficiency has occurred through changes to the inlet and outlet duct design and to the vortex finder length and location. As the unit size increases, cyclone size increases or cyclones are added as required to maintain optimum gas velocities.

Recirculated ash from the furnace/cyclone is directed from below the cyclone hopper at temperatures of 1550-1650° F to a bubbling fluidized bed heat exchanger (FBHE) for the purpose of performing additional boiler heat duty. Solids are diverted using a high temperature ash discharge valve to a series of heat exchanger bundles, which perform superheater, reheater, and evaporator duties.

As CFB's get larger in size, the combustor surface-to-volume ratio decreases and it is not possible to perform the required heat duty in the furnace and backpass. The FBHE's allow incremental duty by passing a sufficient amount of recycle solids into the bundles. An inherent benefit of using a FBHE is the high heat transfer rate from the hot solids to the tube bundles. By standardizing tube bundle arrangements and by utilizing a modular approach, an increase in unit size can be accommodated without developing a new FBHE design.

The backpass of the CFB boiler accommodates horizontal surfaces including the low temperature superheater, low temperature reheater, and economizer. The arrangement is similar to that utilized in a conventional pulverized coal fired unit. The largest backpass used in a PC boiler is approximately three times larger than the size used for a 300-350 MW CFB. The light, dry flyash of the CFB enables the designer to utilize either an in-line spiral finned or bare tube economizer in the design.

#### 2.4.2.2 Heat Transfer Surfaces and Arrangement for the CFB Boilers

A 700MW CFB can be designed with only modest extrapolation from smaller size units. While the combustor size is increased in both height and plan area, its increase is limited to maintain overall size and operating parameters within ALSTOM's experience base. Height has been limited to assure accurate heat transfer predictions, solids recirculation at part loads and to minimize overall building and steel costs. Plan area has been increased in a manner which maintains fuel/air/solids mixing lengths. Cyclones are added in diameters which do not exceed our current operating base. Backpass width has been increased, but not beyond that used in conventional PC unit design. Regardless of the firing technology used, backpass sizing is a well-defined, low-risk procedure. Finally, modularized FBHE construction has been used in the design. The resulting 700MW designs are essentially two 350MW side by side units arranged in the pant leg configuration with the approximate combustor dimensions of 52ft by 77ft.

Similar to the PC designs, there is relatively little difference between the subcritical and supercritical CFB arrangements. The combustor size and auxiliaries are the same. All designs have panels and two division walls suspended in the combustor. In addition, the primary superheater, reheater, and economizer surfaces are installed the backpass. The division walls, in addition to absorbing heat, channel the combustion flue gas to six refractory lined cyclones, three cyclones per side. Coal and limestone are also being fed from the two sides ensuring appropriate mixing of coal, air, and sorbent.

The major difference between the subcritical and supercritical design is the size and materials used in the construction of the heat transfer and other pressure part components. The second significant difference is in the quantity of FBHE's used in each design. The supercritical designs require more heat transfer surface, the installation of which necessitated increasing either the size or the quantity of the FBHE's. The decision was made to maintain a standard size design. The supercritical designs (CFB-3 and CFB-4) are equipped with eight FBHE's, while the subcritical unit (CFB-2) has six. Figure 2.4.4 shows a side elevation view of the 700Mw supercritical CFB boiler.

The designs developed herein were specifically developed for this study. A second generation of CFB boilers, not considered in this study, has been developed by ALSTOM for more generic large supercritical designs. These designs may offer an additional investment cost reduction for the CFB boilers. Figure 2.4.5 shows an isometric view of the second generation supercritical CFB boiler.

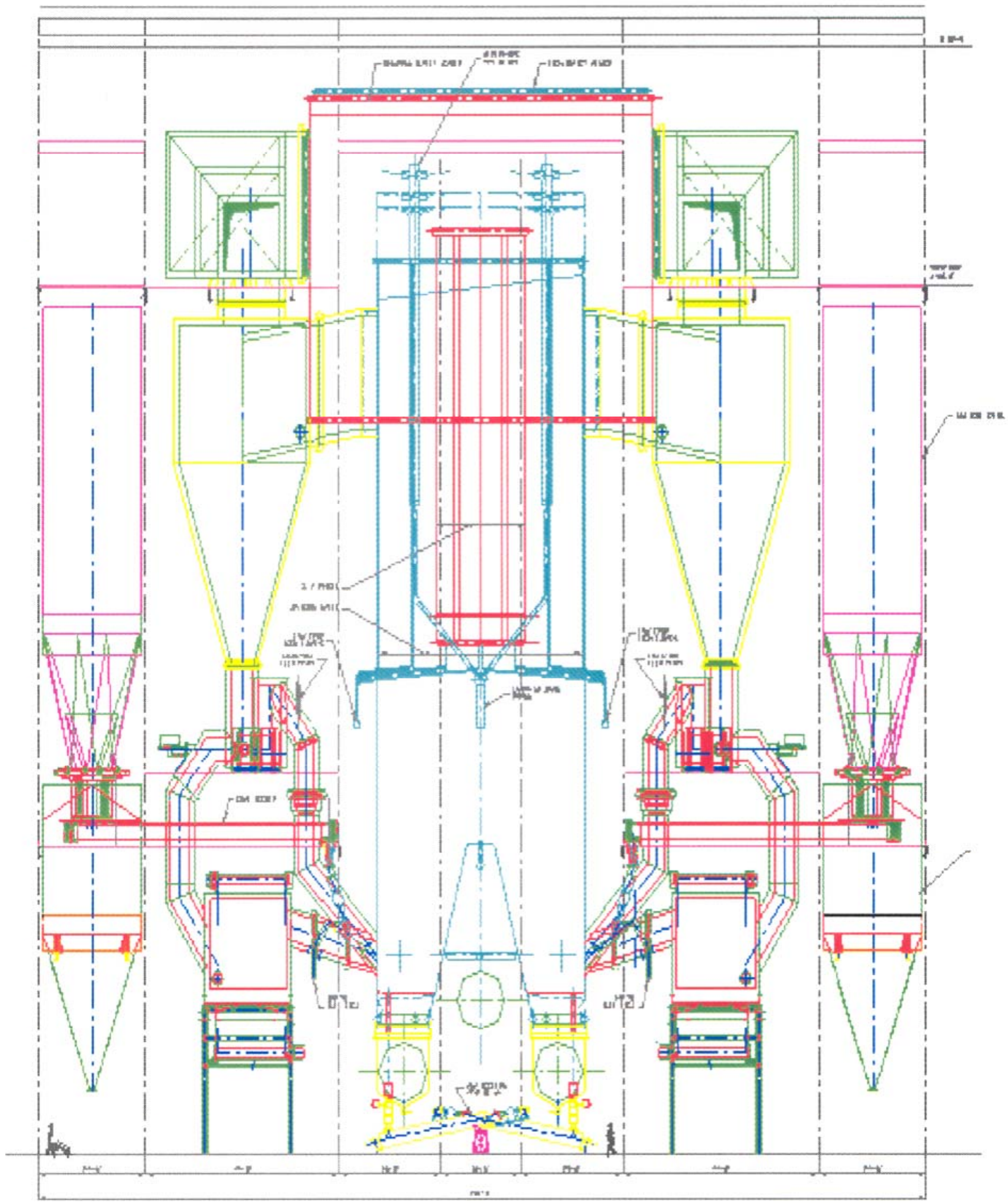


**Figure 2.4. 4: Side View Elevation of a 700 MW Supercritical CFB Boiler**

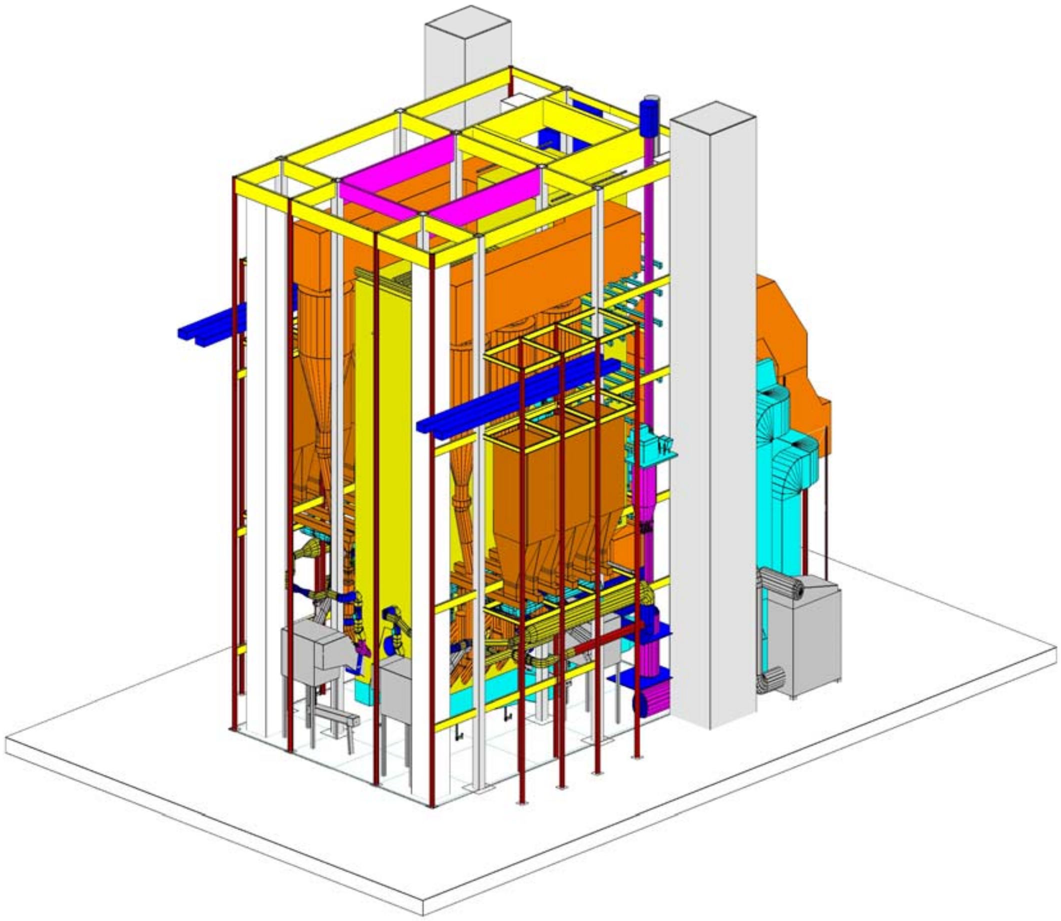


**Figure 2.4. 5: Isometric View of Second-Generation Supercritical CFB Boiler**

### 2.4.2.3 Materials for the CFB Boilers

The materials of construction for the pressure parts are similar to the ones used in the PC designs. For the subcritical case, the waterwall panels are made of carbon steel. Low (T12, T22) and high Chrome (T91) ferritic alloys predominate in the construction of the low temperature reheat and superheat sections. The finishing reheater and superheater tubes are constructed of stainless steels, TP304H, TP347, and HR3C.

The once-through supercritical CFB's feature slightly higher-grade alloys. For the waterwalls the vertical tubes require T12 and T23 alloys. The supercritical designs employ more stainless steel than the subcritical design and the requirement for stainless steel increases for the higher temperature supercritical case. The same SH finish and RH finish materials are used in the construction of the superheat and reheat finishing tubes. For the hottest metal temperature surfaces, high strength stainless steel Super 304H is applied.

### 2.4.2.4 Firing System for the CFB Boilers

The firing system for the CFB boilers is designed to provide controlled efficient conversion of the chemical energy of the fuel into heat energy while minimizing pollutant formation. The heat energy produced is transferred to the heat absorbing surfaces throughout the steam generator. To accomplish this, the firing system introduces fuel, recycle solids, air for combustion, and limestone for sulfur capture. The firing system is designed to mix the reactants and ignite the mixture. The firing system is comprised of several components or sub-systems including the ignition system, the fuel feed system, and the sorbent feed system.

**Ignition System:**
The ignition system for the CFB cases includes the light oil start-up burners, the HEA igniters, the flame scanners, the burner combustion air system, the fuel oil and atomizing media supply systems, and controls.

**Fuel Feed System:**
The fuel feed system transports prepared coal from the storage silos to the lower combustor. The system includes the storage silos, silo isolation valves, fuel feeders, feeder isolation valves, and fuel piping to the furnace.

**Sorbent Feed System:**
The limestone feed system pneumatically transports prepared limestone from the storage silo to the lower combustor. The system includes the storage silos, silo isolation valves, rotary feeders, blower, and piping from the blower to the furnace injection ports and furnace isolation valves.

#### 2.4.2.5 Air Heater System for the CFB Boilers

The air heater system for the CFB boilers is very similar to that for the PC boilers except that no steam coils are installed. Refer to Section 2.3.2.4 for the description.

#### 2.4.2.6 Start-up System for Supercritical CFB Boilers

The start-up system for the supercritical CFB boilers is identical to that for the PC boilers. Refer to Section 2.3.2.5 for the description.

### 2.4.3 Balance of Plant Equipment for the CFB Cases

The balance of plant equipment described in this section includes the gas cleanup system equipment and other BOP equipment. The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment, and miscellaneous BOP equipment. Refer to Appendix I for equipment lists and Appendix II for drawings.

#### 2.4.3.1 Gas Clean-up Systems for the CFB Cases

To achieve the $NO_x$ emissions of 0.05 lbm/MM-Btu the CFB combustor is integrated with the SNCR system. The SNCR method requires the injection of ammonia in the upper region of the combustor. With today's technology such low $NO_x$ emissions are possible for relatively few coals. However, new combustion arrangements, aided by CFD modeling, are being developed to enlarge the range of coals that can be burned producing very low $NO_x$ emissions.

A Flash Dryer Absorber (FDA) system is used for combined particulate and sulfur removal in the CFB cases. The process and equipment are exactly the same for the three CFB cases since each case has the same flue gas flow and analysis. The FDA system is an advanced, dry-scrubbing process, in which the processes of gas cooling and $SO_2$ removal are integrated into the functions of the fabric filter. Please refer to the simplified FDA process schematic shown in Figure 2.4.6.

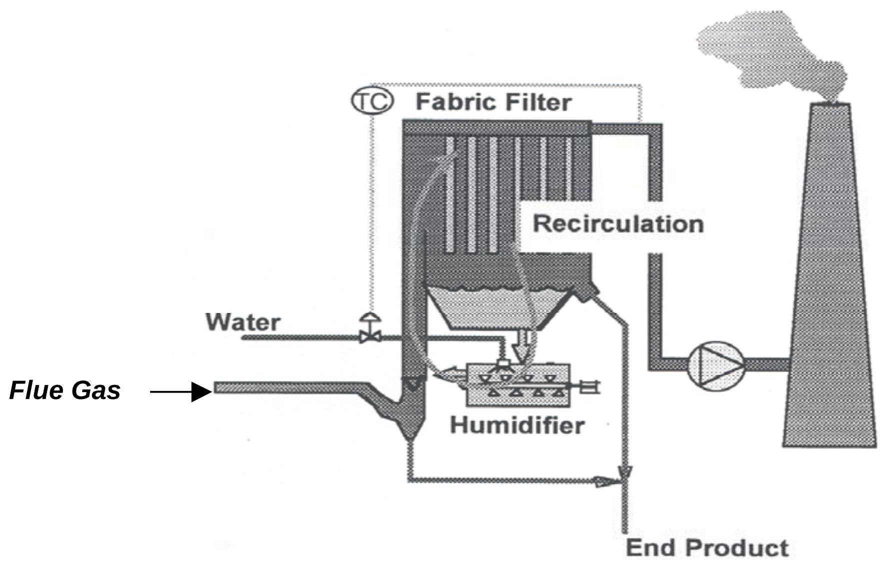



**Figure 2.4. 6: Flash Dryer Absorber (FDA) Process Schematic Diagram**

In the variation of the FDA process used for the present application, limestone is used as the sulfur-capture reagent. A crushed limestone product is purchased and this material is metered into to each fuel feeder along with the coal. The limestone is fed to the combustor through the fuel feed system, and once inside the combustion zones, undergoes calcination to produce calcium oxide (lime). This calcium product is entrained in the combustion gases and carries through the boiler. In the transit through the unit, capture of about one-third of the coal-derived sulfur, as calcium sulfate, occurs. The gas discharge from the boiler to the FDA system thus contains some $SO_2$, and a burden of particulate matter consisting of reacted and unreacted calcium compounds as well as fly ash. Approximately 88% of the sulfur is captured in the furnace. The additional 10% is captured in the FDA.

This particulate-laden flue gas then enters the fabric filter inlet duct, or FDA reactor, where additional (recycle) particulate is added to the gas stream. This flow is then directed into the filter bag compartments where it is distributed to the individual filter bags. The particulate is retained on the outside of the filter bags and the cleaned gas flows out the top of the bags and into the clean-gas outlet ductwork. When the dust deposits on the exterior of the bags reach a point where cleaning is required, a pulse of compressed air removes a portion of the dust cake. The removed dust falls into the fluidized dust hoppers, where the majority of the dust is recycled into the dust humidifier/conditioner. A smaller fraction of the dust is discharged to the flyash handling system.

The process uses a proprietary design fabric filter that is a high-ratio, intermediate-pressure, pulse-cleaning unit known as an LKP. The fabric filter incorporates many unique and proven features that have been developed to insure minimum emissions and maximum equipment and filter media life. Filtration is accomplished on the outside of the bags, with a tubular cage used to support each bag. The coating of Ca-based dust developed on the filter bags during normal operation contributes substantially to the overall $SO_2$ removal efficiency of the system.

A mixer/conditioner is located under each fabric filter compartment where water is added to the dust stream. Dust is metered into the mixer/conditioner from the fluidized fabric-filter hopper where water is uniformly blended with the dust via internal fluidization and mechanical mixing. Control of the water addition rate is based on the amount of flue gas cooling required to allow the acid gas components to react with the lime and recycled alkaline dust. The $SO_2$ reacts readily with the calcium in the recirculated dust under the relatively cool, damp conditions of the gas stream in the duct from the mixer to the fabric filter compartment. The water added for gas cooling and humidification is fully evaporated before the dust reaches the filter bags. Completion of the $SO_2$-calcium reactions occurs in the filter cake on the bags and result in very high overall sulfur removal efficiency.

To maintain a constant inventory of solids in the recycle system, a small portion of the solids collected in the fabric filter must be discharged for disposal. This end product, that constitutes the scrubbing waste product, is a fine, dry material composed primarily of calcium-sulfur compounds, un-reacted lime, and flyash. A mechanical conveyor system is used to collect the discharge from the various fabric filter hoppers and to consolidate it in a transfer bin for pickup by the plant flyash system.

The FDA process is lower in cost, more compact, and higher in efficiency than traditional FGD processes. It has been commercially applied to utility coal-fired boilers. The process has been tested on diesel engines as well as wastes-to-energy flue-gas cleaning applications. The process entered the commercial market in mid-1997, after approximately five years of development.

**Mercury Removal**

Refer to Section 2.3.3.1 for a discussion of this subject.

### 2.4.3.2 Other BOP Systems for the CFB Cases

The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment and miscellaneous BOP equipment. Other than the differences described below for the draft system, the equipment descriptions for other BOP systems for the CFB cases are identical to those for the PC cases and the descriptions are not be repeated here. Refer to Section 2.3.3.2 for the description of the other BOP equipment.

**Draft System:**

The draft system for the CFB cases differs from the PC cases. In addition to the PA fan, SA fan, and ID fan (which are also used in the PC cases) a fluidizing air (FA) fan is also used in the CFB cases. Furthermore, the pressure rises, flow rates, and power requirements for the CFB cases fans are different than for the corresponding fans for the PC cases.

The following fans are provided for the CFB steam generator:

- Primary air fans, which provide forced draft primary airflow to the combustor grate and fuel feed chutes. These fans are centrifugal type units, supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 7,904 kW. This power requirement is the same for all three CFB cases.
- Secondary air fans, which provide forced draft secondary airflow to the combustor. These fans are centrifugal type units supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 3,876 kW. This power requirement is the same for all three CFB cases.
- Induced draft fans, centrifugal units supplied with electric motor drives and inlet dampers. The total electric power required for the electric motor drives is 10,924 kW. This power requirement is the same for all three CFB cases.
- Fluidizing air blowers, which provide air to the external fluidized bed heat exchangers, the seal pots, and solids return piping. These are centrifugal units supplied with electric motor drives and inlet dampers. The total electric power required for the electric motor drives is 2,875 kW. This power requirement is the same for all three CFB cases.

The total power requirement for the CFB case fans is 25,579 kW, which is about 7% higher than the CMB™ cases and about 2.2 times higher than for the PC cases.

### 2.4.4 Overall Plant Performance Comparison for the CFB Cases

Table 2.4.2 shows a fairly detailed comparison of various plant performance parameters, including plant auxiliary power, steam conditions, boiler efficiency, steam cycle efficiency, generator output, net plant output, fuel heat input, net plant heat rate, and thermal efficiency. Generator output ranges from about 711–754 MWe with improved steam conditions, while total auxiliary power ranges from about 9.0 – 10.0 percent of generator output. The increase is primarily the result of increasing feedwater pumping power requirements for the higher steam pressure cases. The resulting net output ranges from 648-678 MWe. Fuel heat input is constant for these three cases. Figure 2.4.7 shows a comparison of thermal efficiency for the CFB cases. This plot visually illustrates the effect of steam cycle parameters (temperature, pressure) on plant thermal efficiency. The thermal efficiency changes for the CFB cases are nearly identical to those for the PC fired cases as would be expected.

**Table 2.4. 2: Overall Plant Performance Comparison for CFB Cases**

| | | CFB-2 | CFB-3 | CFB-4 |
|---|---|---|---|---|
| **Auxiliary Power Listing** | **(units)** | | | |
| Feedwater Pumps (mechanical) | (kw) | 15187 | 22799 | 25858 |
| Feedwater Pumps (electrical) | (kw) | 16874 | 25332 | 28731 |
| Main Condensate Extraction Pumps | (kw) | 1197 | 1347 | 1317 |
| Main Cooling Water Pumps | (kw) | 4728 | 4627 | 4521 |
| Secondary Cooling Water Pumps | (kw) | 199 | 234 | 228 |
| Closed Circuit Cooling Water Pumps | (kw) | 365 | 428 | 418 |
| Cooling Tower Fans | (kw) | 3251 | 3182 | 3109 |
| Forced Draft Fans | (kw) | 3876 | 3876 | 3876 |
| Primary Air Fans | (kw) | 7904 | 7904 | 7904 |
| Induced Draft Fans | (kw) | 10924 | 10924 | 10924 |
| Fluidizing Air Blowers | (kw) | 2875 | 2875 | 2875 |
| Coal Handling | (kw) | 350 | 350 | 350 |
| Pulverizers | (kw) | n/a | n/a | n/a |
| Ash Handling | (kw) | 2783 | 2783 | 2783 |
| Limestone Handling | (kw) | 1153 | 1153 | 1153 |
| Electrostatic Precipitator | (kw) | n/a | n/a | n/a |
| FGD or FDA System | (kw) | 1260 | 1260 | 1260 |
| SCR or SNCR Auxiliary Power | (kw) | 106 | 106 | 106 |
| Boiler Circulation Pumps | (kw) | n/a | n/a | n/a |
| Misc. Aux. Power (Controls, Lighting, HVAC, etc.) | (kw) | 3000 | 3000 | 3000 |
| Transformer Loss | (kw) | 2845 | 2945 | 3016 |
| **Total Auxiliary Power Consumption** | (kw) | 63690 | 72325 | 75571 |
| Fraction of Generator Output | (fraction) | 0.090 | 0.098 | 0.100 |
| Fraction of Generator Output (w/o BFP) | (fraction) | 0.066 | 0.064 | 0.062 |
| **Steam Cycle Parameters** | | | | |
| Main Steam Pressure | (psia) | 2408 | 3625 | 3915 |
| Main Steam Temperature | (Deg F) | 1049 | 1049 | 1085 |
| Reheat Steam Temperature | (Deg F) | 1112 | 1112 | 1148 |
| Feedwater Temperature | (Deg F) | 500 | 500 | 554 |
| Number of Feedwater Heaters | (no.) | 7 | 7 | 8 |
| **Efficiency and Output** | | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8975 | 0.8975 | 0.8975 |
| **Steam Cycle Efficiency** | (fraction) | 0.4543 | 0.4650 | 0.4745 |
| | (Btu/kwhr) | 7512 | 7339 | 7193 |
| **Generator Output** | (kw) | 711278 | 736148 | 753937 |
| **Net Plant Output** | (kw) | 647588 | 663823 | 678366 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 5812 | 5812 | 5812 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 8976 | 8756 | 8568 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3803 | 0.3898 | 0.3983 |

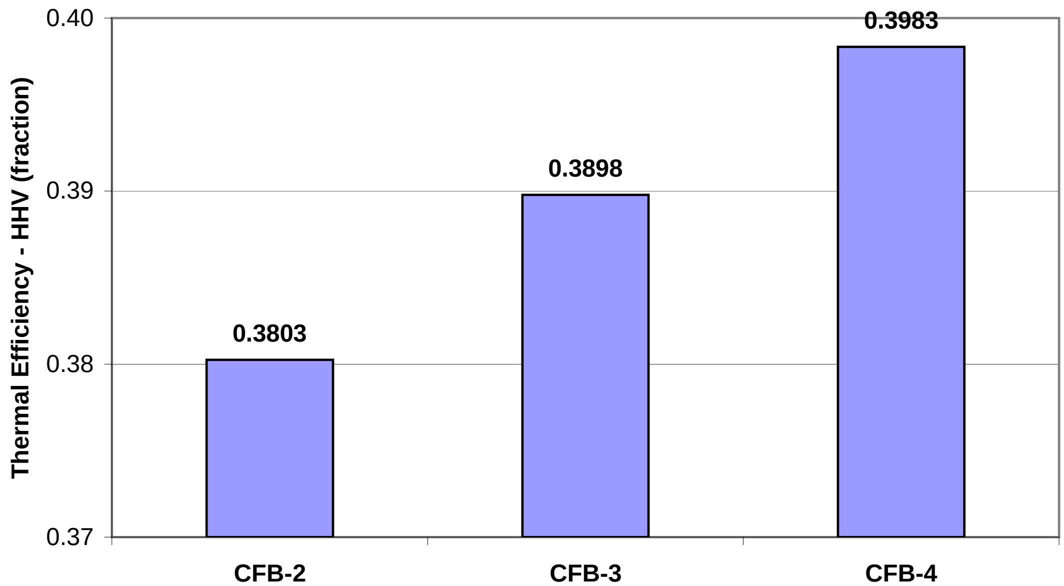



**Figure 2.4. 7: Thermal Efficiency for CFB Cases**

## 2.5 Circulating Moving Bed (CMB$^{TM}$) Cases

Two steam cycles (~736 & 821 MWe gross output) with the following steam conditions are selected for plants equipped with advanced CMB$^{TM}$ steam generators. The CMB$^{TM}$ steam generators both fire the same amount of fuel. These cases are designated CMB$^{TM}$-3 and CMB$^{TM}$-5 as shown below.

- **CMB$^{TM}$-3**: 1,049°F/1,112°F/3,625 psia
- **CMB$^{TM}$-5**: 1,292°F/1,328°F/5,075 psia

The steam cycle used for Case CMB$^{TM}$-3 is identical to that used for Case PC-3 and Case CFB-3. The steam cycle used for Case CMB$^{TM}$-5 is identical to that used for Case PC-5. This commonality of steam cycles provides for comparative analysis of the various coal combustion systems.

Each CMB$^{TM}$ case includes a fabric filter baghouse for particulate removal integrated with a flash dryer absorber (FDA) system for sulfur capture. Both CMB$^{TM}$ cases are identical with respect to the gas side energy and material balance. Figure 2.5.1 shows a simplified gas side process flow diagram for the two CMB$^{TM}$ cases and Table 2.5.1 shows the associated inlet and outlet stream conditions.

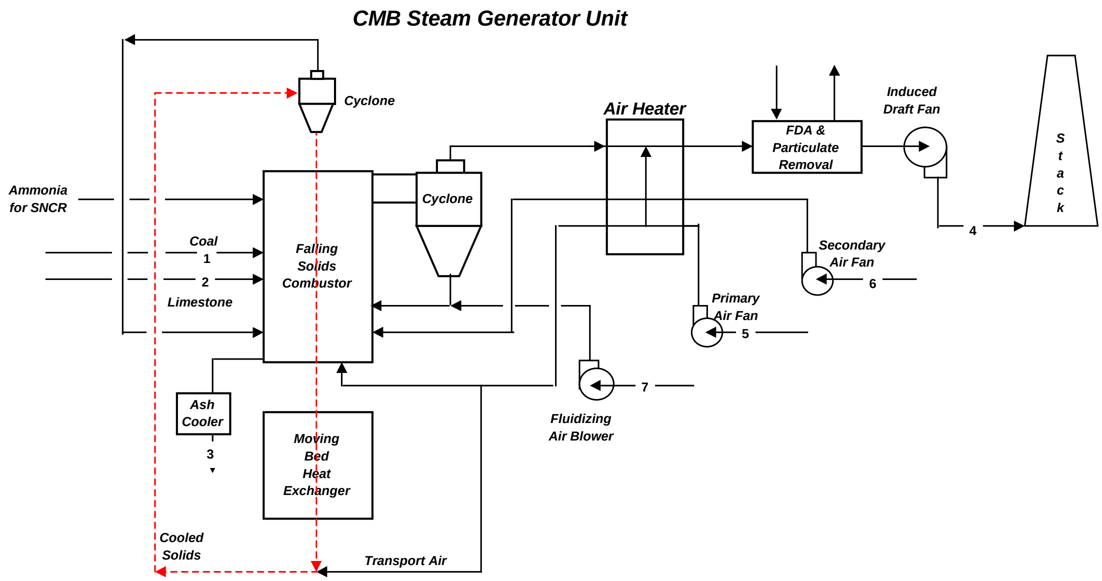



**Figure 2.5. 1: Simplified Gas Side Process Flow Diagram for the CMB$^{TM}$ Cases**

**Table 2.5. 1: Gas Side Material and Energy Balance for the CMB$^{TM}$ Cases**

| CMB Cases | Units | Point 1 Coal In | Point 2 Limestone In | Point 3 Ash Cooler Out | Point 4 ID Fan Out | Point 5 PA Fan In | Point 6 SA Fan In | Point 7 FA Fan In |
|---|---|---|---|---|---|---|---|---|
| **Flow** | lbm/hr | 526,447 | 64,320 | 58,472 | 6,037,959 | 4,647,850 | 801,465 | 113,970 |
| **Temperature** | Deg F | 80 | 80 | 250 | 268 | 80 | 80 | 80 |
| **Gas Analysis** | | | | | | | | |
| N2 | % weight | n/a | n/a | n/a | 71.02 | 74.55 | 74.55 | 74.55 |
| CO2 | % weight | n/a | n/a | n/a | 19.74 | 0.04 | 0.04 | 0.04 |
| H2O | % weight | n/a | n/a | n/a | 4.28 | 1.30 | 1.30 | 1.30 |
| O2 | % weight | n/a | n/a | n/a | 4.82 | 22.84 | 22.84 | 22.84 |
| SO2 | % weight | n/a | n/a | n/a | 0.06 | 0.00 | 0.00 | 0.00 |
| Ar | % weight | n/a | n/a | n/a | 0.08 | 1.27 | 1.27 | 1.27 |

A performance summary for these two CMB$^{TM}$ cases, each of which consumes fuel at the same rate, reveals the following information. The Case CMB$^{TM}$ -3 supercritical plant produces a net output of about 665 MWe with a net plant heat rate and thermal efficiency of 8,781 Btu/kWh and 38.87 percent respectively. Similarly, the Case CMB$^{TM}$ -5 ultra-supercritical plant produces a net output of about 744 MWe with a net plant heat rate and thermal efficiency of 7,853 Btu/kWh and 43.46 percent respectively. Detailed plant performance for the CMB$^{TM}$ cases is shown in Section 2.5.4.

### 2.5.1 Steam Cycles for the CMB$^{TM}$ Cases

The steam cycles for the two CMB$^{TM}$ cases (CMB$^{TM}$ -3, CMB$^{TM}$ -5) are identical to the two steam cycles used for the cases PC-3, and PC-5 respectively, and the description is not repeated here. Refer to Section 2.2.1 for a description of these steam cycles. Additionally, the case CMB$^{TM}$ -3 steam cycle is also the same as was used for case CFB-3.

### 2.5.2 Steam Generator Designs for the CMB$^{TM}$ Cases

Two CMB$^{TM}$ steam generator units of a nominal capacity of 736 & 821 MWe gross were designed for the two steam cycles described above. Each steam cycle requires the same boiler heat output from the CMB$^{TM}$ boiler. The two CMB$^{TM}$ units are directly comparable to the appropriate PC fired units that utilize the identical steam cycle. One of the CMB$^{TM}$ units (CMB$^{TM}$ -3) is also directly comparable to one of the CFB units (CFB-3) described in Section 2.4.

#### 2.5.2.1 CMB$^{TM}$ Background

Circulating Moving Bed (CMB$^{TM}$) combustion system technology (illustrated in Figure 2.5.2) is a new method for solid fuel combustion and heat transfer, which has roots in the traditional circulating fluidized bed (CFB) technology. In the CMB$^{TM}$ combustion system concept there are two separate chambers. The upper chamber, or combustor, has two zones. Coal or other alternate fuels are fed into a high velocity bubbling bed in the lower zone of the combustor, where combustion temperatures may approach 2,000°F. These temperatures are higher than the combustion temperatures of 1,500 to 1,650°F used in traditional CFB boiler designs. Above the bubbling bed, the upper zone is a relatively long residence time reactor that exchanges (recuperates) the heat from the products of combustion (upward gas flow) to a flow of high-density solid particles flowing downward. High alumina content particles can be used for this flow because they have high density, are chemically inert, and are readily available.

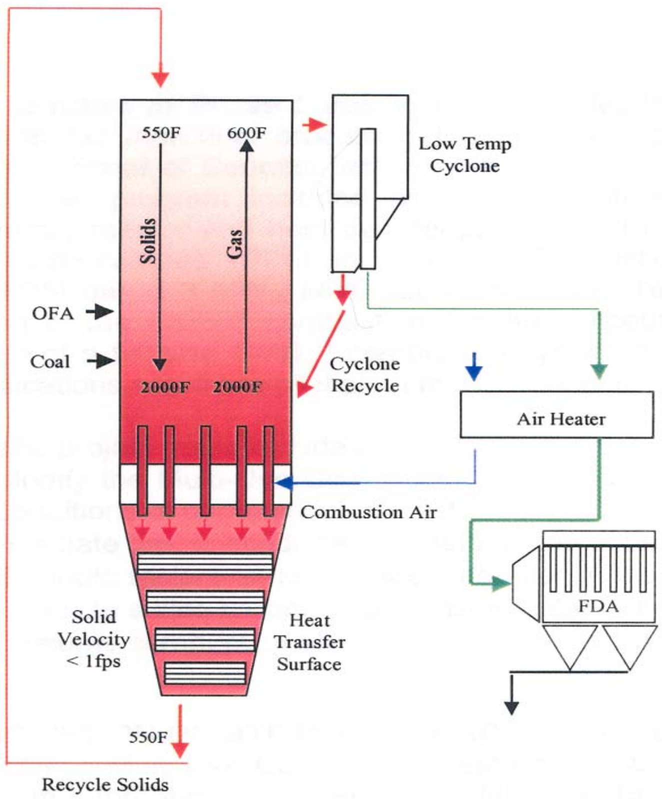



**Figure 2.5. 2: CMB™ Combustion System Schematic**

Once the solids have recuperated the heat of combustion, they collect at the bottom of the combustor where they are fluidized and transferred to a lower chamber through standpipes. The lower chamber consists of a counterflow, direct contact "moving bed heat exchanger" (MBHE) that uses a simple mass flow of solids that move downward at low velocity through a series of tubular heat exchangers. Heat from the moving particles is transferred to the tube circuits that heat steam to the required process temperatures.

The high alumina content particles pass through a MBHE environment largely free of corrosion, erosion, and plugging. This region thus lends itself to a wide range of finned surface heat transfer pressure parts. The heat transfer mechanism in the moving bed is dominated by conduction/convection, with heat transfer rates higher than gas-only convection. The use of extended heat transfer surfaces that have significant contact surface with the moving solids is a key attribute that makes the CMB™ combustion system a cost-effective technology. Leaving the bottom of the moving bed heat exchanger, the cooled solids are transported back to the top of the combustor to restart the heat recuperation process.

In addition to enabling high temperature power plant cycles, the combustion temperature offers excellent carbon burnout, low $N_2O$ emissions, low carbon monoxide emissions, and hence, increased combustion efficiency with reduced pollutant emission. A unique feature of the CMB™ combustion system process is that combustion, heat transfer, and environmental control processes are effectively de-coupled and can be optimized separately. The lower combustor is staged for $NO_x$ control, while flyash entrained in the flue gas is captured in a low temperature cyclone and recycled back to the high temperature lower combustor to reduce carbon loss. The $SO_2$ emissions will be controlled primarily by a backend cleanup system such as ALSTOM's

Flash Dry Absorber (FDA). Limestone is calcined in the combustor for use in the backend desulfurization system and additional sulfur capture can be achieved in the combustor also.

Through an extensive test campaign that has been conducted at the ALSTOM's Multi-Use Test Facility (MTF) in Windsor, Connecticut during the past several years, combustion and heat transfer processes unique to the CMB™ design have been characterized. The test campaign has explored the issues related to combustion, carbon loss, $NO_x$ and $SO_2$ emissions gas flow and bed dynamics, gas to solids heat transfer, solids to tube heat transfer, heat transfer surface fouling, and agglomeration. The information developed so far has been used in the conceptual design and analysis of the two 700MWe CMB™ boilers shown in this study.

#### 2.5.2.2 Heat Transfer Surfaces and Arrangement for the CMB™ Boilers

The two CMB™ designs, supercritical (Case CMB™ -3) and ultra-supercritical (Case CMB™ -5), have many components in common and have the same general arrangement of heat transfer surface and auxiliaries. Both are designed for the same firing rate and have the same size and quantity of combustors, ductwork, and other boiler auxiliaries. Low $NO_x$ and $SO_2$ emissions are controlled by the injection of aqueous ammonia and limestone. Both designs are equipped with the FDA system for sulfur capture.

The main differences between the designs are in the pressure part components, which are selected for different steam parameters. Figure 2.5.3 shows a side view elevation of the supercritical CMB™ design while Figure 2.5.4 shows a side view of the moving bed heat exchanger showing the arrangement of the various heat exchanger sections within the moving bed. Both these figures are for Case CMB™ -3 although as mentioned, Case CMB™ -5 looks very much the same. As shown, the finishing superheater and reheater sections are located at the top of the moving bed, followed by the low temperature superheater and reheater sections, and finally two banks of evaporator. The hot high alumina content particles leaving the combustor enters the top of the moving bed heat exchanger and flows by gravity across the various heat exchanger sections. The particles are progressively cooled while transferring their heat to the steam/water working fluid. The cooled particles leave the moving bed heat exchanger at the bottom where they transported pneumatically with primary air to the top of the combustor.

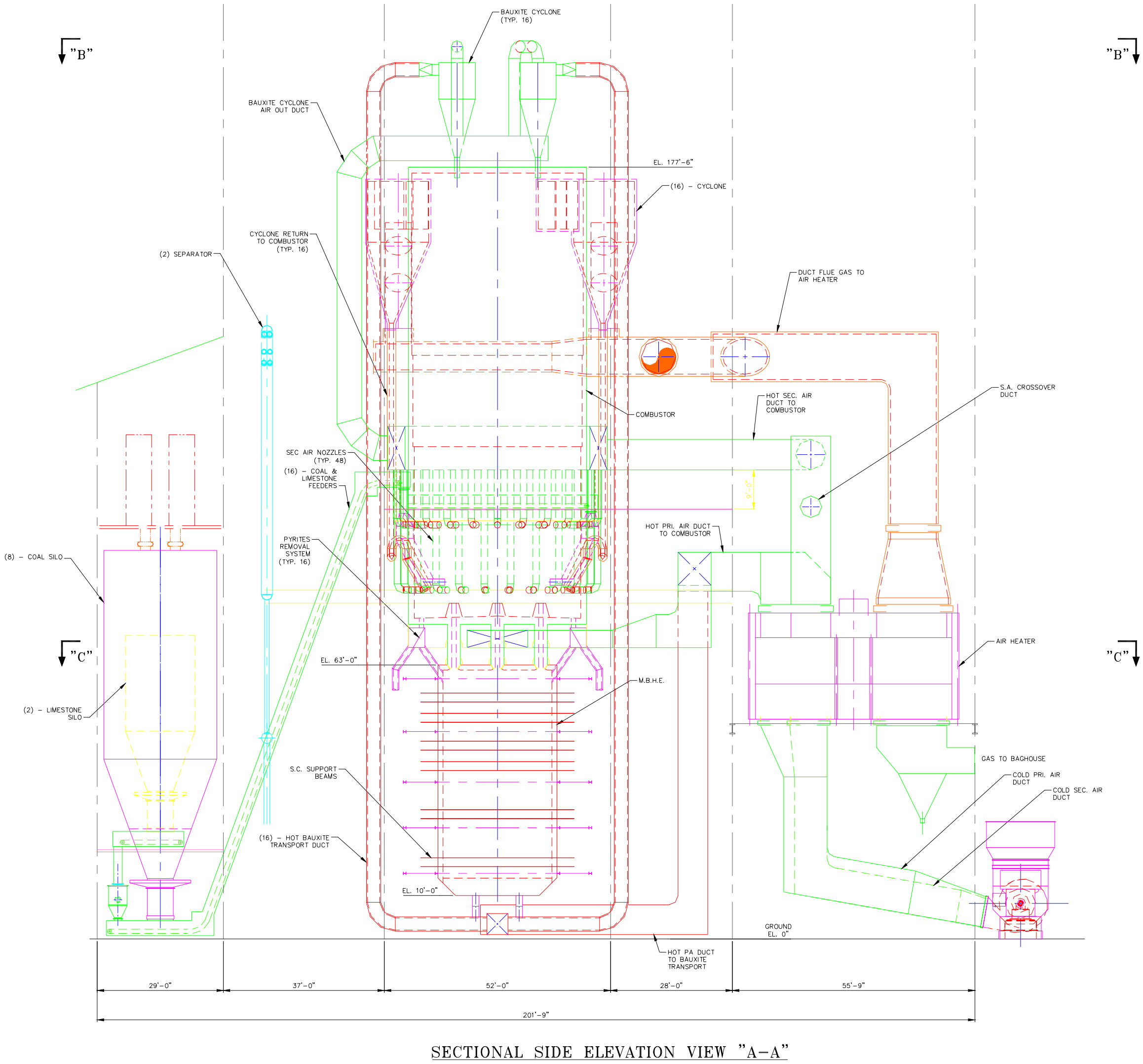



**Figure 2.5. 3: Side Elevation View of a 700MW Supercritical CMB™ Boiler (Case CMB™ -3)**

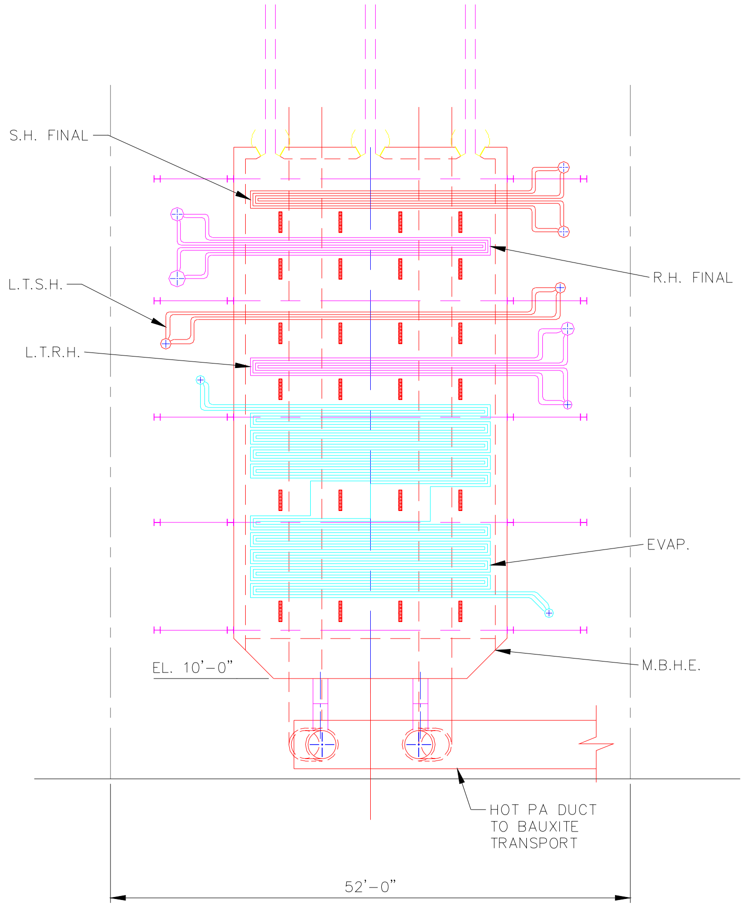



**Figure 2.5. 4: Side Elevation of Moving Bed Heat Exchanger (Case CMB™ -3)**

There is a refractory lined combustor constructed of three octagonal shaped and connected modules. The overall approximate depth and width dimensions are 45 ft by 131 ft. The coal and limestone feed systems are similar to what were used for the CFB designs. Hot high alumina content particles from the combustor bottom are transported to the three MBHE's via the standpipes. The working fluid heat transfer surface is installed in the MBHE's. The feedwater and steam heat exchangers are arranged in countercurrent flow with respect to the moving particles. The three MBHE's are identical modules, each module is 32 ft wide and 31ft deep. The heat transfer surfaces in each module are arranged in parallel steam/water circuits and are connected by links. The heat exchanger tubes are finned and are arranged in staggered configuration for maximum heat transfer. The tube banks are top supported by water cooled hanger tubes.

The cooled particles leaving the three MBHE's are pneumatically transported back to the top of the combustor using several parallel vertical pipes. Air leaving the primary air heater is used for particle transport. At the top of the combustor, the particles are separated from the transport air in an array of relatively small cyclones. The particles are then ready to restart the heat recuperation process. The air streams leaving the small cyclones are used for combustion as part of the secondary air.

#### 2.5.2.3 Materials for the CMB™ Boilers

**Case CMB™ -3:**
The materials of construction for the supercritical design (CMB™ -3) are conventional alloys. Low temperature tubing and fins are constructed of carbon steel, T12, T91, and T409 as listed below:

**Low Temperature Materials:**

| Tubing | Fins |
|---|---|
| Carbon | Carbon |
| T12 | T12 |
| T91 | T409 |

Higher temperature sections are constructed of stainless steel 304H and HR3C (25Cr20Ni).

The headers and piping materials are similar to the ones used for the equivalent steam cycle in the PC and CFB designs.

The fin materials varied from carbon steel for the economizer tubes to stainless steel for the superheat and reheat finish tubes.

**Case CMB™ -5:**
The materials for the construction of tubing for the ultra-supercritical design (CMB™ -5) require Ni-based alloys for high temperature sections. The primary alloys used for the high temperature superheat and reheat sections are IN 617 and IN 740.

The fin material varied from carbon steel for the economizer tubes to stainless steel for the reheat and superheat finish tubes.

The header and piping materials are similar to the selection made for the PC fired ultra-supercritical design.

#### 2.5.2.4 Firing System for the CMB™ Boilers

The firing system for the CMB™ boilers is very similar to that for the CFB boilers. Refer to Section 2.4.2.4 for the description.

#### 2.5.2.5 Air Heater System for the CMB™ Boilers

The air heater system for the CMB™ boilers is very similar to that for the CFB boilers. Refer to Section 2.4.2.5 for the description.

#### 2.5.2.6 Start-up System for Supercritical and Ultra-Supercritical CMB™ Boilers

The start-up system for the supercritical and ultra-supercritical CMB boilers is identical to that for the PC boilers. Refer to Section 2.3.2.5 for the description.

### 2.5.3 Balance of Plant Equipment for the CMB™ Cases

The balance of plant equipment described in this section includes the gas cleanup system equipment and other BOP equipment. The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment, and miscellaneous BOP equipment. Refer to Appendix I for equipment lists and Appendix II for drawings.

#### 2.5.3.1 Gas Clean-up Systems for the CMB™ Cases

The gas cleanup systems ($NO_x$ control, particulate removal, and sulfur removal) for the CMB™ cases are similar to those used for the CFB cases except that most of the $SO_2$ produced is captured in the FDA system. The description of this equipment is not repeated here. Refer to Section 2.4.3.1 for the description of the gas cleanup system.

**Mercury Removal**
Refer to CFB Revised Section on Hg. 2.4.3.1 for a discussion of this subject.

#### 2.5.3.2 Other BOP Systems for the CMB™ Cases

The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment and miscellaneous BOP equipment. Other than the differences described below for the draft system, the equipment descriptions for other BOP systems for the CMB™ cases are identical to those for the PC cases and the descriptions are not repeated here. Refer to Section 2.3.3.2 for the description of the other BOP equipment.

The other BOP equipment for the two CMB™ cases are nearly identical to equipment used for the CFB cases and the description is not repeated here. Refer to Section 2.4.3.2 for the description of the other BOP equipment.

**Draft System:**
The draft system for the CMB™ cases differs from the PC cases. In addition to the PA fan, SA fan and ID fan (which are also used in the PC cases) a fluidizing air (FA) fan is also used in the CMB™ cases. Furthermore, the pressure rises, flow rates, and power requirements for the CMB™ cases fans are different than for the corresponding fans for the PC cases.

The following fans are provided for the CMB™ steam generators:

- Primary air fans, which provide forced draft primary airflow to the combustor grate and fuel feed chutes. These fans are centrifugal type units, supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 14,037 kW. This power requirement is the same for both CMB™ cases.
- Secondary air fans, which provide forced draft secondary airflow to the combustor. These fans are centrifugal type units supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 1,219 kW. This power requirement is the same for both CMB™ cases.
- Induced draft fans, centrifugal units supplied with electric motor drives and inlet dampers. The total electric power required for the electric motor drives is 7,740 kW. This power requirement is the same for both CMB™ cases.
- Fluidizing air blowers, which provide air to the external fluidized bed heat exchangers, the seal pots, and solids return piping. These are centrifugal units supplied with electric motor drives and inlet dampers. The total electric power required for the electric motor drives is 840 kW. This power requirement is the same for both CMB™ cases.

The total power requirement for the CMB™ case fans is 23,835 kW, which is about 7% lower than the CFB cases and about 2.0 times higher than for the PC cases.

### 2.5.4 Overall Plant Performance Comparison for the CMB™ Cases

Table 2.5.2 shows a fairly detailed comparison of various plant performance parameters including plant auxiliary power, steam conditions, boiler efficiency, steam cycle efficiency, generator output, net plant output, fuel heat input, net plant heat rate, and thermal efficiency. Generator output ranges from about 736–821 MWe with improved steam conditions, while total auxiliary power ranges from about 9.4 - 9.6 percent of generator output. The resulting net output ranges from 666-744 MWe. Fuel heat input is constant for these two cases. Figure 2.5.5 shows a comparison of thermal efficiency for the two CMB™ cases. This plot visually illustrates the effect of steam cycle parameters (temperature, pressure) on plant thermal efficiency. The efficiency improvement for the CMB™ cases is almost the same as was shown for the PC fired cases as would be expected.

**Table 2.5. 2: Overall Plant Performance Comparison for CMB™ Cases**

| | | CMB-3 | CMB-5 |
|---|---|---|---|
| **Auxiliary Power Listing** | **(units)** | | |
| Feedwater Pumps (mechanical) | (kw) | 22799 | 29316 |
| Feedwater Pumps (electrical) | (kw) | 25332 | 32573 |
| Main Condensate Extraction Pumps | (kw) | 1347 | 1026 |
| Main Cooling Water Pumps | (kw) | 4627 | 4237 |
| Secondary Cooling Water Pumps | (kw) | 234 | 214 |
| Closed Circuit Cooling Water Pumps | (kw) | 428 | 392 |
| Cooling Tower Fans | (kw) | 3182 | 2914 |
| Forced Draft Fans | (kw) | 1219 | 1219 |
| Primary Air Fans | (kw) | 14037 | 14037 |
| Induced Draft Fans | (kw) | 7740 | 7740 |
| Fluidizing Air Blowers | (kw) | 840 | 840 |
| Coal Handling | (kw) | 352 | 352 |
| Pulverizers | (kw) | n/a | n/a |
| Ash Handling | (kw) | 2783 | 2783 |
| Limestone Handling | (kw) | 1159 | 1159 |
| Electrostatic Precipitator | (kw) | n/a | n/a |
| FGD or FDA System | (kw) | 1267 | 1267 |
| SCR or SNCR Auxiliary Power | (kw) | 106 | 106 |
| Boiler Circulation Pumps | (kw) | n/a | n/a |
| Misc. Aux. Power (Controls, Lighting, HVAC, etc.) | (kw) | 3000 | 3000 |
| Transformer Loss | (kw) | 2945 | 3285 |
| **Total Auxiliary Power Consumption** | (kw) | 70596 | 77144 |
| Fraction of Generator Output | (fraction) | 0.096 | 0.094 |
| Fraction of Generator Output (w/o BFP) | (fraction) | 0.061 | 0.054 |
| **Steam Cycle Parameters** | | | |
| Main Steam Pressure | (psia) | 3625 | 5075 |
| Main Steam Temperature | (Deg F) | 1049 | 1292 |
| Reheat Steam Temperature | (Deg F) | 1112 | 1328 |
| Feedwater Temperature | (Deg F) | 500 | 626 |
| Number of Feedwater Heaters | (no.) | 7 | 9 |
| **Efficiency and Output** | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8926 | 0.8926 |
| **Steam Cycle Efficiency** | (fraction) | 0.4650 | 0.5161 |
| | (Btu/kwhr) | 7339 | 6613 |
| **Generator Output** | (kw) | 736148 | 821374 |
| **Net Plant Output** | (kw) | 665552 | 744230 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 5844 | 5844 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 8781 | 7853 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3887 | 0.4346 |

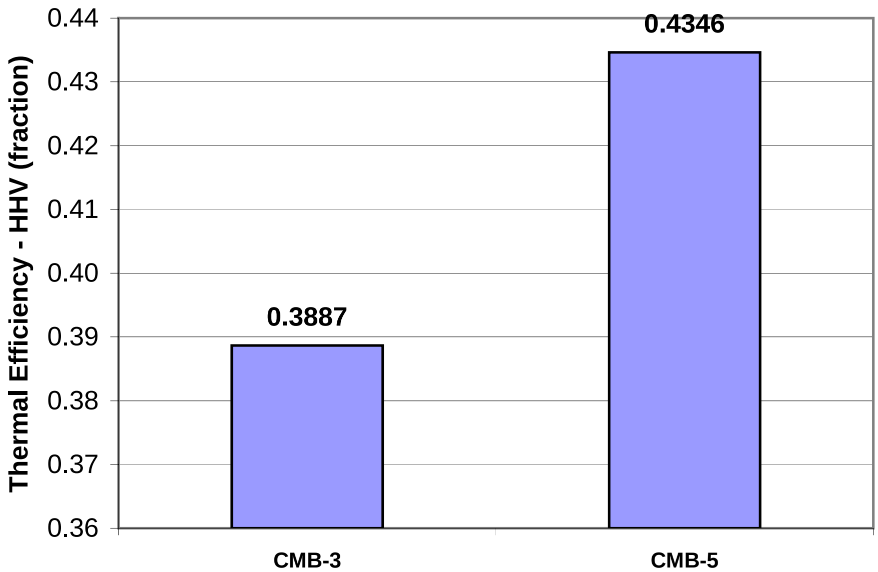
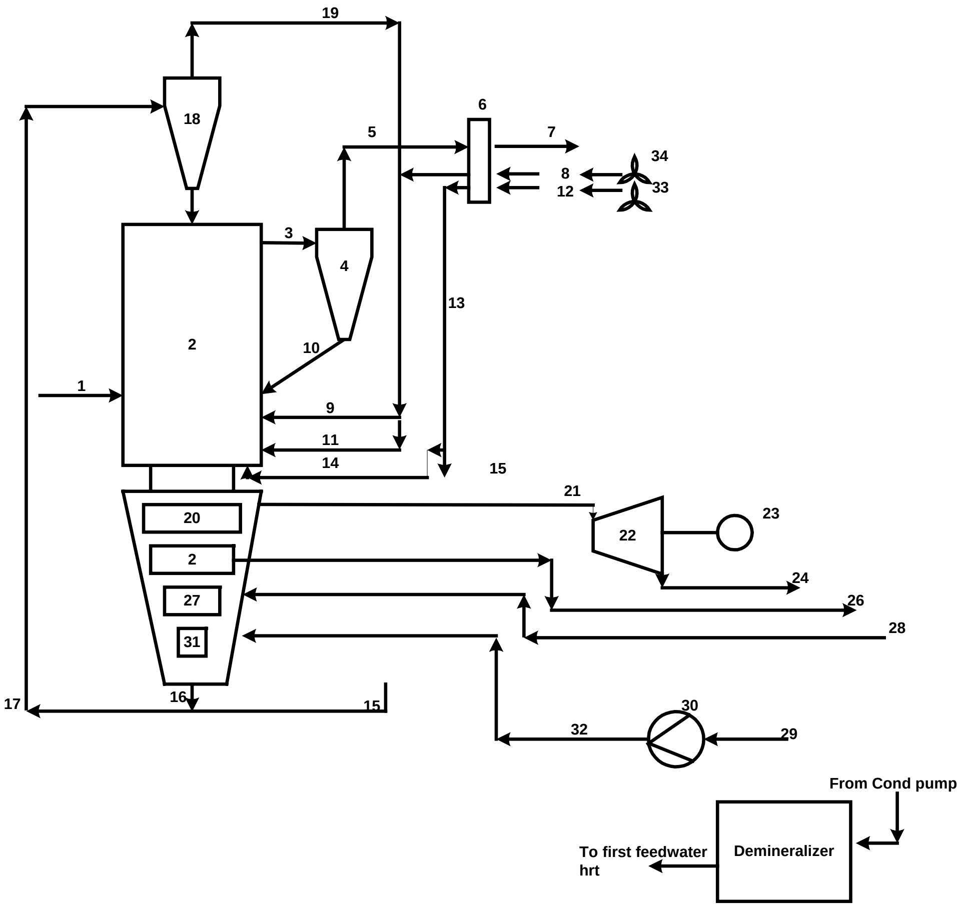



**Figure 2.5. 5: Thermal Efficiency Comparison for CMB™ Cases**

## 2.6 Repowering Case

Most of the older existing coal fired power plants generate power at lower efficiencies than could be produced with the modern state-of-the-art power plants. In exploring a means of upgrading the efficiencies of these plants, a study was performed to determine the economic benefit of a repowered plant for higher steam cycle parameters. Unit #4 of the Philip Sporn power plant, owned and operated by American Electric Power (AEP), has been selected for the analysis. The existing plant (Unit #4) is a pulverized coal unit burning low sulfur coal and capable of generating approximately 169 MWe utilizing a steam cycle with steam turbine conditions of 1,050°F /1,000°F/2,015 psia.

The proposed repowering concept is illustrated in Figure 2.6.1. It uses a number of new plant components and integrates and utilizes the existing components to the maximum extent practical. The repowered plant includes a new CMB™ boiler (refer to Section 2.5.2.1 for CMB™ background) capable of producing steam at 1,292°F/1,005°F/4,337psia conditions. It also includes a new topping steam turbine that expands steam from the new CMB™ boiler at 1,292°F/4,337psia to the steam conditions of 1,050°F/2,015 psia, which match the throttle conditions of the existing steam turbine. The topping turbine produces an output of about 32 MWe. The exhaust steam from the topping steam turbine, at 2,015 psia and 1,050ºF, is piped to the existing steam turbine where it expands through the HP turbine. From the HP turbine exhaust, the steam, at about 505 psia, is piped to the new reheater section installed in the CMB™ boiler where it is reheated to 1,005°F. The reheated steam is then piped back to the existing IP turbine for further expansion and power generation. The installation of the small sized topping steam turbine close to the CMB™ boiler minimizes the length of the very expensive high temperature steam piping.




1 coal feed
2 combustor
3 flue gas
4 cyclone
5 flue gas leav cyclone
6 air heater
7 flue gas to exist precipitator
8 secondary air
9 overfire sec air
10 recycled ash/carbon
11 combustion air
12 primary air
13 primary air leaving air htr
14 fluidizing air to nozzles
15 primary air bauxite transport
16 bauxite
17 primary air/bauxite transport
18 Bauxite cyclone
19 primary air leaving bauxite cycln
20 SH fin system in MBHE
21 Main steam line
22 Topping steam turbine
23 Generator
24 Exhaust steam to existing HP steam turbine
25 Fin reheater
26 Fin reheat to the existing IP turbine
27 Primary reheater
28 RH inlet piping from the existing HP turbine
29 existing feedwater pipe
30 feedwater booster pump
31 Economizer
32 feedwater piping to economizer
33 primary air fan
34 secondary air fan

**Figure 2.6. 1: Simplified Schematic of AEP's Philip Sporn Plant Repowered with a High Efficiency Steam Cycle**

This case utilizes the existing electrostatic precipitator for particulate removal and also the existing ID fan, some existing ductwork, and the existing stack. Figure 2.6.2 shows a simplified process flow diagram for the Boiler Island and Table 2.6.1 shows the inlet and outlet stream conditions.

**Figure 2.6. 2: Simplified Gas Side Process Flow Diagram for the Repowering Case**

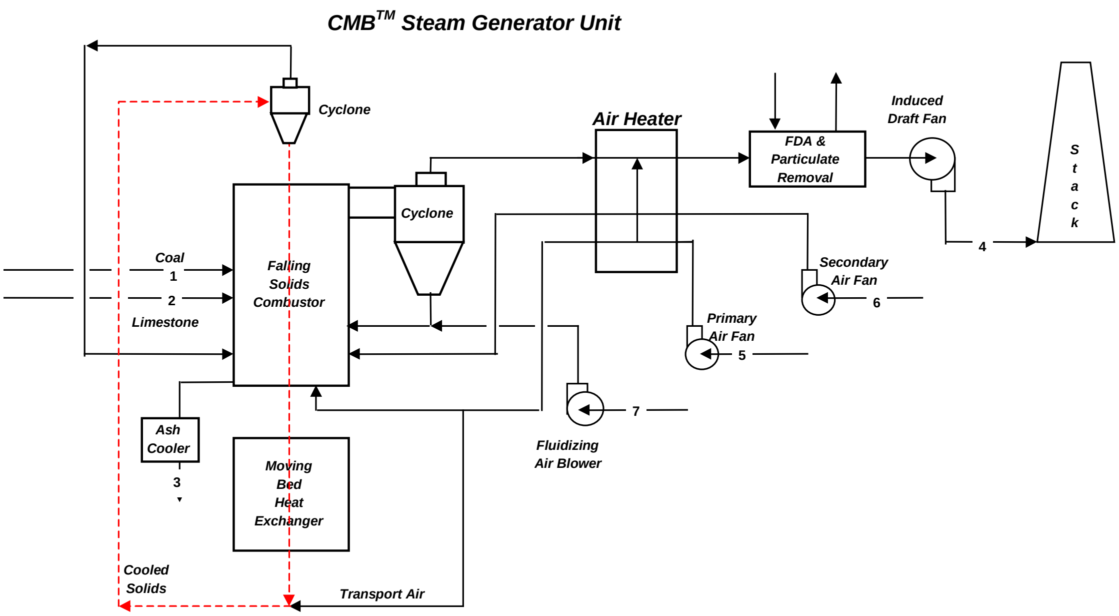



**Table 2.6. 1: Gas Side Material and Energy Balance for the Repowering Case**

| Sporn Repowering | Units | Point 1<br>Coal<br>In | Point 2<br>Limestone<br>In | Point 3<br>Ash Cooler<br>Out | Point 4<br>ID Fan<br>Out | Point 5<br>PA Fan<br>In | Point 6<br>SA Fan<br>In | Point 7<br>FA Fan<br>In |
|---|---|---|---|---|---|---|---|---|
| Flow | lbm/hr | 135,967 | 0 | 5,275 | 1,707,351 | 1,384,658 | 157,939 | 24,528 |
| Temperature | Deg F | 80 | 80 | 250 | 267 | 80 | 80 | 80 |
| Gas Analysis | | | | | | | | |
| N2 | % weight | n/a | n/a | n/a | 70.71 | 74.55 | 74.55 | 74.55 |
| CO2 | % weight | n/a | n/a | n/a | 19.07 | 0.04 | 0.04 | 0.04 |
| H2O | % weight | n/a | n/a | n/a | 5.00 | 1.30 | 1.30 | 1.30 |
| O2 | % weight | n/a | n/a | n/a | 4.97 | 22.84 | 22.84 | 22.84 |
| SO2 | % weight | n/a | n/a | n/a | 0.16 | 0.00 | 0.00 | 0.00 |
| Ar | % weight | n/a | n/a | n/a | 0.09 | 1.27 | 1.27 | 1.27 |

A brief performance summary for this repowering case reveals the following information. The topping steam turbine will generate approximately 32 MWe thereby increasing total plant generator output to approximately 204 MWe. In addition to the increased generating capacity the net plant heat rate improves by approximately 8% or 2.7 percentage points in plant thermal efficiency. The new CMB™ boiler is sized for the required additional firing rate that is about 9.8% higher than in the existing boiler. The repowered supercritical plant produces a net output of about 185 MWe with a net plant heat rate and thermal efficiency of 8,889 Btu/kWh and 39.40 percent respectively. Detailed plant performance for the Repowering Case as well as the existing Sporn plant for comparison is shown in Section 2.6.5.

## 2.6.1 Steam Cycle for the CMB™ Repowering Case

The steam cycle for the repowering case starts at the inlet to the new topping steam turbine. Refer to figure 2.6.3 for the repowering case steam cycle schematic. The new topping steam turbine provides 1,077,835 lbm/hr of steam at 1,292°F/4,337psia from the new CMB™ boiler. This steam is expanded in the topping turbine to exhaust conditions of 1,050°F/2,015 psia. The new topping steam turbine generator produces about 32 MWe of output. The topping turbine was selected such that the exhaust conditions match the required throttle conditions of the existing steam turbine. The topping turbine steam flow is selected to provide the existing high-pressure turbine with the same flow as it would normally expand under MCR conditions. The steam from the topping steam turbine exhaust is piped directly to the existing HP steam turbine inlet where it expands through the existing HP turbine section. From the HP turbine exhaust, the steam is piped to the new reheater section located in the new CMB™ boiler. The steam is reheated to 1,005°F in the new boiler. The hot reheated steam is then piped back to the existing IP turbine for further expansion through the existing IP and LP turbine sections and power generation. The existing HP, IP, and LP steam turbine sections produce about 172 MWe generator output. The total generator output from the new topping turbine and the existing steam turbine is about 204 MWe.

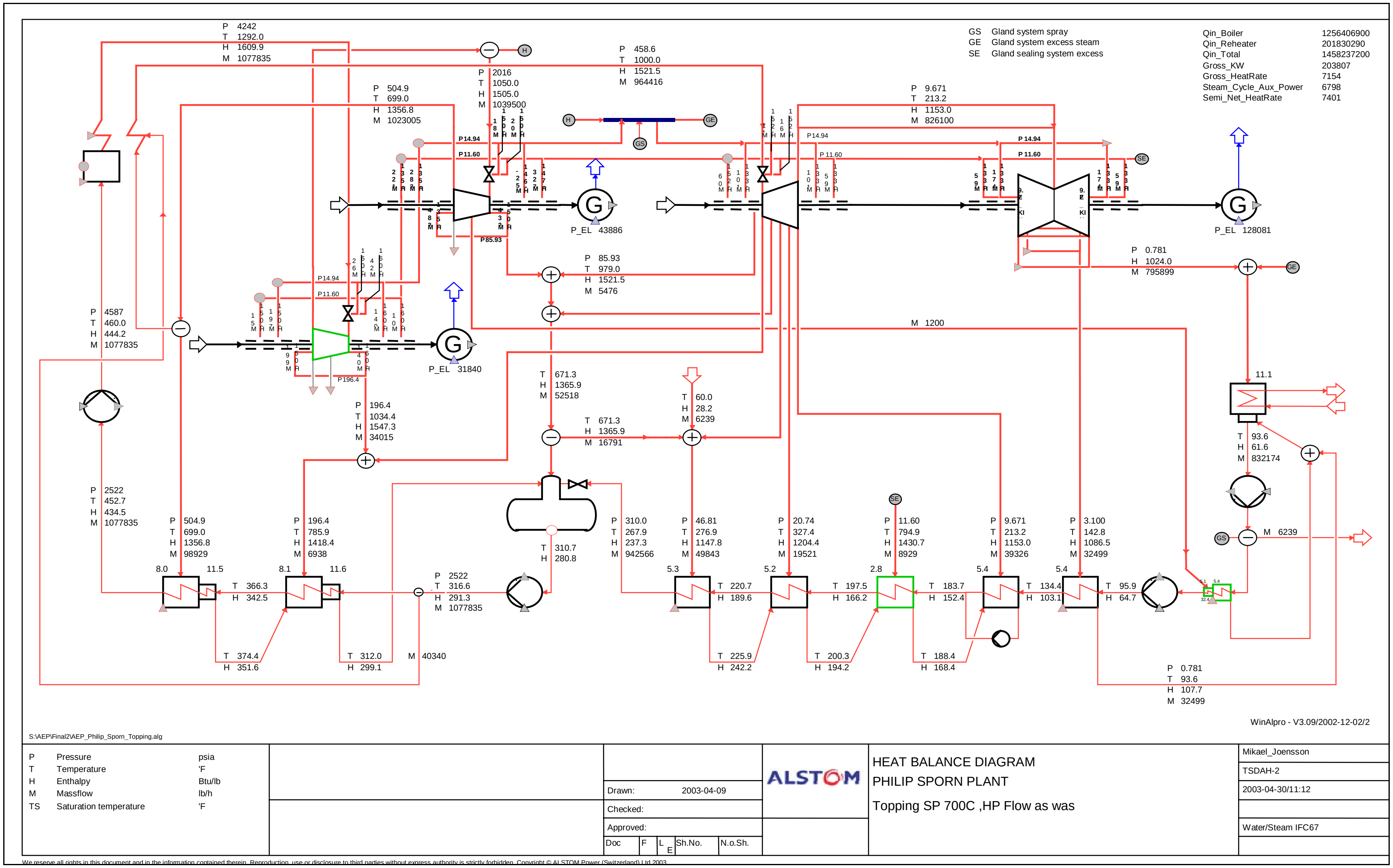



**Figure 2.6. 3: Repowering Case Steam Cycle Schematic Diagram**

Exhaust steam from the existing LP turbine is condensed in the existing condenser and also utilizes the existing condensate and feedwater systems to provide preheated feedwater to the new CMB$^{TM}$ boiler as described below.

The condensate leaving the existing condenser flows to the suction of the existing condensate pumps, which increase the pressure of the fluid and transport it through the new condensate polishing system, the existing low-pressure feedwater heaters, and the existing condensate piping system which enables it to enter the existing open contact heater or deaerator. The condensate passes through the existing gland steam condenser first, followed in series by five low-pressure feedwater heaters. The heaters successively increase the condensate temperature to 267.9°F by condensing and partially sub-cooling steam extracted from the existing LP steam turbine section. Each heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (now referred to as heater drains) is progressively passed to the next lower pressure heater.

The condensate entering the deaerator is further heated and stripped of non-condensable gases by contact with the steam entering the deaerator. The steam is condensed and, along with the heated condensate, flows by gravity to a deaerator storage tank. The existing boiler feedwater pumps take suction from the storage tank and increase the fluid pressure to 2,522 psia. Both the condensate pump and boiler feed pump are electric motor driven. The boosted condensate flows through two existing high-pressure feedwater heaters, increasing in temperature to 452.7°F. The condensate (referred to as boiler feedwater) then enters the new boiler feedwater booster pump where the pressure is increased to 4,587 psia. The new boiler feedwater booster pump is electric motor driven. Each high-pressure feedwater heater receives a separate extraction steam stream at successively higher pressure and temperature. The condensed steam (drains) is progressively passed to the next lower pressure heater, with the drains from the lowest high-pressure heater draining to the deaerator.

Within the new CMB$^{TM}$ boiler, the feedwater is progressively heated to superheater outlet conditions in a “once through” arrangement and supplied to the new topping steam turbine completing the steam cycle for the repowering case.

### 2.6.2 Steam Generator Design for the CMB$^{TM}$ Repowering Case

The CMB$^{TM}$ steam generator unit for the repowering case was designed for a nominal capacity of 204 MWe gross to match the repowered steam cycle described above. The basic description of operation and CMB$^{TM}$ background information was provided previously for Cases CMB$^{TM}$ -3 and CMB$^{TM}$ -5 in Section 2.5.2 and is not repeated here.

#### 2.6.2.1 Heat Transfer Surfaces and Arrangement for the CMB$^{TM}$ Repowering Boiler

The CMB$^{TM}$ combustor, shown on the general arrangement drawings, Figure 2.6.4 and Figure 2.6.5 is a cylindrical vessel having an approximate diameter of 38 feet. Crushed coal is uniformly distributed across the combustor plan area to insure a uniform temperature profile in the combustor. The combustor walls are refractory lined. The upward moving products of combustion transfer the heat generated by burning the coal to the downward falling high alumina content solid particles, injected at the top of the combustor. These solid particles form a bubbling bed at the bottom of the combustor. The bubbling bed temperature is controlled to maintain 2000°F. The flue gas with some entrained solid particles and ash, which includes some unburned carbon, exits the combustor at 1200°F and enters four refractory lined cyclones. The solid particles are removed in the cyclone and are recycled back to the combustor. From the cyclone, the flue gas then enters the un-cooled backpass where a finned tube economizer is installed. Downstream of the economizer there is a last heat transfer surface, the Ljungstrom air preheater, that captures heat from the flue gas to raise the temperature of the primary and secondary air entering the furnace. The flue gas exiting the air preheater proceeds to the existing ESP for the final clean up.

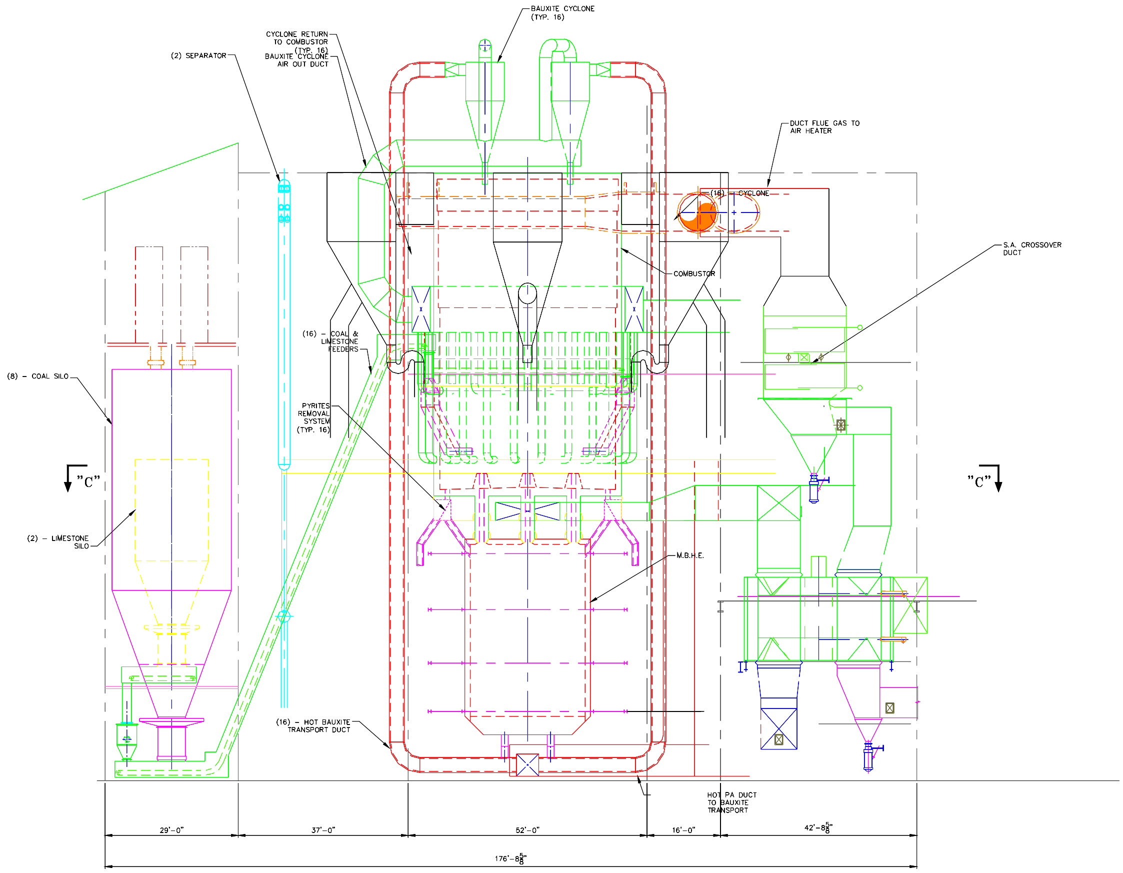



**Figure 2.6. 4: CMB™ Combustor General Arrangement Drawing (Side Elevation)**

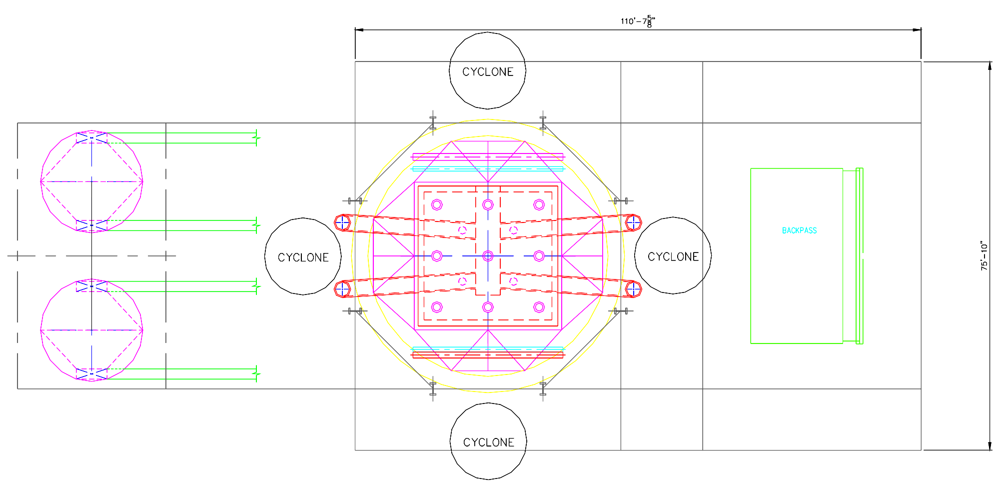



**Figure 2.6. 5: CMB™ Combustor General Arrangement Drawing (Plan View)**

The hot solid particles from the combustor bubbling bed are transported to a single square shaped (22x22') moving bed heat exchanger via a set of standpipes. The heat exchanger accommodates the heat transfer surfaces and the solids moving downward transfer heat to the SH finishing section, RH finishing section, LTSH section, LTRH section, and finally the once-through evaporator. The surface arrangement is shown on Figure 2.6.6. All heat transfer surfaces are constructed with finned tubes.

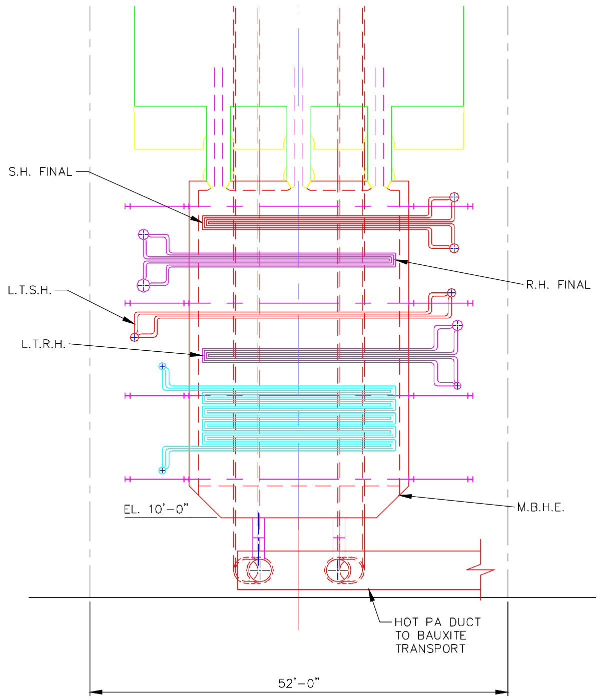



**Figure 2.6. 6: CMB™ Moving Bed Heat Exchanger Surface Arrangement**

The water-steam system includes an integrated start-up system similar to the one discussed in Section 2.3.2.5. The cooled solid particles leave the moving bed heat exchanger at about 1000 $^0$F and are transported by the secondary air to the top of the combustor. At the top of the combustor there are four small cyclones that separate the solid particles and distribute them uniformly across the combustor to repeat the flue gas to solid particles heat exchange process again. The air leaving the cyclones provides secondary combustion air for the furnace.

### 2.6.2.2 Materials for the CMB™ Repowering Boiler

The tubing materials for the construction of the superheater require Ni-based alloys for high temperature sections. The primary alloy used for the superheat section are IN 740, Hayness 230, and stainless steel 347H. The materials of construction for the reheater section are stainless steel 304H and 347H.

The once-through evaporator and economizer sections are constructed of ferritic alloys T-91, T-12 and carbon steel SA-106B.

The fin material varied from carbon steel for the economizer tubes to ferritic for the evaporator and stainless steel for the reheat and superheat tubes.

The headers and piping, except for the superheat finishing header and main steam piping to the topping turbine are made of conventional boiler alloys. Inconel 617was used for these higher temperature components.

#### 2.6.2.3 Firing System for the CMB™ Repowering Boiler

The firing system for the CMB™ repowering boiler is of the same basic design as was used for the Greenfield CMB™ boilers. It is described previously in Section 2.5.2.4 and is not repeated here. The components for the repowering case, however, are much smaller since the repowering case produces about 204 MWe and the Greenfield CMB™ cases produce more than 730 MWe.

#### 2.6.2.4 Air Heater System for the CMB™ Repowering Boiler

The air heater system for the CMB™ repowering boiler is of the same basic design as was used for the Greenfield CMB™ boilers. A single tri-sector unit was selected for this case. It is described previously in Section 2.5.2.5 and is not repeated here. The components for the repowering case, however, are much smaller since the repowering case produces about 204 MWe and the Greenfield CMB™ cases produce more than 730 MWe.

#### 2.6.2.5 Start up System for the CMB™ Repowering Case

The start-up system used for the CMB™ repowering is the same as was used for the Greenfield CMB™ boilers. It was described previously in Section 2.5.2.6 and it is not repeated here.

### 2.6.3 Balance of Plant Equipment for the CMB™ Repowering Case

The CMB™ boiler inherently generates low $NO_x$ emissions. Compared to the existing boiler emission of 0.57 lbm/MM-Btu, the predicted emission from the CMB™ boiler would be 0.10 lbm/MM-Btu. The balance of plant equipment described in this section includes the gas cleanup system equipment and other BOP equipment. The equipment in the category of other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal, limestone, and ash), electrical equipment, and miscellaneous BOP equipment. Refer to Appendix I for equipment lists and Appendix II for drawings.

#### 2.6.3.1 Gas Clean-up Systems for the CMB™ Repowering Case

The gas cleanup system used for the repowering case is the same as what is used for the existing Sporn plant, which consists of an electrostatic precipitator for particulate removal. No sulfur removal equipment is used for the existing plant. Because of the limited scope for this repowering study, it was agreed with AEP that in the framework of this study, no additional environmental control systems would be considered as long as the repowered system meets current emission levels. However, as a part of the economic analysis (Section 4.3.3) limestone injection to remove 30% of the sulfur was also considered.

#### 2.6.3.2 Other BOP Systems for the CMB™ Repowering Case

Other BOP equipment includes the draft system equipment, the cooling system equipment, the material handling equipment (coal and ash), electrical equipment, and miscellaneous BOP equipment.

Analysis has shown that for the repowered plant, the increased firing rate should not be a problem for many of the existing components such as the ESP and ID fans. Much of the existing Sporn Unit #4 balance of plant equipment is utilized for the repowered case. The following additional new balance of plant equipment has been identified (major items only):

- FW booster pump
- Condensate polishing system (full flow)
- Coal feed system
- Air fans and blowers
- Transformer

- Ductwork and dampers
- Feedwater and steam piping

**Draft System:**
The flue gas is moved through the new CMB™ boiler, the existing precipitator, and other Boiler Island equipment with the draft system as shown in Figure 2.6.7. The draft system includes new primary and secondary air fans, the existing induced draft (ID) fan, the associated ductwork and expansion joints (some existing), and the existing stack, which disperses the flue gas leaving the system to the atmosphere. The induced draft (existing), primary air, and secondary air fans are driven with electric motors and controlled to operate the unit in a balanced draft mode with the furnace outlet maintained at a slightly negative pressure (typically, -0.5 inwg). A forced draft primary air (PA) fan provides hot air to the combustor bottom. It is preheated in a regenerative air preheater. Part of this stream is also used for transport of cooled particles leaving the MBHE to the cyclones at the top of the combustor where the particles are recirculated to the combustor. The air leaving the cyclones is used for combustion air in the combustor as shown below.

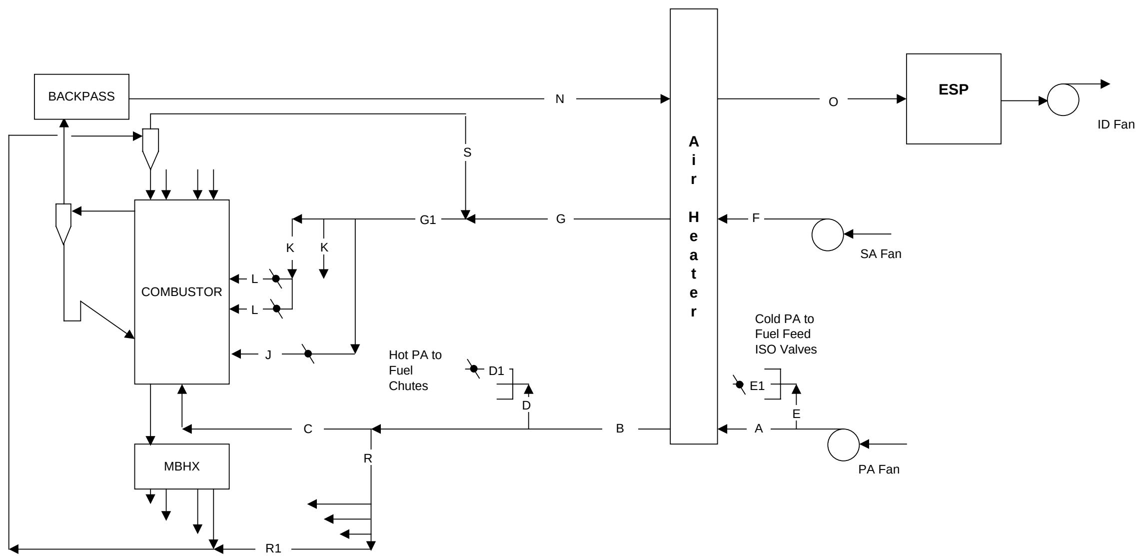



**Figure 2.6. 7: Draft System Schematic Diagram**

A forced draft secondary air (SA) fan provides an air stream to the combustor that is preheated in a regenerative air preheater and is then introduced into the furnace as secondary air for combustion of the coal.

The flue gas exiting the furnace passes through the cyclones and convection pass of the unit, which contains the economizer section. The flue gas leaving the convection pass flows through the regenerative air preheater and then exits the unit and flows to the precipitator for final particulate capture. The flue gas is drawn through the precipitator and other equipment with the Induced Draft (ID) Fan (existing) and is discharged to atmosphere through the stack.

The following fans are provided with the scope of supply of the steam generator:

- Primary air fans, which provides forced draft primary airflow. These fans are centrifugal type units, supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 4,182 kW.

- Secondary air fans, which provides forced draft secondary airflow. These fans are centrifugal type units supplied with electric motor drives, inlet screens, inlet vanes, and silencers. The total electric power required for the electric motor drives is 240 kW.
- Induced draft fans (existing), centrifugal units with electric motor drives and inlet dampers. The total electric power required for the electric motor drives is 2,224 kW for all five cases.

### 2.6.4 Existing Sporn Plant Description and Performance

The existing Philip Sporn plant is owned by AEP and is located in New Haven, West Virginia on a site adjacent to the Ohio River. The plant includes five coal-fired units. Units 1-4 are identical subcritical units generating about 170 MWe each at full load and unit 5 is a large supercritical unit.

The unit selected for the retrofit study is Unit #4 of the Philip Sporn plant. This unit burns low sulfur mid-western high volatile bituminous coal in a pulverized coal fired boiler. The existing boiler was designed by Babcock & Wilcox and is a front wall fired reheat unit with subcritical steam conditions. The unit is a relatively old unit in their system but still operates and dispatches quite well with availability typically in the 85% range.

A partial view of the site is shown below in Figure 2.6.7. Unit #4 is located in the upper right center of Figure 2.6.7. The site was determined to have sufficient space available, adjacent to the existing Unit #4 building and precipitator, to allow installation of the new equipment.

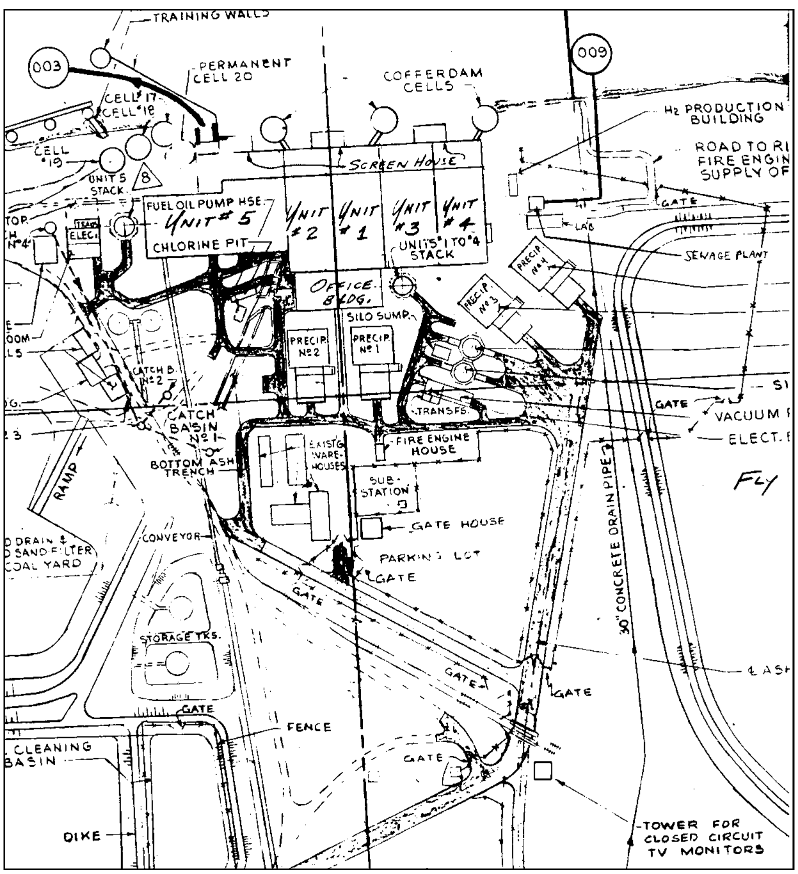



**Figure 2.6. 8: Existing Sporn Site Plan**

Unit #4 utilizes an electrostatic precipitator for particulate removal and has no sulfur removal equipment. This section will show the performance of the existing unit for comparison to the repowered unit. Figure 2.6.8 shows a simplified gas side process flow diagram for the existing unit and Table 2.6.2 shows the associated inlet and outlet stream conditions for the Boiler Island of this unit.

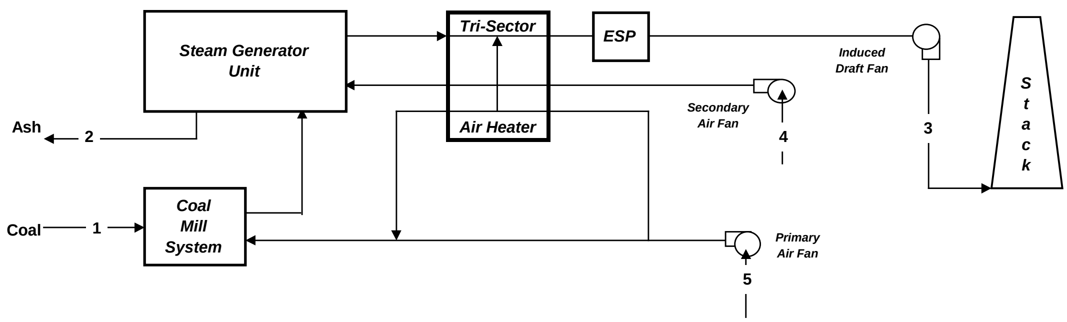



**Figure 2.6. 9: Simplified Gas Side Process Flow Diagram for the Existing Sporn Unit #4**

**Table 2.6. 2: Gas Side Material and Energy Balance for the Existing Sporn Unit #4**

| **Sporn Existing** | **Units** | **Point 1**<br>**Coal In** | **Point 2**<br>**Ash Cooler Out** | **Point 3**<br>**ID Fan Out** | **Point 4**<br>**PA Fan In** | **Point 5**<br>**SA Fan In** |
|---|---|---|---|---|---|---|
| **Flow** | lbm/hr | 123,798 | 2,836 | 1,554,555 | 286,735 | 1,140,143 |
| **Temperature** | Deg F | 80 | 250 | 290 | 80 | 80 |
| **Gas Analysis** | | | | | | |
| N2 | % weight | n/a | n/a | 70.71 | 74.55 | 74.55 |
| CO2 | % weight | n/a | n/a | 19.07 | 0.04 | 0.04 |
| H2O | % weight | n/a | n/a | 5.00 | 1.30 | 1.30 |
| O2 | % weight | n/a | n/a | 4.97 | 22.84 | 22.84 |
| SO2 | % weight | n/a | n/a | 0.16 | 0.00 | 0.00 |
| Ar | % weight | n/a | n/a | 0.09 | 1.27 | 1.27 |

A brief performance summary for this existing case reveals the following information. The existing steam turbine will generate approximately 169 MWe at full load. The subcritical plant produces a net output of about 157 MWe with an auxiliary power consumption of about 7.2 percent of generator output. The resulting net plant heat rate and thermal efficiency are 9,561 Btu/kWh and 35.70 percent respectively. Detailed plant performance for the existing Sporn Unit #4 and the repowering case are shown in Section 2.6.5.

The existing Unit #4 steam turbine is a General Electric turbine which generates ~169 MWe gross output with steam conditions of 1,050°F/1,000°F/2,015 psia. The steam cycle utilizes eight feedwater heaters to provide feedwater to the boiler at 453°F. Figure 2.6.10 shows the existing Sporn Plant Unit #4 steam cycle.

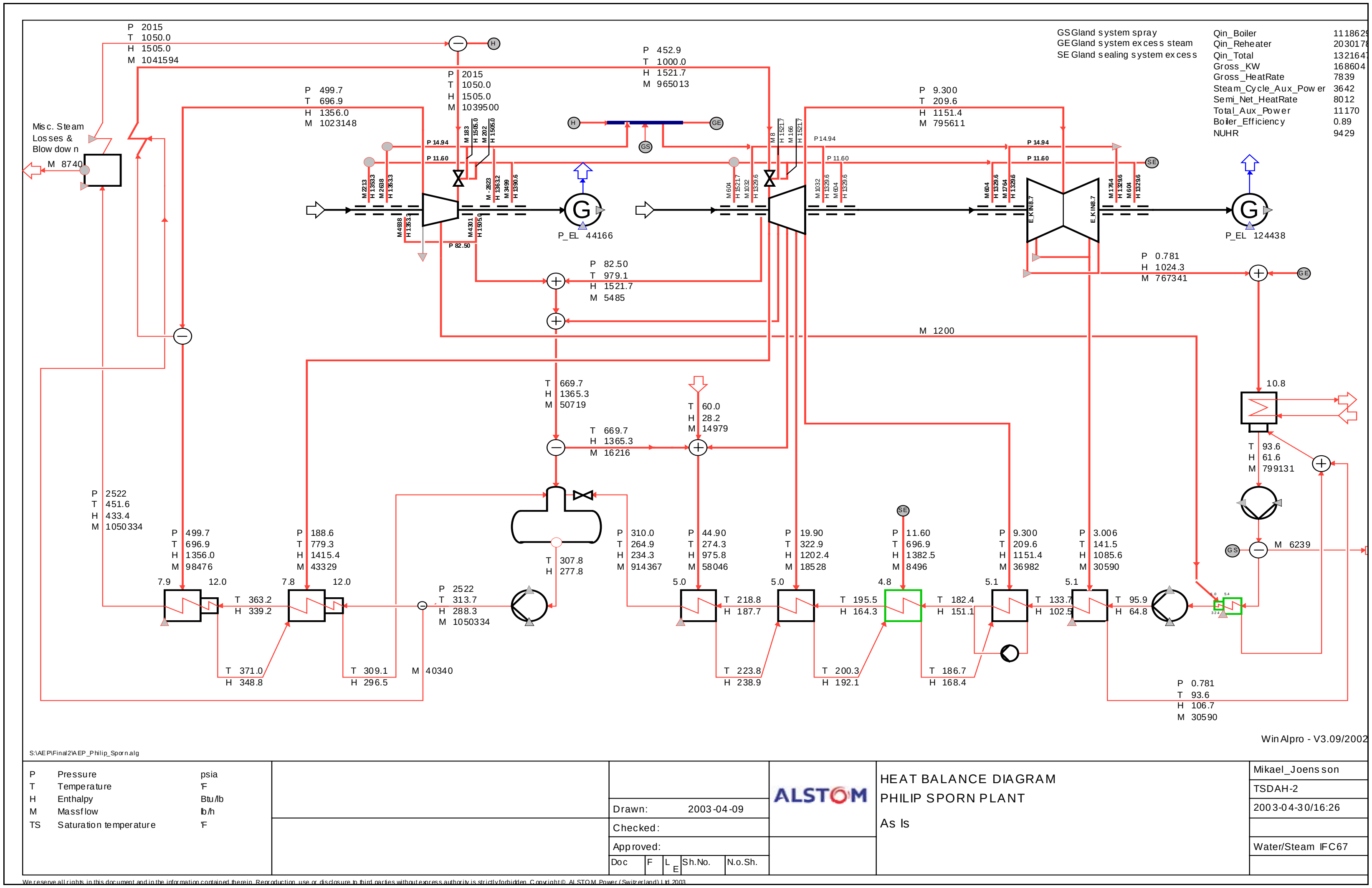



**Figure 2.6.10: Existing Sporn Plant Steam Cycle Schematic Diagram**

### 2.6.5 Overall Plant Performance for the CMB™ Repowering Case

Table 2.6.3 shows a fairly detailed breakdown of various plant performance parameters for the repowering case and the existing unit for comparison. The table compares plant auxiliary power, steam conditions, generator output, net plant output, fuel heat input, net plant heat rate, and thermal efficiency. Figure 2.6.10 illustrates the thermal efficiency improvement for the repowered case. The improved steam conditions for the repowered case are shown to improve plant thermal efficiency by about 2.7 percentage points or about 7.6 percent.

**Table 2.6. 3: Overall Plant Performance Comparison for Repowering Case**

| | | Repower | Existing |
|---|---|---|---|
| **Auxiliary Power Listing** | **(units)** | **--Sporn Unit #4--** | |
| Feedwater Pumps (mechanical) | (kw) | 6379 | 3231 |
| Feedwater Pumps (electrical) | (kw) | 7088 | 3590 |
| Main Condensate Extraction Pumps | (kw) | 280 | 269 |
| Main Cooling Water Pumps | (kw) | 1309 | 1262 |
| Secondary Cooling Water Pumps | (kw) | 55 | 53 |
| Closed Circuit Cooling Water Pumps | (kw) | 101 | 97 |
| Cooling Tower Fans | (kw) | n/a | n/a |
| Forced Draft Fans | (kw) | 240 | 470 |
| Primary Air Fans | (kw) | 4182 | 524 |
| Induced Draft Fans | (kw) | 2224 | 2025 |
| Fluidizing Air Blowers | (kw) | 182 | n/a |
| Coal Handling | (kw) | 99 | 90 |
| Pulverizers | (kw) | n/a | 986 |
| Ash Handling | (kw) | 783 | 622 |
| Limestone Handling | (kw) | n/a | n/a |
| Electrostatic Precipitator | (kw) | 719 | 655 |
| FGD or FDA System | (kw) | n/a | n/a |
| SCR or SNCR Auxiliary Power | (kw) | n/a | n/a |
| Boiler Circulation Pumps | (kw) | n/a | n/a |
| Misc. Aux. Power (Controls, Lighting, HVAC, etc.) | (kw) | 844 | 768 |
| Transformer Loss | (kw) | 815 | 674 |
| **Total Auxiliary Power Consumption** | (kw) | 18920 | 12086 |
| Fraction of Generator Output | (fraction) | 0.093 | 0.072 |
| Fraction of Generator Output (w/o BFP) | (fraction) | 0.058 | 0.050 |
| **Steam Cycle Parameters** | | | |
| Main Steam Pressure | (psia) | 4242 | 2015 |
| Main Steam Temperature | (Deg F) | 1292 | 1050 |
| Reheat Steam Temperature | (Deg F) | 1000 | 1000 |
| Feedwater Temperature | (Deg F) | 460 | 453 |
| Number of Feedwater Heaters | (no.) | 8 | 8 |
| **Efficiency and Output** | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8873 | 0.8816 |
| **Steam Cycle Efficiency** | (fraction) | 0.4604 | 0.4269 |
| | (Btu/kwhr) | 7413 | 7994 |
| **Generator Output** | (kw) | 203807 | 168604 |
| **Net Plant Output** | (kw) | 184887 | 156518 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 1643 | 1496 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 8889 | 9561 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3840 | 0.3570 |

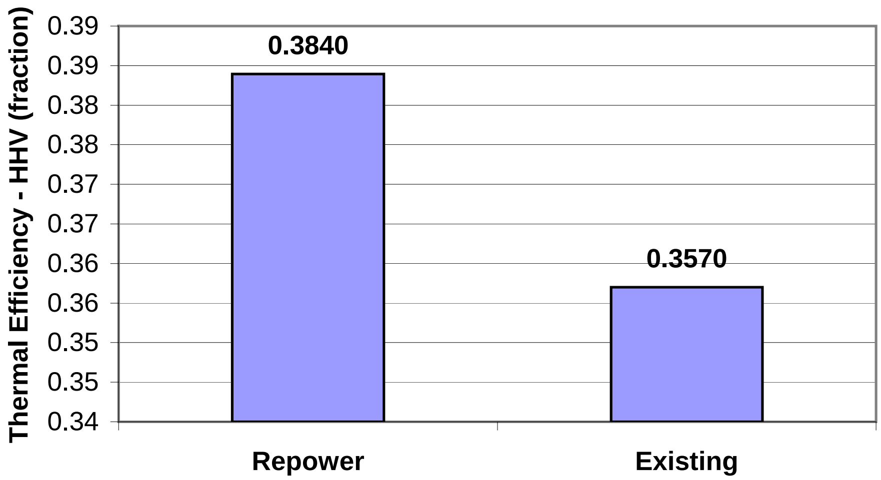



**Figure 2.6.11: Thermal Efficiency Comparison for the Repowered and Existing Unit**

## 2.7 Overall Plant Performance Comparison (all Cases)

Steam power production is based on a thermodynamic cycle known as the Rankine cycle. The measure of the ability of the Rankine plant to convert heat released in a furnace to generate electrical power is the plant thermal efficiency. In the industry, it is customary to express this efficiency in terms of a net plant heat rate (NPHR). Since, by definition, one kilowatt-hour of electrical power is equivalent to 3412.7 Btu, to convert the thermal efficiency to net plant heat rate divide 3412.7 Btu/kWh by the efficiency fraction. The thermal efficiency may be determined in one of several ways. In the "input-output method, the fuel energy input and the net plant power output are determined and the plant heat rate and thermal efficiency are calculated as follows:

**NPHR** = Mcoal x HHV / (Wgen out - Waux)

Or:

**Thermal Efficiency** = (3412.7/NPHR) x 100%

<u>Where:</u>

| | | | |
|---|---|---|---|
| NPHR | = | Net plant heat rate | (Btu/kWh) |
| Mcoal | = | Mass flow rate of coal fired | (lbm/hr) |
| HHV | = | Higher heating value of coal | (Btu/lbm) |
| Wgen out | = | Gross generator output | (kW) |
| Waux | = | Power consumed by auxiliary components | (kW) |

The net plant heat rate depends on many factors. Some of the major factors are listed below:

- Steam turbine throttle pressure
- Main steam and reheat steam temperatures
- Number of reheat stages
- Number of feedwater heaters
- Steam turbine design
- Steam turbine isentropic expansion efficiencies
- Condenser pressure
- Type of coal fired
- Auxiliary components
- Component pressure drops

### 2.7.1 Auxiliary Power Basis:

The largest power consumers in the cycle are the electrically driven boiler feedwater pumps. The sum of the mechanical drives power requirements at the pump shaft for the two pumps operating in parallel was determined by a program for circuit computation. These values were then entered into the appropriate steam cycle energy balances. The efficiency of the entire boiler feed pump drive system, which comprises a mechanical speed-transforming gear, a hydraulic variable-speed gear, and an asynchronous motor, was estimated at 0.90 for the 100 % load point.

Power consumption for other auxiliary components and systems were then determined rigorously for Case PC-1. Using the Case PC-1 as the basis, the auxiliary power requirements were determined for all other cases by linear interpolation. Specifically, the interpolation was performed in accordance with the following list:

| | |
|---|---|
| • Main condensate extraction pumps: | Proportional to the condensate mass flow (But 15 % higher in supercritical cases because of the additional pressure loss of the condensate polishing plant) |
| • Main cooling water pumps: | Proportional to the condenser heat rejection quantity |
| • Secondary cooling water pumps: | Proportional to the condenser heat rejection quantity (But 20 % higher in supercritical cases because of the higher feedwater pump power consumption) |
| • Closed circuit cooling water pumps: | Proportional to the secondary cooling water pump power consumption |
| • Forced draft fans: | Proportional to the fuel heat input |
| • Primary air fans: | " |
| • Induced draft fans: | " |
| • Coal handling system: | " |
| • Pulverizers: | " |
| • Ash handling system: | " |
| • Electrostatic precipitator: | " |
| • Boiler circulation pumps: | " (Zero for supercritical cases) |
| • Other auxiliary power consumption: | Constant value for all cases |
| • Transformer efficiency | 99.6 % |

### 2.7.2 Plant Performance Summary:

Table 2.7.1 shows a fairly detailed comparison of the various plant performance parameters for all cases. This table includes detailed plant auxiliary power breakdowns, boiler and steam cycle efficiencies, steam conditions, generator outputs, net plant outputs, fuel heat inputs, net plant heat rates, and plant thermal efficiencies for all the cases considered in this study.

Figures 2.7.1 – 2.74 illustrate, for all the cases, the primary plant performance parameters which contribute to the plants overall thermal efficiency. Bars of a uniform color and case numbers indicate common steam cycles among the cases. The last two bars compare the repowered and existing unit cases of the Sporn Unit #4 repowering study.

Figure 2.7.1 shows the comparison of boiler efficiency for all cases. The PC and CFB cases of the Greenfield study are identical whereas the CMB$^{TM}$ case is about 0.5 percentage points lower. The lower value for the CMB$^{TM}$ cases is due to partial sulfation in the combustor.

Figure 2.7.2 shows for all cases the comparison of steam cycle thermal efficiency and the effects of steam parameters.

Figure 2.7.3 shows for all cases the comparison of total plant auxiliary power. The CMB$^{TM}$ cases are slightly lower than the PC and CFB cases at the same steam conditions. Also because the boiler feed pumps are electrically driven, the steam cycle variation also affects this parameter.

Finally, Figure 2.7.4 shows for all cases the comparison of overall plant thermal efficiency, which represents the combined effects of changes in boiler efficiency, steam cycle efficiency, and auxiliary power.

Additionally, Figure 2.7.5 shows a comparison of specific $CO_2$ emissions (lbm/kWh) for all the cases. This figure in combination with Figure 2.7.4 shows the direct correlation of $CO_2$ emissions and plant thermal efficiency.

## Table 2.7. 1: Overall Plant Performance Comparison (all Cases)

| | | PC-1 | PC-2 | PC-3 | PC-4 | PC-5 | CFB-2 | CFB-3 | CFB-4 | CMB-3 | CMB-5 | Repower | Existing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auxiliary Power Listing** | **(units)** | | | | | | | | | | | --Sporn Unit #4-- | |
| Feedwater Pumps (mechanical) | (kw) | 15606 | 15187 | 22799 | 25858 | 29316 | 15187 | 22799 | 25858 | 22799 | 29316 | 6379 | 3231 |
| Feedwater Pumps (electrical) | (kw) | 17340 | 16874 | 25332 | 28731 | 32573 | 16874 | 25332 | 28731 | 25332 | 32573 | 7088 | 3590 |
| Main Condensate Extraction Pumps | (kw) | 1255 | 1197 | 1347 | 1317 | 1026 | 1197 | 1347 | 1317 | 1347 | 1026 | 280 | 269 |
| Main Cooling Water Pumps | (kw) | 4799 | 4728 | 4627 | 4521 | 4237 | 4728 | 4627 | 4521 | 4627 | 4237 | 1309 | 1262 |
| Secondary Cooling Water Pumps | (kw) | 202 | 199 | 234 | 228 | 214 | 199 | 234 | 228 | 234 | 214 | 55 | 53 |
| Closed Circuit Cooling Water Pumps | (kw) | 370 | 365 | 428 | 418 | 392 | 365 | 428 | 418 | 428 | 392 | 101 | 97 |
| Cooling Tower Fans | (kw) | 3300 | 3251 | 3182 | 3109 | 2914 | 3251 | 3182 | 3109 | 3182 | 2914 | n/a | n/a |
| Forced Draft Fans | (kw) | 1589 | 1589 | 1589 | 1589 | 1589 | 3876 | 3876 | 3876 | 1219 | 1219 | 240 | 470 |
| Primary Air Fans | (kw) | 1322 | 1322 | 1322 | 1322 | 1322 | 7904 | 7904 | 7904 | 14037 | 14037 | 4182 | 524 |
| Induced Draft Fans | (kw) | 8950 | 8950 | 8950 | 8950 | 8950 | 10924 | 10924 | 10924 | 7740 | 7740 | 2224 | 2025 |
| Fluidizing Air Blowers | (kw) | n/a | n/a | n/a | n/a | n/a | 2875 | 2875 | 2875 | 840 | 840 | 182 | n/a |
| Coal Handling | (kw) | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 352 | 352 | 99 | 90 |
| Pulverizers | (kw) | 1949 | 1949 | 1949 | 1949 | 1949 | n/a | n/a | n/a | n/a | n/a | n/a | 986 |
| Ash Handling | (kw) | 2417 | 2417 | 2417 | 2417 | 2417 | 2783 | 2783 | 2783 | 2783 | 2783 | 783 | 622 |
| Limestone Handling | (kw) | 741 | 741 | 741 | 741 | 741 | 1153 | 1153 | 1153 | 1159 | 1159 | n/a | n/a |
| Electrostatic Precipitator | (kw) | 1400 | 1400 | 1400 | 1400 | 1400 | n/a | n/a | n/a | n/a | n/a | 719 | 655 |
| FGD or FDA System | (kw) | 13200 | 13200 | 13200 | 13200 | 13200 | 1260 | 1260 | 1260 | 1267 | 1267 | n/a | n/a |
| SCR or SNCR Auxiliary Power | (kw) | 200 | 200 | 200 | 200 | 200 | 106 | 106 | 106 | 106 | 106 | n/a | n/a |
| Boiler Circulation Pumps | (kw) | 621 | 621 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Misc. Aux. Power (Controls, Lighting, HVAC, etc.) | (kw) | 3000 | 3000 | 3000 | 3000 | 3000 | 3000 | 3000 | 3000 | 3000 | 3000 | 844 | 768 |
| Transformer Loss | (kw) | 2785 | 2845 | 2945 | 3016 | 3285 | 2845 | 2945 | 3016 | 2945 | 3285 | 815 | 674 |
| **Total Auxiliary Power Consumption** | (kw) | 65790 | 65198 | 73212 | 76458 | 79759 | 63690 | 72325 | 75571 | 70596 | 77144 | 18920 | 12086 |
| Fraction of Generator Output | (fraction) | 0.094 | 0.092 | 0.099 | 0.101 | 0.097 | 0.090 | 0.098 | 0.100 | 0.096 | 0.094 | 0.093 | 0.072 |
| Fraction of Generator Output (w/o BFP) | (fraction) | 0.070 | 0.068 | 0.065 | 0.063 | 0.057 | 0.066 | 0.064 | 0.062 | 0.061 | 0.054 | 0.058 | 0.050 |
| **Steam Cycle Parameters** | | | | | | | | | | | | | |
| Main Steam Pressure | (psia) | 2408 | 2408 | 3625 | 3915 | 5075 | 2408 | 3625 | 3915 | 3625 | 5075 | 4242 | 2015 |
| Main Steam Temperature | (Deg F) | 1000 | 1049 | 1049 | 1085 | 1292 | 1049 | 1049 | 1085 | 1049 | 1292 | 1292 | 1050 |
| Reheat Steam Temperature | (Deg F) | 1000 | 1112 | 1112 | 1148 | 1328 | 1112 | 1112 | 1148 | 1112 | 1328 | 1000 | 1000 |
| Feedwater Temperature | (Deg F) | 500 | 500 | 500 | 554 | 626 | 500 | 500 | 554 | 500 | 626 | 460 | 453 |
| Number of Feedwater Heaters | (no.) | 7 | 7 | 7 | 8 | 9 | 7 | 7 | 8 | 7 | 9 | 8 | 8 |
| **Efficiency and Output** | | | | | | | | | | | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8926 | 0.8926 | 0.8873 | 0.8816 |
| **Steam Cycle Efficiency** | (fraction) | 0.4442 | 0.4543 | 0.4650 | 0.4745 | 0.5161 | 0.4543 | 0.4650 | 0.4745 | 0.4650 | 0.5161 | 0.4604 | 0.4269 |
| | (Btu/kwhr) | 7683 | 7512 | 7339 | 7193 | 6613 | 7512 | 7339 | 7193 | 7339 | 6613 | 7413 | 7994 |
| **Generator Output** | (kw) | 696316 | 711278 | 736148 | 753937 | 821374 | 711278 | 736148 | 753937 | 736148 | 821374 | 203807 | 168604 |
| **Net Plant Output** | (kw) | 630526 | 646080 | 662936 | 677479 | 741615 | 647588 | 663823 | 678366 | 665552 | 744230 | 184887 | 156518 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5844 | 5844 | 1643 | 1496 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 9218 | 8997 | 8768 | 8580 | 7838 | 8976 | 8756 | 8568 | 8781 | 7853 | 8889 | 9561 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3702 | 0.3794 | 0.3893 | 0.3978 | 0.4355 | 0.3803 | 0.3898 | 0.3983 | 0.3887 | 0.4346 | 0.3840 | 0.3570 |

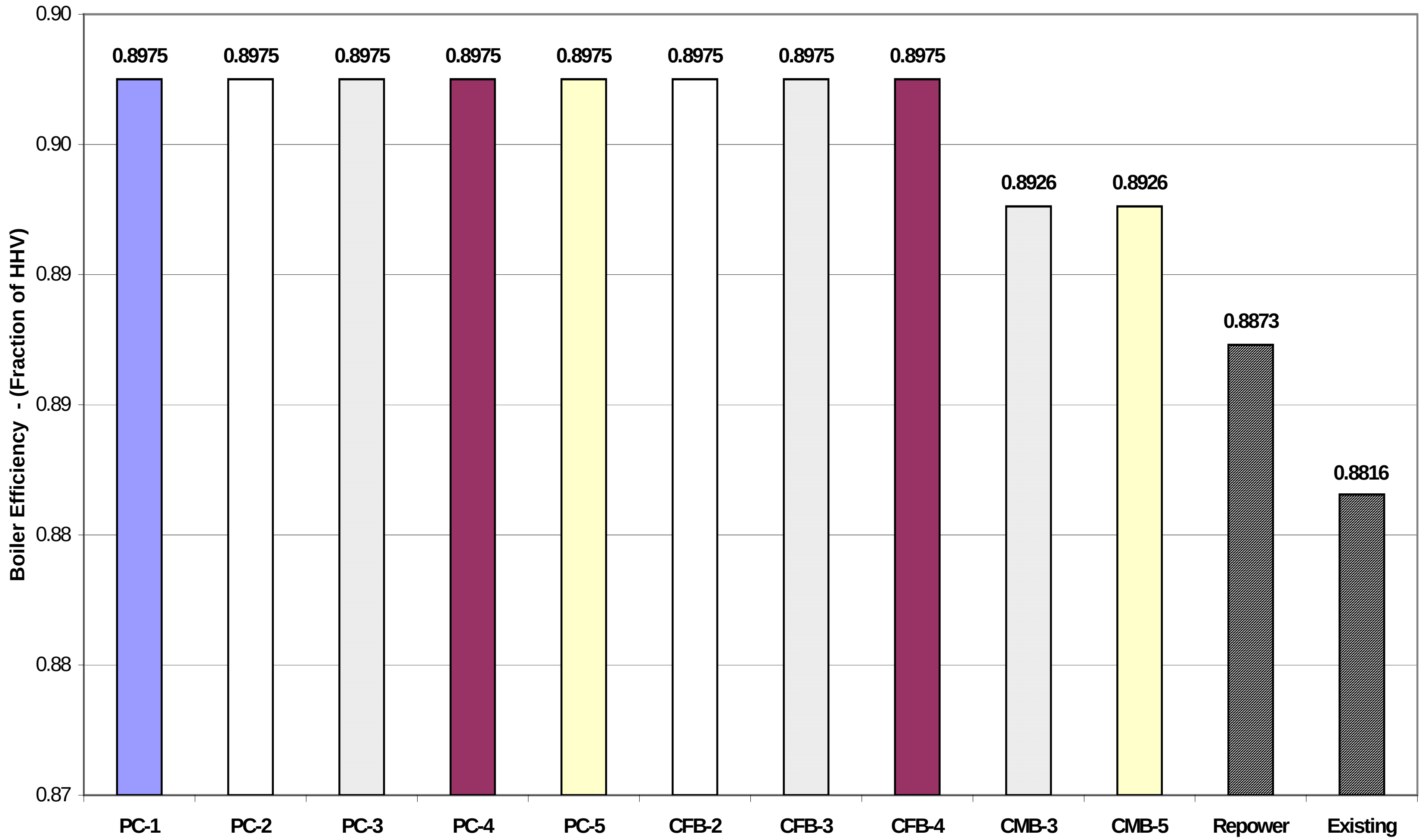



**Figure 2.7. 1: Boiler Efficiency Comparison for all Cases**

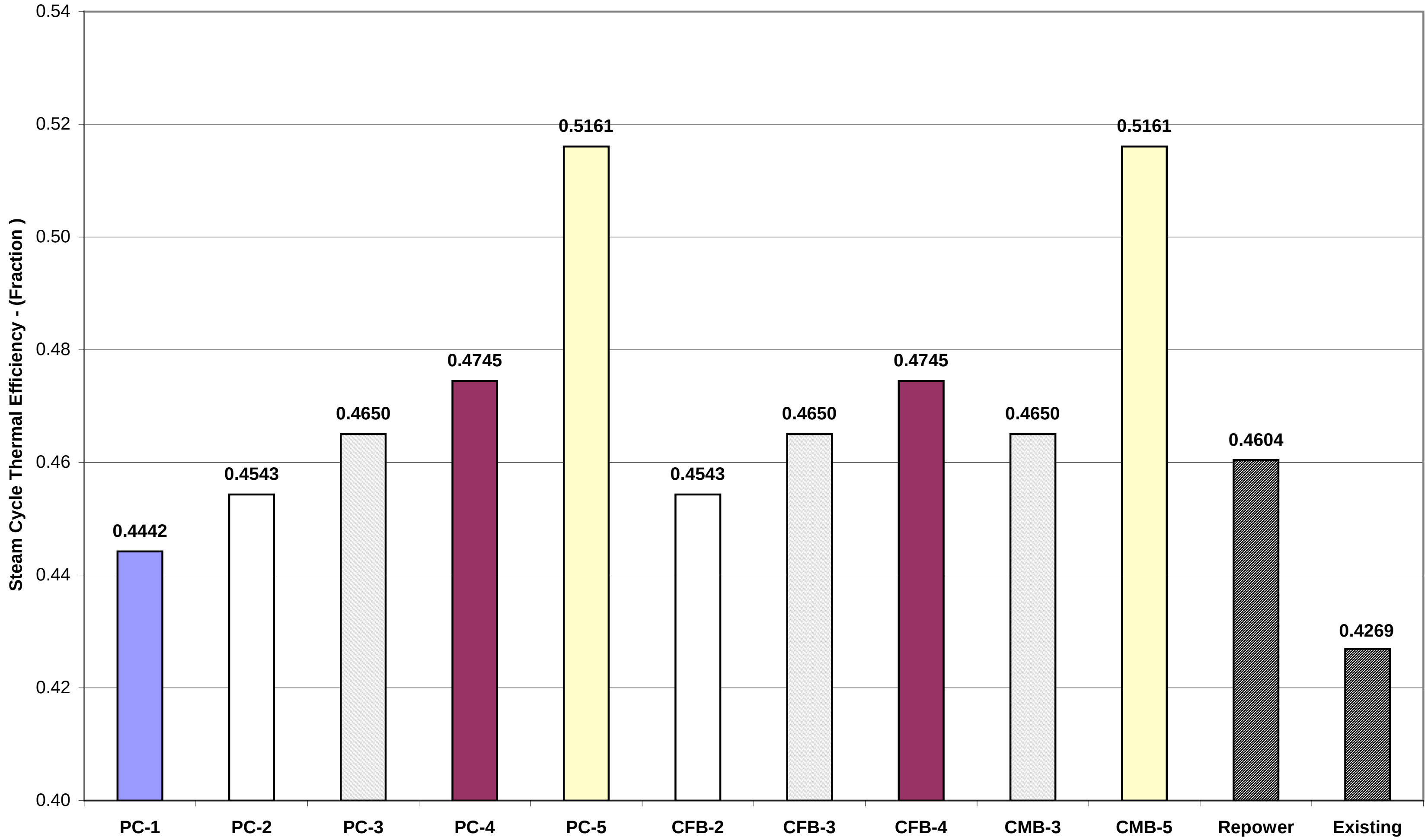



**Figure 2.7. 2: Steam Cycle Thermal Efficiency Comparison for all Cases**

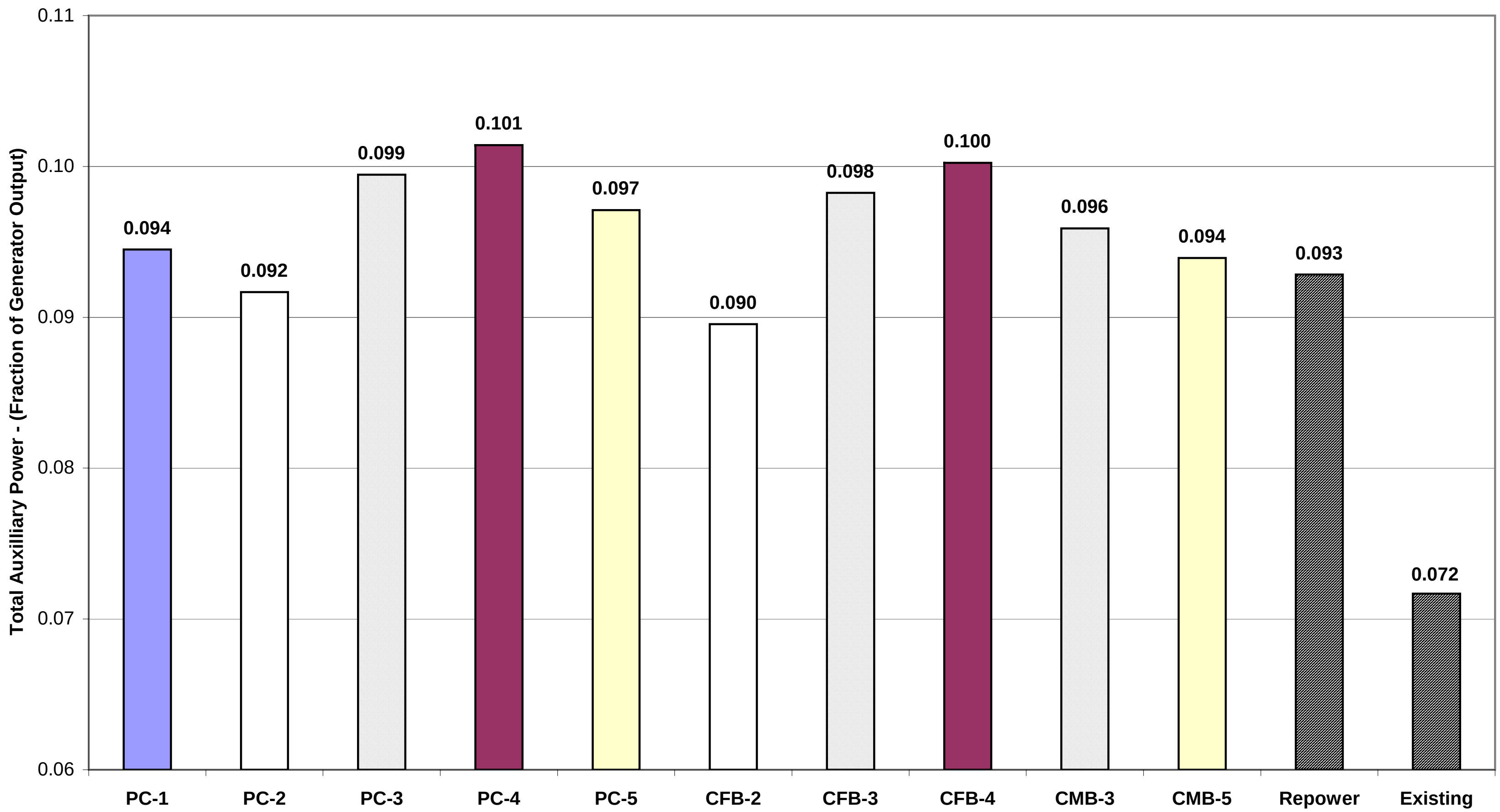



**Figure 2.7. 3: Total Auxiliary Power Comparison for all Cases**

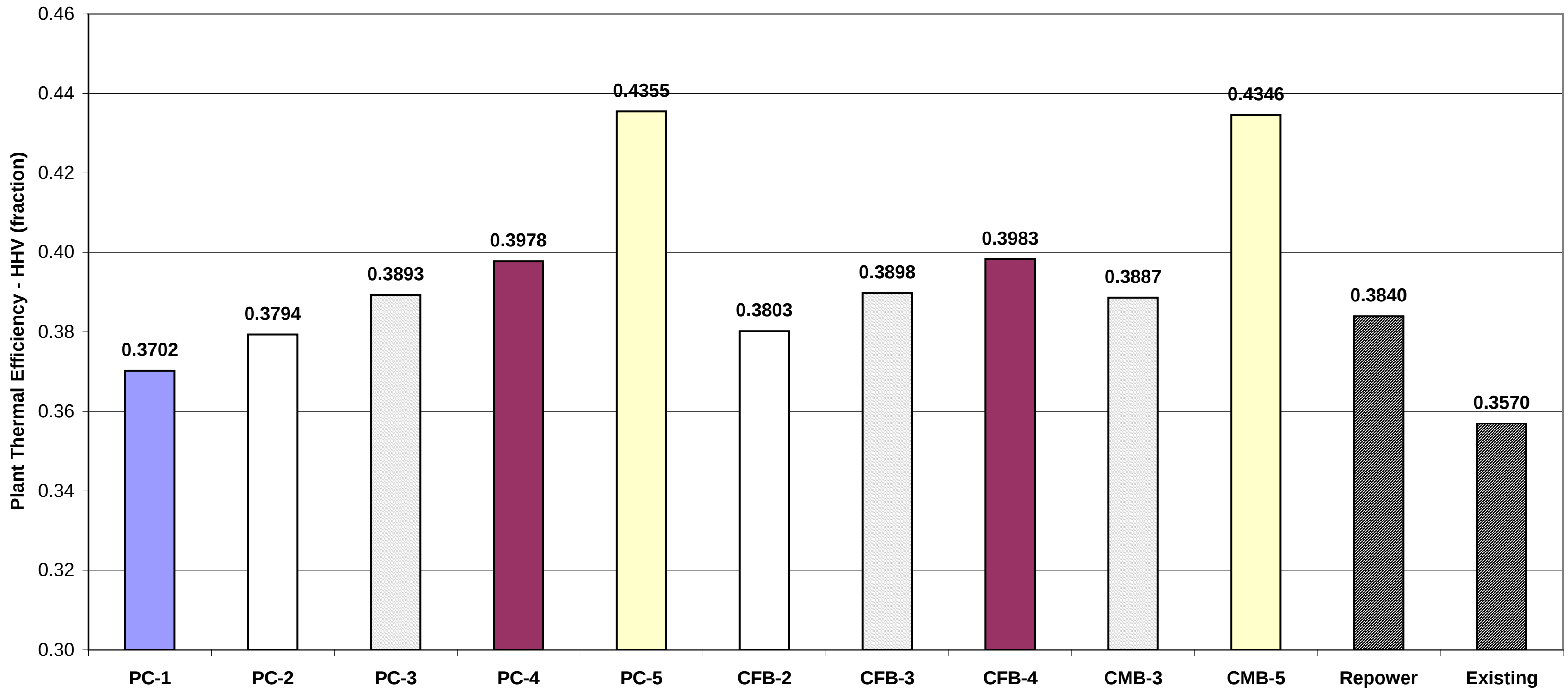



**Figure 2.7. 4: Plant Thermal Efficiency Comparison for all Cases**

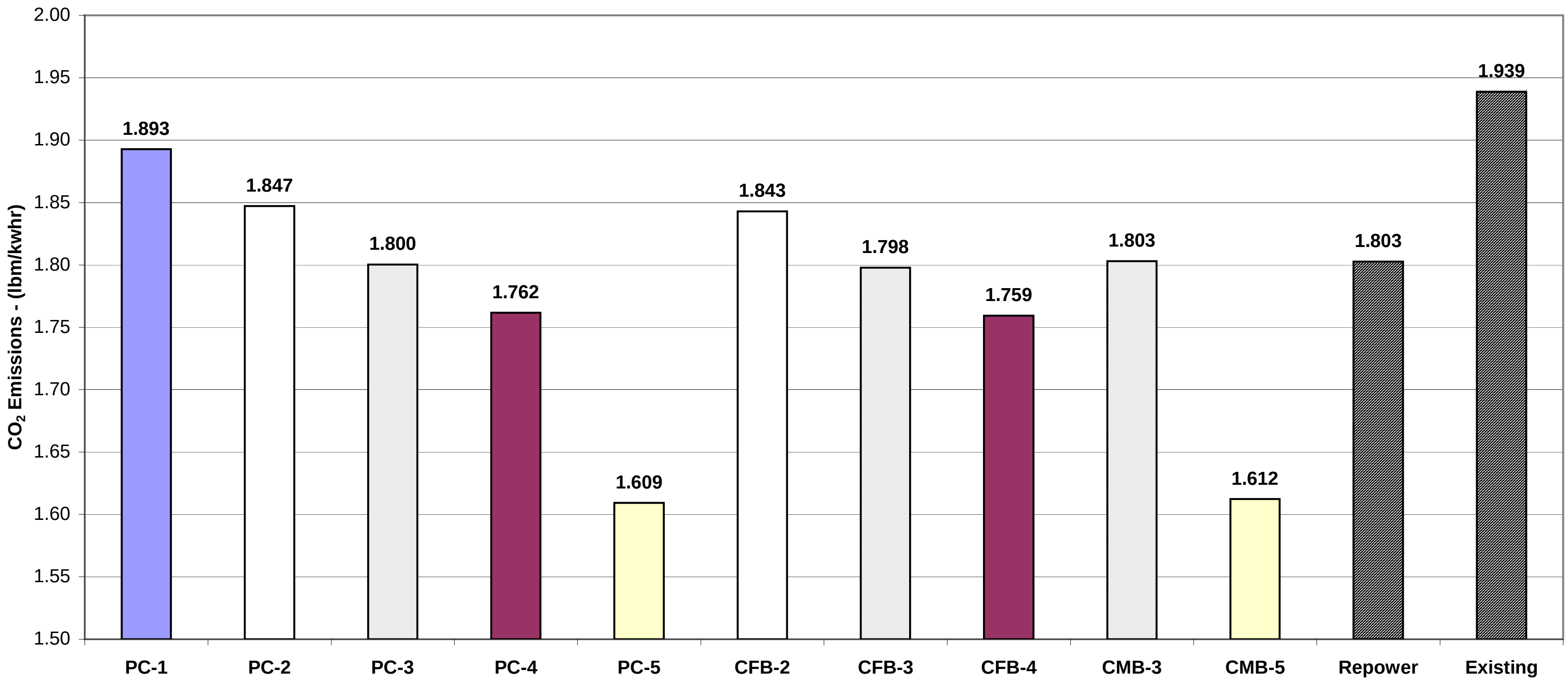



**Figure 2.7. 5: Plant $CO_2$ Emission Comparison for all Cases**

### 2.7.3 The Effect of Steam Cycle Parameters on Plant Performance:

Figures 2.7.6 and 2.7.7 show the net plant heat rate variation as a function of steam and feedwater conditions for twenty-five (25) pulverized coal (PC) fired power plants (Palkes, Liljedahl, Kruger, Weirich; 1999). Similar results would be achieved for plants utilizing CFB and CMB™ combustion systems since boiler efficiency and auxiliary power requirements for these combustion systems are very comparable to pulverized coal firing.

Figure 2.7.6 is a three-dimensional plot depicting eleven subcritical cycles and Figure 2.7.7 shows a similar plot for fourteen supercritical cases. All calculations were made for a condenser pressure of 2.5" Hg and the net power output is calculated at the output side of the transformer.

Five of the cases shown on these plots (Cases 23, 7, 18. 27, and 28) represent cases also included in this study, as listed below. The other cases shown on the plots, although not included in this study, have thermal efficiencies calculated on a directly comparable basis to those in this study and therefore are shown for comparison.

- Case PC-1 = Case 23
- Case PC-2 = Case 7
- Case PC-3 = Case 18
- Case PC-4 = Case 27
- Case PC-5 = Case 28

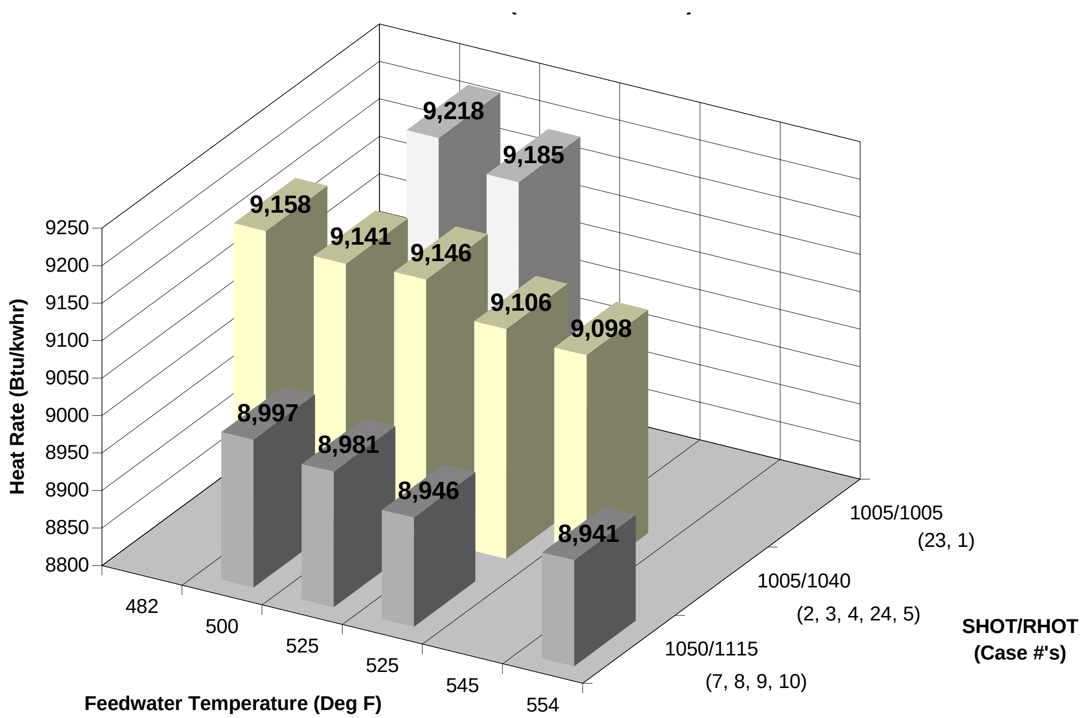



**Figure 2.7. 6: Net Plant Heat Rates (HHV basis) for Subcritical (2,400 psia) Cycles**

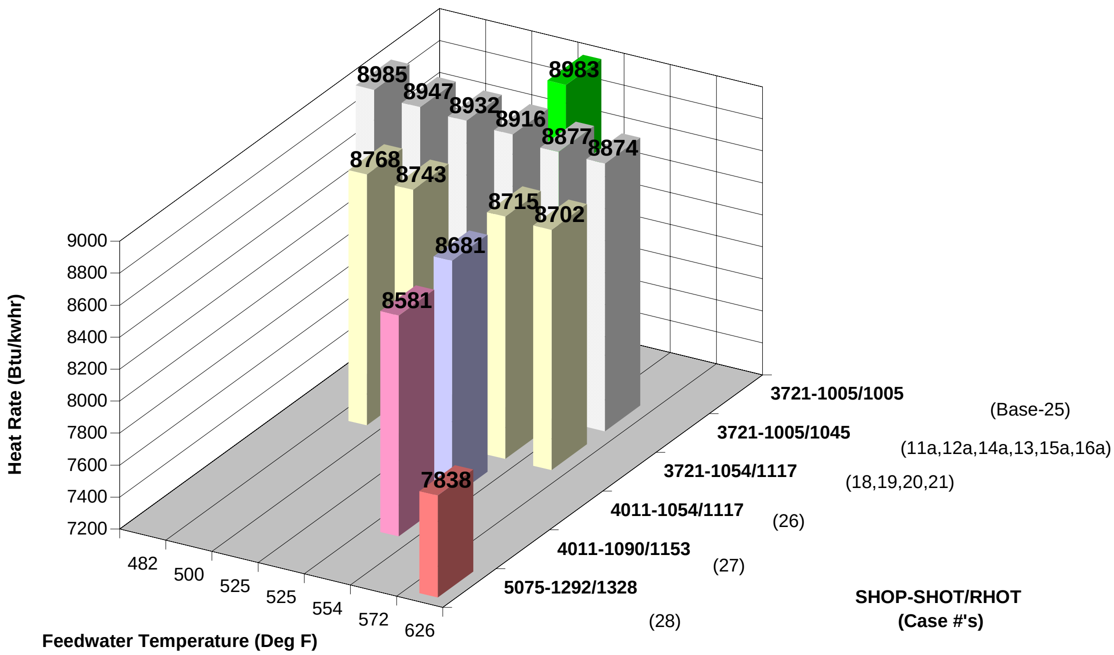



**Figure 2.7. 7: Net Plant Heat Rates (HHV basis) for Supercritical Cycles**

These plots illustrate and quantify the effects on net plant heat rate of changes in steam conditions for pulverized coal fired steam plants. Results for CFB and CMB™ combustion systems would be nearly identical. In general, the transition from a subcritical plant with 2,400 psia main steam pressure to a supercritical plant with 3,625 psia, given constant fuel heat input and the same steam temperatures (i.e. PC-2 vs. PC-3 or Case-7 vs. Case-18) leads to an improvement in thermal efficiency of approximately 2.4%. The ultra high steam conditions case (Case PC-5 or Case 28 on Figure 2.7.2) offers almost 18% thermal efficiency improvement over a conventional subcritical design (Case PC-1 or Case-23).

### 2.7.4 The Effect of Combustion System on Plant Performance:

Three combustion systems were utilized in this study; pulverized coal (PC), circulating fluidized bed (CFB), and circulating moving bed (CMB™). The effect of the combustion system on plant thermal efficiency is quantified in Table 2.7.1 by comparing the cases with common steam cycles. For example, a comparison of cases PC-3, CFB-3, and CMB™ -3 indicates that the PC fired case is essentially equivalent to the CFB case and the CMB™ based plant is about 0.10 percentage points lower. The steam cycle efficiencies for these three cases are identical. Therefore the difference in plant thermal efficiency results from slight differences in boiler efficiency and/or plant auxiliary power.

The boiler efficiency for Case PC-3 is 89.75%, the same as Case CFB-3 (89.75%), and Case CMB™ -3 is 89.26%. The primary contributors to CFB and CMB™ boiler efficiency differences are the calcination and sulfation reactions associated with the CFB and CMB™ cases. In the CMB™ designs, only partial sulfation takes place in the boiler as most of the sulfur is captured in the FDA reactor.

The auxiliary power for Case PC-3 and CFB-3 is about 73 MWe or about 9.9 percent of the generator output. The auxiliary power for Case CMB™ -3 is about 71 MWe or about 9.6 percent of the generator output. The main difference in auxiliary power between cases CFB-3 and CMB™ -3 is due to the fans. The Case CMB™ -3 fans utilize about 97% as much power as Case CFB-3. In comparing the auxiliary power requirements of Case PC-3 to Case CFB-3 several individual differences are apparent, which tend to cancel each other out when totaled. The primary differences occur in the fans, pulverizers (for the PC cases), ash and limestone handling systems, and in the FGD system (used for PC) or FDA system (used for CFB and CMB™) which are used for sulfur removal.

The above comments with respect to the effect of combustion system type on plant thermal efficiency, boiler efficiency, and plant auxiliary power can be further quantified by comparing other cases with common steam cycles (i.e.; PC-2 vs. CFB-2; PC-4 vs. CFB-4; PC-5 vs. CMB™ -5). These additional comparisons indicate nearly the same differences described above and these differences will not be repeated here.

### 2.7.5 Comparison of $CO_2$ Emissions for All Cases:

The following figure shows a comparison of specific $CO_2$ emissions (lbm/kWh) for all the cases. This figure, in combination with the thermal efficiency results shown above, shows the direct correlation of $CO_2$ emissions and plant thermal efficiency. For example, Case PC-5 is about 18% more efficient than Case PC-1 and it also emits about 18% less $CO_2$ per kWh of net output.

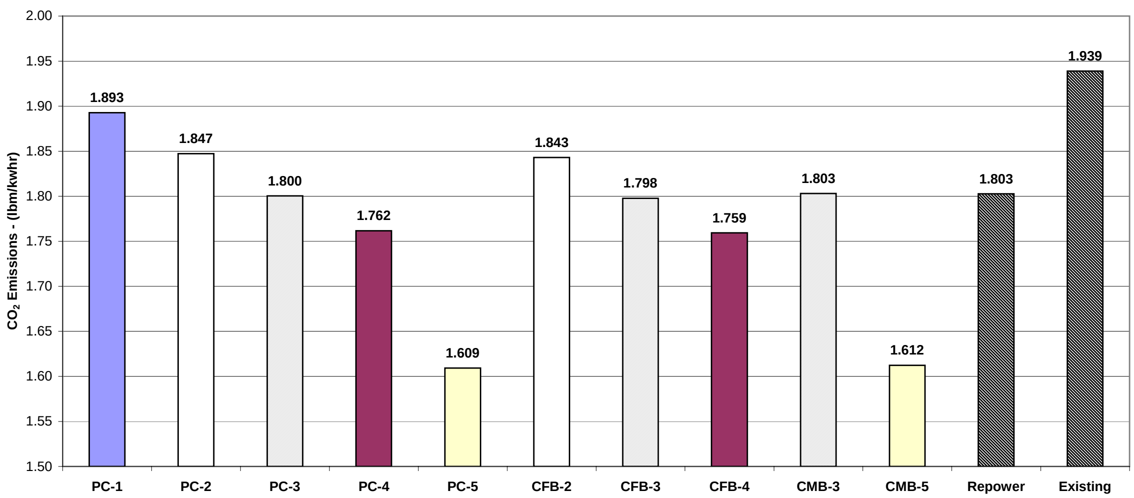



**Figure 2.7. 8: $CO_2$ Emissions (lbm/kWh) – All Cases**

# 3. Cost Analysis

The plant investment cost estimate summaries, including engineering, procurement, and construction (EPC basis), are shown in this section for the eleven (11) power plants included in this study. The EPC basis does not include owner's costs. Owner's costs are, however, included in the economic analysis (Section 4). Operating and Maintenance costs are also shown in this section. The costs are expressed in July 2003 dollars. The level of accuracy of the cost estimates for these conceptual level designs is expected to be about +/- 30 percent.

**Investment Cost Basis:**
These plants are assumed to be constructed on a common Greenfield site in the Gulf Coast region of southeastern Texas. The boundary limit for these plants includes the complete plant facility within the "fence line". It includes the coal receiving and water supply systems and terminates at the high-voltage side of the main power transformers.

The EPC costs for the pulverized coal cases, circulating fluidized bed cases, and circulating moving bed cases include all required equipment, including the traditional Boiler Island equipment, and Balance of Plant equipment (steam turbine, condensate and feedwater system, draft system gas clean-up, material handling, cooling, electrical, instrumentation and control, and misc.).

The cost estimates include equipment, materials, labor, indirect construction costs, and engineering. The labor cost to install the equipment and materials was estimated on the basis of labor man-hours. The labor costing approach was a multiple contract labor basis with the labor cost including direct and indirect labor cost plus fringe benefits and allocations for contractor expenses and markup.

The costs included in the Engineering, CM, H.O. & Fee category consist of professional services and "other costs". Professional services include the cost for engineering, construction management, and startup assistance. The engineering services include all preliminary and detailed engineering and design for the total plant scope. It includes specifying equipment for purchase, procurement, performing project scheduling and cost control services for the project; providing engineering and design liaison during the construction period; and providing startup support. Construction management (CM) services cost includes a field management staff capable of performing all field contract administration; field inspection and quality assurance; project construction control; safety and medical services as required; field and construction insurance administration, field office clerical and administrative support. The "other costs" category includes a cost allowance for freight costs, heavy haul, insurance, taxes, and indirect startup spares.

The investment cost estimates for these plants were calculated based on a combination of vendor-furnished quotes and cost estimating database values. The Boiler Island costs were estimated based on calculated material weights for all components, conceptual equipment arrangement drawings, and equipment lists which were developed as a part of the conceptual design of the required equipment.

The following assumptions were made in developing the EPC cost estimates for each concept evaluated:

- Investment costs are expressed in July 2003 US dollars
- Construction labor rates are based on Gulf Coast non-union rates
- The plant is constructed on a Greenfield site in southeastern Texas
- All costs are based on mature level ($n^{th}$ plant) commercial design

- Owners costs (including interest during construction, start-up fuel, land, land rights, plant licensing, permits, etc.) are not included in the investment costs but are included in the Cost of Electricity analysis
- Ash is to be shipped off site with provisions for short-term storage only
- Investment in new utility systems is outside the scope
- No special limitations for transportation of large equipment
- No protection against unusual airborne contaminants (dust, salt, etc.)
- No unusual wind storms
- No earthquakes
- No piling required
- Annual operating time is 7008 h/yr (80 percent capacity factor).
- The investment cost estimate was developed as a factored estimate based on a combination of vendor quotes and in-house data for the major equipment. Such an estimate can be expected to have an accuracy of +/-30 percent.
- No purchases of utilities or charges for shutdown time have been charged against the project.

Other exclusions from the EPC investment cost estimate are as follows:

- Fuels required for startup
- Relocation or removal of buildings, utilities, and highways
- Permits
- Land and land rights
- Soil investigation
- Environmental Permits
- Disposal of hazardous or toxic waste
- Disposal of existing materials
- Custom's and Import duties
- Sales/Use tax.
- Forward Escalation
- Capital spare parts
- Chemical loading facilities
- Financing cost
- Owners costs
- Guards during construction
- Site Medical and Ambulance service
- Cost & Fees of Authorities
- Overhead High voltage feed lines
- Cost to run a natural gas pipeline to the plant
- Excessive piling

Overall plant investment costs and the associated specific plant investment costs ($/kW) can vary quite significantly for any given plant design depending on several factors. Some of the more important factors are listed below.

- Plant Location and Site Conditions
- Construction Labor Basis
- Coal Analysis
- Ambient Conditions

For the cases in this study, the design coal analysis, design ambient conditions, plant location and site conditions are described in Section 2.1 under Plant Design Basis. The construction labor basis used is Gulf Coast non-union. The sensitivity of plant specific cost to construction labor basis is indicated by observing that for these studies, changing from Gulf Coast non-union to

Ohio River Valley union basis, for example, would increase the EPC plant costs by about 20 percent.

**Operating and Maintenance Costs Basis:**
Operating and Maintenance (O&M) costs are calculated for each plant and are listed as either fixed or variable. The fixed costs are those costs which are incurred irrespective of the number of hours of plant operation, whereas the variable costs are directly proportional to the operating hours. The variable operating and maintenance (VOM) costs for the new equipment included such categories as chemicals, waste handling, maintenance material and labor, supplemental fuel usage, and contracted services. The fixed operating and maintenance (FOM) costs for the new equipment includes operating labor only.

The O&M costs for the power plant equipment was developed quantitatively by Parsons and ALSTOM. Operating labor cost was calculated based on the number of operator jobs (O.J.) required. Table 3.0.1 shows the operating labor requirements for both the Greenfield plants and Sporn Unit #4. The operating labor requirements shown for Sporn Unit #4 were used for both the repowering and existing cases.

**Table 3.0. 1: Operating Labor Requirements**

| Operating Labor Requirements (O.J.) per shift | Greenfield | Sporn Unit #4 |
|---|---|---|
| Skilled Operator | 2 | 1 |
| Operator | 9 | 7 |
| Foreman | 1 | 1 |
| Lab Tech's, etc. | 2 | 1 |
| TOTAL Operator Jobs (O.J.'s) | 14 | 10 |

The average labor rate used to determine the annual cost was 30.90 $/hr, with a labor burden of 30 percent. The labor administration and overhead cost was assessed at a rate of 25 percent of the O&M labor. Maintenance cost was evaluated as a percentage of the initial capital cost.

**Consumable Costs Basis:**
Consumable costs including fuel, limestone, ammonia, water, and chemicals were determined on the basis of individual flow rates as listed in the material and energy balances, individual unit costs (listed below), and the plant annual operating hours. Waste disposal cost was also based on flow rates from the material and energy balances, unit costs, and operating hours.

- Coal cost - 1.25 $/MM-Btu
- Limestone cost - 10.00 $/Ton
- Ammonia cost – 150.00 $/Ton
- Water cost - 1.00 $/1,000 gallons
- Water Treatment Chemicals cost - 0.16 $/lbm
- Ash Disposal cost - 8.00 $/Ton
- By-product credits were not considered for these cases

## 3.1 Greenfield Cases Investment Costs

The estimated investment cost for each Greenfield case includes all major ALSTOM and vendor supplied components. The investment cost was first estimated for cases PC-3, CFB-3, and CMB™ -3. The plant cost for each other case was determined by estimating new absolute costs or cost differences from the Base Cases for the components that required modifications because of changes in combustion system, gas cleanup system, steam cycle system, electrical, and feedwater system design parameters. The cost differences were then added to the cost of the corresponding Base Cases components to generate the cost for the other cases.

In estimating the costs, following assumptions were made:

- The configuration of components was similar to the Base Case designs and the structure of all buildings remained unchanged for all cases.
- Within a given combustion system group (PC, CFB, or CMB™), the locations of the terminal points for pipe connections to the steam generator were the same for all subcritical cases. Similarly, this assumption was also made for supercritical designs.
- For the PC cases, the cold reheat connection for the subcritical designs was in front of the boiler while for the supercritical designs the same connection was in the boiler backpass.
- Location of the terminal points for the steam turbines was the same for all cases.
- Electrical components (except for the generator, transformer and large motors) and the instrumentation and controls package remained unchanged among the cases.

### 3.1.1 Total Plant Investment Costs:

The total plant investment cost breakdown for the ten (10) Greenfield plants are summarized in Table 3.1.1 and these results are illustrated on Figure 3.1.1. These costs were developed consistent with the approach and basis identified in the design basis. The capital cost estimate (EPC basis) is expressed in July 2003 dollars.

## Table 3.1. 1: Total Plant Investment Cost Summary for the Greenfield Cases

| Acct | | Case PC-1 | | Case PC-2 | | Case PC-3 | | Case PC-4 | | Case PC-5 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Item/Description | $ x 1000 | $/kW | $ x 1000 | $/kW | $ x 1000 | $/kW | $ x 1000 | $/kW | $ x 1000 | $/kW |
| 1 | COAL & SORBENT HANDLING | 28,275 | 45 | 28,275 | 44 | 28,275 | 43 | 28,275 | 42 | 28,275 | 38 |
| 2 | COAL & SORBENT PREP & FEED | 22,262 | 35 | 22,262 | 34 | 22,262 | 34 | 22,262 | 33 | 22,262 | 30 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 45,686 | 72 | 47,010 | 73 | 47,834 | 72 | 49,024 | 72 | 52,523 | 71 |
| 4 | BOILER & ACCESSORIES | 128,693 | 204 | 129,534 | 200 | 132,145 | 199 | 134,345 | 198 | 199,460 | 269 |
| 5 | FLUE GAS CLEANUP | 136,384 | 216 | 136,384 | 211 | 136,384 | 206 | 136,384 | 201 | 136,384 | 184 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 34,160 | 54 | 34,160 | 53 | 34,160 | 52 | 34,160 | 50 | 34,160 | 46 |
| 8 | STEAM TURBINE GENERATOR | 104,782 | 166 | 111,507 | 173 | 115,360 | 174 | 120,839 | 178 | 174,326 | 235 |
| 9 | COOLING WATER SYSTEM | 38,723 | 61 | 38,581 | 60 | 38,415 | 58 | 38,240 | 56 | 37,773 | 51 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 34,358 | 54 | 34,358 | 53 | 34,358 | 52 | 34,358 | 51 | 34,358 | 46 |
| 11 | ACCESSORY ELECTRIC PLANT | 39,585 | 63 | 39,702 | 61 | 40,229 | 61 | 40,516 | 60 | 41,324 | 56 |
| 12 | INSTRUMENTATION & CONTROL | 22,780 | 36 | 22,780 | 35 | 22,780 | 34 | 22,780 | 34 | 22,780 | 31 |
| 13 | IMPROVEMENTS TO SITE | 13,810 | 22 | 13,810 | 21 | 13,810 | 21 | 13,810 | 20 | 13,810 | 19 |
| 14 | BUILDINGS & STRUCTURES | 68,867 | 109 | 68,867 | 107 | 68,867 | 104 | 68,867 | 102 | 68,867 | 93 |
| | **TOTAL COST** | **718,365** | **1,139** | **727,231** | **1,126** | **734,880** | **1,109** | **743,861** | **1,098** | **866,303** | **1,168** |

| Acct | | Case CFB-2 | | Case CFB-3 | | Case CFB-4 | | Case CMB-3 | | Case CMB-5 | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Item/Description | $ x 1000 | $/kW | $ x 1000 | $/kW | $ x 1000 | $/kW | $ x 1000 | $/kW | $ x 1000 | $/kW |
| 1 | COAL & SORBENT HANDLING | 28,867 | 45 | 28,867 | 43 | 28,867 | 43 | 28,867 | 43 | 28,867 | 39 |
| 2 | COAL & SORBENT PREP & FEED | 23,414 | 36 | 23,414 | 35 | 23,414 | 35 | 23,414 | 35 | 23,414 | 31 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 47,010 | 73 | 47,834 | 72 | 49,024 | 72 | 47,834 | 72 | 52,523 | 71 |
| 4 | BOILER & ACCESSORIES | 146,955 | 227 | 150,114 | 226 | 159,692 | 235 | 138,887 | 209 | 179,650 | 241 |
| 5 | FLUE GAS CLEANUP | 61,889 | 96 | 61,889 | 93 | 61,889 | 91 | 61,889 | 93 | 61,889 | 83 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 34,160 | 53 | 34,160 | 51 | 34,160 | 50 | 34,160 | 51 | 34,160 | 46 |
| 8 | STEAM TURBINE GENERATOR | 111,507 | 172 | 115,360 | 174 | 120,839 | 178 | 115,360 | 173 | 164,939 | 222 |
| 9 | COOLING WATER SYSTEM | 38,581 | 60 | 38,415 | 58 | 38,240 | 56 | 38,415 | 58 | 37,773 | 51 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 43,037 | 66 | 43,037 | 65 | 43,037 | 63 | 43,037 | 65 | 43,037 | 58 |
| 11 | ACCESSORY ELECTRIC PLANT | 39,702 | 61 | 40,229 | 61 | 40,516 | 60 | 40,229 | 60 | 41,324 | 56 |
| 12 | INSTRUMENTATION & CONTROL | 22,780 | 35 | 22,780 | 34 | 22,780 | 34 | 22,780 | 34 | 22,780 | 31 |
| 13 | IMPROVEMENTS TO SITE | 13,810 | 21 | 13,810 | 21 | 13,810 | 20 | 13,810 | 21 | 13,810 | 19 |
| 14 | BUILDINGS & STRUCTURES | 68,867 | 106 | 68,867 | 104 | 68,867 | 102 | 68,867 | 103 | 68,867 | 93 |
| | **TOTAL COST** | **680,579** | **1,051** | **688,776** | **1,038** | **705,135** | **1,039** | **677,549** | **1,018** | **773,033** | **1,039** |

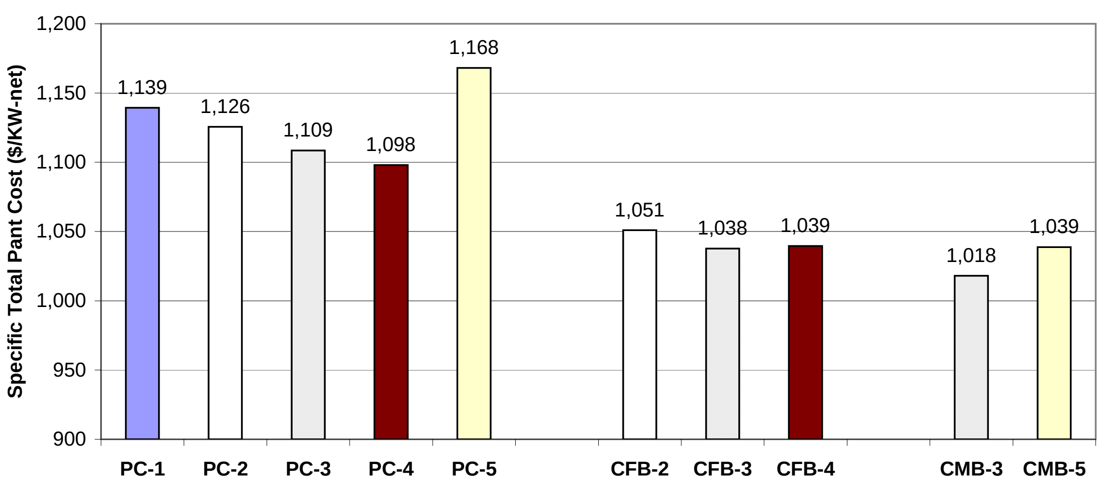



**Figure 3.1. 1: EPC Plant Costs – Summary of all Cases**

Specific investment costs for the entire spectrum of Greenfield cases range from 1,018 – 1,168$/kW-net. The incremental cost of the repowering case is 413 $/kW-net. Taken as groups, the effect of combustion system (PC, CFB, or CMB$^{TM}$) on specific investment cost ($/kW-net) were as follows:

- There was about a 7% difference between the total plant specific investment costs for the PC and CFB combustion systems (PC-2 vs. CFB-2; PC-3 vs. CFB-3; PC-4 vs. CFB-4) with the CFB cases being lower. The investment cost difference was primarily attributable to cost differences in the gas cleanup system.

- The CMB™ combustion system was shown to have slightly lower total plant investment cost than the CFB system (CMB™ -3 vs. CFB-3). It requires also about 8-11% less investment cost than the PC power plant (CMB™ -3 vs. PC-3, CMB™ -5 vs. PC-5). The lower investment cost is attributed to the lower cost of the back-end installed clean-up systems (SCR, ESP, and wet FGD for the PC and SNCR and FDA for the CMB™) the use of the finned tube surfaces, and the reduction in application of the Ni materials for the design of the ultra-supercritical cases.

Similarly, the effect of steam cycle parameters on total plant specific investment cost ($/kW-net) were as follows:

- The higher temperatures and pressures generally were shown to reduce specific investment costs ($/kW) slightly as the increase in net output was enough to more than break even with the increase in investment cost.

- This trend held true for all cases except for the cases with ultra-supercritical steam conditions (Cases PC-5 and CMB™ -5) where the higher temperature and pressure of these cases increased the total plant specific investment cost significantly. It should be emphasized however that the costs for the ultra-supercritical cases are somewhat more uncertain because of the use of the Ni based alloys. This cost uncertainty for these alloys is discussed further and results of a sensitivity study are shown in Section 4.

The procedure involved in developing cost estimates for the individual components is briefly explained in the sections below. Unless otherwise specified a linear cost behavior for the component cost as a function of the output was assumed. This may lead to inaccuracies for individual components, but totaling the individual costs minimizes any errors. Otherwise, the results would be invalid if cost jumps (step changes in cost) were not smoothed out; the results would then be exact only for the particular output range concerned.

### 3.1.2 Boiler Island Costs:

The total Boiler Island cost for each case was computed on the basis of the cost differential between the Base Cases (Case PC-3, CFB-3, CMB™ -3) and all other cases. In developing the Boiler Island costs the following assumptions were made:

- Within a given combustion system group (PC, CFB, or CMB™), fuel, sorbent, air, and flue gas dependent components were the same for all cases.

- Within a given combustion system group (PC, CFB, or CMB™), the number of wallblowers and sootblowers were the same for all cases.

- Steam loading per foot of drum length was constant for all subcritical designs.

- Header velocities were similar for all cases.

- To simplify cost analyses tube intermesh for heat transfer surfaces was consistent with the base case within a given combustion system group (PC, CFB, or CMB™).

- Potential changes in the circulation system design due to differences in the superheat steam flow for subcritical designs were assumed to be too small to effect cost differences among subcritical designs and were neglected.

- Similarly, design differences between the circulation and start-up systems designs for supercritical units were neglected.

For each case, in addition to the cost of the heat transfer surfaces, estimates were made to account for changes in drum length (subcritical pressure), headers and connecting links diameters and materials, and the steam cooled back - pass height.

Figure 3.1.2 shows the specific ($/kW) boiler costs (Account 4) for all Greenfield cases. Account 4 includes the boiler, boiler structure, boiler foundations, and fans. The shading and case numbers in this figure indicates common steam cycles. In general, an increase in steam parameters (Temperature and Pressure) causes a slight decrease in the specific boiler costs as the increase in net output was greater, on a relative basis, than the increase in investment cost. This trend held true except for the ultra-supercritical cases (PC-5, CMB™ -5).

The costs of the PC-5 and CMB™ -5 boiler are not easily determined since both of these designs require high strength Ni based alloys. These alloys have not been used by the boiler industry in the past and the costs for tubing, piping, plates, fabrication, and welding are very uncertain. These materials, including fabrication techniques, are being investigated under the DOE sponsored program, " Boiler Materials for Ultra-supercritical Coal Fired Plants". For the economic analysis, the cost of these alloys was assumed to be at $28.00/lbm. Because of the uncertainty involved with the costs, an economic sensitivity study was performed at two other costs of $20.00/lbm and $32.90/lbm (see Section 4.3.4).

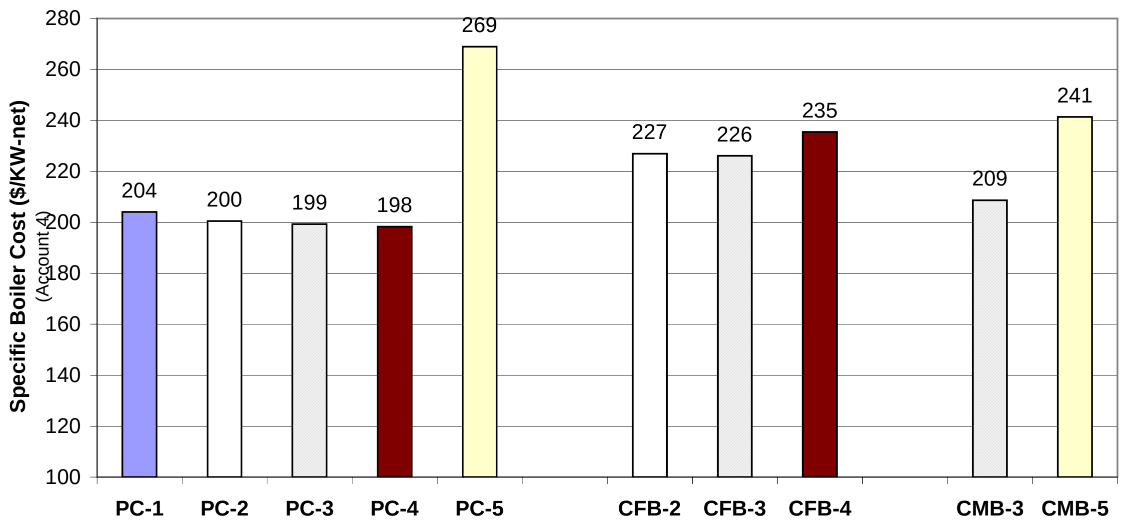



**Figure 3.1. 2: Specific Boiler Costs (Account 4)**

Similarly, Figure 3.1.3 shows the specific Boiler Island costs, which include the boiler, the flue gas cleanup equipment, ducting and stack (Accounts 4, 5 and 7 respectively). Again, an increase in steam parameters (Temperature and Pressure) causes a slight decrease in the specific Boiler Island specific costs as the increase in net output was greater, on a relative basis, than the increase in investment cost except for the ultra-supercritical cases (PC-5, CMB™ -5).

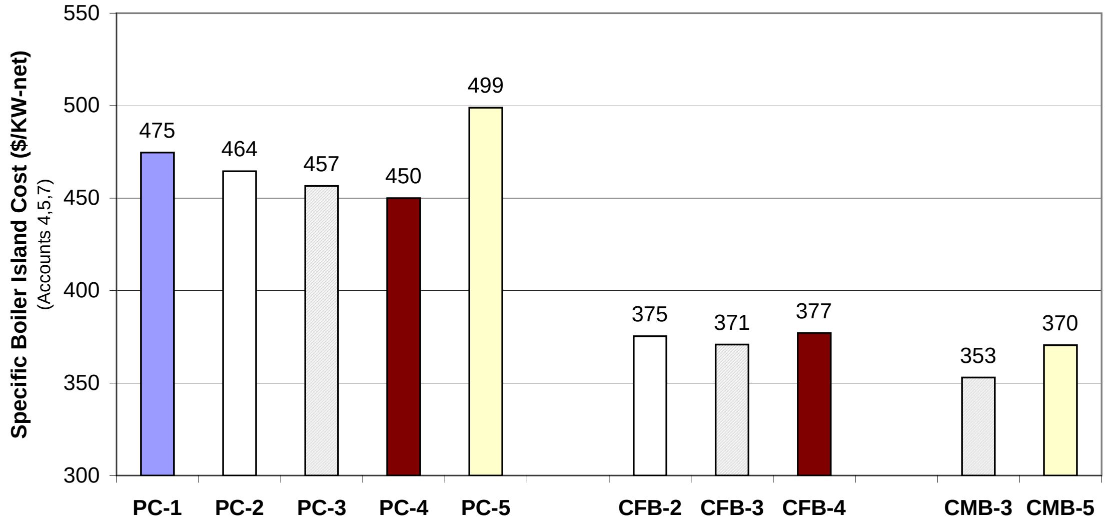



**Figure 3.1. 3: Specific Boiler Island Costs (Accounts 4, 5 and 7)**

### 3.1.3 Turbine Island Costs:

The total Turbine Island cost for each case was computed on the basis of the cost differential between the Base Case (Case PC-3) and all other cases. In developing the Turbine Island costs the following assumptions were made:

- Steam Turbine:
  The procedure used to develop the costs for the steam turbine was the same as for formal quotation preparation.

- Generators:
  Two types of generators cover the entire output range (50 MT 23E-120 and 50 MT 23E – 138). The prices for these two generators differ by 1.7 %. Due to this relatively insignificant difference, the average value was used for the base case. Other cases were proportioned to the output.

- Feedwater Heaters:
  The data from the steam turbine balances were used to select all feedwater heaters. Weights were determined for casings and tubing and costs were obtained.

- Condenser, Cooling Water System:
  The condenser of the Base Case was dimensioned in the same fashion as the heaters, and the costs were estimated. The costs for the other cases were linearly proportioned to the heat rejection.

- Piping, incl. Valves and Insulation, Bypass Equipment:
  Calculations included piping costs for main steam, hot reheat, cold reheat extraction steam, and feedwater. The piping design (diameter, wall-thickness, and material) is individually adapted to the physical parameters (mass flow, pressure, and temperature). Ni based alloy piping was estimated at $28.00/lbm. An economic sensitivity study was performed at $20.00/lbm and $32.90/lbm also (see Section 4.3.4).

- Other Equipment:
  For the supercritical cases a high-pressure and low-pressure bypass system (each 2 x 50 %) have been estimated.

- For the supercritical cases the cost for a condensate polishing plant was estimated.

- The price for the main transformer and station-service transformer for the Base Case were estimated. The costs for the other cases were linearly proportioned to the net output and the unit auxiliary power consumption respectively.

Figure 3.1.4 shows the specific ($/kW-net) turbine costs (Account 8) for all Greenfield cases. Account 8 includes the steam turbine, generator, condenser, steam piping and turbine generator foundations. The shading in this figure indicates common steam cycles. In general, an increase in steam parameters (Temperature and Pressure) causes a slight increase in the specific turbine costs as the increase in net output was smaller, on a relative basis, than the increase in investment cost. The ultra high steam conditions of cases PC-5 and CMB™ -5 however were shown to cause about a 35% and 28% increase in specific turbine cost as compared to cases PC-3 and CMB™ -3 respectively. The smaller increase for the CMB™ case as compared to the PC case is due to shorter steam piping runs for the CMB™ cases.

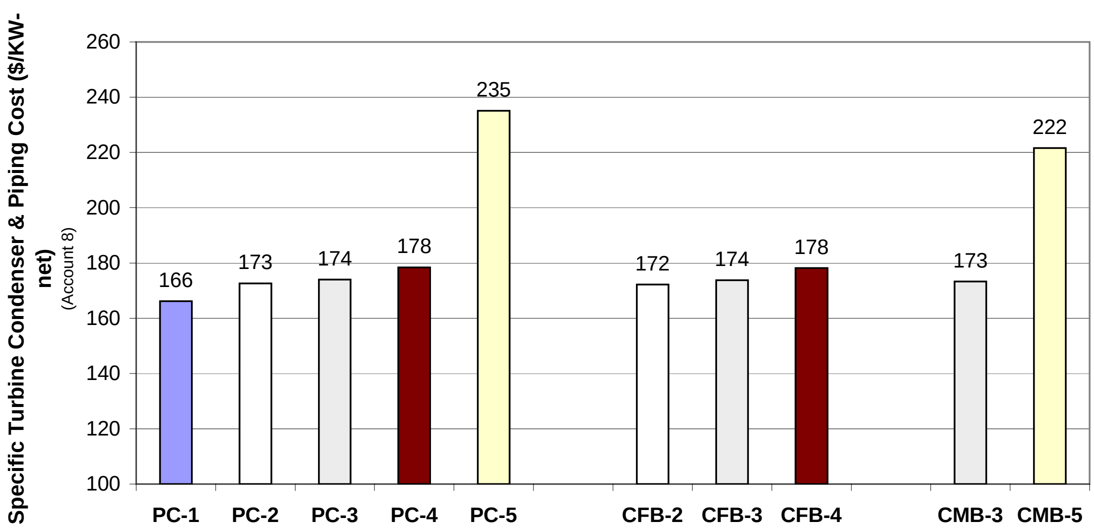



**Figure 3.1. 4: Specific Turbine Costs (Account 8)**

Similarly, Figure 3.1.5 shows the specific Turbine Island costs, which include the turbine generator system, feedwater system, cooling water system, and the accessory electrical equipment (Accounts 8, 3, 9 and 11 respectively). Here, the increased turbine costs shown above associated with increased steam conditions are compensated for by decreases in feedwater system, cooling water system, and the accessory electrical equipment specific costs for all cases except PC-5 and CMB™ -5. The ultra high steam conditions of cases PC-5 and CMB™ -5 were shown to cause about a 13% and 10% increase in specific Turbine Island cost as compared to cases PC-3 and CMB™ -3 respectively.

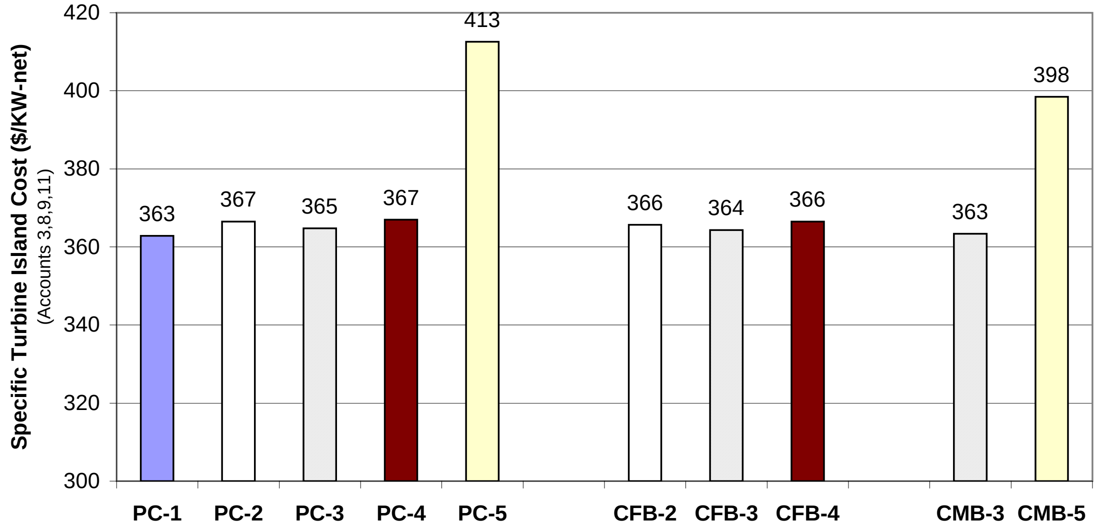



**Figure 3.1. 5: Specific Turbine Island Costs (Accounts 8, 3, 9, and 11)**

### 3.1.4 Other Balance of Plant Equipment Costs:

Figure 3.1.6 shows the specific costs for "other BOP equipment". This includes the coal and sorbent handling system, the coal and sorbent preparation and feed system, the ash and spent sorbent handling system, the instrumentation and control system, improvements to the site, and the buildings and structures (Accounts 1, 2, 10, 12, 13, and 14 respectively). Here, the other BOP equipment costs shown in Table 3.1.1 above are constant within a given combustion system group and the increased output associated with improved steam conditions causes a significant reduction in the specific costs as shown.

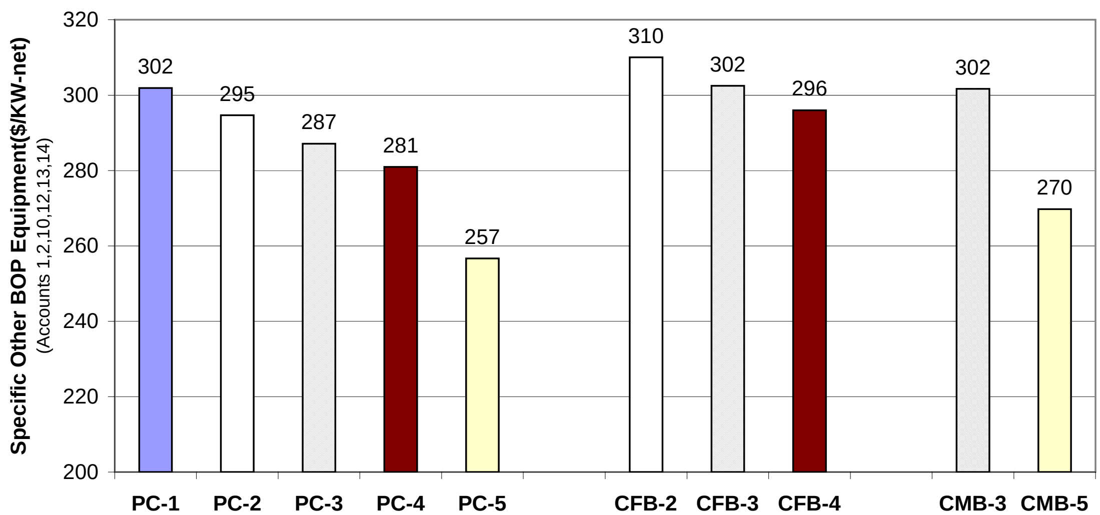



**Figure 3.1. 6: Specific Other BOP Equipment Costs (Accounts 1, 2, 10, 12, 13, and 14)**

## 3.2 Repowering Case Investment Costs

The total plant investment cost breakdown for the Sporn Unit #4 repowering case is summarized in Table 3.2.1. A more detailed breakdown is shown in Appendix III. These costs were developed consistent with the approach and basis identified in the design basis. The capital cost estimate (EPC basis) is expressed in July 2003 dollars. The following list indicates the major items included in the equipment scope.

- CMB™ Boiler
- Topping Steam Turbine
- Main Steam Piping
- FW booster pump
- Condensate polishing system
- Coal feed system
- Air fans and blowers
- Transformer
- Ductwork and dampers
- Feedwater and steam piping

**Table 3.2. 1: Total Plant Investment Cost Summary for the Repowering Case**

| Equipment Description | Installed Cost | $/kW net | $/kW incr |
|---|---|---|---|
| **Boiler:** | 54,182,000 | 293.1 | 1909.9 |
| **Topping Turbine/Generator:** | 10,725,000 | 58.0 | 378.1 |
| **Balance of Plant Equipment:** | 5,607,000 | 30.3 | 197.6 |
| **Piping:** | 5,830,000 | 31.5 | 205.5 |
| **TOTAL COST** | **76,344,000** | **413** | **2,691** |

The two columns on the right side of Table 3.2.1 show specific investment costs expressed as $/kW-net and $/kW-incremental. These totals are 413 $/kW-net and 2,691 $/kW-incremental respectively.

The vast majority of the investment costs (about 85%) are for the new CMB™ Boiler and new topping steam turbine/generator. Lesser amounts are expended for the balance of plant equipment, which includes new feedwater booster pumps, the coal feed system, topping turbine transformer, and new ductwork/dampers from the new boiler to the existing electrostatic precipitator.

Piping is also broken out as a separate account in Table 3.2.1, as this also represents a significant expense. The piping account includes the following major items:

- A link from the existing condensate pumps to the Demineralizer.
- A link from the Demineralizer to the existing #1 feedwater heater.
- Main steam piping from the new CMB™ boiler to the new topping turbine.
- A link from the new topping turbine exhaust to the existing HP turbine inlet.
- New reheater inlet and reheater outlet links.
- A link from the new feedwater booster pump to the new economizer.

The cost estimate presented for this repowering case assumes that the existing Sporn Unit #4 boiler is left in place and the new CMB™ boiler is located on available land adjacent to the existing Unit #4 boiler building. ALSTOM estimated the cost for the new CMB™ boiler and new topping steam turbine. AEP estimated the balance of plant costs. Additional assumptions and exclusions from the AEP cost estimate are listed below:

- Construction Equipment: Erection of large prefabricated pieces was assumed.
- General site preparation including moving the lab building and providing construction access and permanent access was not included in the AEP estimate.
- Cost of construct management was not included in the AEP estimate.
- Permits were not included in the AEP estimate.
- Refurbishment of existing equipment to obtain lifetime and availability goals consistent with the new equipment was not included in the AEP estimate.
- Contingency was not included in the AEP estimate.

## 3.3 Operating and Maintenance Costs

The production costs consist of plant operating labor, maintenance (material and labor), an allowance for administrative and support labor, consumables, solid waste disposal, and fuel costs. The production cost and expenses were developed on a first-year basis with a July 2003 plant in-service date. The costs were determined assuming an equivalent plant operating capacity factor of 80 percent.

The operating and maintenance (O&M) results for the ten (10) Greenfield plants, the Sporn Unit #4 repowering case, and the unmodified existing Sporn Unit #4 are summarized in Table 3.3.1.

**Table 3.3. 1: Total Plant Operating and Maintenance Costs**

| Case Number | Operating & Maintenance (O&M) Costs | | | | | Annual Generation ($10^6$ kWh) | Total O&M (Cents/kWh) |
|---|---|---|---|---|---|---|---|
| | Fixed | | Variable @ 80% CF | | Total | | |
| | ($/year) | ($/kW) | ($/year) | ($/kWh) | ($/year) | | |
| **Case PC-1** | 9,639,466 | 15.3 | 18,326,741 | 0.0041 | 27,966,208 | 4,419 | 0.633 |
| **Case PC-2** | 9,683,793 | 15.0 | 18,369,295 | 0.0041 | 28,053,088 | 4,528 | 0.620 |
| **Case PC-3** | 9,722,038 | 14.7 | 18,406,010 | 0.0040 | 28,128,048 | 4,646 | 0.605 |
| **Case PC-4** | 9,766,944 | 14.4 | 18,449,120 | 0.0039 | 28,216,064 | 4,748 | 0.594 |
| **Case PC-5** | 10,379,154 | 14.0 | 19,036,841 | 0.0037 | 29,415,995 | 5,197 | 0.566 |
| **Case CFB-2** | 9,531,512 | 14.7 | 12,723,866 | 0.0028 | 22,255,378 | 4,538 | 0.490 |
| **Case CFB-3** | 9,572,495 | 14.4 | 12,763,210 | 0.0027 | 22,335,705 | 4,652 | 0.480 |
| **Case CFB-4** | 9,654,292 | 14.2 | 12,841,735 | 0.0027 | 22,496,027 | 4,754 | 0.473 |
| **Case CMB-3** | 9,516,360 | 14.3 | 12,724,400 | 0.0027 | 22,240,761 | 4,664 | 0.477 |
| **Case CMB-5** | 9,993,780 | 13.4 | 13,182,724 | 0.0025 | 23,176,504 | 5,216 | 0.444 |
| **Sporn #4 Repowering** | 5,543,775 | 30.0 | 2,512,502 | 0.0018 | 8,056,277 | 1,377 | 0.585 |
| **Sporn #4 Existing** | 5,543,775 | 35.4 | 2,137,534 | 0.0018 | 7,681,309 | 1,165 | 0.659 |

The range of O&M costs for the Greenfield cases is from 0.44 – 0.63 Cents/kWh. The O&M costs for the existing unmodified Sporn Unit #4 is shown in addition to the repowering case since it was utilized to calculate the incremental cost of electricity for the repowering case. A more detailed breakdown of the individual O&M costs for each case is shown in Appendix III.

# 4. Economic Analysis

A comprehensive economic evaluation comparing the various Rankine cycle power plants was performed. These comparisons were done for three types of plants (PC, CFB, and CMB$^{TM}$). In addition the economics of repowering an existing coal fired plant with a new CMB$^{TM}$ boiler and supercritical topping steam turbine was also investigated. An economic sensitivity analysis was also completed for all cases.

The purpose of the evaluation was to quantify the impact of steam cycle and boiler type on the Cost of Electricity (COE) of new Greenfield coal fired plants including PC, CFB, and advanced CMB$^{TM}$ type units. Additionally a comparison between all cases is also provided. The economic evaluation results are presented as Costs of Electricity (levelized basis).

The model used to perform the economic evaluations is the proprietary ALSTOM Power Plant Laboratories' Project Economic Evaluation Pro-Forma Model. This cash flow model, developed by the Company's Project & Trade Finance group, has the capability to analyze the economic effects of different technologies based on differing efficiencies, investment costs, operating and maintenance costs, fuel costs, and cost of capital assumptions. Various categories of results are available from the model. In addition to cost of electricity, net present value, project internal rate of return, payback period, and other evaluation parameters are available.

## 4.1 Economic Analysis Assumptions

Numerous financial assumptions were required in performing the economic evaluations. These assumptions are listed in Table 4.1.1. The assumptions are grouped in the Greenfield cases and the repowering case. The parameters that vary between the Greenfield cases and the repowering case are availability factor, fuel cost, interest rate, and discount factor. All other financial inputs are equivalent for all cases.

The 30-month construction period of the PC and CFB systems are known from the experience in the industry. The construction period for the CMB$^{TM}$ systems is thought to be similar to the CFB systems since the system complexity is very similar. The construction period for the repowering case is 30-month based on a CMB$^{TM}$ system.

Table 4.1.1 summarizes the primary technical and financial assumptions used in the model for the Greenfield and repowering cases. Items that are indicated as "Case Sensitive" are discussed in the corresponding case study section of this report. Items shaded in yellow represent parameters that were varied in the economic sensitivity study (Section 4.3.4).

**Table 4.1. 1: Economic Evaluation Study Assumptions**

| | PC, CFB, and CMB Systems - Cases PC-1, PC-2, PC-3, PC-4, PC-5, CFB-2, CFB-3, CFB-4, CMB-3, CMB-5 | Base and Repowering |
|---|---|---|
| **POWER GENERATION** | | |
| Net output (MW) | Case Sensitive | Case Sensitive |
| Capacity factor (%) | 100% | 100% |
| Availability factor (%) | 80% | 85% |
| Net plant heat rate, HHV (Btu per kWh) | Case Sensitive | Case Sensitive |
| Degradation factor (%) | 0.0% | 0.0% |
| **TIME FRAME** | | |
| Construction period (months) | 30 | 30 |
| Depreciation Term (years) | 30 | 20 |
| Analysis Horizon (years) | 30 | 20 |
| **PROJECT COSTS** | | |
| EPC Price ($1000s) | Case Sensitive | Case Sensitive |
| High Temperature Alloy Costs ($/lb) [1] | 28.00 | 28.00 |
| Fixed O&M costs ($ per kW) | Case Sensitive | Case Sensitive |
| Variable O&M costs (cents per kWh) | Case Sensitive | Case Sensitive |
| Owner's EPC Contingency | 0.0% | 0.0% |
| Initial spares and consumables | 1.0% | 1.0% |
| Insurance | | |
| Insurance during Construction | 1.0% | 1.0% |
| Insurance during first year of operation | 0.5% | 0.5% |
| Development Costs | | |
| Development Costs & Fees | 4.0% | 4.0% |
| Reimburseable Dev't Costs | 3.0% | 3.0% |
| Advisory Fees | 3.0% | 3.0% |
| Financial and Legal Fees | 3.0% | 3.0% |
| Start-up Fuel | 0.5% | 0.5% |
| Fuel Stock Pile | 0.5% | 0.5% |
| Other Costs | 0.5% | 0.5% |
| Total Initial Project Costs (% of EPC) | 17.0% | 17.0% |
| **FUEL COST** | | |
| Coal Price ($ per MMBtu) | 1.25 | 1.27 |
| **EMISSIONS CREDITS** | | |
| NOx ($ per ton) | N/A | 0 |
| SOx ($ per ton) | N/A | 0 |
| **ESCALATION FACTORS** | | |
| Coal Price | 0.0% | 0.0% |
| Variable O&M | 0.0% | 0.0% |
| Fixed O&M (including payroll) | 0.0% | 0.0% |
| Consumer Price Index | 0.0% | 0.0% |
| **FINANCING ASSUMPTIONS** | | |
| Equity | 50.0% | 50.0% |
| Debt | 50.0% | 50.0% |

| | PC, CFB, and CMB Systems - Cases PC-1, PC-2, PC-3, PC-4, PC-5, CFB-2, CFB-3, CFB-4, CMB-3, CMB-5 | Base and Repowering |
|---|---|---|
| **DEBT PORTFOLIO** | | |
| Interest Rates (Financed) [2] | | |
| During Construction | | |
| Base Rate | 1.32% | 2.22% |
| Swap/Reinvestment cushion | 1.28% | 1.28% |
| Fixed Rate Margin | 3.00% | 3.00% |
| All-In Fixed Rate | 5.60% | 6.50% |
| During Operation | | |
| Base Rate | 1.32% | 2.22% |
| Swap/Reinvestment cushion | 1.28% | 1.28% |
| Fixed Rate Margin | 2.50% | 3.00% |
| All-In Fixed Rate | 5.10% | 6.50% |
| Up-front Fee (Financed) | 2.0% | 2.0% |
| Commitment Fee | 1.0% | 1.0% |
| Grace Period (months) | 0 | 0 |
| Loan Tenor (years after construction) | 30 | 30 |
| **TAXES** | | |
| Corporate Tax | 20.0% | 20.0% |
| Tax holiday (years after commissioning) | 0.0% | 0.0% |
| Customs Duty | 0.0% | 0.0% |
| Customs Clearance Fee | 0.0% | 0.0% |
| **COST OF CAPITAL ASSUMPTIONS** | | |
| Discount Factor | 10.0% | 15.0% |
| **PROGRESS PAYMENT SCHEDULES** | | |
| Month | | |
| 1 | 10% | 10% |
| 8 | 15% | 15% |
| 10 | | |
| 16 | | |
| 17 | 25% | 25% |
| 20 | | |
| 22 | 20% | 20% |
| 25 | | |
| 26 | 20% | 20% |
| 30 | 10% | 10% |
| 31 | | |
| 32 | | |
| 36 | | |
| 41 | | |
| 48 | | |
| Total | 100% | 100% |

[1] PC-5, CMB-5, and Repowering Cases Only
[2] Wall Street Journal, 4/23/03, London Interbank Offered Rate (LIBOR) Swap Curve

## 4.2 Cost of Electricity Calculation

Levelized cost of electricity (COE) was used as one criterion to compare the systems in this study. The cost of electricity result consists of the following components: financial, fixed O&M, variable O&M, and fuel. The cash flow model is structured to calculate the corresponding annual cash flows for each of these items over the evaluation life of the project. The annual expenses are distributed over the corresponding net annual electricity generated (kWh/year) in order to determine a unit cost (cents/kWh). These costs are subsequently levelized to get a corresponding value of each component over the plant life. In other words, each of the cash flow streams is converted to annuity payments corresponding to a constant value over the life of the study.

The financial component of the COE represents the costs which are associated with payment of the original engineered, procured and constructed (EPC) price, all associated owner's costs, custom's and financing fees, and interests accrued both during construction and during operation. The fixed O&M component represents the costs that occur regardless of whether the unit is in operation or not. The variable O&M component represents the incremental costs which occur when the unit is in operation. The fuel cost component represents the cost of the fuel, which is consumed by a given technology.

## 4.3 Economic Analysis Results

The economic analysis results of the PC systems are discussed in Section 4.3.1. The CFB and CMB$^{TM}$ systems are discussed in Section 4.3.2. The Repowering system is discussed in Section 4.3.3. The case studies are compared using levelized cost of electricity (COE) evaluation criterion.

### 4.3.1 Pulverized Coal Fired Cases

The levelized COE for the PC systems is summarized in Table 4.3.1. The supercritical cases PC-3, PC-4and PC-5 have relatively low production costs among the PC systems. The high investment cost for the PC-5 is partially offset by the decreased fuel cost of the high efficiency cycle.

**Table 4.3. 1: Pulverized Coal Systems (PC-1, PC-2, PC-3, PC-4, PC-5) – Economic Analysis Summary**

| | PC-1 | PC-2 | PC-3 | PC-4 | PC-5 |
|---|---|---|---|---|---|
| Levelized Cost of Electricity at 80% Availability Factor (cents / kWh) | | | | | |
| Financial | 2.18 | 2.15 | 2.12 | 2.10 | 2.23 |
| Fixed O&M | 0.22 | 0.21 | 0.21 | 0.21 | 0.20 |
| Variable O&M | 0.41 | 0.40 | 0.40 | 0.38 | 0.36 |
| Fuel | 1.15 | 1.12 | 1.10 | 1.07 | 0.98 |
| Total | 3.96 | 3.89 | 3.82 | 3.76 | 3.77 |

### 4.3.2 CFB and CMB$^{TM}$ Cases

The levelized COE values for the CFB and CMB$^{TM}$ systems are summarized in Table 4.3.2. Case CMB$^{TM}$ -5 had the lowest production cost of the CFB and CMB$^{TM}$ systems because of its highest net plant efficiency and the relatively low investment cost. Compared to the increase in the investment cost for the PC-5, the incremental increase in the investment cost of CMB$^{TM}$ -5 was not as high since the design required significantly less amounts of expensive Ni materials.

**Table 4.3. 2: CFB and CMB$^{TM}$ Systems (CFB-2, CFB-3, CMB$^{TM}$ -3, CMB$^{TM}$ -4, CMB$^{TM}$ -5) – Economic Analysis Summary**

| | CFB-2 | CFB-3 | CFB-4 | CMB-3 | CMB-5 |
|---|---|---|---|---|---|
| Levelized Cost of Electricity at 80% Availability Factor (cents / kWh) | | | | | |
| Financial | 2.01 | 1.98 | 1.99 | 1.95 | 1.99 |
| Fixed O&M | 0.21 | 0.21 | 0.20 | 0.20 | 0.19 |
| Variable O&M | 0.28 | 0.27 | 0.27 | 0.27 | 0.25 |
| Fuel | 1.12 | 1.09 | 1.07 | 1.10 | 0.98 |
| Total | 3.62 | 3.56 | 3.53 | 3.52 | 3.41 |

### 4.3.3 Repowering Case

The levelized incremental Cost of Electricity (COE) value for the Repowering Case and Base Case are summarized in Table 4.3.3 and Figure 4.3.1. The incremental COE (2.80 - 1.87 = 0.93 Cents/kWh) is relative to the existing plant without any modifications and does not include any $NO_x$ trading benefits.

**Table 4.3. 3: Repowering System – Economic Analysis Summary**

| | Retrofit | Base |
|---|---|---|
| Levelized Cost of Electricity at 85% Availability Factor (cents / kWh) | | |
| Financial | 1.11 | 0.00 |
| Fixed O&M | 0.40 | 0.48 |
| Variable O&M | 0.16 | 0.18 |
| Fuel | 1.13 | 1.21 |
| Total | 2.80 | 1.87 |

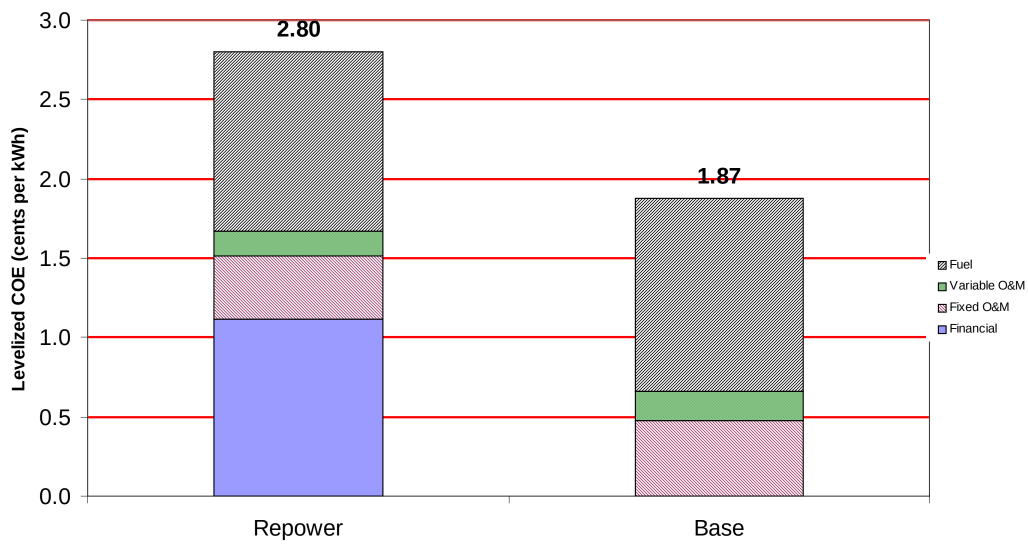



**Figure 4.3. 1: Levelized Cost of Electricity Comparison for Repowering Versus Base Plant (without Emissions Sold or Purchased)**

A more realistic economic picture is presented in Figure 4.3.2, which accounts for purchasing and selling of $NO_x$ credits. For the existing unit, the $NO_x$ emission is 0.57 lbm/MM-Btu. During the five months ozone season that limits $NO_x$ emission to 0.15 lbm/MM-Btu the plant is required to purchase $NO_x$ credits which amount to a difference of 0.42 lbm/MM-Btu. For the repowered case, since the $NO_x$ emission is only 0.1 lbm/MM-Btu, a credit of 0.05 lbm/MM-Btu could be traded for additional revenue during the ozone season. This reduces the incremental COE by 50% to 0.47 cents/KWh.

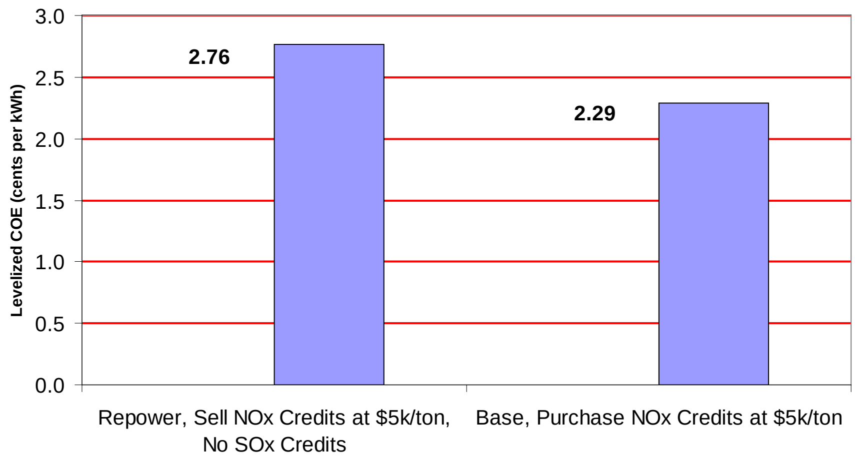



**Figure 4.3. 2: Repowering versus Base Case – With $NO_x$ Credits**

### 4.3.4 Economic Sensitivity Study Summary

Sensitivity analyses were conducted for all case studies to determine the effect on COE of variation of selected base parameter values by ± 25 percent. These parameters (shaded in yellow in Table 4.1.1) are availability factor, EPC price, coal price, equity rate, corporate tax rate, and the discount rate for cost of capital. The base parameter values represent the point where all the sensitivity curves intersect (point 0, 0). Selected sensitivity analysis “spider plots” for selected cases are provided in the following section. The complete package of sensitivity results for all case studies are provided in Appendix IV. In general, for the variable ranges studied, availability factor, plant investment cost, and discount rate, in order of decreasing significance, have the greatest effect on the COE.

Other COE sensitivity studies were conducted on:

1) High temperature Nickel alloy cost ($20, $28, and $32.90 per pound) for cases PC-5, CMB™ -5, and the repowering case.

2) $NO_x$ emissions credit on the repowering case.

3) $SO_x$ emissions credit on the repowering case.

#### 4.3.4.1 Case PC-3

Results for the Case PC-3 COE sensitivity study are shown in Figure 4.3.3. The tabulated results for Case PC-3 are provided in Appendix IV. The levelized COE for the base parameter values is 3.8 cents per kWh. Levelized COE ranges from a low of 3.3 to a high of 4.6 cents per kWh.

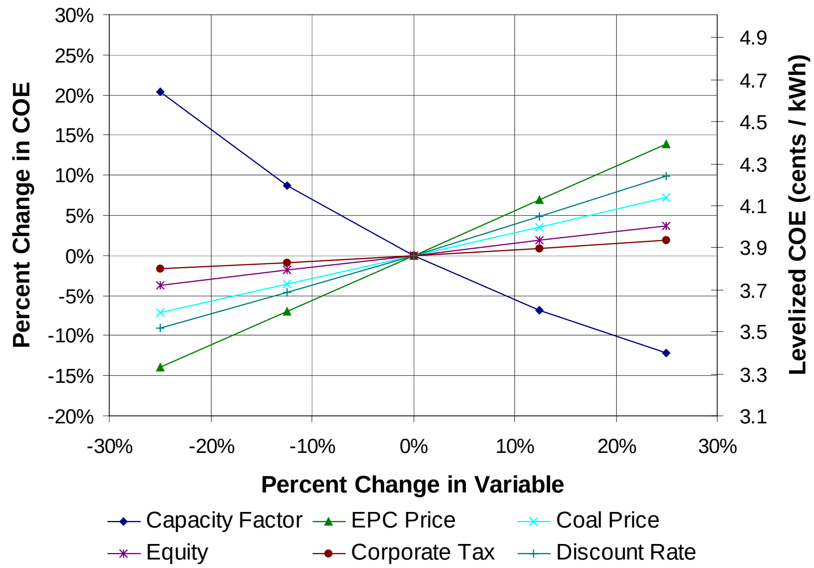



**Figure 4.3. 3: Case PC-3 - Economic Sensitivity Results**

### 4.3.4.2 Case CFB-3

Results for the Case CFB-3 COE sensitivity study are shown in Figure 4.3.4. The tabulated results for Case CFB-3 are provided in Appendix IV. The levelized COE for the base parameter values is 3.6 cents per kWh. Levelized COE ranges from a low of 3.1 to a high of 4.3 cents per kWh. These results are similar to those for Case PC-3.

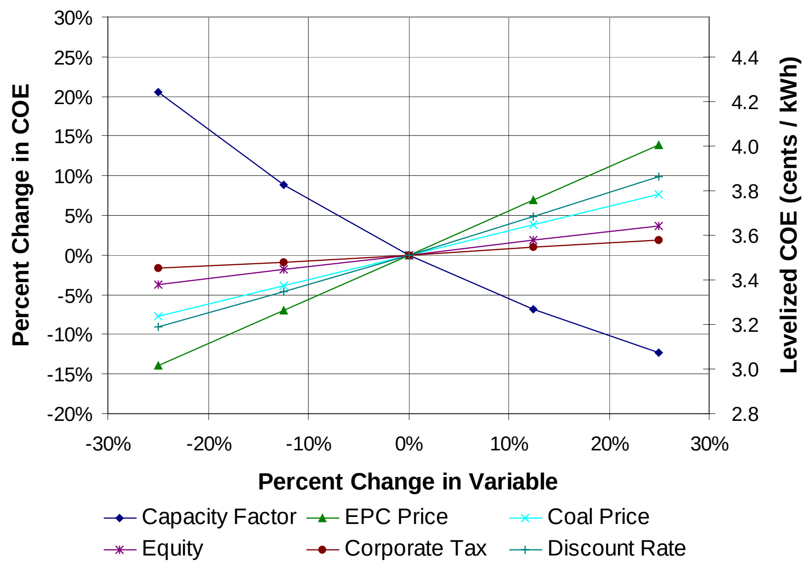



**Figure 4.3. 4: Case CFB-3 - Economic Sensitivity Results**

### 4.3.4.3 High Temperature Nickel Alloy Sensitivity Study

In general, the cost of Ni alloys affected the COE by about -1 ¼% when the alloy cost is decreased from $28 to $20 per pound and by about +1 ¼% when the alloy cost is increased from $28 to $32.90 per pound.

Results for the high temperature alloy Case PC-5 COE sensitivity study are shown in Figure 4.3.5 and tabulated in Appendix IV. The levelized COE for the base parameter values is 3.77 cents per kWh. Levelized COE ranges from a low of 3.71 to a high of 3.81 cents per kWh.

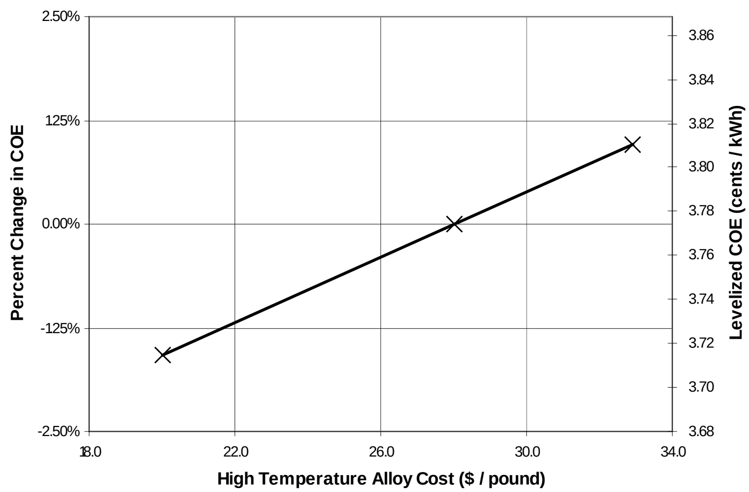



**Figure 4.3. 5: Case PC-5 – High Temperature Alloy Sensitivity Results**

Similarly, the results for the high temperature alloy Case CMB™ -5 COE sensitivity study are shown in Figure 4.3.6 and tabulated in Appendix IV. The levelized COE for the base parameter values is 3.41 cents per kWh. Levelized COE ranges from a low of 3.40 to a high of 3.42 cents per kWh.

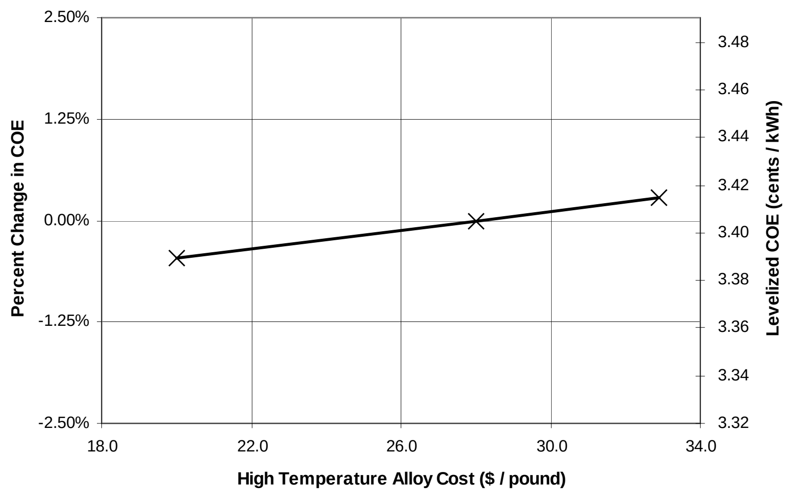



**Figure 4.3. 6: Case CMB™ -5 – High Temperature Alloy Sensitivity Results**

Results for the high temperature alloy repowering Case COE sensitivity study are shown in Figure 4.3.7 and tabulated in Appendix IV. The levelized COE for the base parameter values is 2.8 cents per kWh. Levelized COE ranges from a low of 2.76 to a high of 3.83 cents per kWh.

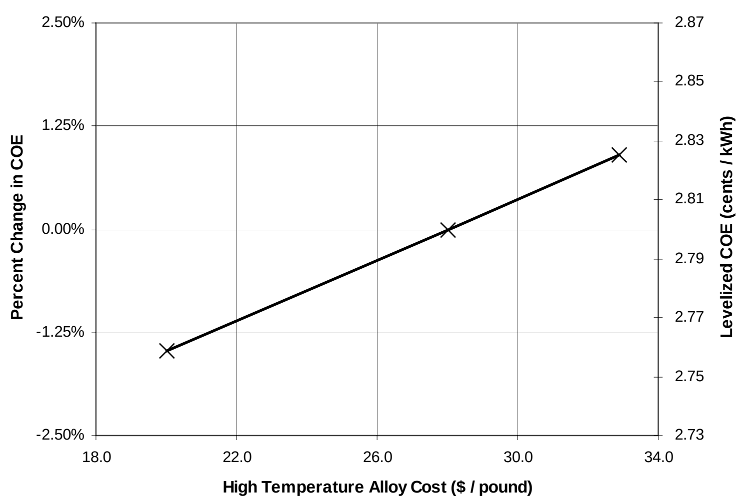



**Figure 4.3. 7: Case Repowering – High Temperature Alloy Sensitivity Results**

#### 4.3.4.4 $NO_x$ / $SO_x$ Credit Sensitivity Study for Repowering Case

Results for the $NO_x$ / $SO_x$ credit for the repowering Case COE sensitivity study are shown in Figure 4.3.8 and tabulated in Appendix IV. The $NO_x$ credits are based on the reduction of $NO_x$ emissions with repowering versus the base plant during the five month ozone season which the base plant purchases $NO_x$ credits. The $SO_x$ credits are based on the reduction of $SO_x$ emissions by 30% from the repowering case versus the base plant for the entire year. The sulfur capture is in-furnace only and no additional back-end equipment is provided to facilitate higher percent of sulfur removal. The investment cost was increased by about $1,000,000 to account for a limestone feed system.

When comparing the COE of the repowering cases selling emissions credits versus the base plant purchasing credits, $NO_x$ credits of about $6,500 per ton $NO_x$ sold would produce a COE similar to the COE of the base plant purchasing $NO_x$ credits at $5,000 per ton $NO_x$.

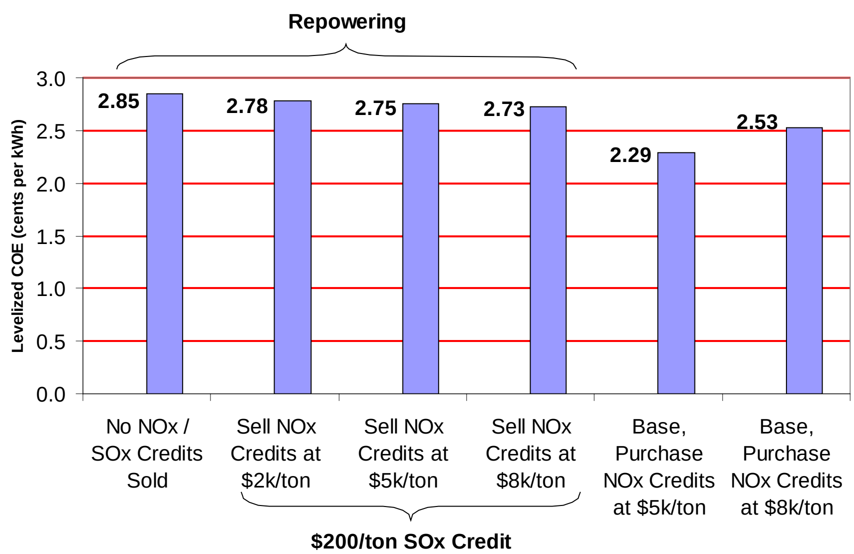



**Figure 4.3. 8: Case Repowering – $NO_x$ Credit Sensitivity Results**

Figure 4.3.9 provides the breakdown of levelized COE for the scenarios shown in Figure 4.3.8. $NO_X$ and $SO_x$ credits offset the variable O&M cost for the repowering case.

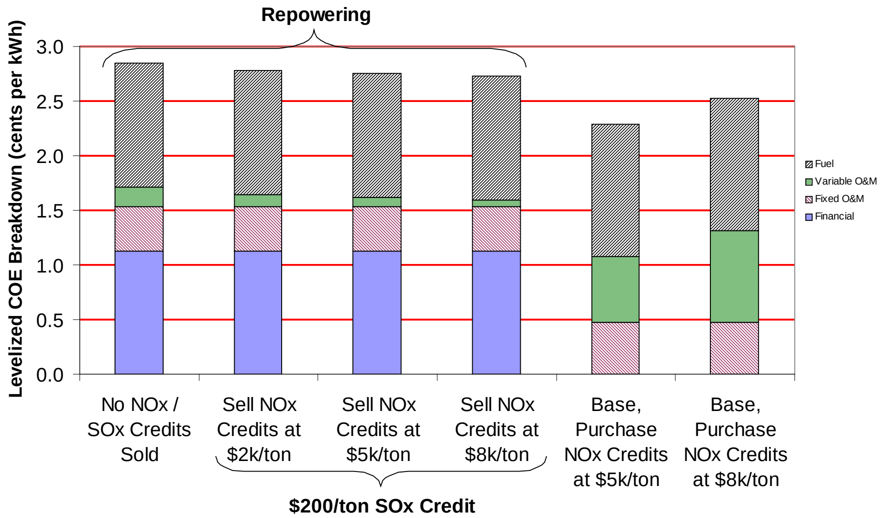



**Figure 4.3. 9: Case Repowering – Breakdown of COE from $NO_x$ Credit Sensitivity Study**

## 4.4 Economic Study Summary and Conclusions

The economic study results are summarized by comparing the levelized COE results for the PC, CFB, and CMB™ cases as shown in Figure 4.4.1. The ultra-supercritical case CMB™ -5 has the lowest cost of electricity. The lower cost is directly related to high efficiency of power generation and the lower cost of finned surfaces applied in the boiler. The finned surface arrangement minimizes the need for expensive Ni alloy tubing and piping. Among the state-of-the-art technology, the supercritical CFB cases, CFB-3 and CFB-4, have the lowest COE. The CFB and CMB™ based systems both produce lower COE than the PC based systems. The main reason for the lower cost is that the PC-systems, to achieve environmental goals, require more expensive flue gas clean-up systems (SCR, ESP, and wet FGD). There is no significant difference in COE within the supercritical PC cases (PC-3, PC-4, and PC-5). Subcritical PC cases have the highest electricity production costs. Similarly, there are no significant differences in COE within the CFB and CMB™ cases.

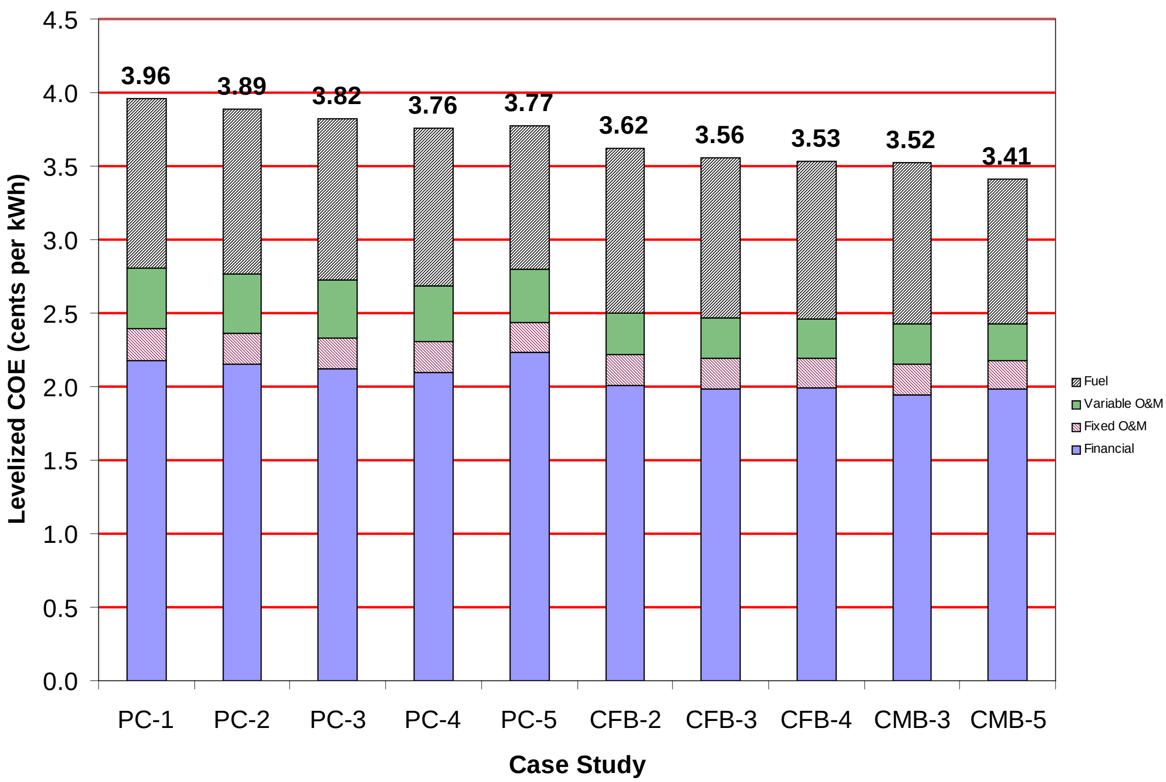



**Figure 4.4. 1: Levelized Cost of Electricity Comparison for PC and CFB/ CMB™ Cases**

The economic study results for repowering the base plant are summarized by comparing the levelized COE results for the repowering and base plant cases as shown in Figure 4.4.2. This figure illustrates how the cost of $NO_x$ credits impacts the COE. As the price of $NO_x$ credits increases, the difference in the COE between the repowering case and the base case becomes progressively smaller. It should be noted that the comparison shown is based on the new boiler that is subject to amortization in future years and the existing boiler that is already fully depreciated. It should be also noted that any major investment cost required to refurbish the existing old boiler or potential decrease in future availability caused by the aging equipment has not been considered in estimating the COE of the base case.

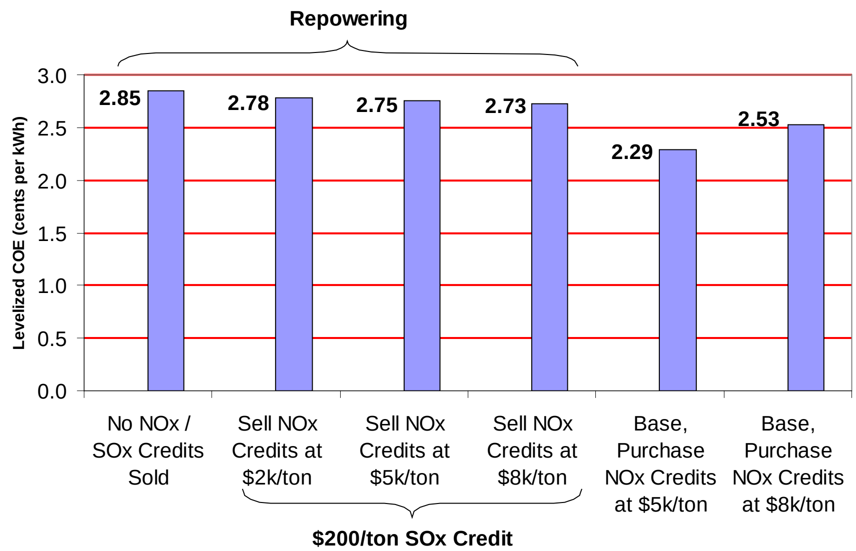



**Figure 4.4. 2: Levelized Cost of Electricity Comparison for Repowering versus Base Plant**

The effect of coal cost on the COE for the PC Cases are shown in Figure 4.4.3. Case PC-5 shows the lowest COE at coal costs greater than about $1.40 per MM-Btu. PC-4 has the lowest COE of coal costs less than $1.40 per MM-Btu

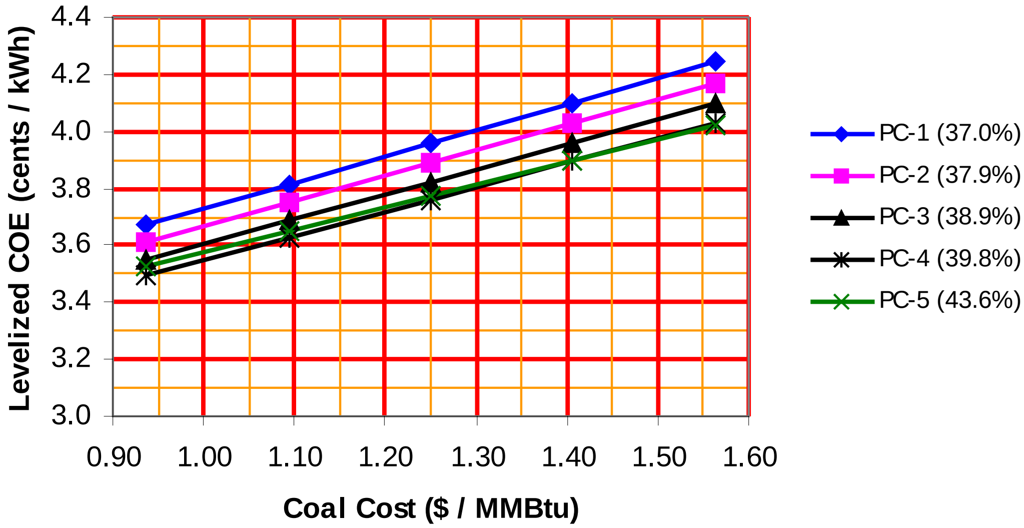



**Figure 4.4. 3: Effect of Coal Cost on COE for PC Cases**

The effect of coal cost on the COE for the CFB/ CMB™ Cases are shown in Figure 4.4.4. Case CMB™ -5 has the lowest COE over the entire coal cost range of $0.90 per MM-Btu to $1.60 per MM-Btu.

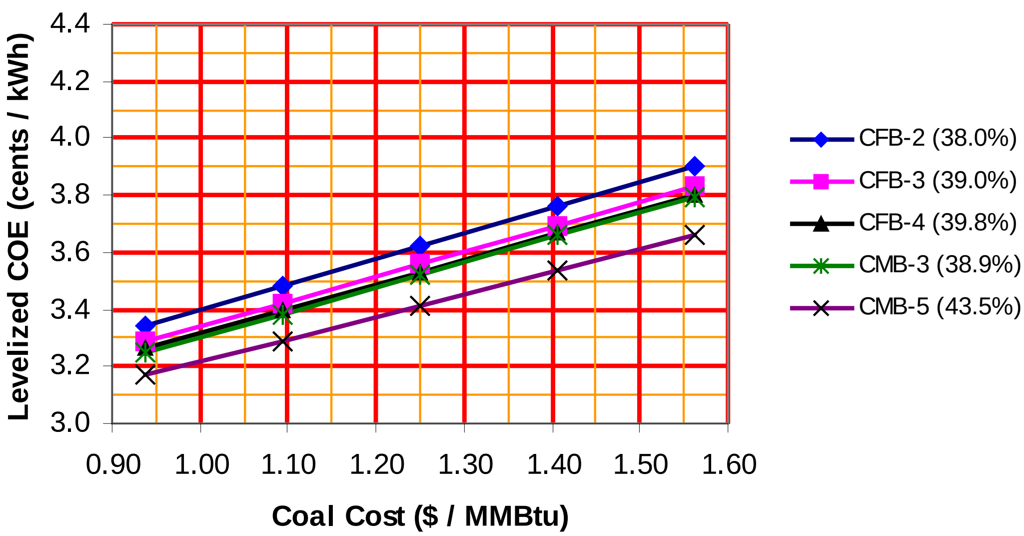



**Figure 4.4. 4: Effect of Coal Cost on COE for CFB/ CMB™ Cases**

The study has also investigated the impact of potential taxes placed on $CO_2$ emissions. The figure below illustrates the changes in the COE as the potential $CO_2$ tax increases for the PC power plant cases. As expected, the COE increases significantly with the increase in the tax. The figure also shows that the tax would become a major driver in utility companies' selection process of the power plant cycle parameters and the high efficiency plants would become the technologies of choice.

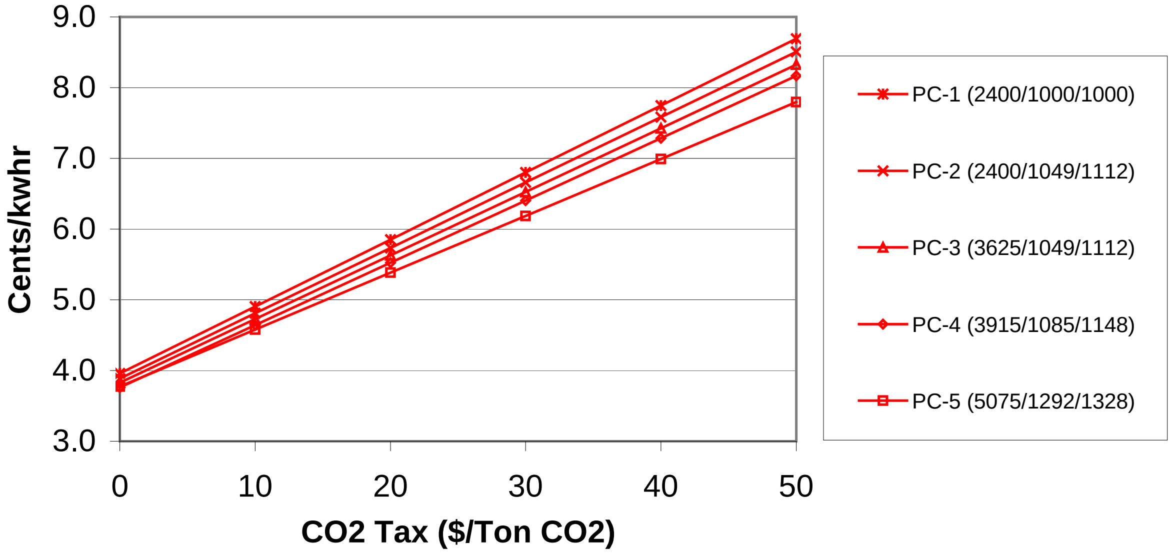



**Figure 4.4. 5: Cost of Electricity for PC Power Plant Cases For Different $CO_2$ Emissions Tax Rate**

# 5. Conclusions and Recommendations

Primary results for both parts of the study (Greenfield and Repowering) are summarized in terms of thermal efficiency, investment costs, and cost of electricity (COE). The table shown below defines the case studies in terms of steam cycle parameters and combustion technology and also summarizes the primary results (thermal efficiency, investment cost, and COE) for all the cases.

**Table 5.0. 1: Primary Results Summary: Thermal Efficiency, Investment Costs, and Cost of Electricity**

| | | PC-1 | PC-2 | PC-3 | PC-4 | PC-5 | CFB-2 | CFB-3 | CFB-4 | CMB-3 | CMB-5 | Repower | Existing |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Steam Cycle Parameters** | | | | | | | | | | | | | |
| Main Steam Pressure | (psia) | 2408 | 2408 | 3625 | 3915 | 5075 | 2408 | 3625 | 3915 | 3625 | 5075 | 4242 | 2015 |
| Main Steam Temperature | (Deg F) | 1000 | 1049 | 1049 | 1085 | 1292 | 1049 | 1049 | 1085 | 1049 | 1292 | 1292 | 1050 |
| Reheat Steam Temperature | (Deg F) | 1000 | 1112 | 1112 | 1148 | 1328 | 1112 | 1112 | 1148 | 1112 | 1328 | 1000 | 1000 |
| Feedwater Temperature | (Deg F) | 500 | 500 | 500 | 554 | 626 | 500 | 500 | 554 | 500 | 626 | 460 | 453 |
| Number of Feedwater Heaters | (no.) | 7 | 7 | 7 | 8 | 9 | 7 | 7 | 8 | 7 | 9 | 8 | 8 |
| **Efficiency and Output** | | | | | | | | | | | | | |
| **Boiler Efficiency (HHV basis)** | (fraction) | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8975 | 0.8926 | 0.8926 | 0.8873 | 0.8816 |
| **Steam Cycle Efficiency** | (fraction) | 0.4442 | 0.4543 | 0.4650 | 0.4745 | 0.5161 | 0.4543 | 0.4650 | 0.4745 | 0.4650 | 0.5161 | 0.4604 | 0.4269 |
| | (Btu/kwhr) | 7683 | 7512 | 7339 | 7193 | 6613 | 7512 | 7339 | 7193 | 7339 | 6613 | 7413 | 7994 |
| **Generator Output** | (kw) | 696316 | 711278 | 736148 | 753937 | 821374 | 711278 | 736148 | 753937 | 736148 | 821374 | 203807 | 168604 |
| **Net Plant Output** | (kw) | 630526 | 646080 | 662936 | 677479 | 741615 | 647588 | 663823 | 678366 | 665552 | 744230 | 184887 | 156518 |
| **Fuel Heat Input (HHV basis)** | (MM-Btu/hr) | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5812 | 5844 | 5844 | 1643 | 1496 |
| **Net Plant Heat Rate (HHV basis)** | (Btu/kwhr) | 9218 | 8997 | 8768 | 8580 | 7838 | 8976 | 8756 | 8568 | 8781 | 7853 | 8889 | 9561 |
| **Thermal Efficiency (HHV basis)** | (fraction) | 0.3702 | 0.3794 | 0.3893 | 0.3978 | 0.4355 | 0.3803 | 0.3898 | 0.3983 | 0.3887 | 0.4346 | 0.3840 | 0.3570 |
| **Costs and Economics** | | | | | | | | | | | | | |
| **Investment Costs** | ($/kWe net) | 1,139 | 1,126 | 1,109 | 1,098 | 1,168 | 1,051 | 1,038 | 1,039 | 1,018 | 1,039 | 413 | n/a |
| **Levelized Cost of Electricity** | (Cents/kWh) | 3.96 | 3.89 | 3.82 | 3.76 | 3.77 | 3.62 | 3.56 | 3.53 | 3.52 | 3.41 | 2.76 | 2.29 |

### Greenfield Cases:

For the ten Greenfield cases, the calculated thermal efficiencies (HHV basis) range from 37.02% to 43.55%. With respect to thermal efficiency, for the same steam conditions, there is little difference when comparing among the combustion systems (PC, CFB, and CMB™) as would be expected. In general, the thermal efficiency of the PC fired systems are about the same as for the CFB based systems. The CFB and PC systems thermal efficiency are about 0.1 percentage points higher than the CMB™ systems which is due to only partial sulfation in the CMB™ combustor. The effect of the increasing steam cycle parameters (Temperature and Pressure) is also clearly illustrated.

The specific investment cost results for the Greenfield cases shown in the table above range from about 1,018 to 1,168 $/kW-net. For the same steam conditions, the CMB™ combustion system plants require the lowest investment costs as compared to PC or CFB plants. This cost advantage increases as steam cycle conditions (Temperature and Pressure) are raised. The CFB systems are about 70 $/kW lower in cost than the PC type combustion systems. This difference is primarily attributable to the differences in the costs for the gas cleanup system equipment.

The cost of electricity (COE) results for the Greenfield cases shown in the table above range from about 3.4 to 4.0 Cents/kWh. These results indicate that Case CMB™ -5 is the most economical from a COE basis. Compared to Case PC-5, it requires significantly less of very expensive Ni alloy tubing. The effect of increased steam conditions on COE is also shown in the graph below with the increased steam conditions offering a slight advantage. For the same steam conditions there is very little difference in the COE between CFB and CMB™ designs.

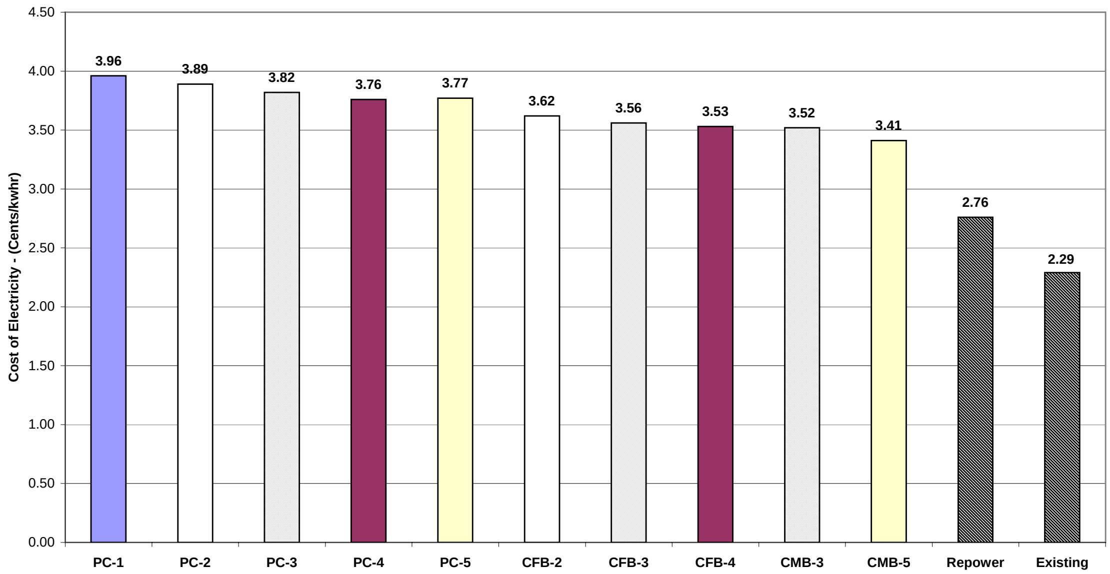



**Figure 5.0. 1: Cost of Electricity Comparison (All Cases)**

Similar to the investment cost results, the PC cases are about 7% higher than the CFB type combustion systems with respect to COE at the same steam conditions. The advantage of the CFB systems is attributable to the investment cost savings discussed above. Because of the additional reduction in investment cost associated with CMB$^{TM}$ based systems, the CMB$^{TM}$ combustion system offers a COE advantage as compared to PC of about 8-10% (greater advantage at higher steam conditions).

The cost of electricity is directly related to the cost of fuel. The above COE's are calculated for the price of fuel of $1.25/MBtu. As the cost of fuel increases, as shown in Figure 5.0.2, the cost of electricity increases also and at the same time the economics continue to shift towards the more efficient power plant systems. For example, at a of coal price of $1.80 MM-Btu the COE is the lowest for the ultra-supercritical case PC-5 among the PC power plant cases. The ultra-supercritical CMB-5 continues to offer the lowest COE among the power plant cycles analyzed.

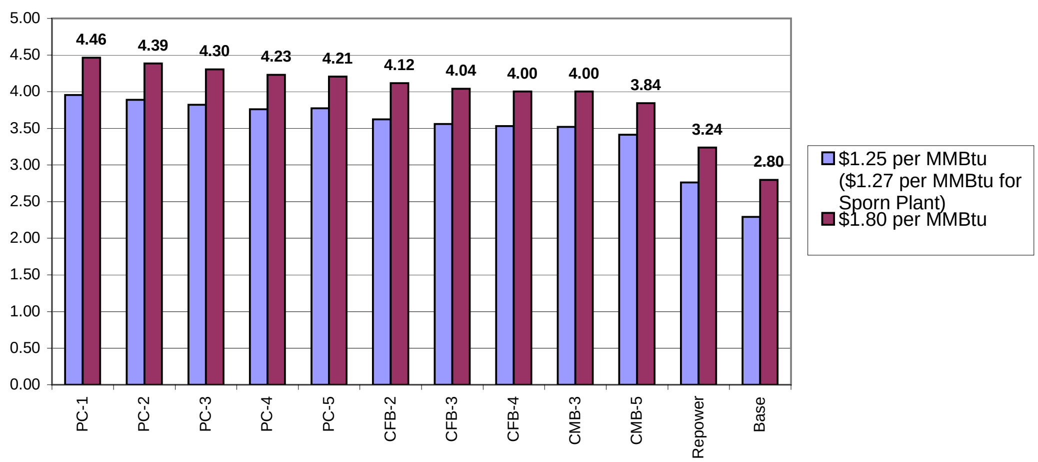



**Figure 5.0. 2: Cost of Electricity Comparison for 1.25 and 1.80 $/MM-Btu Fuel Cost – All Cases**

**Repowering Case:**

For the Repowering case, the calculated thermal efficiency (HHV basis) is improved from 35.70% for the existing unit to 38.40%. The investment costs necessary for all the equipment required for this repowering project is 413 $/kW-net and the resulting incremental cost of electricity is calculated to be 0.47 Cents/kWh (2.76 – 2.29 Cents/kWh). Incremental is calculated relative to the unmodified existing unit. This difference may quickly disappear if the price of $NO_x$ credits continues to increase and/or a major capital investment is required to refurbish the existing boiler of if there is loss of availability caused by the aging equipment.

**Recommendations:**

In summary, from the results of the study the evaluated power plant systems fall either into the near term or long term category with respect to technology implementation. All combustion technologies can achieve low levels of pollutants and comply with the CURC 2010 air pollution targets. Technology is available today to facilitate construction of all the PC cycles, except for the ultra-supercitical steam conditions of Case PC-5, and all the CFB steam cycles. Technology is being developed to enable market introduction of Case PC-5 and both CMB™ cycles in a 10 to 15 year timeframe. The very high steam temperatures of the ultra-supecritical steam cycle do not appear to be practical for conventional CFB technology where combustion temperature is generally limited to 1,550$^0$F. CMB™ technology with the combustion temperature of 2000$^0$F allows greater latitude in selecting the range of steam cycle parameters. The ultra-supecritical CMB™ design offers the prospect of the lowest COE.

The CFB power plants are the technology of choice for high sulfur coals. For low sulfur coals the PC power plants that don't require installation of the back end $NO_x$ and $SO_x$ control technologies would be favored. The supercritical CFB plants have the lowest cost of electricity and its cost continues to improve for higher steam conditions.

Building up on these results, the next step in the development effort of the Rankine power plant cycle is recommended. It should include a CFB design with steam conditions of 4,000 psi to 5000 psi and main and reheat steam temperatures of approximately 1,200$^0$F. The potential plant efficiency improvement would be significant and the efficiency should be in the range of 41-42% (HHV basis). These steam conditions may require some CFB process modifications to enable the higher steam temperatures but would represent the upper limit for conventional boiler alloys. Such a design would fulfill the promise of high efficiency and low cost of the intermediate term (3 to 5 years) power plant cycle.

Based on reliability, investment costs, emissions and cost of electricity a coal fired steam power plant will continue to be a good investment for power plant owners especially compared to other options such as IGCC for coal powered electric power production. The thermal efficiencies of today's steam power plants with supercritical steam cycles are higher than today's IGCC plants. For power plants of the future, studies show that coal fired steam plants with ultra-supercritical steam cycles will maintain this efficiency advantage over future IGCC plants with advanced gas turbines. [MARION,10]

# 6. Bibliography

Bustard et al., DOE Full Scale Data, Air Quality III Conference, September 2002.

Coal Utilization Research Council - CURC (www.coal.org).

Jukkola, G.; Turek, D.; Levasseur, A.; Teigen, B.; "Operating Experience with ALSTOM's Circulating Moving Bed Combustor", Proceedings of FBC-2003, 17th International Fluidized Bed Combustion Conference, Jacksonville, Florida USA, May 18-21, 2003.

Marchetti, M.; Semedard, J.; Devroe, S.; Czarnecki, T.; Lemasle, J.; " ALSTOM's Large CFB's and Results" Proceedings of FBC-2003, 17th International Fluidized Bed Combustion Conference, Jacksonville, Florida USA, May 18-21, 2003.

Marion,J.; Liljedahl, G.; Black, S.; " A review of the State-of-the-art and a View of the Future for Combustion-Based Coal Power Generation" 29th International Technical Conference on Coal Utilization and Fuel Science, Clearwater, Florida USA, April 18-22, 2004.

Palkes, M.; "Boiler Materials for Ultra Supercritical Coal Power Plants", Task 1A, Conceptual Design, ALSTOM Approach, Topical Report, Prepared for the U.S. Department of Energy Grant Number DE-FG26-01NT41175, Ohio Coal Development Office Grant No: D-00-20, February 2003.

Palkes, M.; Banas, J.; Weissinger, G.; Kessel, W.; "State-of-the-Art Sliding Pressure Supercritical Steam Generators" International Power Generation Conference, Las Vegas, Nevada USA, December 2001.

Palkes, M.; Liljedahl, G.; Kruger, H.; Weirich, P.; "The Next Step Power Plant – a Boiler/Turbine Optimization Study" Alstom Power Proprietary Internal Publication, March 1999.

Palkes, M.; Waryasz, R.; Kamalendu, D.; "Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants", Twentieth Annual International Pittsburgh Coal Conference, September 15-19, 2003.

Singer, J.; "Combustion Fossil Power" Fourth Edition; Copyright 1991; Combustion Engineering Inc.

# 7. Appendices

The four appendices provided in this section are described and listed below:

- **Appendix I**: Plant equipment lists
- **Appendix II**: Plant investment cost and operating and maintenance cost breakdowns
- **Appendix III**: Boiler drawings
- **Appendix IV**: Economic sensitivity study results

## 7.1 Appendix I - Plant Equipment Lists

This appendix provides a listing of all major plant equipment provided for all power plants included in this study. The equipment lists are divided into two groups, Boiler island equipment and Balance of plant equipment.

The Boiler Island equipment for the Greenfield cases is subdivided by combustion system type (i.e. PC, CFB, and CMB$^{TM}$).

Balance of Plant Equipment for the Greenfield cases is shown in a single list. Because much of the equipment is common to all the Greenfield plants, a single list is used with differences among the cases indicated where necessary. For example, the Coal Receiving and Handling equipment (Account 1) is the same for all cases ant therefore it is only listed once and is identified as "Common to all Cases". Where there are differences, they are indicated. For example, the Feedwater Systems (Account 3A) are differentiated by using five separate lists for this equipment account and indicating Steam Cycle 1, 2, 3, 4, and 5, for the five different steam cycles used in this study. Specific study case identifiers (i.e. PC-1) are also listed where differences occur.

The equipment required for the Sporn repowering case (Boiler Island and Balance of Plant) are listed after the Greenfield cases. The Balance of Plant list shows only the new major items that were added for the repowering and does not include existing BOP equipment.

### 7.1.1 Boiler Island Equipment for Greenfield Cases

#### 7.1.1.1 PC Cases Boiler Island Equipment

This section contains a list of all equipment associated with the boiler scope of supply for the PC boilers for cases PC-1, PC-2, PC-3, PC-4, and PC-5. Cases PC-1 and PC-2 are subcritical pressure designs and Cases PC-3, PC-4, and PC-5 are supercritical pressure designs. A large portion of the equipment is common to all five boilers and therefore a single equipment list is provided with differences between the three cases indicated in this list where necessary.

| |
|---|
| Fuel Feeding System: |
| - Day Silo |
| - Fuel Silo Isolation Valves |
| - Fuel Feeders |
| - Feeder Isolation Valves |
| - Piping to Furnace |
| Furnace Equipment: |
| - PC-1,-2 |
| Drum Including Internals, Nozzles, Lugging, Hanger Rods |
| Downcomer System |
| - PC-3,-4,-5 |
| Separator Including Nozzles, Lugging, Hanger Rods |
| Start-up System Including Recirculation Pump, Storage Tank, Piping |
| - Connecting Tubes/Piping |
| - Furnace Tube Panels/Headers |
| - PC-1, PC-2, PC-3, PC-4 and PC-5 Furnace Superheater Pendants/Headers/Piping (panels and platens) |
| - PC-3,-4,-5 In Tunnel Superheat Pendant/Headers/Piping (spaced) |
| - PC-1, PC-2, PC-3, PC-4 and PC-5 Above Arch Reheater Pendants/Headers/Piping (platens) |
| - PC-1,-2 In Tunnel Reheater Pendant/Headers/Piping (spaced) |
| - PC-1,-2 Reheater Radiant Wall/Headers/Piping |
| - Bottom Ash Removal System |
| - Start-up Burner System (Including Burners, Piping, Ducts, and Local Control Equipment) |
| - Backpass Enclosure |
| - Metal/Fabric Expansion Joints |
| - Buckstay System: |
| Furnace |
| Backpass |
| Backpass Equipment: |
| - Connecting Tubes/Piping |
| - Backpass Tube Panels/Headers |
| - Backpass Heat Absorbing Surface: |
| PC-1,-2 Horizontal Superheater/Economizer |
| PC-3.-4.-5 Horizontal Reheater/Economizer |
| - Superheater/Reheater Desuperheaters |
| - Desuperheater Block Valves |
| - Desuperheater Piping |

| |
|---|
| - PC-1,-2 Economizer Piping to Drum |
| - PC-3,-4,-5 Economizer Piping to Furnace Walls |
| - Superheater Interconnecting Piping |
| - Feedwater Stop, Feedwater Check |
| - Safety Valves/Discharge Piping/Silencers |
| - Electro. Relief Valve/Silencer and Discharge Piping |
| Trim Valves: |
| - Double Valving |
| Drum Level Gauge and Indicators |
| Sootblowing System: |
| - Economizer |
| - Superheater/Reheater |
| - Airheater |
| - Sootblower Control System |
| Air System: |
| - Primary Air Fan w/Drive (by others) |
| - Secondary Air Fan w/Drive (by others) |
| - Fan and Blower Inlet Silencers (by others) |
| - Sealing Air System |
| - Ljungstrom Regenerative Air Heater |
| - Ductwork - Fan Outlet(s) to Airheater Inlet(s) |
| - Steam Coil Air Preheaters |
| - Air Duct Expansion Joints |
| Combustion Gas System: |
| - Ductwork and Expansion Joints - Economizer Outlet to Airheater |
| - Ductwork - Airheater Outlet (including airheater plenum & hoppers) to ESP |
| - Ductwork ESP Outlet to I.D. Fan Inlet |
| - I.D. Fan w/Drive (by others) |
| - Ductwork – I.D. Fan Outlet to FGD Flange Connection |
| Ash Handling System: |
| - Bottom ash Scraper Conveyor System |
| Fuel System: |
| - Pulverized Coal Burners and Windbox |
| - Pulverizers and Motors with Accessories |
| - Pulverized Coal Piping |
| - Pulverizer Inerting and Cleaning System |
| - Ignition Equipment |
| Structural: |
| - Structural Steel including platforms, walkways, stairways, and ladders |
| - Boiler Internal Grid Steel |
| - Boiler Island Elevator |
| - Pressure Part Support Steel |
| - Boiler Building Siding, Weather Enclosure, HVAC |
| Instrumentation and Controls: |
| - Burner Management System (BMS) Logic |
| - Field Instruments |
| - Controller Drives |
| Refractories: |

| |
|---|
| - Material for All Internal Refractory Linings for Furnished Process and Boiler Equipment |
| Insulation and Lagging: |
| - Material for Insulation and Lagging for Heat Conservation and Personnel Protection for furnished equipment |
| Painting: |
| - Shop Prime Paint Coating for Seller furnished Equipment |

| |
|---|
| Miscellaneous: |
| - Operator Training Program |
| - Maintenance Training Program |
| - Instruction Manuals |
| - Spare Parts for commissioning |
| - Technical Representation during start-up and testing |
| - Field Erection of Equipment Scope |
| - Freight to Site |

### 7.1.1.2 CFB Cases Boiler Island Equipment

This section contains a list of all equipment associated with the boiler scope of supply for the CFB boilers for cases CFB-2, CFB-3, and CFB-4. Case CFB-2 is a subcritical pressure design and Cases CFB-3 and CFB-4 are both supercritical pressure designs. A large portion of the equipment is common to all three boilers and therefore a single equipment list is provided with differences between the three cases indicated in this list where necessary.

| |
|---|
| Fuel Feeding System: |
| - Day Silo |
| - Fuel Silo Isolation Valves |
| - Fuel Feeders |
| - Feeder Isolation Valves |
| - Piping to Furnace |
| Limestone Feeding System: |
| - Day Silo |
| - Limestone Silo Isolation Valves |
| - Rotary Feeder |
| - Blower |
| - Piping from Blower to Furnace Injection Points |
| Furnace Loop Equipment: |
| - CFB-2 |
| Drum Including Internals, Nozzles, Lugging, Hanger Rods |
| Downcomer System |
| - CFB-3,-4 |
| Separator Including Nozzles, Lugging, Hanger Rods |
| Start-up System Including Recirculation Pump, Storage Tank, Piping |
| - Connecting Tubes/Piping |
| - Furnace Tube Panels/Headers |
| - Furnace Superheater Pendants/Headers/Piping |
| - CFB-2 Furnace Evaporator Pendants/Headers/Piping |
| - CFB-3,-4 Furnace Once Though Pendants/Headers/Piping |
| - Furnace Grate and Plenum Including Air Nozzles |
| - Ash Drain Valve(s) |
| - Start-up Burner System (Including Burners, Piping, Ducts, and Local Control Equipment) |
| - Ductwork – Furnace to Recycle Particle Separators |
| - Refractory-Lined Recycle Particle Separator – Complete |
| - Ductwork – Recycle Particle Separator to Backpass Inlet |
| - Backpass Enclosure |
| - Metal/Fabric Expansion Joints |
| - Seal pots and Seal pot Grate – Including Air Nozzles and Plenum |
| - Buckstay System: |
| Furnace |
| Backpass |
| Backpass & FBHE Equipment: |
| - Connecting Tubes/Piping |
| - Backpass Tube Panels/Headers |
| - Backpass Heat Absorbing Surface: |
| CFB-2,-3 Horizontal Reheater/Economizer |
| CFB-4 Horizontal Superheater/Reheater/Economizer |

| |
|---|
| - FBHE Heat Absorbing Surface: |
| CFB-2 Superheater/Reheater |
| CFB-3,-4 Superheater/Reheater/Economizer |
| - Superheater/Reheater Desuperheaters |
| - Desuperheater Block Valves |
| - Desuperheater Piping |
| - CFB-2 Economizer Piping to Drum |
| - CFB-3,-4 Economizer Piping to Furnace Walls |
| - Superheater Interconnecting Piping |
| - Feedwater Stop, Feedwater Check |
| - Safety Valves/Discharge Piping/Silencers |
| - Electro. Relief Valve/Silencer and Discharge Piping |
| Trim Valves: |
| - Double Valving |
| Drum Level Gauge and Indicators |
| Sootblowing System: |
| - Economizer |
| - Superheater/Reheater |
| - Airheater |
| - Sootblower Control System |
| Air System: |
| - Primary Air Fan w/Drive (by others) |
| - Secondary Air Fan w/Drive (by others) |
| - Fluidizing Air Blower w/Drive (by others) |
| - Fan and Blower Inlet Silencers (by others) |
| - Ljungstrom Regenerative Air Heater |
| - Ductwork - Fan Outlet(s) to Airheater Inlet(s) |
| - Ductwork - Blower Outlets to Seal pots |
| - Steam Coil Air Preheater |
| - Air Duct Expansion Joints |
| Combustion Gas System: |
| - Ductwork and Expansion Joints - Economizer Outlet to Airheater |
| - Ductwork - Airheater Outlet (including airheater plenum & hoppers) |
| - Ductwork Outlet to I.D. Fan Inlet |
| - I.D. Fan w/Drive (by others) |
| - Ductwork – I.D. Fan Outlet to Stack Flange Connection |
| Ash Handling System: |
| - Bed Ash Drains and Ash Coolers |
| Structural: |
| - Structural Steel including platforms, walkways, stairways, and ladders |
| - Boiler Internal Grid Steel |
| - Boiler Island Elevator |
| - Pressure Part Support Steel |
| - Boiler Building Siding, Weather Enclosure, HVAC |
| Instrumentation and Controls: |
| - Burner Management (FBSS) Logic |
| - CFB Field Instruments |
| - Controller Drives |
| Refractories: |

| |
|---|
| - Material for All Internal Refractory Linings for Furnished Process and Boiler Equipment |
| Insulation and Lagging: |
| - Material for Insulation and Lagging for Heat Conservation and Personnel Protection for furnished equipment |
| Painting: |
| - Shop Prime Paint Coating for Seller furnished Equipment |

| |
|---|
| Miscellaneous: |
| - Operator Training Program |
| - Maintenance Training Program |
| - Instruction Manuals |
| - Spare Parts for commissioning |
| - Technical Representation during start-up and testing |
| - Field Erection of Equipment Scope |
| - Freight to Site |

### 7.1.1.3 CMB™ Cases Boiler Island Equipment

This section contains a list of all equipment associated with the boiler scope of supply for the CMB™ boilers for cases CMB™ -3, and CMB™ -5. Cases CMB™ -3 and CMB™ -5 are supercritical and ultra-supercritical pressure designs. A large portion of the equipment is common to both boilers and therefore a single equipment list is provided with differences between the two cases indicated in this list where necessary.

| |
|---|
| Fuel Feeding System: |
| - Day Silo |
| - Fuel Silo Isolation Valves |
| - Fuel Conveyors & Feeders |
| - Feeder Isolation Valves |
| - Piping to Furnace |
| Limestone Feeding System: |
| - Day Silo |
| - Limestone Silo Isolation Valves |
| - Rotary Feeder |
| - Blower |
| - Piping from Blower to Furnace Injection Points |
| Furnace Loop Equipment: |
| - Furnace Grate and Plenum Including Air Nozzles & Drain Tubes |
| - Ash Drain Valve(s) |
| - Start-up Burner System (Including Burners, Piping, Ducts, and Local Control Equipment) |
| - Ductwork – Furnace to Recycle Particle Separators |
| - Particle Separator – Complete |
| - Ductwork – Recycle Particle Separator to Air Heater Inlet |
| - Metal/Fabric Expansion Joints |
| - Seal pots and Seal pot Grate – Including Air Nozzles and Plenum |
| - Buckstay System |
| MBHE Equipment: |
| - Separator Including Nozzles, Lugging, Hanger Rods |
| - Start-up System Including Recirculation Pump, Storage Tank, Piping |
| - Connecting Tubes/Piping |
| - Tubing /Headers |
| - Buckstay System |
| - MBHE Heat Absorbing Surface: |
| Horizontal Superheaters |
| Horizontal Reheater |
| Horizontal Once Through Heat Exchanger |
| Steam Cooled Support System |
| - Superheater/Reheater Desuperheaters |
| - Reheat Steam Temperature Control Valving |
| - Desuperheater Block Valves |
| - Desuperheater Piping |
| - Once Through Heat Exchanger Piping to Separator |
| - Superheater Interconnecting Piping |
| - Feedwater Stop, Feedwater Check valves |

| |
|---|
| - Safety Valves/Discharge Piping/Silencers |
| - Electro. Relief Valve/Silencer and Discharge Piping |
| Particle Return System: |
| -Particle Removal Cyclones |
| -Ductwork |
| PA Fan to MBHE Outlet |
| Particle transport pipes from MBHE outlet to Cyclone separator |
| Cyclone gas outlets to Furnace |
| Trim Valves: |
| - Double Valving |
| Sootblowing System: |
| - Air heater |
| - Sootblower Control System |
| Combustion Gas System: |
| - Ductwork and Expansion Joints - Cyclone Outlet to Air Heater Inlet |
| - Ductwork – Air Heater Outlet to FDA Inlet |
| - Ductwork FDA Outlet to ID Fan Inlet |
| - I.D. Fan w/Drive (by others) |
| - Ductwork ID Fan Outlet to Stack |
| Air System: |
| - PA Fan w/Drive (by others) |
| - Ductwork – PA Fan Outlets to Air Heater |
| - Ductwork – Air Heater Outlet to Furnace |
| - SA Fan w/Drive (by others) |
| - Ductwork – SA Fan Outlets to Air Heater |
| - Ductwork – Air Heater Outlet to Furnace |
| - Fluidizing Air Blower w/Drive (by others) |
| - Ductwork – FA Blower Outlets to Seal pot |
| Ash Handling System: |
| - Bed Ash Drains and Ash Coolers |
| Structural: |
| - Structural Steel including platforms, walkways, stairways, and ladders |
| - Boiler Internal Grid Steel |
| - Boiler Island Elevator |
| - Pressure Part Support Steel |
| - Boiler Building Siding, Weather Enclosure, HVAC |
| Instrumentation and Controls: |
| - Burner Management (FBSS) Logic |
| - CFB Field Instruments |
| - Controller Drives |
| Refractories: |
| - Material for All Internal Refractory Linings for Furnished Process and Boiler Equipment |
| Insulation and Lagging: |
| - Material for Insulation and Lagging for Heat Conservation and Personnel Protection for furnished equipment |
| Painting: |
| - Shop Prime Paint Coating for Seller furnished Equipment |

| |
|---|
| Miscellaneous: |
| - Operator Training Program |
| - Maintenance Training Program |
| - Instruction Manuals |
| - Spare Parts for commissioning |
| - Technical Representation during start-up and testing |
| - Field Erection of Equipment Scope |
| - Freight to Site |

### 7.1.2 Balance of Plant Equipment for Greenfield Cases

This section contains the balance of plant equipment list corresponding to the Greenfield power plant configurations. This list, along with the material and energy balances and supporting performance data, was used to generate plant costs used in the financial analysis. In the following, all feet (ft) conditions specified for process pumps correspond to feet of liquid being pumped.

Because much of the equipment is common to all the Greenfield plants, a single list is used with differences among the cases indicated where necessary. For example, the Coal Receiving and Handling equipment (Account 1) is the same for all cases and therefore it is only listed once and is identified as “Common to all Cases”. Where there are differences, they are indicated. For example, the Feedwater Systems (Account 3A) are differentiated by using five separate lists for this equipment account and indicating Steam Cycle 1, 2, 3, 4, and 5, for the five different steam cycles used in this study. Specific study case identifiers (i.e. PC-1) are also listed where differences occur.

**ACCOUNT 1 COAL RECEIVING AND HANDLING (Common to all cases)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Bottom Trestle Dumper and Receiving Hoppers | N/A | 200 ton | 3 |
| 2 | Feeder | Vibratory | 700 tph | 2 |
| 3 | Conveyor 1 | 54" belt | 700 tph | 2 |
| 4 | As-Received Coal Sampling System | Two-stage | N/A | 1 |
| 5 | Conveyor 2 | 54" belt | 700 tph | 2 |
| 6 | Reclaim Hopper | N/A | 40 ton | 2 |
| 7 | Feeder | Vibratory | 350 tph | 2 |
| 8 | Conveyor 3 | 48" belt | 700 tph | 1 |
| 9 | Crusher Tower | N/A | 700 tph | 1 |
| 10 | Coal Surge Bin w/ Vent Filter | Compartment | 700 ton | 1 |

## ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

### ACCOUNT 2A COAL PREPARATION AND FEED SYSTEM (Common to all cases)

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Crusher | Granulator reduction | 6" x 0 - 3" x 0 | 1 |
| 2 | Crusher | Impactor reduction | 3" x 0 – 1/4" x 0 | 1 |
| 3 | As-Fired Coal Sampling System | Swing hammer | 700 tph | 2 |
| 4 | Conveyor 4 | 48" belt | 700 tph | 1 |
| 5 | Transfer Tower | N/A | 700 tph | 1 |
| 6 | Tripper | N/A | 700 tph | 1 |
| 7 | Coal Silo w/ Vent Filter and Slide Gates | N/A | Boiler Scope | |
| 8 | Feeder | Gravimetric | Boiler Scope | |

### ACCOUNT 2B LIMESTONE PREPARATION AND FEED SYSTEM (Common to all cases)

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Bin Activator | | 20 tph | 1 |
| 2 | Weigh Feeder | Gravimetric | 20 tph | 1 |
| 3 | Storage Silo | Cylindrical | 1,000 ton | 1 |
| 4 | Blowers | Roots | Site | 2 |

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

**ACCOUNT 3A FEEDWATER SYSTEMS**

**FEEDWATER SYSTEMS (Steam Cycle #1; Case PC-1)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Condensate Storage Tank | Field fabricated | 400,000 gal. | 1 |
| 2 | Surface Condenser | Two shell, transverse tubes | 3,000,000 lbm/hr<br>2.5 in. Hg | 1 |
| 3 | Condenser Vacuum Pumps | Rotary water sealed | 2,500/25 scfm | 2 |
| 4 | Condensate Pumps and drive motors | Vertical canned | 1,300,000 lbm/hr<br>800 ft | 3 |
| 5 | Gland Steam Condenser | Horizontal U Tube | 3,700,000 lbm/hr<br>109°F to 110°F | 1 |
| 5 | LP Feedwater Heater 1 | Horizontal U Tube | 3,700,000 lbm/hr<br>110°F to 154°F | 1 |
| 6 | LP Feedwater Heater 2 | Horizontal U Tube | 3,700,000 lbm/hr<br>154°F to 197°F | 1 |
| 7 | LP Feedwater Heater 3 | Horizontal U Tube | 3,700,000 lbm/hr<br>197°F to 247°F | 1 |
| 8 | LP Feedwater Heater 4 | Horizontal U Tube | 3,700,000 lbm/hr<br>247°F to 282°F | 1 |
| 9 | Deaerator and Storage Tank | Horizontal spray type | 3,700,000 lbm/hr<br>282°F to 361°F | 1 |
| 10 | Boiler Feedwater Booster Pumps and drive motors | Horizontal split | 2,350,000 lbm/hr<br>2,900 psia | 2 |
| 11 | Startup Boiler Feedwater Pumps and drive motors | Barrel type multi-stage centrifugal | 800,000 lbm/hr<br>2,900 psia | 2 |
| 12 | HP Feedwater Heater 6 | Horizontal U Tube | 4,400,000 lbm/hr<br>368°F to 434°F | 1 |
| 13 | HP Feedwater Heater 7 | Horizontal U Tube | 4,400,000 lbm/hr<br>434°F to 500°F | 1 |

**FEEDWATER SYSTEMS (Steam Cycle #2; Cases PC-2, CFB-2)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Condensate Storage Tank | Field fabricated | 400,000 gal. | 1 |
| 2 | Surface Condenser | Two shell, transverse tubes | 2,900,000 lbm/hr<br>2.5 in. Hg | 1 |
| 3 | Condenser Vacuum Pumps | Rotary water sealed | 2,500/25 scfm | 2 |
| 4 | Condensate Pumps and drive motors | Vertical canned | 1,200,000 lbm/hr<br>800 ft | 3 |
| 5 | Gland Steam Condenser | Horizontal U Tube | 3,600,000 lbm/hr<br>109°F to 110°F | 1 |
| 5 | LP Feedwater Heater 1 | Horizontal U Tube | 3,600,000 lbm/hr<br>110°F to 152°F | 1 |
| 6 | LP Feedwater Heater 2 | Horizontal U Tube | 3,600,000 lbm/hr<br>152°F to 196°F | 1 |
| 7 | LP Feedwater Heater 3 | Horizontal U Tube | 3,600,000 lbm/hr<br>196°F to 246°F | 1 |
| 8 | LP Feedwater Heater 4 | Horizontal U Tube | 3,600,000 lbm/hr<br>246°F to 282°F | 1 |
| 9 | Deaerator and Storage Tank | Horizontal spray type | 3,600,000 lbm/hr<br>282°F to 361°F | 1 |
| 10 | Boiler Feedwater Booster Pumps and drive motors | Horizontal split | 2,200,000 lbm/hr<br>3,000 psia | 2 |
| 11 | Startup Boiler Feedwater Pumps and drive motors | Barrel type multi-stage centrifugal | 800,000 lbm/hr<br>3,000 psia | 2 |
| 12 | HP Feedwater Heater 6 | Horizontal U Tube | 4,400,000 lbm/hr<br>368°F to 434°F | 1 |
| 13 | HP Feedwater Heater 7 | Horizontal U Tube | 4,400,000 lbm/hr<br>434°F to 500°F | 1 |

**FEEDWATER SYSTEMS (Steam Cycle #3; Cases PC-3, CFB-3, CMB™ -3)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Condensate Storage Tank | Field fabricated | 400,000 gal. | 1 |
| 2 | Surface Condenser | Two shell, transverse tubes | 2,800,000 lbm/hr<br>2.5 in. Hg | 1 |
| 3 | Condenser Vacuum Pumps | Rotary water sealed | 2,500/25 scfm | 2 |
| 4 | Condensate Pumps and drive motors | Vertical canned | 1,200,000 lbm/hr<br>800 ft | 3 |
| 5 | Gland Steam Condenser | Horizontal U Tube | 3,500,000 lbm/hr<br>109°F to 110°F | 1 |
| 5 | LP Feedwater Heater 1 | Horizontal U Tube | 3,500,000 lbm/hr<br>110°F to 151°F | 1 |
| 6 | LP Feedwater Heater 2 | Horizontal U Tube | 3,500,000 lbm/hr<br>151°F to 195°F | 1 |
| 7 | LP Feedwater Heater 3 | Horizontal U Tube | 3,500,000 lbm/hr<br>195°F to 245°F | 1 |
| 8 | LP Feedwater Heater 4 | Horizontal U Tube | 3,500,000 lbm/hr<br>245°F to 280°F | 1 |
| 9 | Deaerator and Storage Tank | Horizontal spray type | 3,500,000 lbm/hr<br>280°F to 364°F | 1 |
| 10 | Boiler Feedwater Booster Pumps and drive motors | Horizontal split | 2,200,000 lbm/hr<br>4,500 psia | 2 |
| 11 | Startup Boiler Feedwater Pumps and drive motors | Barrel type multi-stage centrifugal | 800,000 lbm/hr<br>4,500 psia | 2 |
| 12 | HP Feedwater Heater 6 | Horizontal U Tube | 4,400,000 lbm/hr<br>375°F to 442°F | 1 |
| 13 | HP Feedwater Heater 7 | Horizontal U Tube | 4,400,000 lbm/hr<br>442°F to 500°F | 1 |

**FEEDWATER SYSTEMS (Steam Cycle #4; Cases PC-4, CFB-4)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Condensate Storage Tank | Field fabricated | 400,000 gal. | 1 |
| 2 | Surface Condenser | Two shell, transverse tubes | 2,800,000 lbm/hr<br>2.5 in. Hg | 1 |
| 3 | Condenser Vacuum Pumps | Rotary water sealed | 2,500/25 scfm | 2 |
| 4 | Condensate Pumps and drive motors | Vertical canned | 1,150,000 lbm/hr<br>800 ft | 3 |
| 5 | Gland Steam Condenser | Horizontal U Tube | 3,400,000 lbm/hr<br>109°F to 110°F | 1 |
| 5 | LP Feedwater Heater 1 | Horizontal U Tube | 3,400,000 lbm/hr<br>110°F to 150°F | 1 |
| 6 | LP Feedwater Heater 2 | Horizontal U Tube | 3,400,000 lbm/hr<br>150°F to 194°F | 1 |
| 7 | LP Feedwater Heater 3 | Horizontal U Tube | 3,400,000 lbm/hr<br>194°F to 244°F | 1 |
| 8 | LP Feedwater Heater 4 | Horizontal U Tube | 3,400,000 lbm/hr<br>244°F to 278°F | 1 |
| 9 | Deaerator and Storage Tank | Horizontal spray type | 3,400,000 lbm/hr<br>278°F to 361°F | 1 |
| 10 | Boiler Feedwater Booster Pumps and drive motors | Horizontal split | 2,300,000 lbm/hr<br>4,900 psia | 2 |
| 11 | Startup Boiler Feedwater Pumps and drive motors | Barrel type multi-stage centrifugal | 800,000 lbm/hr<br>4,900 psia | 2 |
| 12 | HP Feedwater Heater 6 | Horizontal U Tube | 4,600,000 lbm/hr<br>373°F to 440°F | 1 |
| 13 | HP Feedwater Heater 7 | Horizontal U Tube | 4,600,000 lbm/hr<br>440°F to 509°F | 1 |
| 14 | HP Feedwater Heater 8 | Horizontal U Tube | 4,600,000 lbm/hr<br>509°F to 554°F | 1 |

**FEEDWATER SYSTEMS (Steam Cycle #5; Cases PC-5, CMB™ -5)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Condensate Storage Tank | Field fabricated | 400,000 gal. | 1 |
| 2 | Surface Condenser | Two shell, transverse tubes | 2,600,000 lbm/hr<br>2.5 in. Hg | 1 |
| 3 | Condenser Vacuum Pumps | Rotary water sealed | 2,500/25 scfm | 2 |
| 4 | Condensate Pumps and drive motors | Vertical canned | 900,000 lbm/hr<br>800 ft | 3 |
| 5 | Gland Steam Condenser | Horizontal U Tube | 2,700,000 lbm/hr<br>109°F to 110°F | 1 |
| 5 | LP Feedwater Heater 1 | Horizontal U Tube | 2,700,000 lbm/hr<br>110°F to 148°F | 1 |
| 6 | LP Feedwater Heater 2 | Horizontal U Tube | 2,900,000 lbm/hr<br>148°F to 191°F | 1 |
| 7 | Heater #2 Drain Pump | Vertical canned | 112,000 lbm/hr<br>800 ft | 1 |
| 8 | LP Feedwater Heater 3 | Horizontal U Tube | 2,900,000 lbm/hr<br>191°F to 242°F | 1 |
| 9 | LP Feedwater Heater 4 | Horizontal U Tube | 3,200,000 lbm/hr<br>242°F to 280°F | 1 |
| 10 | Heater #4 Drain Pump | Vertical canned | 104,000 lbm/hr<br>800 ft | 1 |
| 11 | LP Feedwater Heater 5 | Horizontal U Tube | 3,200,000 lbm/hr<br>280°F to 340°F | 1 |
| 12 | Deaerator and Storage Tank | Horizontal spray type | 3,200,000 lbm/hr<br>340°F to 407°F | 1 |
| 13 | Boiler Feedwater Booster Pumps and drive motors | Horizontal split | 2,200,000 lbm/hr<br>5,700 psia | 2 |
| 14 | Startup Boiler Feedwater Pumps and drive motors | Barrel type multi-stage centrifugal | 800,000 lbm/hr<br>5,700 psia | 2 |
| 15 | HP Feedwater Heater 7 | Horizontal U Tube | 4,300,000 lbm/hr<br>423°F to 468°F | 1 |
| 16 | HP Feedwater Heater 8 | Horizontal U Tube | 4,300,000 lbm/hr<br>468°F to 554°F | 1 |
| 17 | HP Feedwater Heater 9 | Horizontal U Tube | 4,300,000 lbm/hr | 1 |

| | | | | |
|---|---|---|---|---|
| | | | 554°F to 617°F | |
| 18 | Topping de-superheater | Horizontal U Tube | 4,300,000 lbm/hr<br>617°F to 626°F | 1 |

**ACCOUNT 3B MISCELLANEOUS SYSTEMS (Common to all cases)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Auxiliary Boiler | Shop fabricated water tube | 400 psig, 650°F | 1 |
| 2 | Fuel Oil Storage Tank | Vertical, cylindrical | 500,000 gal | 1 |
| 3 | Fuel Oil Unloading Pump | Gear | 150 ft, 800 gpm | 1 |
| 4 | Fuel Oil Supply Pump | Gear | 400 ft, 80 gpm | 2 |
| 5 | Service Air Compressors | SS, double acting | 100 psig, 800 scfm | 3 |
| 6 | Inst. Air Dryers | Duplex, regenerative | 400 scfm | 1 |
| 7 | Service Water Pumps | SS, double suction | 100 ft, 6,000 gpm | 2 |
| 8 | Closed Cycle Cooling Heat Exch. | Shell and tube | 50% cap. each | 2 |
| 9 | Closed Cycle Cooling Water Pumps | Horizontal, centrifugal | 185 ft, 600 gpm | 2 |
| 11 | Fire Service Booster Pump | Two-stage centrifugal | 250 ft, 700 gpm | 1 |
| 12 | Engine-Driven Fire Pump | Vertical turbine, diesel engine | 350 ft, 1,000 gpm | 1 |
| 13 | Raw Water Pumps | SS, single suction | 100 ft, 1,000 gpm | 2 |
| 14 | Filtered Water Pumps | SS, single suction | 200 ft, 200 gpm | 2 |
| 15 | Filtered Water Tank | Vertical, cylindrical | 15,000 gal | 1 |
| 16 | Makeup Demineralizer | Anion, cation, and mixed bed | 150 gpm | 2 |
| 17 | Liquid Waste Treatment System | - | Site | 1 |

**ACCOUNT 4 BOILER AND ACCESSORIES (different for each case as shown)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Power Boiler | Pulverized Coal Fired Case PC-1 | 4.7 x $10^6$ lbm/hr<br>2,400psi<br>1,000°F/1,000°F | 1 |
| 1 | Power Boiler | Pulverized Coal Fired Case PC-2 | 4.4 x $10^6$ lbm/hr<br>2,400psi<br>1,049°F/1,112°F | 1 |
| 1 | Power Boiler | Pulverized Coal Fired Case PC-3 | 4.3 x $10^6$ lbm/hr<br>3,625 psi<br>1,049°F/1,112°F | 1 |
| 1 | Power Boiler | Pulverized Coal Fired Case PC-4 | 4.6 x $10^6$ lbm/hr<br>3,915 psi<br>1,085°F/1,148°F | 1 |
| 1 | Power Boiler | Pulverized Coal Fired Case PC-5 | 4.3 x $10^6$ lbm/hr<br>5,075 psi<br>1,292°F/1,328°F | 1 |
| 1 | Power Boiler | Circulating Fluidized Bed Case CFB-2 | 4.4 x $10^6$ lbm/hr<br>2,400 psi<br>1,049°F/1,112°F | 1 |
| 1 | Power Boiler | Circulating Fluidized Bed Case CFB-3 | 4.3 x $10^6$ lbm/hr<br>3,625 psi<br>1,049°F/1,112°F | 1 |
| 1 | Power Boiler | Circulating Fluidized Bed Case CFB-4 | 4.6 x $10^6$ lbm/hr<br>3,915 psi<br>1,085°F/1,148°F | 1 |
| 1 | Power Boiler | Circulating Moving Bed Case CMB™ -3 | 4.6 x $10^6$ lbm/hr<br>3,915 psi<br>1,085°F/1,148°F | 1 |
| 1 | Power Boiler | Circulating Moving Bed Case CMB™ -5 | 4.3 x $10^6$ lbm/hr<br>5,075 psi<br>1,292°F/1,328°F | 1 |
| 2 | Primary Air Fan | Centrifugal (Cases PC-1, PC-2, PC-3, PC-4, PC-5) | 1,165,000 pph,<br>281,000 acfm,<br>98" wg, 1,322 kW | 1 |
| 3 | Secondary Air Fan | Centrifugal (Cases PC-1, PC-2, PC-3, PC-4, PC-5) | 677,000 pph,<br>163,000 acfm,<br>78" wg, 1,589 kW | 1 |
| 4 | ID Fan | Centrifugal (Cases PC-1, PC-2, PC-3, PC-4, PC-5) | 2,168,000 pph,<br>724,000 acfm,<br>39" wg, 8,950 kW | 1 |

| | | | | |
|---|---|---|---|---|
| 2 | Primary Air Fan | Centrifugal (Cases CFB-2, CFB-3, CFB-4) | 1,165,000 pph, 281,000 acfm, 98" wg, 7,904 kW | 1 |
| 3 | Secondary Air Fan | Centrifugal (Cases CFB-2, CFB-3, CFB-4) | 677,000 pph, 163,000 acfm, 78" wg, 3,876 kW | 1 |
| 4 | ID Fan | Centrifugal (Cases CFB-2, CFB-3, CFB-4) | 2,168,000 pph, 724,000 acfm, 39" wg, 10,924 kW | 1 |
| 5 | Fluidizing Air Blower | Centrifugal (Cases CFB-2, CFB-3, CFB-4) | 16,000 acfm, 25 psig, 2,875 kW | 2 |

| | | | | |
|---|---|---|---|---|
| 2 | Primary Air Fan | Centrifugal (Cases CMB™ -3, CMB™ -5) | 1,165,000 pph, 281,000 acfm, 98" wg, 1,219 kW | 1 |
| 3 | Secondary Air Fan | Centrifugal (Cases CMB™ -3, CMB™ -5) | 677,000 pph, 163,000 acfm, 78" wg, 3,182 kW | 1 |
| 4 | ID Fan | Centrifugal (Cases CMB™ -3, CMB™ -5) | 2,168,000 pph, 724,000 acfm, 39" wg, 7,740kW | 1 |
| 5 | Fluidizing Air Blower | Centrifugal (Cases CMB™ -3, CMB™ -5) | 16,000 acfm, 25 psig, 840 kW | 2 |

**ACCOUNT 5 FLUE GAS CLEANUP**

**ACCOUNT 5A PARTICULATE CONTROL**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Bag Filter for CFB and CMB™ cases as part of FDA system (Cases CFB-2, CFB-3, CFB-4, CMB™ -3, and CMB™ -5) | Pulse-jet cleaned | ~6,100,000 lbm/hr, total removal efficiency = 99.9%+ | 1 |
| 1 | ESP for PC Cases (Cases PC-1, PC-2, PC-3, PC-4, and PC-5) | N/A | ~6,100,000 lbm/hr, total removal efficiency = 99.9%+ | 1 |

**ACCOUNT 5B FLUE GAS DESULFURIZATION**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Flash Dryer Absorber System for CFB and CMB™ cases (Cases CFB-2, CFB-3, CFB-4, CMB™ -3, and CMB™ -5) | N/A | ~6,100,000 lbm/hr, total removal efficiency = 98% | 1 |
| 1 | Wet FGD System for PC Cases (Cases PC-1, PC-2, PC-3, PC-4, and PC-5) | N/A | ~6,100,000 lbm/hr, total removal efficiency = 98% | 1 |

**ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES**

Not applicable.

**ACCOUNT 7 DUCTING AND STACK (Common to all cases)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Boiler Stack | Concrete with FRP liner | ~6,100,000 lbm/hr | 1 |

**ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES (Note: differences between Steam Cycles are indicated)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | 696 MW Turbine Generator | Subcritical, 2 flow IP, 4 flow LP; **Steam Cycle #1** (Case PC-1) | 2,400 psig/1,000°F/ 1,000°F/ | 1 |
| 1 | 711 MW Turbine Generator | Subcritical, 2 flow IP, 4 flow LP; **Steam Cycle #2** (Cases PC-2, CFB-2) | 2,400 psig/1,049°F/ 1,112°F/ | 1 |
| 1 | 736 MW Turbine Generator | Supercritical, 2 flow IP, 4 flow LP; **Steam Cycle #3** (Cases PC-3, CFB-3, CMB™ -3) | 3,625 psig/1,049°F/ 1,112°F/ | 1 |
| 1 | 754 MW Turbine Generator | Supercritical, 2 flow IP, 4 flow LP; **Steam Cycle #4** (Cases PC-4, CFB-4) | 3,915 psig/1,085°F/ 1,148°F/ | 1 |
| 1 | 821 MW Turbine Generator | Ultra-supercritical, 2 flow IP, 4 flow LP; **Steam Cycle #5** (Cases PC-5, CMB™ -5) | 5,075 psig/1,292°F/ 1,328°F/ | 1 |
| 2 | Bearing Lube Oil Coolers | Plate and frame | - | 2 |
| 3 | Bearing Lube Oil Conditioner | Pressure filter closed loop | - | 1 |
| 4 | Control System | Electro-hydraulic | 1,600 psig | 1 |
| 5 | Generator Coolers | Shell and tube | - | 2 |
| 6 | Hydrogen Seal Oil System | Closed loop | - | 1 |
| 7 | Generator Exciter | Solid state brushless | - | 1 |

**ACCOUNT 9 COOLING WATER SYSTEM (Note: differences between Steam Cycles are indicated)**

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Cooling Tower | Mechanical draft | **Steam Cycle #1** = 2,810 MM-Btu/hr (Case PC-1)<br><br>**Steam Cycle #2** = 2,770 MM-Btu/hr (Cases PC-2, CFB-2)<br><br>**Steam Cycle #3** = 2,710 MM-Btu/hr (Cases PC-3, CFB-3, CMB™ -3)<br><br>**Steam Cycle #4** = 2,650 MM-Btu/hr (Cases PC-4, CFB-4)<br><br>**Steam Cycle #5** = 2,480 MM-Btu/hr (Cases PC-5, CMB-5)<br><br>Al Cases 95°F to 75°F | 1 |
| 2 | Circ. W. Pumps | Vertical wet pit | 60,000 gpm @ 80 ft | 6 |

## ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

### ACCOUNT 10A BOTTOM ASH HANDLING

In boiler scope of supply.

### ACCOUNT 10B FLY ASH HANDLING (Common to all cases)

| Equipment No. | Description | Type | Design Condition | Qty |
|---|---|---|---|---|
| 1 | Baghouse/ESP Hoppers (part of Baghouse/ESP scope of supply) | | | 12 |
| 2 | Air Heater Hopper (part of boiler scope of supply) | | | 1 |
| 3 | Air Blower | | 1,800 cfm | 1 |
| 4 | Fly Ash Silo | Reinforced concrete | 800 tons | 2 |
| 5 | Slide Gate Valves | | | 2 |
| 6 | Wet Unloader | | 30 tph | 1 |
| 7 | Telescoping Unloading Chute | | | 1 |

### 7.1.3 Sporn Repowering Case Equipment List

This section provides a listing of all major plant equipment provided for the repowered Sporn Unit #4 power plant. The list is subdivided into Boiler Island and Balance of Plant Equipment.

#### 7.1.3.1 Sporn Repowering Case Boiler Island Equipment

This section contains a list of all equipment associated with the boiler scope of supply for the CMB™ boiler for the Sporn Unit #4 repowering case.

| |
|---|
| Fuel Feeding System: |
| - Day Silo |
| - Fuel Silo Isolation Valves |
| - Fuel Conveyors & Feeders |
| - Feeder Isolation Valves |
| - Piping to Furnace |
| Limestone Feeding System: (not used) |
| Furnace Loop Equipment: |
| - Furnace Grate and Plenum Including Air Nozzles & Drain Tubes |
| - Ash Drain Valve(s) |
| - Start-up Burner System (Including Burners, Piping, Ducts, and Local Control Equipment) |
| - Ductwork – Furnace to Recycle Particle Separators |
| - Particle Separator – Complete |
| - Ductwork – Recycle Particle Separator to Air Heater Inlet |
| - Metal/Fabric Expansion Joints |
| - Seal pots and Seal pot Grate – Including Air Nozzles and Plenum |
| - Buckstay System |
| MBHE Equipment: |
| - Separator Including Nozzles, Lugging, Hanger Rods |
| - Start-up System Including Recirculation Pump, Storage Tank, Piping |
| - Connecting Tubes/Piping |
| - Tubing /Headers |
| - Buckstay System |
| - MBHE Heat Absorbing Surface: |
| Horizontal Superheaters |
| Horizontal Reheater |
| Horizontal Once Through Heat Exchanger |
| Steam Cooled Support System |
| - Superheater/Reheater Desuperheaters |
| - Reheat Steam Temperature Control Valving |
| - Desuperheater Block Valves |
| - Desuperheater Piping |
| - Once Through Heat Exchanger Piping to Separator |
| - Superheater Interconnecting Piping |
| - Feedwater Stop, Feedwater Check valves |
| - Safety Valves/Discharge Piping/Silencers |
| - Electro. Relief Valve/Silencer and Discharge Piping |
| Particle Return System: |
| -Particle Removal Cyclones |
| -Ductwork |
| PA Fan to MBHE Particle Outlet |
| Particle transport pipes from MBHE outlet to Cyclone separator |

| |
|---|
| Cyclone gas outlets to Furnace |
| Trim Valves: |
| - Double Valving |
| Sootblowing System: |
| - Air heater |
| - Sootblower Control System |
| Combustion Gas System: |
| - Ductwork and Expansion Joints - Cyclone Outlet to Air Heater Inlet |
| - Ductwork – Air Heater Outlet to ESP Inlet |
| - I.D. Fan w/Drive (existing) |
| - Ductwork – ID Fan Outlet to Stack (existing) |
| Air System: |
| - PA Fan w/Drive (by others) |
| - Ductwork – PA Fan Outlets to Air Heater |
| - Ductwork – Air Heater Outlet to Furnace |
| - SA Fan w/Drive (by others) |
| - Ductwork – SA Fan Outlets to Air Heater |
| - Ductwork – Air Heater Outlet to Furnace |
| - Fluidizing Air Blower w/Drive (by others) |
| - Ductwork – FA Blower Outlets to Seal pot |
| Ash Handling System: |
| - Bed Ash Drains and Ash Coolers |
| Structural: |
| - Structural Steel including platforms, walkways, stairways, and ladders |
| - Boiler Internal Grid Steel |
| - Boiler Island Elevator |
| - Pressure Part Support Steel |
| - Boiler Building Siding, Weather Enclosure, HVAC |
| Instrumentation and Controls: |
| - Burner Management (FBSS) Logic |
| - CFB Field Instruments |
| - Controller Drives |
| Refractories: |
| - Material for All Internal Refractory Linings for Furnished Process and Boiler Equipment |
| Insulation and Lagging: |
| - Material for Insulation and Lagging for Heat Conservation and Personnel Protection for furnished equipment |
| Painting: |
| - Shop Prime Paint Coating for Seller furnished Equipment |
| Miscellaneous: |
| - Operator Training Program |
| - Maintenance Training Program |
| - Instruction Manuals |
| - Spare Parts for commissioning |
| - Technical Representation during start-up and testing |
| - Field Erection of Equipment Scope |
| - Freight to Site |

### 7.1.3.2 Sporn Repowering Case Balance of Plant Equipment

This section contains the balance of plant equipment list corresponding to the Sporn Unit #4 repowering case. This list, along with the material and energy balances and supporting performance data, was used to generate plant costs used in the financial analysis. The list below shows only the major new items that were added to the existing plant and does not show existing BOP equipment still in use.

| Equipment Description | Measures | Comments & Issues |
|---|---|---|
| **Topping Turbine/Generator:** | ~32 MWe, 1,080,000 lbm/hr, no extraction | 4,242 psi, 1,292F inlet; 2,015 psi, 1,050F exhaust |
| | | |
| **Balance of Plant Equipment:** | | |
| FW booster pump including valves and controls | Actual discharge head 4,842psi and inlet pressure 2,522psi, flow 1,080,000 lbm/hr | Single pump |
| Full flow condensate polishing system | 950,000 lb/hr condensate flow | Includes foundation and sump |
| Coal feed system from the coal pile to the coal bunker | Top of feeders elev. 676 ft (90 ft above grade) | Includes top works on silos (head house). Assumes conveyor tube can be routed through obstructions with slight rotation of the silos. |
| Transformer | 37.5 MVA | Includes generator leads to transmission interconnection, pad, fire protection, oil containment, metering and protection CTs, etc. Topping turbine rotated 180 deg. |
| Flue gas duct and dampers to precipitator | 210 ft | Includes foundations and crane rental for installation |
| | | |
| **Piping:** | | |
| Link to Demin. from condensate | 1 x 275 ft | |
| Link from Demin. to #1 Feedwater Heater | 1 x 275 ft | |
| Main Steam to Topping Turbine | 1 x 100 ft | Insulated, 1 line, 4,242 psi, 1,292F |
| Topping Turbine to Existing Turbine | 1 x 200 ft | Insulated, 1 line |
| R.H. Inlet Link | 2 x 200 ft | Insulated, 2 lines |
| R.H. Outlet Link | 2 x 200 ft | Insulated, 2 lines |
| Economizer Inlet Link from new Feedwater Booster Pump | 2 x 300 ft | Insulated, 2 lines |

## 7.2 Appendix II - Drawings

This appendix shows drawings of the various Greenfield case boilers (PC, CFB, and CMB$^{TM}$) used in the study. Drawings for the repowering case are also included in this appendix. All drawings included in this appendix are listed below.

**Greenfield Cases:**



**Repowering Cases:**

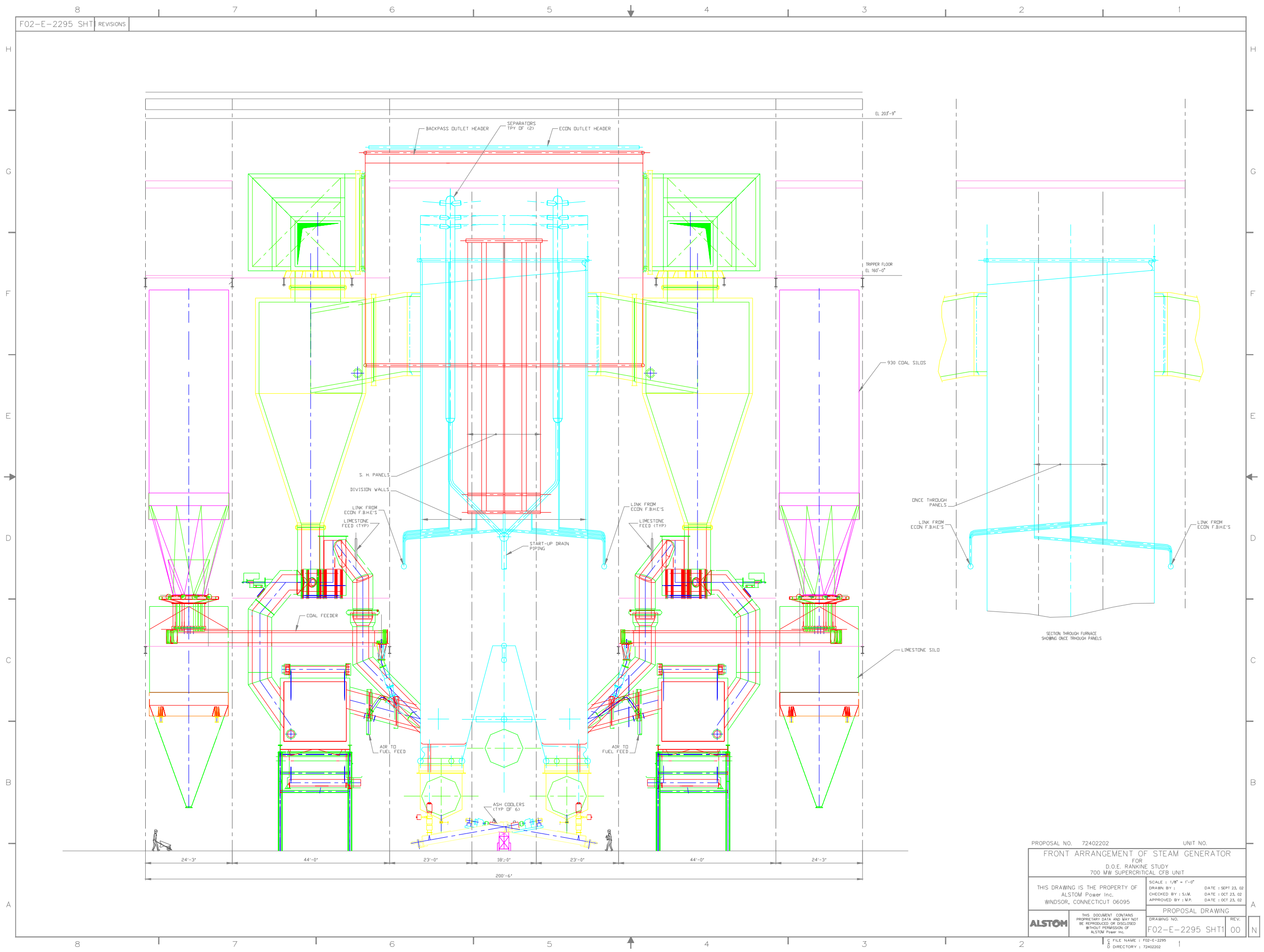



**Figure 7.2. 1 Front Arrangement of 700MW Supercritical CFB Steam Generator**

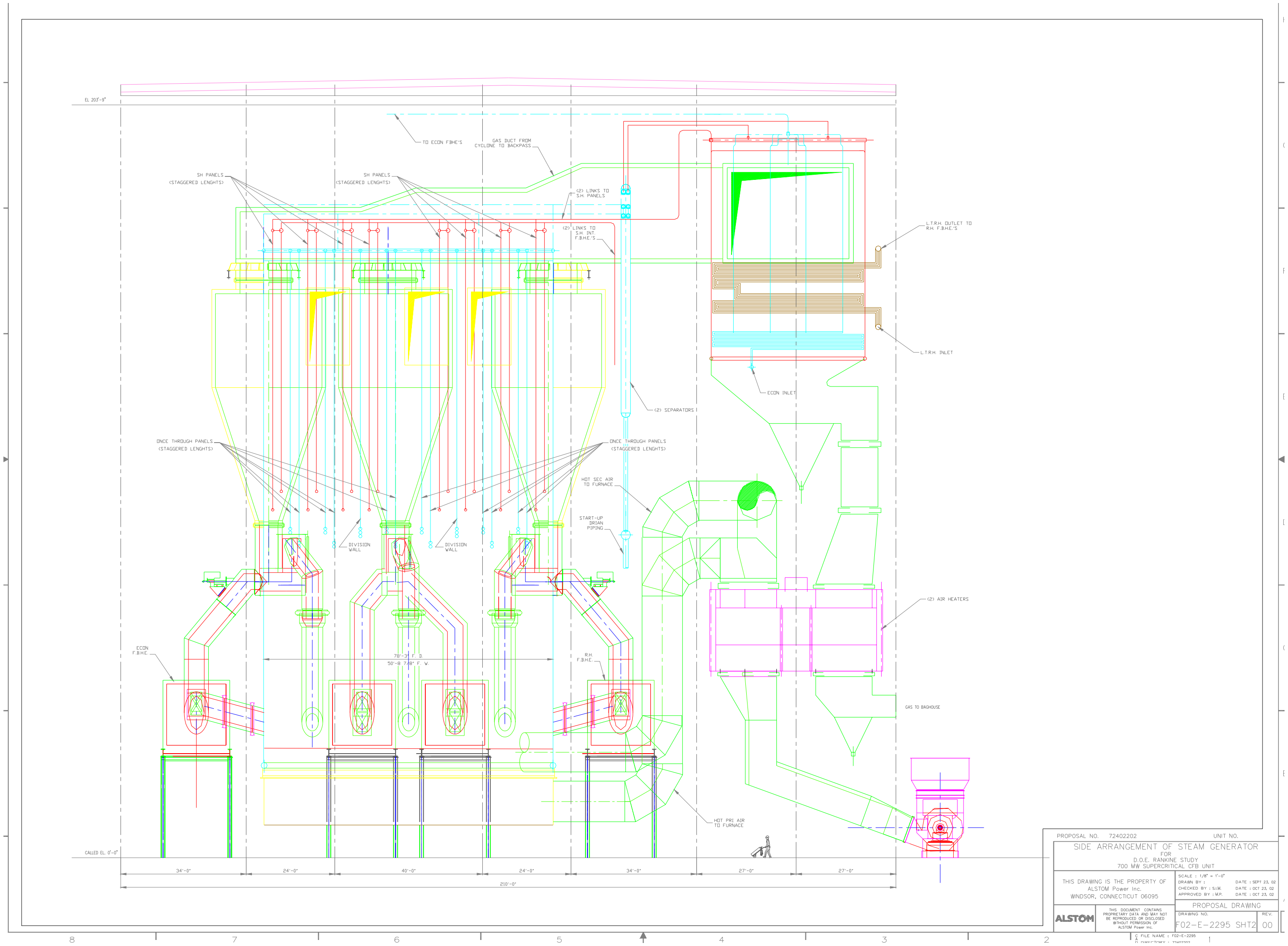


Figure 7.2. 2 Side Arrangement of 700MW Supercritical CFB Steam Generator

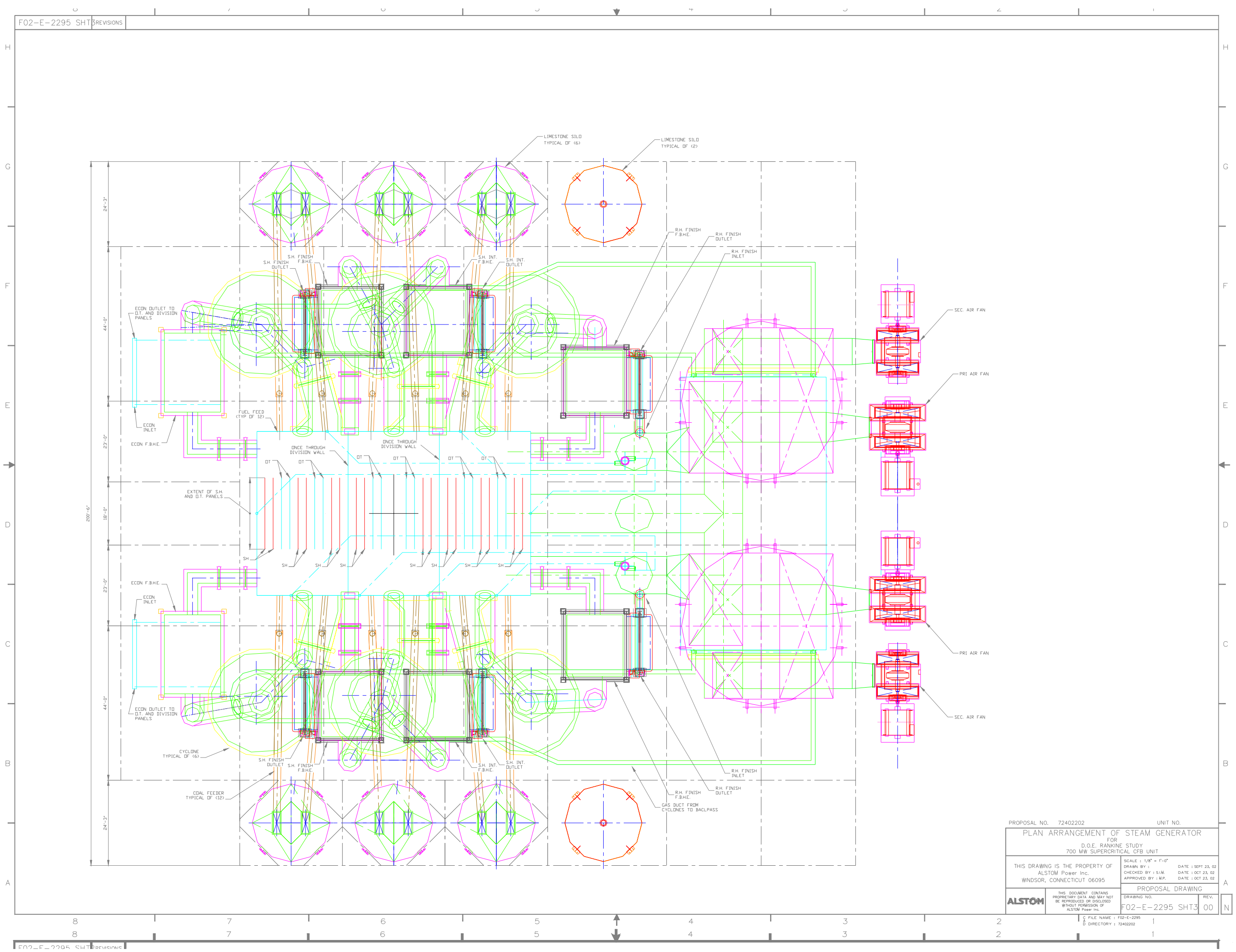



**Figure 7.2. 3 Plan Arrangement of 700MW Supercritical CFB Steam Generator**

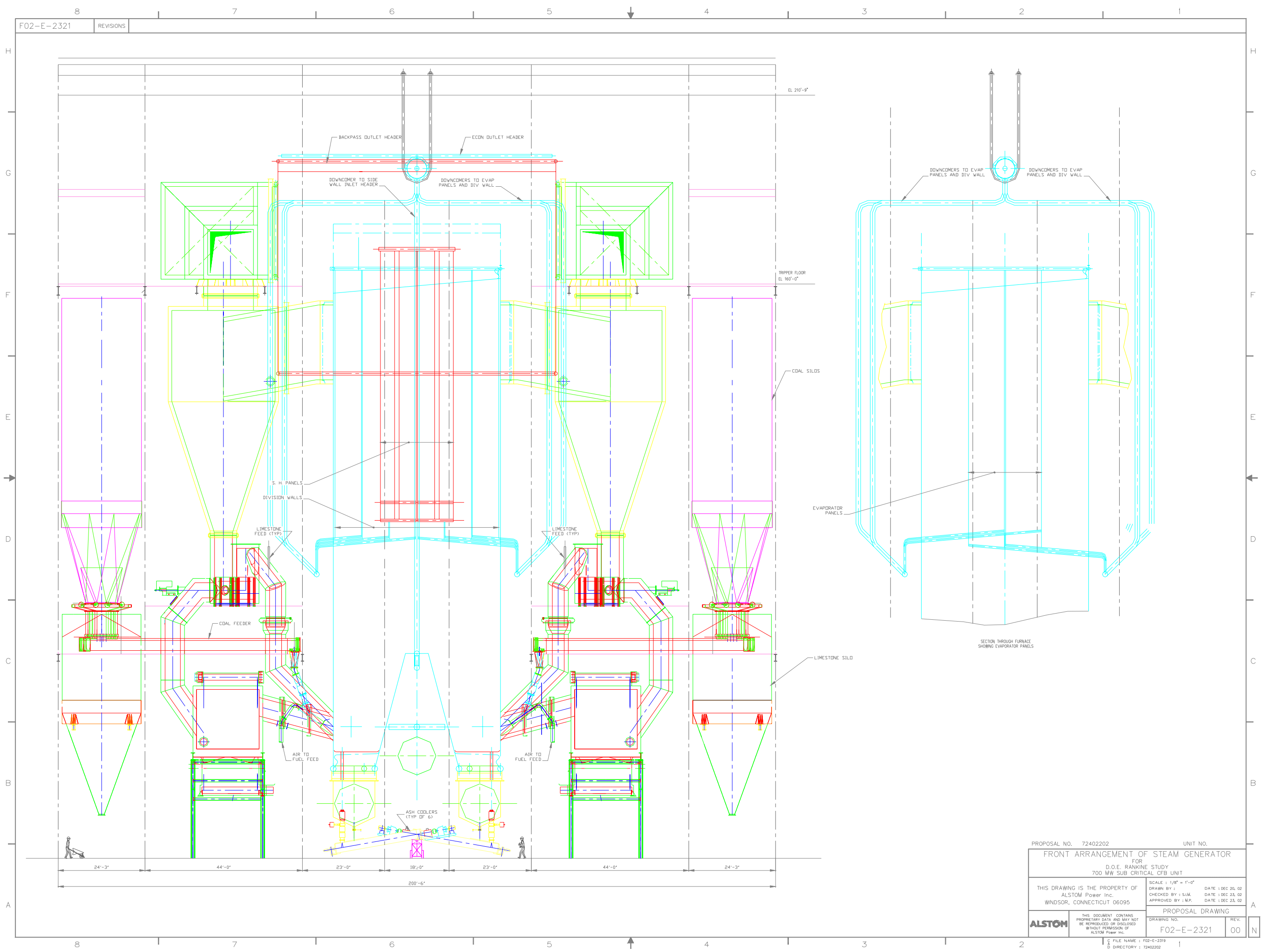



**Figure 7.2. 4 Front Arrangement of 700MW Subcritical CFB Steam Generator**

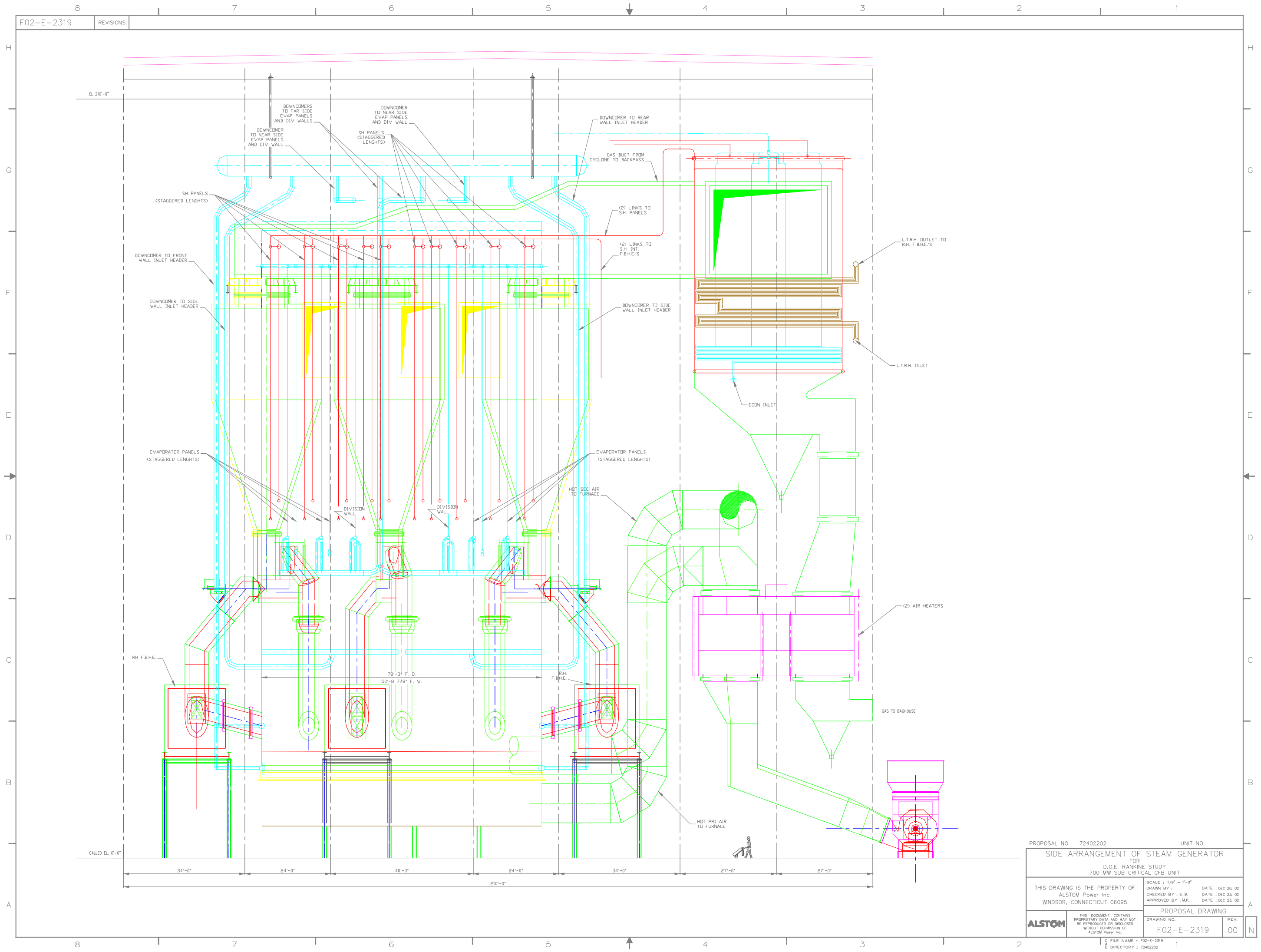



**Figure 7.2. 5 Side Arrangement of 700MW Subcritical CFB Steam Generator**

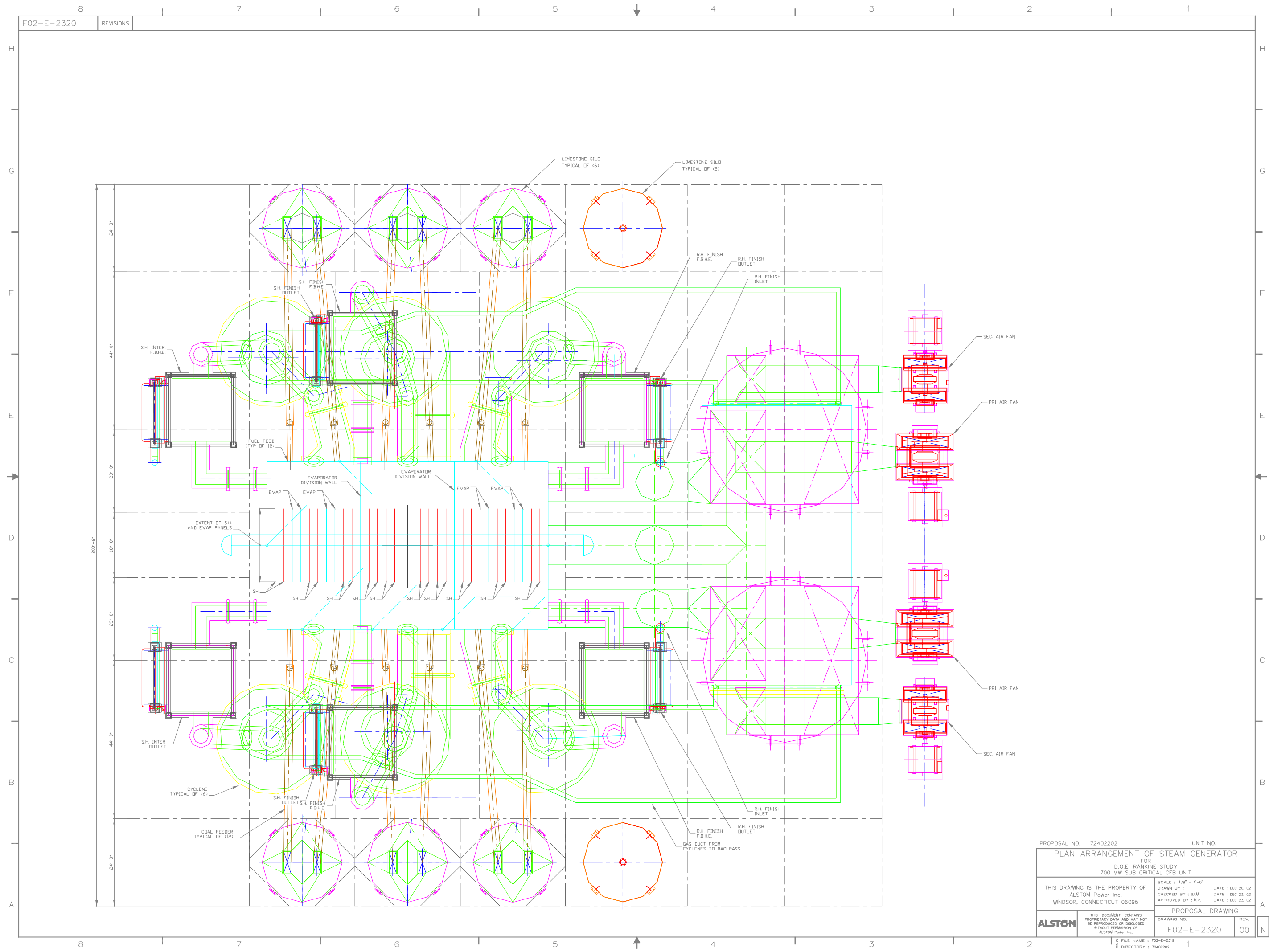



**Figure 7.2. 6 Side Arrangement of 700MW Subcritical CFB Steam Generator**

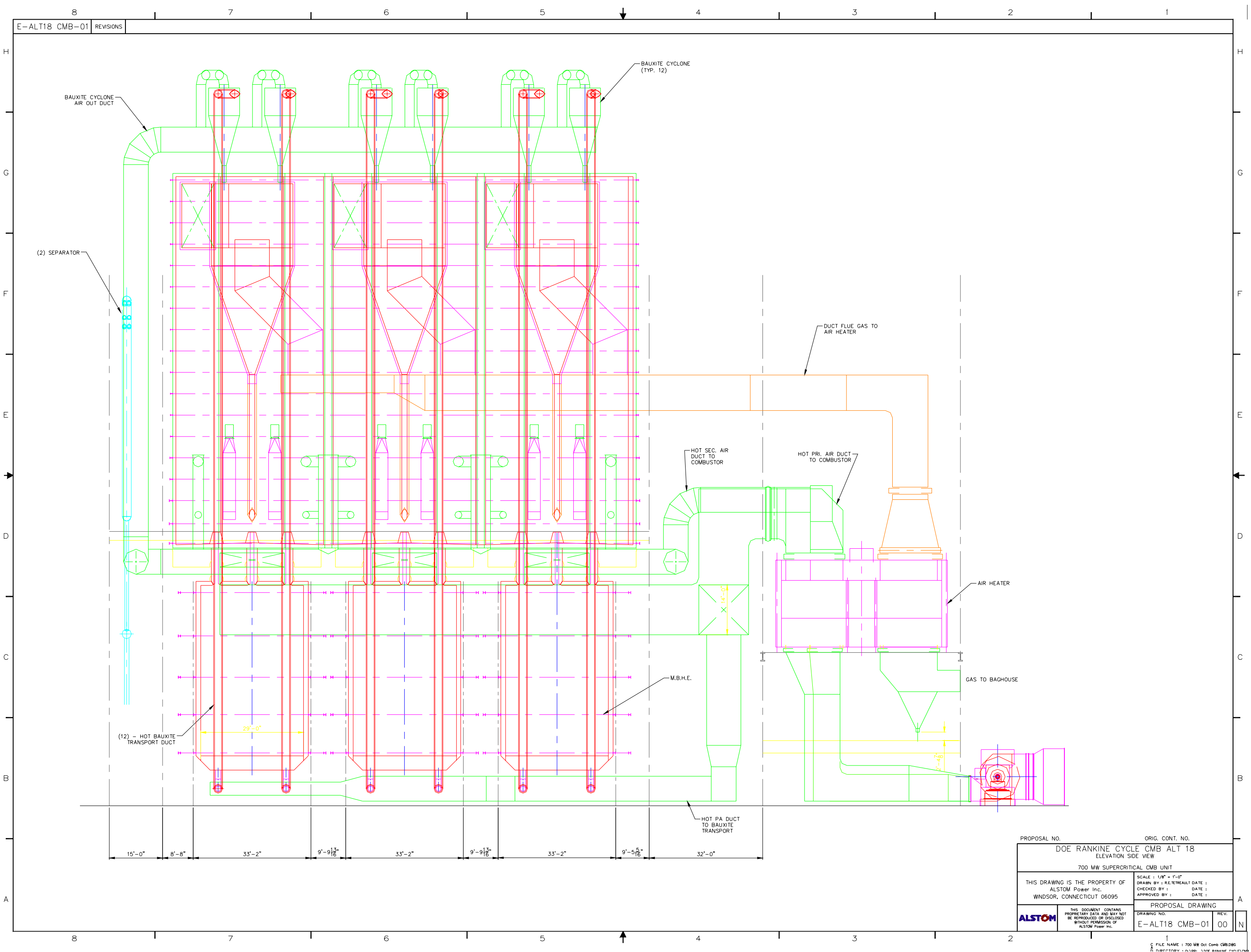



**Figure 7.2. 7 Front Arrangement of 700MW Supercritical CMB Steam Generator**

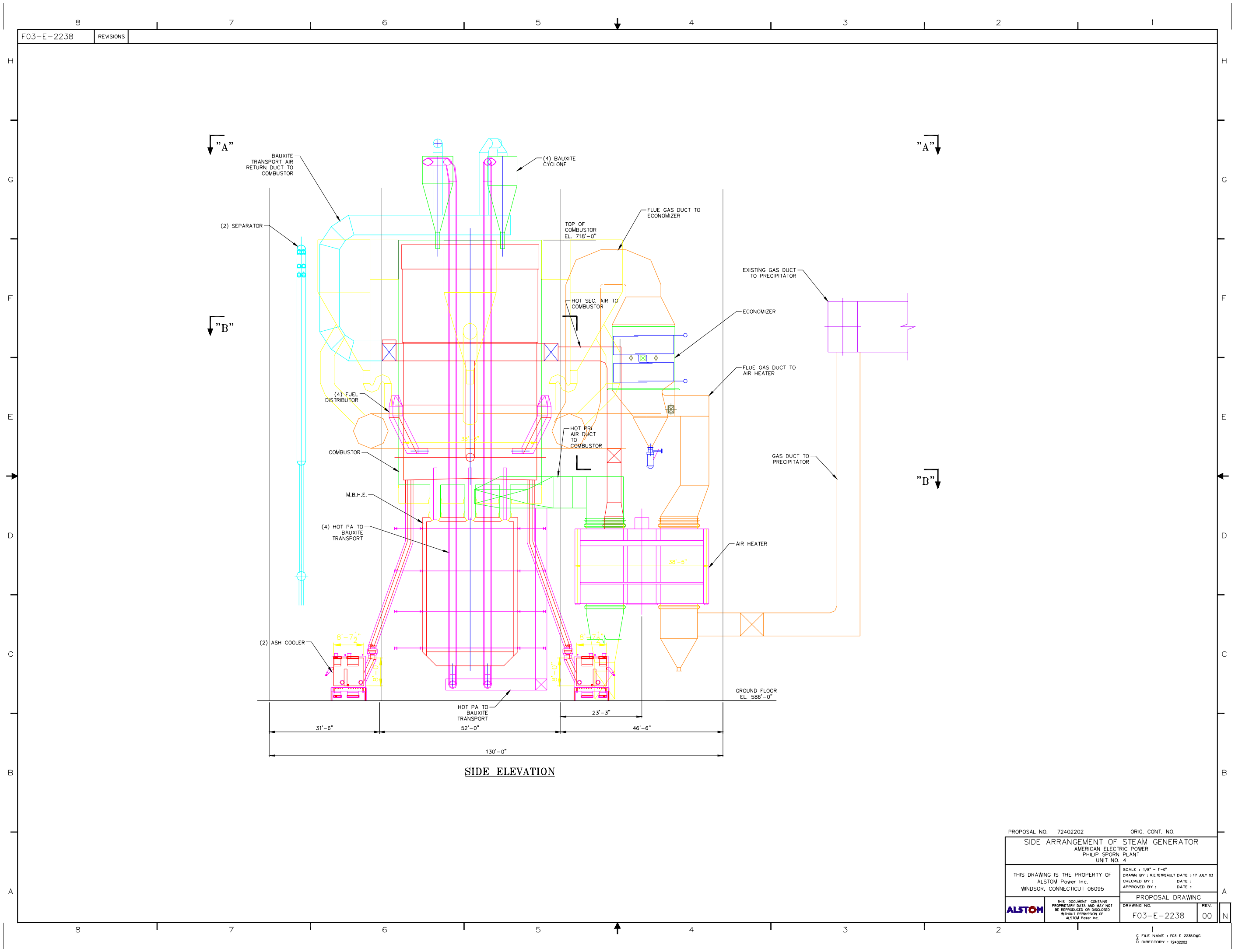



**Figure 7.2. 8 Side Arrangement of 700MW Supercritical CMB Steam Generator**

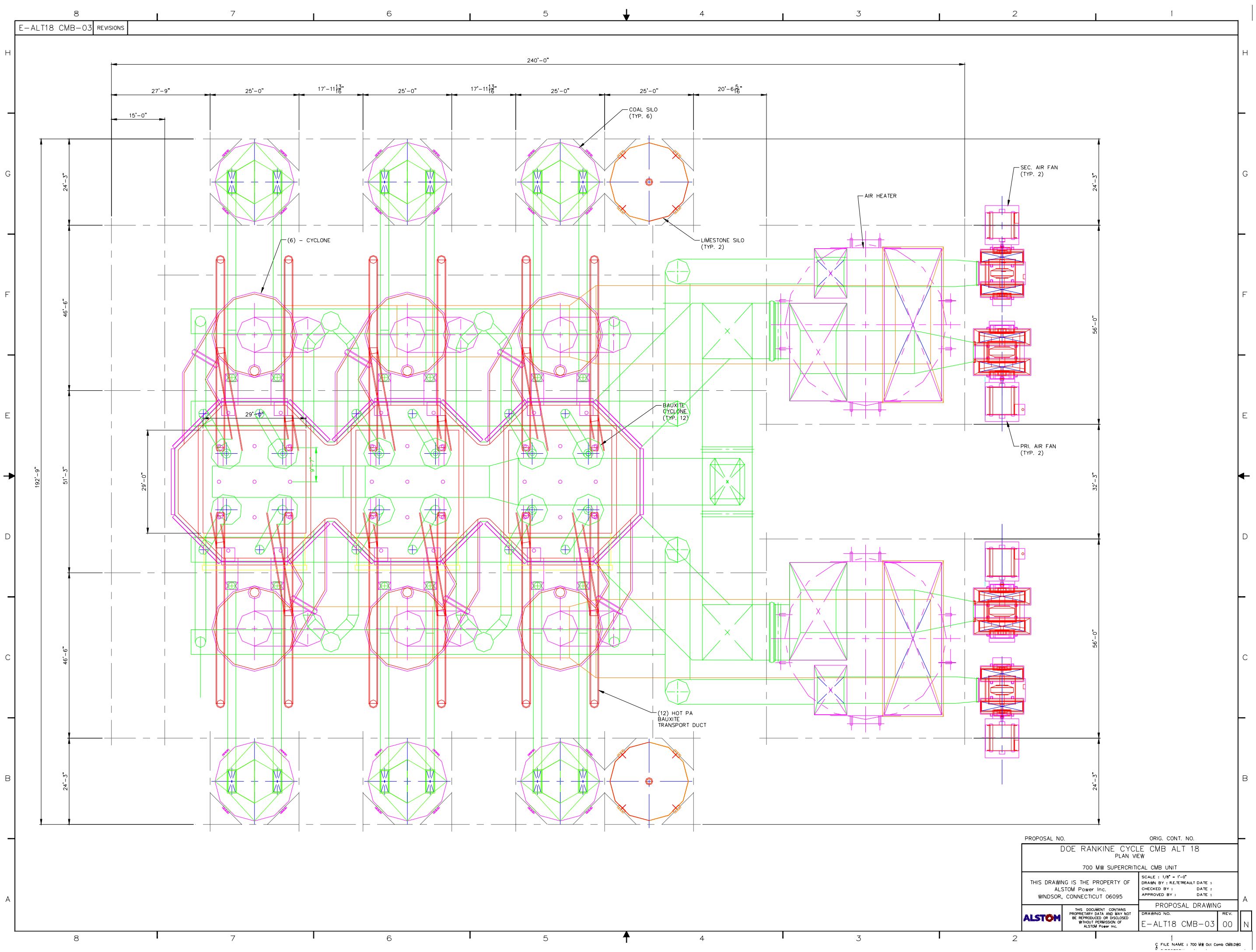



**Figure 7.2. 9 Plan Arrangement of 700MW Supercritical CMB Steam Generator**

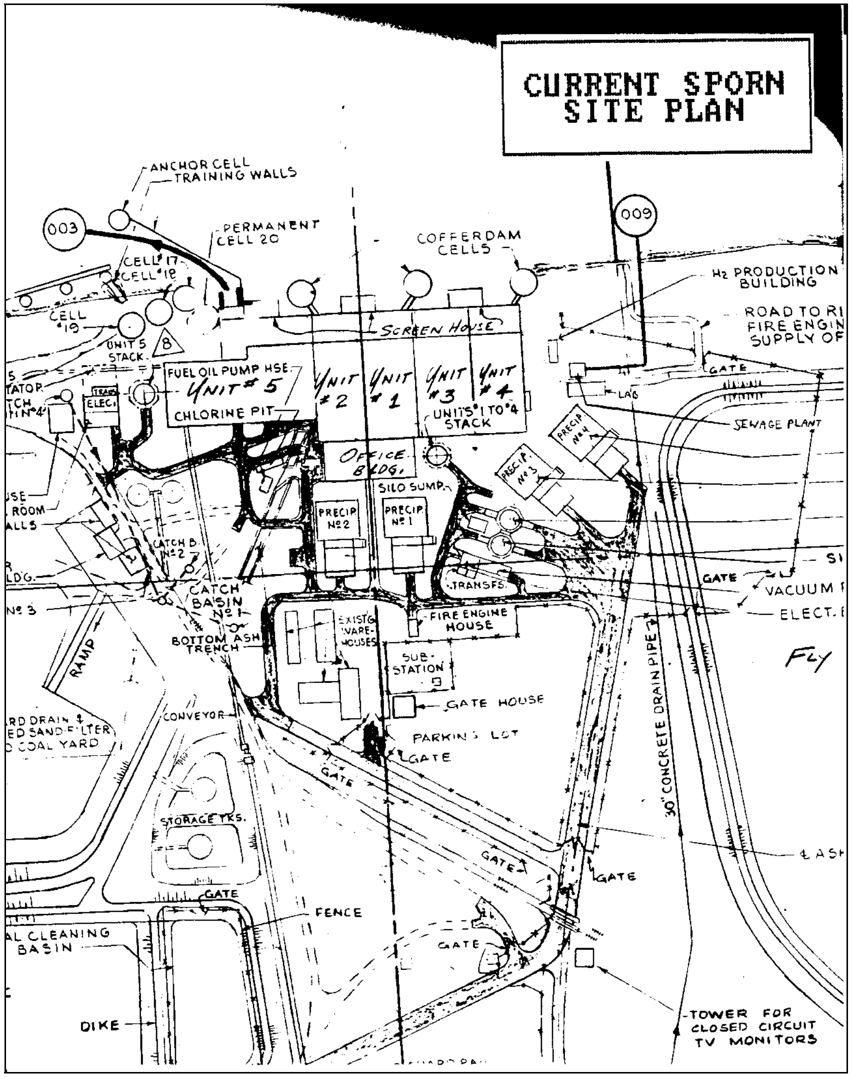



**Figure 7.2.10:Philip Sporn Plant - Plan View of Existing Site**

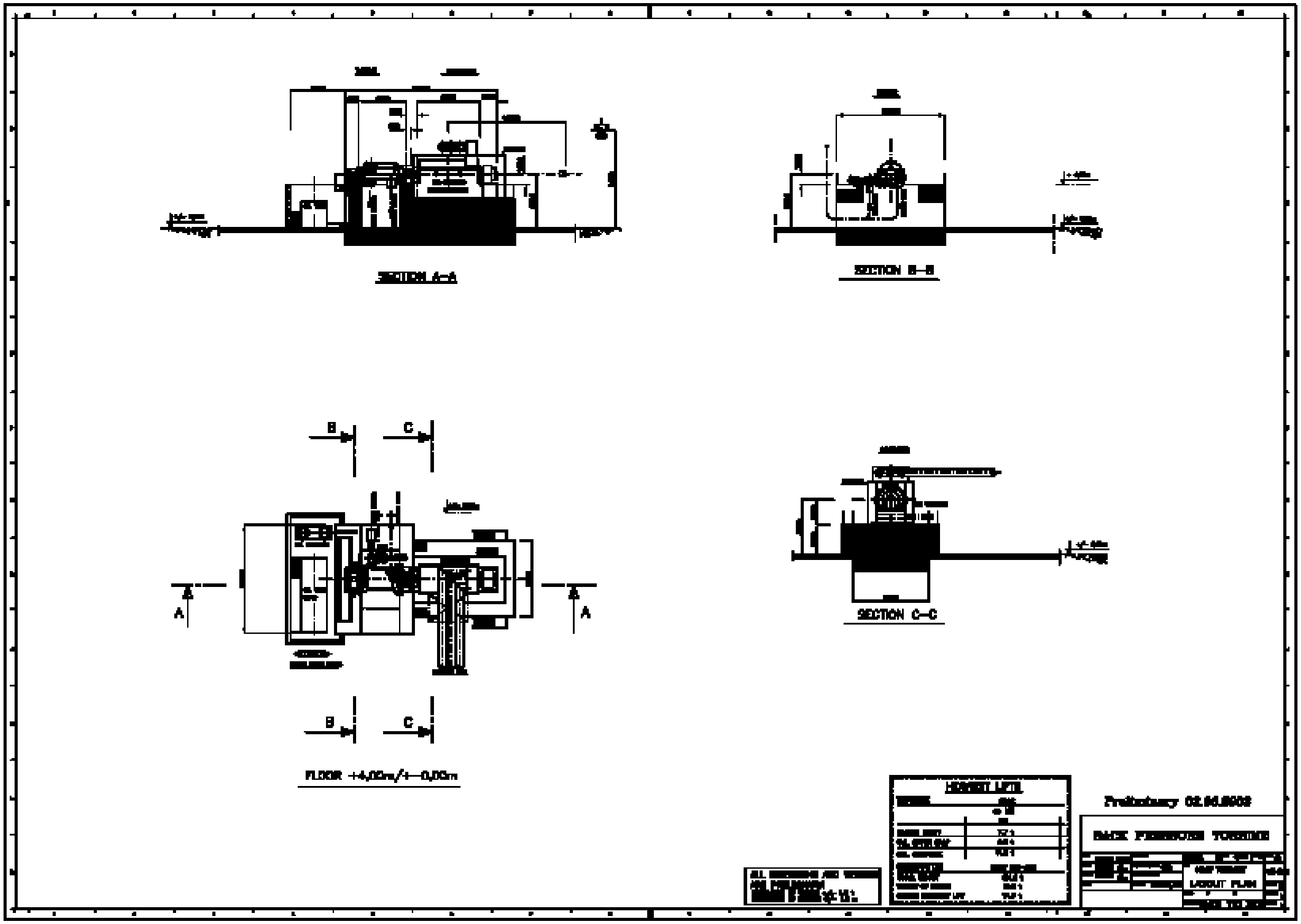



**Figure 7.2.11:Topping Steam Turbine for Sporn Unit #4 Repowering Case**

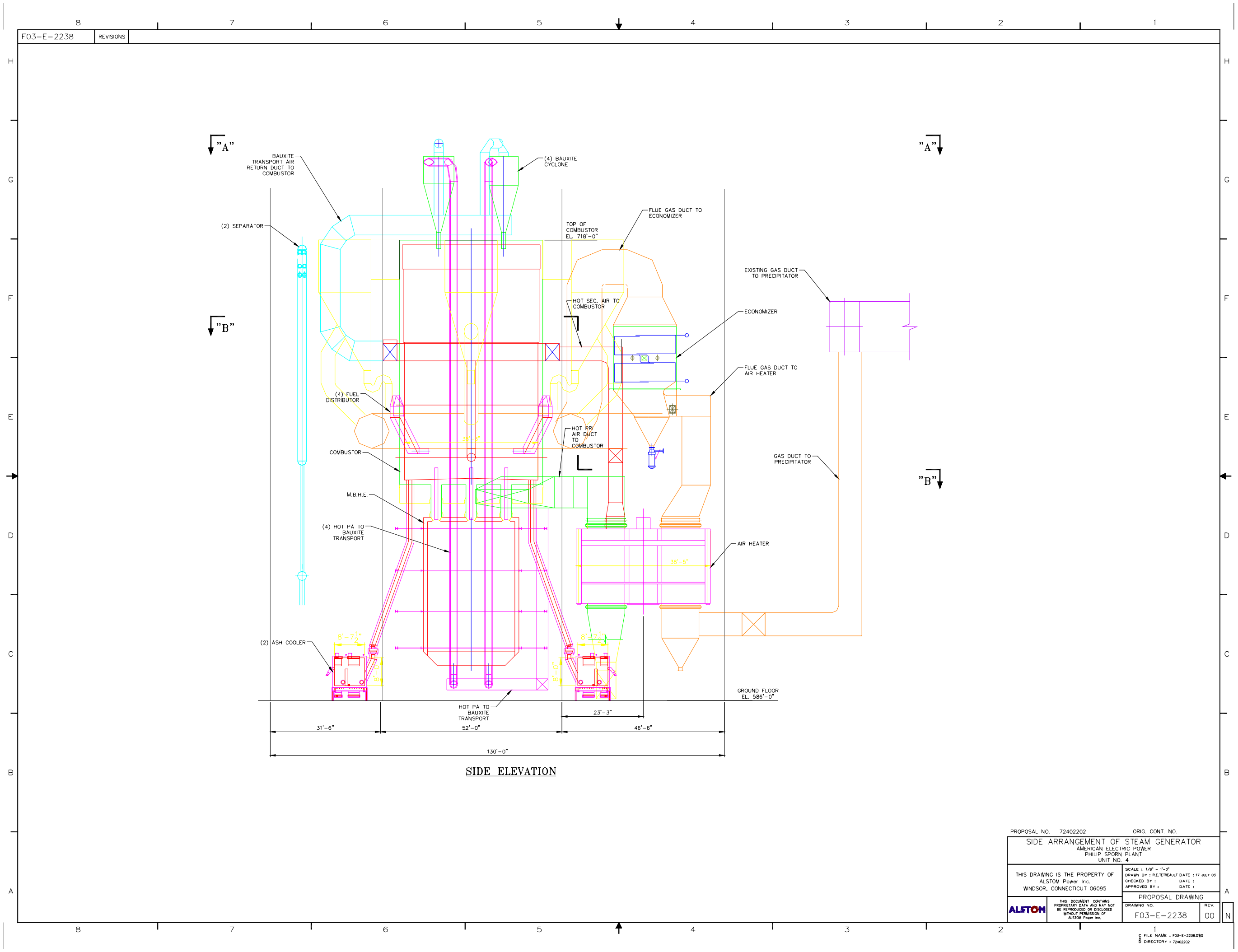



**Figure 7.2.12: Philip Sporn Sectional Side Elevation of Steam Generator Repowering Case**

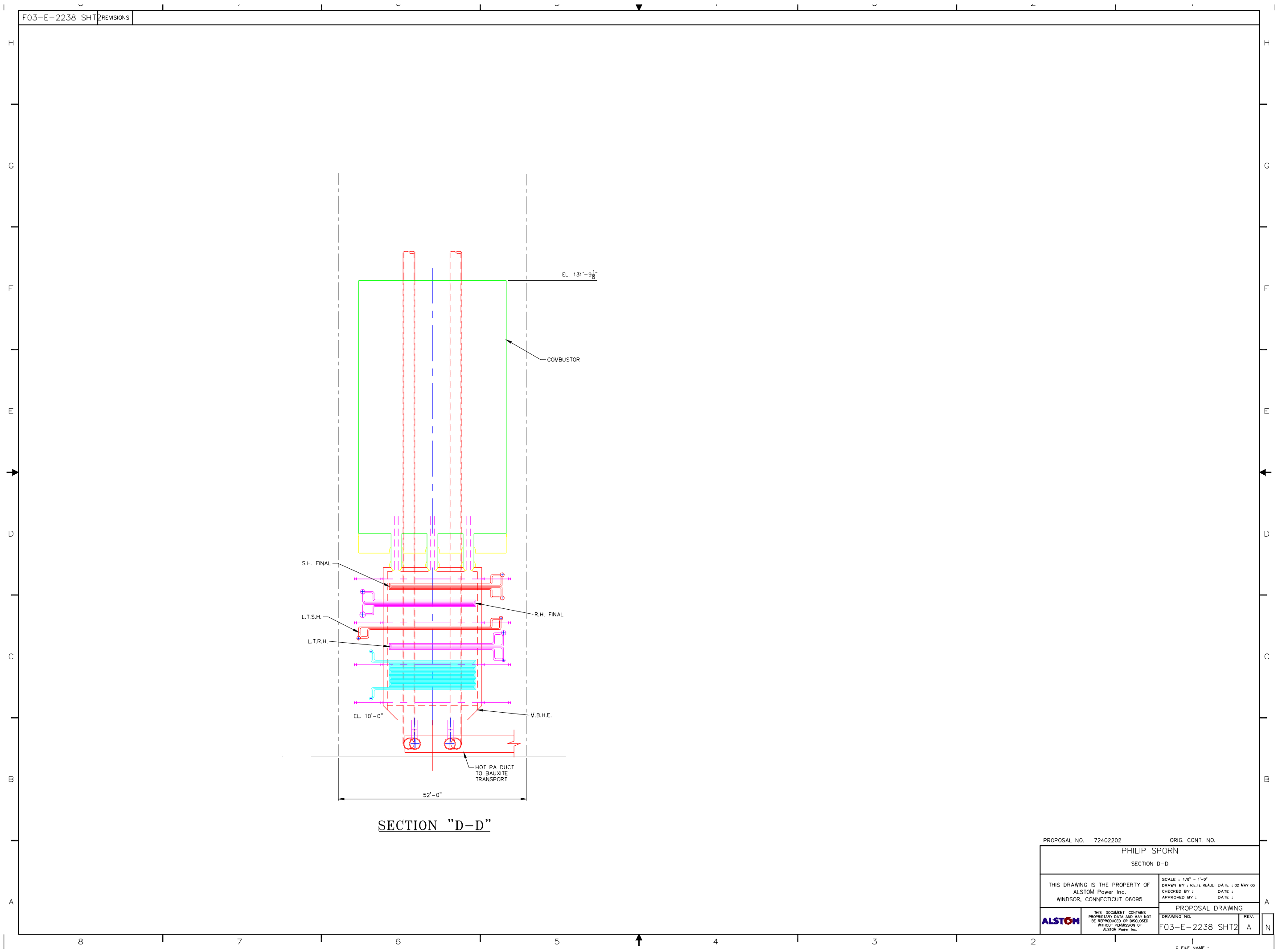



**Figure 7.2.13:Philip Sporn Front Elevation of Steam Generator Repowering Case**

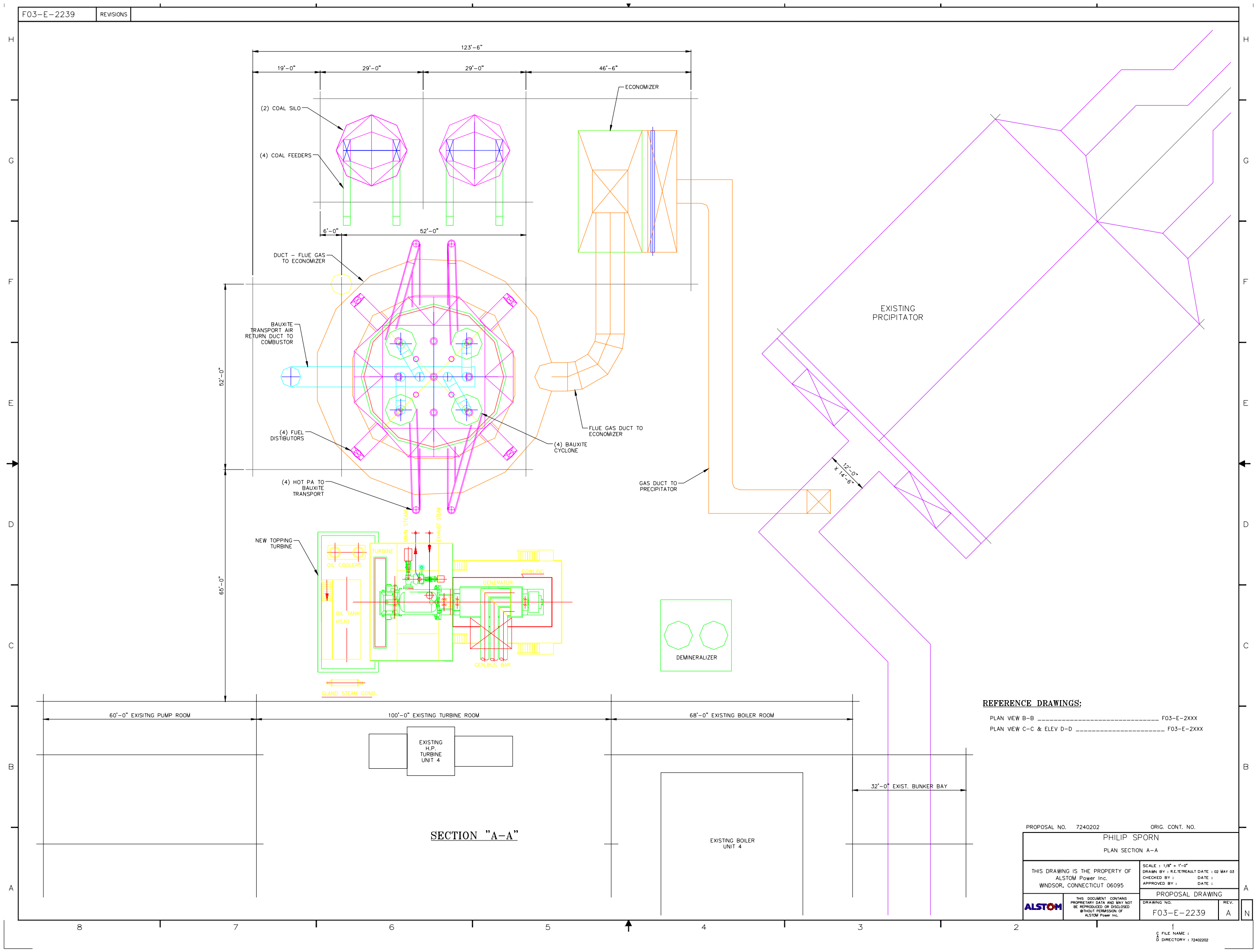



**Figure 7.2. 14: Philip Sporn Plan View of Steam Generator Repowering Case**

## 7.3 Appendix III – Detailed Investment Costs and Operating and Maintenance Costs

This appendix provides plant investment cost breakdowns and operating & maintenance cost breakdowns for each of the ten Greenfield plants studied. The costs tables are presented in the following order: Case PC-1, PC-2, PC-3, PC-4, PC-5, CFB-2, CFB-3, CFB-5, CMB™ -3, and finally Case CMB™ -5.

Additionally, the investment cost breakdown for the Sporn Unit #4 repowering case is also shown as well as operating & maintenance cost breakdowns for both the repowering case and the existing Sporn Unit #4 without modifications.

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants
**Report Date:** 14-Nov-03

**Case:** PC-1; Subcritical Pulverized Coal Fired Boiler Plant
**Plant Size:** 630,526 KWe,net
**Estimate Type:** Conceptual
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,283 | 3,630 | 9,372 | 656 | 25,941 | 2,335 | 0 | 0 | 28,275 | 45 |
| 2 | COAL & SORBENT PREP & FEED | 15,320 | 0 | 4,769 | 334 | 20,424 | 1,838 | 0 | 0 | 22,262 | 35 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 28,634 | 0 | 12,411 | 869 | 41,914 | 3,772 | 0 | 0 | 45,686 | 72 |
| 4 | PC BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 128,693 | 204 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 136,384 | 216 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 54 |
| 8 | STEAM TURBINE GENERATOR | 74,422 | 594 | 19,733 | 1,381 | 96,130 | 8,652 | 0 | 0 | 104,782 | 166 |
| 9 | COOLING WATER SYSTEM | 14,032 | 7,300 | 13,265 | 929 | 35,525 | 3,197 | 0 | 0 | 38,723 | 61 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 10,613 | 139 | 19,410 | 1,359 | 31,521 | 2,837 | 0 | 0 | 34,358 | 54 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,353 | 5,094 | 13,897 | 973 | 36,316 | 3,268 | 0 | 0 | 39,585 | 63 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 36 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 22 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 109 |
| | **TOTAL COST** | **$203,331** | **$46,894** | **$154,799** | **$10,836** | **$415,860** | **$37,427** | **$0** | **$0** | **$718,365** | **$1,139** |

**Table 7.3. 1: Case PC-1 Investment Costs**

**Client:** DOE - NETL

**INITIAL & ANNUAL O&M EXPENSES**

Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case PC-1** - 1 x 630 MW PC Fired Steam Plant

Net Plant Heat Rate (Btu/kWh): 9,218

Net Power Output (kW): 630,526

Capacity Factor (%): 80

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| OPERATING & MAINTENANCE LABOR | | | | | | | |
| Operating Labor | | | | | | | |
| Operating Labor Rate (Base): | 30.90 $/hour | | | | | | |
| Operating Labor Burden: | 30.00 % | | | | | | |
| Labor O-H change Rate: | 25.00 % of O&M labor | | | | | | |
| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant | | | | | |
| Skilled Operator | 2.0 | 2.0 | | | | | |
| Operator | 9.0 | 9.0 | | | | | |
| Foreman | 1.0 | 1.0 | | | | | |
| Lab Tech's, etc. | 2.0 | 2.0 | | | | | |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 | | | | | |
| | | | | | | Annual Cost $ / year | Annual Unit Cost $/kW-net |
| Annual Operating Labor Costs (calc'd) | | | | | | 4,926,449 | 7.81 |
| Maintenance Labor Costs (calc'd) | | | | | | 2,785,124 | 4.42 |
| Administrative & Support Labor (calc'd) | | | | | | 1,927,893 | 3.06 |
| ***TOTAL FIXED OPERATING COSTS*** | | | | | | ***9,639,466*** | ***15.29*** |
| | | | | | | | $/kWh-net |
| Maintenance Material Cost (calc'd) | | | | | | 3,342,149 | 0.00076 |
| **Consumables** | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | | 887,253 | 0.00020 |
| Chemicals | | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | | 1,155,479 | 0.00026 |
| Limestone (ton) | 19,880 | 662.7 | 10.00 | 198,801 | | 1,935,000 | 0.00044 |
| Formic Acid (lbs.) | | | 0.60 | | | | |
| Ammonia, NH3 (ton) | 210 | 7.0 | 150 | 31,500 | | 306,600 | 0.00007 |
| Subtotal Chemicals: | | | | 349,015 | | 3,397,079 | 0.00077 |
| Other Consumables | | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | 5,840,000 | 0.0013 |
| Emissions Penalties | | | | | | | |
| Subtotal Other: | | | | | | | |
| Waste Disposal | | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 1,180.6 | 8.00 | | | 2,757,860 | 0.0006 |
| Subtotal Solid Waste Disposal: | | | | | | 2,757,860 | 0.0006 |
| By-Products | | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | | 0 | 0.0000 |
| Sludge (ton) | | 900.0 | 8.00 | | | 2,102,400 | 0.0005 |
| Subtotal By-Products: | | | | | | 2,102,400 | 0.0005 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | | ***18,326,741*** | ***0.0041*** |

Annual Generation 4419 (MM-kwhr/yr)
Total O&M Cost 0.63 (Cents/kwhr)

**Table 7.3. 2: Case PC-1 Operating and Maintenance Costs**

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants
**Report Date:** 14-Nov-03

**Case:** PC-2; Subcritical Pulverized Coal Fired Boiler Plant
**Plant Size:** 646,080 KWe,net
**Estimate Type:** Conceptual
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,283 | 3,630 | 9,372 | 656 | 25,941 | 2,335 | 0 | 0 | 28,275 | 44 |
| 2 | COAL & SORBENT PREP & FEED | 15,320 | 0 | 4,769 | 334 | 20,424 | 1,838 | 0 | 0 | 22,262 | 34 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 29,463 | 0 | 12,771 | 894 | 43,128 | 3,882 | 0 | 0 | 47,010 | 73 |
| 4 | PC BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 129,534 | 200 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 136,384 | 211 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 53 |
| 8 | STEAM TURBINE GENERATOR | 79,198 | 632 | 21,000 | 1,470 | 102,300 | 9,207 | 0 | 0 | 111,507 | 173 |
| 9 | COOLING WATER SYSTEM | 13,980 | 7,273 | 13,216 | 925 | 35,395 | 3,186 | 0 | 0 | 38,581 | 60 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 10,613 | 139 | 19,410 | 1,359 | 31,521 | 2,837 | 0 | 0 | 34,358 | 53 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,401 | 5,109 | 13,938 | 976 | 36,424 | 3,278 | 0 | 0 | 39,702 | 61 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 35 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 21 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 107 |
| | **TOTAL COST** | **$208,935** | **$46,921** | **$156,418** | **$10,949** | **$423,223** | **$38,090** | **$0** | **$0** | **$727,231** | **$1,126** |

**Table 7.3. 3: Case PC-2 Investment Costs**

**Client:** DOE - NETL

**INITIAL & ANNUAL O&M EXPENSES**

Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Improvenents for Coal Fired Power Plants

**Case PC-2** - 1x650 MW PC Fired Steam Plant

Net Plant Heat Rate (Btu/kWh): 8,997

Net Power Output (kW): 646,080

Capacity Factor (%): 80

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.63 |
| Maintenance Labor Costs (calc'd) | 2,820,586 | 4.37 |
| Administrative & Support Labor (calc'd) | 1,936,759 | 3.00 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,683,793*** | ***14.99*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 3,384,703 | 0.00075 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00020 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00026 |
| Limestone (ton) | 19,880 | 662.7 | 10.00 | 198,801 | 1,935,000 | 0.00043 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | 7.0 | 150 | 31,500 | 306,600 | 0.00007 |
| Subtotal Chemicals: | | | | 349,015 | 3,397,079 | 0.00075 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | 5,840,000 | 0.0013 |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 1,180.6 | 8.00 | | 2,757,860 | 0.0006 |
| Subtotal Solid Waste Disposal: | | | | | 2,757,860 | 0.0006 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 900.0 | 8.00 | | 2,102,400 | 0.0005 |
| Subtotal By-Products: | | | | | 2,102,400 | 0.0005 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***18,369,295*** | ***0.0041*** |

| | | |
|---|---|---|
| Annual Generation | 4528 | (MM-kwhr/yr) |
| Total O&M Cost | 0.62 | (Cents/kwhr) |

## Table 7.3. 4: Case PC-2 Operating and Maintenance Costs

TOTAL PLANT COST SUMMARY

**Client:** DOE - NETL
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants
**Report Date:** 14-Nov-03

**Case:** PC-3; Supercritical Pulverized Coal Fired Boiler Plant
**Plant Size:** 662,936 KWe,net
**Estimate Type:** Conceptual
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,283 | 3,630 | 9,372 | 656 | 25,941 | 2,335 | 0 | 0 | 28,275 | 43 |
| 2 | COAL & SORBENT PREP & FEED | 15,320 | 0 | 4,769 | 334 | 20,424 | 1,838 | 0 | 0 | 22,262 | 34 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 29,980 | 0 | 12,995 | 910 | 43,884 | 3,950 | 0 | 0 | 47,834 | 72 |
| 4 | PC BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 132,145 | 199 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 136,384 | 206 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 52 |
| 8 | STEAM TURBINE GENERATOR | 81,935 | 654 | 21,725 | 1,521 | 105,835 | 9,525 | 0 | 0 | 115,360 | 174 |
| 9 | COOLING WATER SYSTEM | 13,920 | 7,242 | 13,159 | 921 | 35,243 | 3,172 | 0 | 0 | 38,415 | 58 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 10,613 | 139 | 19,410 | 1,359 | 31,521 | 2,837 | 0 | 0 | 34,358 | 52 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,619 | 5,177 | 14,123 | 989 | 36,908 | 3,322 | 0 | 0 | 40,229 | 61 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 34 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 21 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 104 |
| | **TOTAL COST** | **$212,345** | **$46,979** | **$157,495** | **$11,025** | **$427,844** | **$38,506** | **$0** | **$0** | **$734,880** | **$1,109** |

**Table 7.3. 5: Case PC-3 Investment Costs**

**Client:** DOE - NETL

**INITIAL & ANNUAL O&M EXPENSES**

Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Improvenements for Coal Fired Power Plants

**Case PC-3** - 1x660 MW PC Fired Steam Plant

Net Plant Heat Rate (Btu/kWh): 8,768

Net Power Output (kW): 662,936

Capacity Factor (%): 80

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.43 |
| Maintenance Labor Costs (calc'd) | 2,851,182 | 4.30 |
| Administrative & Support Labor (calc'd) | 1,944,408 | 2.93 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,722,038*** | ***14.67*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 3,421,418 | 0.00074 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00019 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00025 |
| Limestone (ton) | 19,880 | 662.7 | 10.00 | 198,801 | 1,935,000 | 0.00042 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | 7.0 | 150 | 31,500 | 306,600 | 0.00007 |
| Subtotal Chemicals: | | | | 349,015 | 3,397,079 | 0.00073 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | 5,840,000 | 0.0013 |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 1,180.6 | 8.00 | | 2,757,860 | 0.0006 |
| Subtotal Solid Waste Disposal: | | | | | 2,757,860 | 0.0006 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 900.0 | 8.00 | | 2,102,400 | 0.0005 |
| Subtotal By-Products: | | | | | 2,102,400 | 0.0005 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***18,406,010*** | ***0.0040*** |

| | | |
|---|---|---|
| Annual Generation | 4646 | (MM-kwhr/yr) |
| Total O&M Cost | 0.61 | (Cents/kwhr) |

**Table 7.3. 6: Case PC-3 Operating and Maintenance Costs**

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL
**Report Date:** 14-Nov-03
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case:** PC-4; Supercritical Pulverized Coal Fired Boiler Plant
**Estimate Type:** Conceptual
**Plant Size:** 677,479 KWe,net
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor | | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Direct | Indirect | | | Process | Project | $ | $/kW |
| 1 | COAL & SORBENT HANDLING | 12,283 | 3,630 | 9,372 | 656 | 25,941 | 2,335 | 0 | 0 | 28,275 | 42 |
| 2 | COAL & SORBENT PREP & FEED | 15,320 | 0 | 4,769 | 334 | 20,424 | 1,838 | 0 | 0 | 22,262 | 33 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 30,726 | 0 | 13,318 | 932 | 44,976 | 4,048 | 0 | 0 | 49,024 | 72 |
| 4 | PC BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 134,345 | 198 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 136,384 | 201 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 50 |
| 8 | STEAM TURBINE GENERATOR | 85,826 | 685 | 22,757 | 1,593 | 110,861 | 9,978 | 0 | 0 | 120,839 | 178 |
| 9 | COOLING WATER SYSTEM | 13,857 | 7,209 | 13,100 | 917 | 35,082 | 3,157 | 0 | 0 | 38,240 | 56 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 10,613 | 139 | 19,410 | 1,359 | 31,521 | 2,837 | 0 | 0 | 34,358 | 51 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,738 | 5,214 | 14,224 | 996 | 37,171 | 3,345 | 0 | 0 | 40,516 | 60 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 34 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 20 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 102 |
| | **TOTAL COST** | **$217,038** | **$47,014** | **$158,891** | **$11,122** | **$434,066** | **$39,066** | **$0** | **$0** | **$743,861** | **$1,098** |

**Table 7.3. 7: Case PC-4 Investment Costs**

| | | |
|---|---|---|
| **Client:** DOE - NETL | **INITIAL & ANNUAL O&M EXPENSES** | Cost Base: Jul-03 |
| **Project:** Economics and Feasibility of Rankine Cycle Improvenements for Coal Fired Power Plants | **Case PC-4** - 1x680 MW PC Fired Steam Plant | |
| | | Net Plant Heat Rate (Btu/kWh): 8,580 |
| | | Net Power Output (kW): 677,479 |
| | | Capacity Factor (%): 80 |

OPERATING & MAINTENANCE LABOR

Operating Labor

| | |
|---|---|
| Operating Labor Rate (Base): | 30.90 $/hour |
| Operating Labor Burden: | 30.00 % |
| Labor O-H change Rate: | 25.00 % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.27 |
| Maintenance Labor Costs (calc'd) | 2,887,106 | 4.26 |
| Administrative & Support Labor (calc'd) | 1,953,389 | 2.88 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,766,944*** | ***14.42*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 3,464,528 | 0.00073 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00019 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00024 |
| Limestone (ton) | 19,880 | 662.7 | 10.00 | 198,801 | 1,935,000 | 0.00041 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | 7.0 | 150 | 31,500 | 306,600 | 0.00006 |
| Subtotal Chemicals: | | | | 349,015 | 3,397,079 | 0.00072 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | 5,840,000 | 0.0012 |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 1,180.6 | 8.00 | | 2,757,860 | 0.0006 |
| Subtotal Solid Waste Disposal: | | | | | 2,757,860 | 0.0006 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 900.0 | 8.00 | | 2,102,400 | 0.0004 |
| Subtotal By-Products: | | | | | 2,102,400 | 0.0004 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***18,449,120*** | ***0.0039*** |

| | |
|---|---|
| Annual Generation | 4748 (MM-kwhr/yr) |
| Total O&M Cost | 0.59 (Cents/kwhr) |

**Table 7.3. 8: Case PC-4 Operating and Maintenance Costs**

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL **Report Date:** 14-Nov-03
**Project:** Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants

**Case:** PC-5; Ultra-Supercritical Pulverized Coal Fired Boiler Plant **Estimate Type:** Conceptual
**Plant Size:** 741,615 KWe,net **Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,283 | 3,630 | 9,372 | 656 | 25,941 | 2,335 | 0 | 0 | 28,275 | 38 |
| 2 | COAL & SORBENT PREP & FEED | 15,320 | 0 | 4,769 | 334 | 20,424 | 1,838 | 0 | 0 | 22,262 | 30 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 32,919 | 0 | 14,269 | 999 | 48,186 | 4,337 | 0 | 0 | 52,523 | 71 |
| 4 | PC BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 199,460 | 269 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 136,384 | 184 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 46 |
| 8 | STEAM TURBINE GENERATOR | 123,816 | 988 | 32,830 | 2,298 | 159,932 | 14,394 | 0 | 0 | 174,326 | 235 |
| 9 | COOLING WATER SYSTEM | 13,688 | 7,121 | 12,940 | 906 | 34,654 | 3,119 | 0 | 0 | 37,773 | 51 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 10,613 | 139 | 19,410 | 1,359 | 31,521 | 2,837 | 0 | 0 | 34,358 | 46 |
| 11 | ACCESSORY ELECTRIC PLANT | 17,071 | 5,318 | 14,507 | 1,016 | 37,912 | 3,412 | 0 | 0 | 41,324 | 56 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 31 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 19 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 93 |
| | **TOTAL COST** | **$257,384** | **$47,333** | **$170,039** | **$11,903** | **$486,659** | **$43,799** | **$0** | **$0** | **$866,303** | **$1,168** |

**Table 7.3. 9: Case PC-5 Investment Costs**

**Client:** DOE - NETL

**INITIAL & ANNUAL O&M EXPENSES**

Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case PC-5** - 1x740 MW PC Fired Steam Plant

Net Plant Heat Rate (Btu/kWh): 7,838

Net Power Output (kW): 741,615

Capacity Factor (%): 80

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 6.64 |
| Maintenance Labor Costs (calc'd) | 3,376,874 | 4.55 |
| Administrative & Support Labor (calc'd) | 2,075,831 | 2.80 |
| ***TOTAL FIXED OPERATING COSTS*** | ***10,379,154*** | ***14.00*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 4,052,249 | 0.00078 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00017 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00022 |
| Limestone (ton) | 19,880 | 662.7 | 10.00 | 198,801 | 1,935,000 | 0.00037 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | 7.0 | 150 | 31,500 | 306,600 | 0.00006 |
| Subtotal Chemicals: | | | | 349,015 | 3,397,079 | 0.00065 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | 5,840,000 | 0.0011 |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 1,180.6 | 8.00 | | 2,757,860 | 0.0005 |
| Subtotal Solid Waste Disposal: | | | | | 2,757,860 | 0.0005 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 900.0 | 8.00 | | 2,102,400 | 0.0004 |
| Subtotal By-Products: | | | | | 2,102,400 | 0.0004 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***19,036,841*** | ***0.0037*** |

| | | |
|---|---|---|
| Annual Generation | 5197 | (MM-kwhr/yr) |
| Total O&M Cost | 0.57 | (Cents/kwhr) |

**Table 7.3.10: Case PC-5 Operating and Maintenance Costs**

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL **Report Date:** 14-Nov-03
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case:** CFB-2; Subcritical Circulating Fluid Bed Boiler Plant **Estimate Type:** Conceptual
**Plant Size:** 647,588 KWe,net **Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor | | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Direct | Indirect | | | Process | Project | $ | $/kW |
| 1 | COAL & SORBENT HANDLING | 12,693 | 3,630 | 9,496 | 665 | 26,483 | 2,383 | 0 | 0 | 28,867 | 45 |
| 2 | COAL & SORBENT PREP & FEED | 15,457 | 0 | 5,630 | 394 | 21,481 | 1,933 | 0 | 0 | 23,414 | 36 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 29,463 | 0 | 12,771 | 894 | 43,128 | 3,882 | 0 | 0 | 47,010 | 73 |
| 4 | CFB BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 146,955 | 227 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61,889 | 96 |
| | | | | | 0 | | | | | | |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 53 |
| 8 | STEAM TURBINE GENERATOR | 79,198 | 632 | 21,000 | 1,470 | 102,300 | 9,207 | 0 | 0 | 111,507 | 172 |
| 9 | COOLING WATER SYSTEM | 13,980 | 7,273 | 13,216 | 925 | 35,395 | 3,186 | 0 | 0 | 38,581 | 60 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 13,265 | 209 | 24,309 | 1,702 | 39,484 | 3,554 | 0 | 0 | 43,037 | 66 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,401 | 5,109 | 13,938 | 976 | 36,424 | 3,278 | 0 | 0 | 39,702 | 61 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 35 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 21 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 106 |
| | **TOTAL COST** | **$212,134** | **$46,990** | **$162,300** | **$11,361** | **$432,785** | **$38,951** | **$0** | **$0** | **$680,579** | **$1,051** |

**Table 7.3.11: Case CFB-2 Investment Costs**

**Client:** DOE - NETL | **INITIAL & ANNUAL O&M EXPENSES** | Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Improvenements for Coal Fired Power Plants

**Case CFB-2** - 1 x 650 MW CFB Steam Plant

Net Plant Heat Rate (Btu/kWh): 8,976

Net Power Output (kW): 647,588

Capacity Factor (%): 80

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.61 |
| Maintenance Labor Costs (calc'd) | 2,698,760 | 4.17 |
| Administrative & Support Labor (calc'd) | 1,906,302 | 2.94 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,531,512*** | ***14.72*** |
| | | $/kWh-net |
| Maintenance Material Cost (calc'd) | 3,238,513 | 0.00071 |

| **Consumables** | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | Annual Unit Cost $/kWh-net |
|---|---|---|---|---|---|---|
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00020 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00025 |
| Limestone (ton) | 23,086 | 769.5 | 10.00 | 230,861 | 2,247,045 | 0.00050 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | 150 | | 85,680 | 0.00002 |
| Subtotal Chemicals: | | | | 349,574 | 3,488,204 | 0.00075 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 2,187.5 | 8.00 | | 5,109,896 | 0.0011 |
| Subtotal Solid Waste Disposal: | | | | | 5,109,896 | 0.0011 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***12,723,866*** | ***0.0028*** |

| | | |
|---|---|---|
| Annual Generation | 4538 | (MM-kwhr/yr) |
| Total O&M Cost | 0.49 | (Cents/kwhr) |

**Table 7.3.12: Case CFB-2 Operating and Maintenance Costs**

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants
**Report Date:** 14-Nov-03

**Case:** CFB-3; Supercritical Circulating Fluid Bed Boiler Plant
**Plant Size:** 663,823 KWe,net
**Estimate Type:** Conceptual
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,693 | 3,630 | 9,496 | 665 | 26,483 | 2,383 | 0 | 0 | 28,867 | 43 |
| 2 | COAL & SORBENT PREP & FEED | 15,457 | 0 | 5,630 | 394 | 21,481 | 1,933 | 0 | 0 | 23,414 | 35 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 29,980 | 0 | 12,995 | 910 | 43,884 | 3,950 | 0 | 0 | 47,834 | 72 |
| 4 | CFB BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 150,114 | 226 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61,889 | 93 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 51 |
| 8 | STEAM TURBINE GENERATOR | 81,935 | 654 | 21,725 | 1,521 | 105,835 | 9,525 | 0 | 0 | 115,360 | 174 |
| 9 | COOLING WATER SYSTEM | 13,920 | 7,242 | 13,159 | 921 | 35,243 | 3,172 | 0 | 0 | 38,415 | 58 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 13,265 | 209 | 24,309 | 1,702 | 39,484 | 3,554 | 0 | 0 | 43,037 | 65 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,619 | 5,177 | 14,123 | 989 | 36,908 | 3,322 | 0 | 0 | 40,229 | 61 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 34 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 21 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 104 |
| | **TOTAL COST** | **$215,545** | **$47,048** | **$163,377** | **$11,436** | **$437,406** | **$39,367** | **$0** | **$0** | **$688,776** | **$1,038** |

**Table 7.3.13: Case CFB-3 Investment Costs**

**Client:** DOE - NETL

**INITIAL & ANNUAL O&M EXPENSES**

Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants

**Case CFB-3** - 1 x 660 MW CFB Steam Plant

Net Plant Heat Rate (Btu/kWh): 8,756

Net Power Output (kW): 663,823

Capacity Factor (%): 80

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.42 |
| Maintenance Labor Costs (calc'd) | 2,731,547 | 4.11 |
| Administrative & Support Labor (calc'd) | 1,914,499 | 2.88 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,572,495*** | ***14.42*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 3,277,857 | 0.00070 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00019 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00025 |
| Limestone (ton) | 23,086 | 769.5 | 10.00 | 230,861 | 2,247,045 | 0.00048 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | 150 | | 85,680 | 0.00002 |
| Subtotal Chemicals: | | | | 349,574 | 3,488,204 | 0.00073 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 2,187.5 | 8.00 | | 5,109,896 | 0.0011 |
| Subtotal Solid Waste Disposal: | | | | | 5,109,896 | 0.0011 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***12,763,210*** | ***0.0027*** |

| | | |
|---|---|---|
| Annual Generation | 4652 | (MM-kwhr/yr) |
| Total O&M Cost | 0.48 | (Cents/kwhr) |

## Table 7.3.14: Case CFB-3 Operating and Maintenance Costs

TOTAL PLANT COST SUMMARY

**Client:** DOE - NETL
**Report Date:** 14-Nov-03
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case:** CFB-4; Supercritical Circulating Fluid Bed Boiler Plant
**Estimate Type:** Conceptual
**Plant Size:** 678,366 KWe,net
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,693 | 3,630 | 9,496 | 665 | 26,483 | 2,383 | 0 | 0 | 28,867 | 43 |
| 2 | COAL & SORBENT PREP & FEED | 15,457 | 0 | 5,630 | 394 | 21,481 | 1,933 | 0 | 0 | 23,414 | 35 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 30,726 | 0 | 13,318 | 932 | 44,976 | 4,048 | 0 | 0 | 49,024 | 72 |
| 4 | CFB BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 159,692 | 235 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61,889 | 91 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 50 |
| 8 | STEAM TURBINE GENERATOR | 85,826 | 685 | 22,757 | 1,593 | 110,861 | 9,978 | 0 | 0 | 120,839 | 178 |
| 9 | COOLING WATER SYSTEM | 13,857 | 7,209 | 13,100 | 917 | 35,082 | 3,157 | 0 | 0 | 38,240 | 56 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 13,265 | 209 | 24,309 | 1,702 | 39,484 | 3,554 | 0 | 0 | 43,037 | 63 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,738 | 5,214 | 14,224 | 996 | 37,171 | 3,345 | 0 | 0 | 40,516 | 60 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 34 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 20 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 102 |
| | **TOTAL COST** | **$220,237** | **$47,083** | **$164,773** | **$11,534** | **$443,628** | **$39,926** | **$0** | **$0** | **$705,135** | **$1,039** |

**Table 7.3.15: Case CFB-4 Investment Costs**

| | | |
|---|---|---|
| **Client:** DOE - NETL | **INITIAL & ANNUAL O&M EXPENSES** | Cost Base: Jul-03 |
| **Project:** Economics and Feasibility of Rankine Cycle Improvenents for Coal Fired Power Plants | **Case CFB-4** - 1 x 680 MW CFB Steam Plant | |
| | | Net Plant Heat Rate (Btu/kWh): 8,568 |
| | | Net Power Output (kW): 678,366 |
| | | Capacity Factor (%): 80 |

OPERATING & MAINTENANCE LABOR

| Operating Labor | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.26 |
| Maintenance Labor Costs (calc'd) | 2,796,985 | 4.12 |
| Administrative & Support Labor (calc'd) | 1,930,858 | 2.85 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,654,292*** | ***14.23*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 3,356,382 | 0.00071 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00019 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00024 |
| Limestone (ton) | 23,086 | 769.5 | 10.00 | 230,861 | 2,247,045 | 0.00047 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | 150 | | 85,680 | 0.00002 |
| Subtotal Chemicals: | | | | 349,574 | 3,488,204 | 0.00072 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 2,187.5 | 8.00 | | 5,109,896 | 0.0011 |
| Subtotal Solid Waste Disposal: | | | | | 5,109,896 | 0.0011 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***12,841,735*** | ***0.0027*** |

| | | |
|---|---|---|
| Annual Generation | 4754 | (MM-kwhr/yr) |
| Total O&M Cost | 0.47 | (Cents/kwhr) |

**Table 7.3.16: Case CFB-4 Operating and Maintenance Costs**

TOTAL PLANT COST SUMMARY

**Client:** DOE - NETL **Report Date:** 14-Nov-03
**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case:** CMB-3; Supercritical Circulating Moving Bed Boiler Plant **Estimate Type:** Conceptual
**Plant Size:** 665,552 KWe,net **Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor | | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies | | TOTAL PLANT COST | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Direct | Indirect | | | Process | Project | $ | $/kW |
| 1 | COAL & SORBENT HANDLING | 12,693 | 3,630 | 9,496 | 665 | 26,483 | 2,383 | 0 | 0 | 28,867 | 43 |
| 2 | COAL & SORBENT PREP & FEED | 15,457 | 0 | 5,630 | 394 | 21,481 | 1,933 | 0 | 0 | 23,414 | 35 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 29,980 | 0 | 12,995 | 910 | 43,884 | 3,950 | 0 | 0 | 47,834 | 72 |
| 4 | CMB BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 138,887 | 209 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61,889 | 93 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 51 |
| 8 | STEAM TURBINE GENERATOR | 81,935 | 654 | 21,725 | 1,521 | 105,835 | 9,525 | 0 | 0 | 115,360 | 173 |
| 9 | COOLING WATER SYSTEM | 13,920 | 7,242 | 13,159 | 921 | 35,243 | 3,172 | 0 | 0 | 38,415 | 58 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 13,265 | 209 | 24,309 | 1,702 | 39,484 | 3,554 | 0 | 0 | 43,037 | 65 |
| 11 | ACCESSORY ELECTRIC PLANT | 16,619 | 5,177 | 14,123 | 989 | 36,908 | 3,322 | 0 | 0 | 40,229 | 60 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 34 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 21 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 103 |
| | **TOTAL COST** | **$215,545** | **$47,048** | **$163,377** | **$11,436** | **$437,406** | **$39,367** | **$0** | **$0** | **$677,549** | **$1,018** |

**Table 7.3.17: Case CMB-3 Investment Costs**

**Client:** DOE - NETL

**INITIAL & ANNUAL O&M EXPENSES**

Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Impronements for Coal Fired Power Plants

**Case CMB-3** - 1 x 670 MW CMB Steam Plant

Net Plant Heat Rate (Btu/kWh): 8,781

Net Power Output (kW): 665,552

Capacity Factor (%): 80

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 2.0 | 2.0 |
| Operator | 9.0 | 9.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 2.0 | 2.0 |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 4,926,449 | 7.40 |
| Maintenance Labor Costs (calc'd) | 2,686,639 | 4.04 |
| Administrative & Support Labor (calc'd) | 1,903,272 | 2.86 |
| ***TOTAL FIXED OPERATING COSTS*** | ***9,516,360*** | ***14.30*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | Annual Cost $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (calc'd) | | | | | 3,223,967 | 0.00069 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 3,039 | 1.00 | | 887,253 | 0.00019 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00025 |
| Limestone (ton) | 23,086 | 769.5 | 10.00 | 230,861 | 2,247,045 | 0.00048 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | 150 | | 85,680 | 0.00002 |
| Subtotal Chemicals: | | | | 349,574 | 3,488,204 | 0.00073 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 2,193.9 | 8.00 | | 5,124,976 | 0.0011 |
| Subtotal Solid Waste Disposal: | | | | | 5,124,976 | 0.0011 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***12,724,400*** | ***0.0027*** |

| | | |
|---|---|---|
| Annual Generation | 4664 | (MM-kwhr/yr) |
| Total O&M Cost | 0.48 | (Cents/kwhr) |

**Table 7.3.18: Case CMB-3 Operating and Maintenance Costs**

**TOTAL PLANT COST SUMMARY**

**Client:** DOE - NETL
**Project:** Economics and Feasibility of Rankine Cycle Improvements for Coal Fired Power Plants
**Report Date:** 14-Nov-03

**Case:** CMB-5; Ultra-Supercritical Circulating Moving Bed Boiler Plant
**Plant Size:** 744,230 KWe,net
**Estimate Type:** Conceptual
**Cost Base:** July 2003; $ x 1000

| Acct No. | Item/Description | Equipment Cost | Material Cost | Labor Direct | Labor Indirect | Bare Erected Cost $ | Eng'g CM H.O.& Fee | Contingencies Process | Contingencies Project | TOTAL PLANT COST $ | TOTAL PLANT COST $/kW |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | COAL & SORBENT HANDLING | 12,693 | 3,630 | 9,496 | 665 | 26,483 | 2,383 | 0 | 0 | 28,867 | 39 |
| 2 | COAL & SORBENT PREP & FEED | 15,457 | 0 | 5,630 | 394 | 21,481 | 1,933 | 0 | 0 | 23,414 | 31 |
| 3 | FEEDWATER & MISC. BOP SYSTEMS | 32,919 | 0 | 14,269 | 999 | 48,186 | 4,337 | 0 | 0 | 52,523 | 71 |
| 4 | CMB BOILER & ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 179,650 | 241 |
| 5 | FLUE GAS CLEANUP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 61,889 | 83 |
| 6 | COMBUSTION TURBINE/ACCESSORIES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | HRSG, DUCTING & STACK | 17,192 | 507 | 12,748 | 892 | 31,339 | 2,821 | 0 | 0 | 34,160 | 46 |
| 8 | STEAM TURBINE GENERATOR | 115,204 | 988 | 32,830 | 2,298 | 151,320 | 13,619 | 0 | 0 | 164,939 | 222 |
| 9 | COOLING WATER SYSTEM | 13,688 | 7,121 | 12,940 | 906 | 34,654 | 3,119 | 0 | 0 | 37,773 | 51 |
| 10 | ASH/SPENT SORBENT HANDLING SYS | 13,265 | 209 | 24,309 | 1,702 | 39,484 | 3,554 | 0 | 0 | 43,037 | 58 |
| 11 | ACCESSORY ELECTRIC PLANT | 17,071 | 5,318 | 14,507 | 1,016 | 37,912 | 3,412 | 0 | 0 | 41,324 | 56 |
| 12 | INSTRUMENTATION & CONTROL | 11,075 | 0 | 9,182 | 643 | 20,899 | 1,881 | 0 | 0 | 22,780 | 31 |
| 13 | IMPROVEMENTS TO SITE | 3,409 | 1,960 | 6,823 | 478 | 12,670 | 1,140 | 0 | 0 | 13,810 | 19 |
| 14 | BUILDINGS & STRUCTURES | 0 | 27,670 | 33,188 | 2,323 | 63,181 | 5,686 | 0 | 0 | 68,867 | 93 |
| | **TOTAL COST** | **$251,972** | **$47,402** | **$175,920** | **$12,314** | **$487,609** | **$43,885** | **$0** | **$0** | **$773,033** | **$1,039** |

**Table 7.3.19: Case CMB-5 Investment Costs**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Client:** DOE - NETL | **INITIAL & ANNUAL O&M EXPENSES** | | | | | Cost Base: | Jul-03 |
| **Project:** Economics and Feasibility of Rankine Cycle Improvenements for Coal Fired Power Plants | **Case CMB-5** - 1 x 750 MW CMB Steam Plant | | | | | | |
| | | | | | | Net Plant Heat Rate (Btu/kWh): | 7,853 |
| | | | | | | Net Power Output (kW): | 744,230 |
| | | | | | | Capacity Factor (%): | 80 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| OPERATING & MAINTENANCE LABOR | | | | | | | |
| Operating Labor | | | | | | | |
| Operating Labor Rate (Base): | 30.90 $/hour | | | | | | |
| Operating Labor Burden: | 30.00 % | | | | | | |
| Labor O-H change Rate: | 25.00 % of O&M labor | | | | | | |
| | | | | | | | |
| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant | | | | | |
| Skilled Operator | 2.0 | 2.0 | | | | | |
| Operator | 9.0 | 9.0 | | | | | |
| Foreman | 1.0 | 1.0 | | | | | |
| Lab Tech's, etc. | 2.0 | 2.0 | | | | | |
| TOTAL Operator Jobs (O.J.'s) | 14.0 | 14.0 | | | | | |
| | | | | | | Annual Cost $ / year | Annual Unit Cost $/kW-net |
| Annual Operating Labor Costs (calc'd) | | | | | | 4,926,449 | 6.62 |
| Maintenance Labor Costs (calc'd) | | | | | | 3,068,575 | 4.12 |
| Administrative & Support Labor (calc'd) | | | | | | 1,998,756 | 2.69 |
| ***TOTAL FIXED OPERATING COSTS*** | | | | | | ***9,993,780*** | ***13.43*** |
| | | | | | | | $/kWh-net |
| Maintenance Material Cost (calc'd) | | | | | | 3,682,290 | 0.00071 |
| **Consumables** | | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | | |
| Water (1000 gallons) | | | 3,039 | 1.00 | | 887,253 | 0.00017 |
| Chemicals | | | | | | | |
| MU & WT Chem. (lbs.) | | 741,960 | 24,732 | 0.16 | 118,714 | 1,155,479 | 0.00022 |
| Limestone (ton) | | 23,086 | 769.5 | 10.00 | 230,861 | 2,247,045 | 0.00043 |
| Formic Acid (lbs.) | | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | | 150 | | 85,680 | 0.00002 |
| Subtotal Chemicals: | | | | | 349,574 | 3,488,204 | 0.00065 |
| Other Consumables | | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | | |
| Emissions Penalties | | | | | | | |
| Subtotal Other: | | | | | | | |
| Waste Disposal | | | | | | | |
| Fly Ash & Bottom Ash (ton) | | | 2,193.9 | 8.00 | | 5,124,976 | 0.0010 |
| Subtotal Solid Waste Disposal: | | | | | | 5,124,976 | 0.0010 |
| By-Products | | | | | | | |
| Gypsum (ton) | | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | | ***13,182,724*** | ***0.0025*** |
| | | | | | Annual Generation | 5216 | (MM-kwhr/yr) |
| | | | | | Total O&M Cost | 0.44 | (Cents/kwhr) |

## Table 7.3.20: Case CMB-5 Operating and Maintenance Costs

| Equipment Description | Measures | Installed Cost | Comments & Issues | $/kW net | $/kW incr |
|---|---|---|---|---|---|
| **Boiler:** | ~186 MWe-net (1,080,000 lbm/hr steam) | 54,182,000 | Circulating Moving Bed (4,500Psia/1,292F/1,000F) | 293.1 | 1909.9 |
| **Topping Turbine/Generator:** | ~32 MWe, 1,080,000 lbm/hr, no extraction | 10,725,000 | 4,242 psi, 1,292F inlet; 2,015 psi, 1,050F exhaust | 58.0 | 378.1 |
| | | | | | |
| **Balance of Plant Equipment:** | | | | | |
| FW booster pump including valves and controls | Actual discharge head 4,842psi and inlet pressure 2,522psi, flow 1,080,000 lbm/hr | 500,000 | Single pump | 2.7 | 17.6 |
| Full flow condensate polishing system | 950,000 lb/hr condensate flow | 1,067,000 | Includes foundation and sump | 5.8 | 37.6 |
| Coal feed system from the coal pile to the coal bunker | Top of feeders elev. 676 ft (90 ft above grade) | 1,510,000 | Includes top works on silos (head house). Assumes conveyor tube can be routed through obstructions with slight rotation of the silos. | 8.2 | 53.2 |
| Transformer | 37.5 MVA | 1,700,000 | Includes generator leads to transmission interconnection, pad, fire protection, oil containment, metering and protection CTs, etc. Topping turbine rotated 180 deg. | 9.2 | 59.9 |
| Flue gas duct and dampers to precipitator | 210 ft | 830,000 | Includes foundations and crane rental for installation | 4.5 | 29.3 |
| | | | | | |
| **Piping:** | | | | | |
| Link to Demin. from condensate | 1 x 275 ft | 37,000 | | 0.2 | 1.3 |
| Link from Demin. to #1 Feedwater Heater | 1 x 275 ft | 29,000 | | 0.2 | 1.0 |
| Main Steam to Topping Turbine | 1 x 100 ft | 4,180,000 | Insulated, 1 line, 4,242 psi, 1,292F | 22.6 | 147.3 |
| Topping Turbine to Existing Turbine | 1 x 200 ft | 615,000 | Insulated, 1 line | 3.3 | 21.7 |
| R.H. Inlet Link | 2 x 200 ft | 331,000 | Insulated, 2 lines | 1.8 | 11.7 |
| R.H. Outlet Link | 2 x 200 ft | 396,000 | Insulated, 2 lines | 2.1 | 14.0 |
| Economizer Inlet Link from new Feedwater Booster Pump | 2 x 300 ft | 242,000 | Insulated, 2 lines | 1.3 | 8.5 |
| **TOTAL COST** | | **76,344,000** | | **413** | **2,691** |

**Table 7.3.21: Sporn Unit #4 Repowering Case Investment Costs**

**Client:** DOE - NETL

**Project:** Economics and Feasibility of Rankine Cycle Imprornements for Coal Fired Power Plants

**INITIAL & ANNUAL O&M EXPENSES**

**Sporn Unit #4 Repowering Case** - 1 x 185 MW CMB Steam Plant

Cost Base: Jul-03

Net Plant Heat Rate (Btu/kWh): 8,889

Net Power Output (kW): 184,887

Capacity Factor (%): 85

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| OPERATING & MAINTENANCE LABOR | | | | | | | |
| Operating Labor | | | | | | | |
| Operating Labor Rate (Base): | 30.90 $/hour | | | | | | |
| Operating Labor Burden: | 30.00 % | | | | | | |
| Labor O-H change Rate: | 25.00 % of O&M labor | | | | | | |
| | | | | | | | |
| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant | | | | | |
| Skilled Operator | 1.0 | 1.0 | | | | | |
| Operator | 7.0 | 7.0 | | | | | |
| Foreman | 1.0 | 1.0 | | | | | |
| Lab Tech's, etc. | 1.0 | 1.0 | | | | | |
| TOTAL Operator Jobs (O.J.'s) | 10.0 | 10.0 | | | | | |
| | | | | | | Annual Cost $ / year | Annual Unit Cost $/kW-net |
| Annual Operating Labor Costs (calc'd) | | | | | | 3,518,892 | 19.03 |
| Maintenance Labor Costs (calc'd) | | | | | | 916,128 | 4.96 |
| Administrative & Support Labor (calc'd) | | | | | | 1,108,755 | 6.00 |
| ***TOTAL FIXED OPERATING COSTS*** | | | | | | ***5,543,775*** | ***29.98*** |
| | | | | | | | $/kWh-net |
| Maintenance Material Cost (New Equipment) | | | | | | 389,354 | 0.00028 |
| Maintenance Material Cost (Existing Equipment) | | | | | | 778,709 | 0.00057 |
| **Consumables** | | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | | |
| Water (1000 gallons) | | | 887 | 1.00 | | 275,325 | 0.00020 |
| Chemicals | | | | | | | |
| MU & WT Chem. (lbs.) | | 205,696 | 6,857 | 0.16 | 32,911 | 340,359 | 0.00025 |
| Limestone (ton) | | 3,290 | 109.7 | 10.00 | 32,896 | 340,194 | 0.00025 |
| Formic Acid (lbs.) | | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | | 150 | | | |
| Subtotal Chemicals: | | | | | 65,807 | 680,553 | 0.0005 |
| Other Consumables | | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | | |
| Emissions Penalties | | | | | | | |
| Subtotal Other: | | | | | | | |
| Waste Disposal | | | | | | | |
| Fly Ash & Bottom Ash (ton) | | | 156.6 | 8.00 | | 388,560 | 0.0003 |
| Subtotal Solid Waste Disposal: | | | | | | 388,560 | 0.0003 |
| By-Products | | | | | | | |
| Gypsum (ton) | | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | | ***2,512,502*** | ***0.0018*** |

Annual Generation 1377 (MM-kwhr/yr)
Total O&M Cost 0.59 (Cents/kwhr)

**Table 7.3.22: Sporn Unit #4 Repowering Case Operating and Maintenance Costs**

**Client:** DOE - NETL | **INITIAL & ANNUAL O&M EXPENSES** | Cost Base: Jul-03

**Project:** Economics and Feasibility of Rankine Cycle Improvenents for Coal Fired Power Plants | **Sporn Unit #4 Existing** - 1 x 155 MW CMB Steam Plant

Net Plant Heat Rate (Btu/kWh): 9,561
Net Power Output (kW): 156,518
Capacity Factor (%): 85

OPERATING & MAINTENANCE LABOR

Operating Labor

| | | |
|---|---|---|
| Operating Labor Rate (Base): | 30.90 | $/hour |
| Operating Labor Burden: | 30.00 | % |
| Labor O-H change Rate: | 25.00 | % of O&M labor |

| Operating Labor Requirements (O.J.) per shift | 1 unit/mod. | Total Plant |
|---|---|---|
| Skilled Operator | 1.0 | 1.0 |
| Operator | 7.0 | 7.0 |
| Foreman | 1.0 | 1.0 |
| Lab Tech's, etc. | 1.0 | 1.0 |
| TOTAL Operator Jobs (O.J.'s) | 10.0 | 10.0 |

| | Annual Cost $ / year | Annual Unit Cost $/kW-net |
|---|---|---|
| Annual Operating Labor Costs (calc'd) | 3,518,892 | 22.48 |
| Maintenance Labor Costs (calc'd) | 916,128 | 5.85 |
| Administrative & Support Labor (calc'd) | 1,108,755 | 7.08 |
| ***TOTAL FIXED OPERATING COSTS*** | ***5,543,775*** | ***35.42*** |

| | Consumption Initial | Consumption Per Day | Unit Cost | Initial Cost | $ / year | $/kWh-net |
|---|---|---|---|---|---|---|
| Maintenance Material Cost (Existing Equipment) | | | | | 1,168,063 | 0.00100 |
| **Consumables** | | | | | | |
| Water (1000 gallons) | | 887 | 1.00 | | 275,325 | 0.00024 |
| Chemicals | | | | | | |
| MU & WT Chem. (lbs.) | 205,696 | 6,857 | 0.16 | 32,911 | 340,359 | 0.00029 |
| Limestone (ton) | 0 | 0.0 | 10.00 | 0 | - | 0.00000 |
| Formic Acid (lbs.) | | | 0.60 | | | |
| Ammonia, NH3 (ton) | | | 150 | | | |
| Subtotal Chemicals: | | | | 32,911 | 340,359 | 0.0003 |
| Other Consumables | | | | | | |
| Supplemental Fuel (MBtu) | | | | | | |
| SCR Catalyst Replacement (MBtu) | | | | | | |
| Emissions Penalties | | | | | | |
| Subtotal Other: | | | | | | |
| Waste Disposal | | | | | | |
| Fly Ash & Bottom Ash (ton) | | 142.5 | 8.00 | | 353,786 | 0.0003 |
| Subtotal Solid Waste Disposal: | | | | | 353,786 | 0.0003 |
| By-Products | | | | | | |
| Gypsum (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Sludge (ton) | | 0.0 | 8.00 | | 0 | 0.0000 |
| Subtotal By-Products: | | | | | 0 | 0.0000 |
| ***TOTAL VARIABLE OPERATING COST*** | | | | | ***2,137,534*** | ***0.0018*** |

| | | |
|---|---|---|
| Annual Generation | 1165 | (MM-kwhr/yr) |
| Total O&M Cost | 0.66 | (Cents/kwhr) |

**Table 7.3.23: Existing Sporn Unit #4 Operating and Maintenance Costs**

## 7.4 Appendix IV - Economic Sensitivity Study Results

Sensitivity analyses were conducted for all PC and CFB/ CMB™ case studies to determine the effect on COE of variation of selected base parameter values by ± 25 percent. These parameters (shaded in yellow in Table 4.1.1) are availability factor, EPC price, coal price, equity rate, corporate tax rate, and the discount rate for cost of capital. The base parameter values represent the point where all the sensitivity curves intersect (point 0, 0). Sensitivity analysis results tables and "spider plots" for all cases are provided in this appendix.

Other COE sensitivity studies were conducted on:

1) High temperature alloy cost ($20, $28, and $32.90 per pound) for PC-5, CMB™ -5, and the repowering case.
2) $NO_x$ emissions credit on the repowering case.

### 7.4.1 Case PC-1 – 1 x 630 MW PC Fired Steam Plant with SCR

Results for the Case PC-1 COE sensitivity study are shown in Figure 7.4.1 and summarized in Table 7.4.1. The levelized COE for the base parameter values is 4.0 cents per kWh. Levelized COE ranges from a low of 3.4 to a high of 4.8 cents per kWh.

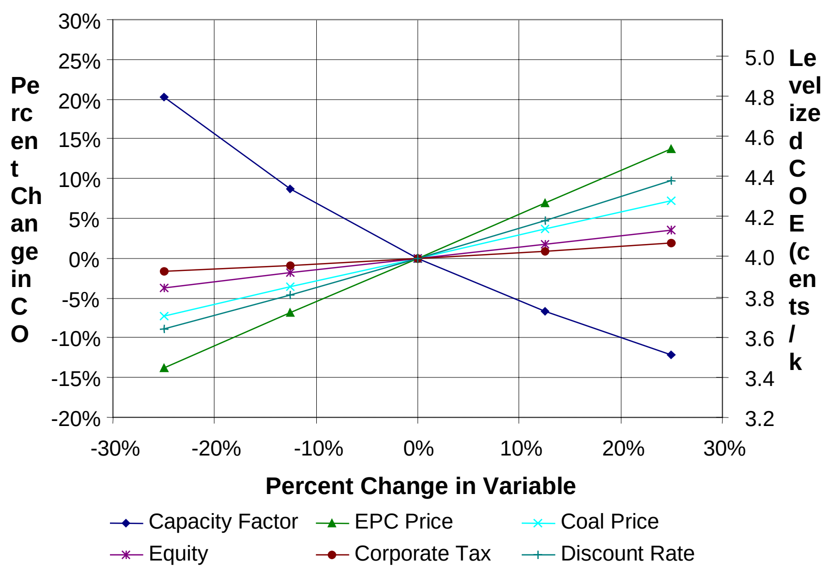



**Figure 7.4. 1: Case PC-1 - 1 x 630 MW PC Fired Steam Plant with SCR Economic Sensitivity Results**

## Table 7.4. 1: Case PC-1 – 1 x 630 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results

| Parameter | Units | Case PC-1 - 1 x 630 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 |
| Net Plant Heat Rate, HHV | Btu / kWh | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 |
| Net Generation | MWh / year | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 854 | 997 | 1,282 | 1,424 | 1,139 | 1,139 | 1,139 | 1,139 |
| EPC Price | $1000s | **718,365** | 718,365 | 718,365 | 718,365 | 718,365 | 538,774 | 628,570 | 808,161 | 897,957 | 718,365 | 718,365 | 718,365 | 718,365 |
| Fixed O&M Costs | $1000 / year | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 |
| Fixed O&M Costs | $ / kW | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 |
| Variable O&M Costs | $1000 / year | 18,020 | 13,515 | 15,768 | 20,273 | 22,525 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 |
| Variable O&M Costs | cents / kWh | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 |
| Total O&M Costs | cents / kWh | 0.63 | 0.70 | 0.66 | 0.60 | 0.58 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.18 | 2.91 | 2.49 | 1.94 | 1.74 | 1.63 | 1.91 | 2.45 | 2.72 | 2.18 | 2.18 | 2.18 | 2.18 |
| Fixed O&M | | 0.22 | 0.29 | 0.25 | 0.19 | 0.17 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 |
| Variable O&M | | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 |
| Fuel | | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 0.86 | 1.01 | 1.30 | 1.44 |
| Total | | 3.96 | 4.76 | 4.30 | 3.69 | 3.48 | 3.41 | 3.68 | 4.23 | 4.50 | 3.67 | 3.81 | 4.10 | 4.25 |

| Parameter | Units | Case PC-1 - 1 x 630 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 | 630,525 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 | 37.0 |
| Net Plant Heat Rate, HHV | Btu / kWh | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 | 9218 |
| Net Generation | MWh / year | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 | 4,418,719 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 |
| EPC Price | $1000s | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 | 718,365 |
| Fixed O&M Costs | $1000 / year | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 | 9,639 |
| Fixed O&M Costs | $ / kW | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 | 15.29 |
| Variable O&M Costs | $1000 / year | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 | 18,020 |
| Variable O&M Costs | cents / kWh | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 |
| Total O&M Costs | cents / kWh | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 | 0.63 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 2.03 | 2.11 | 2.25 | 2.32 | 2.11 | 2.14 | 2.22 | 2.25 | 1.83 | 2.00 | 2.37 | 2.56 |
| Fixed O&M | | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 |
| Variable O&M | | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 |
| Fuel | | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 | 1.15 |
| Total | | 3.81 | 3.88 | 4.03 | 4.10 | 3.89 | 3.92 | 3.99 | 4.03 | 3.60 | 3.78 | 4.15 | 4.34 |

### 7.4.2 Case PC-2 – 1 x 650 MW PC Fired Steam Plant with SCR

Results for the Case PC-2 COE sensitivity study are shown in Figure 7.4.2 and summarized in Table 7.4.2. The levelized COE for the base parameter values is 3.9 cents per kWh. Levelized COE ranges from a low of 3.4 to a high of 4.7 cents per kWh.

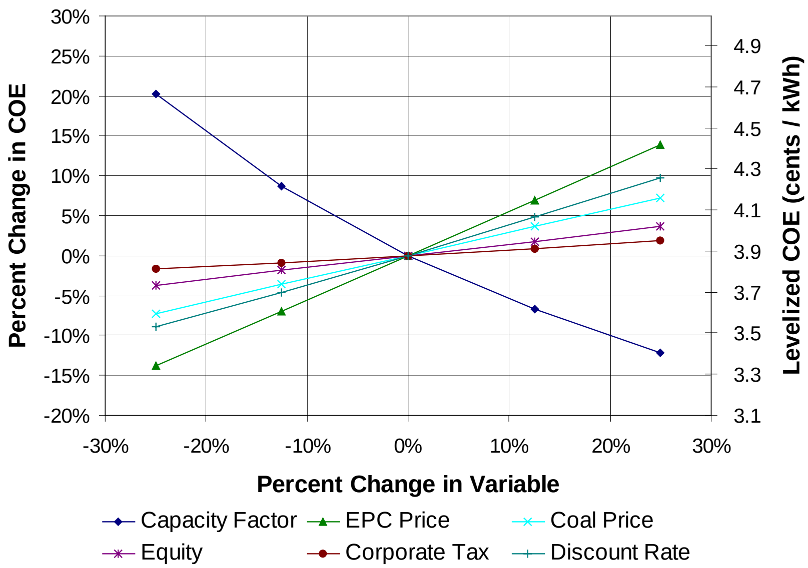



**Figure 7.4. 2: Case PC-2 – 1 x 650 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results**

## Table 7.4. 2: Case PC-2 – 1 x 650 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results

| Parameter | Units | Case PC-2 - 1 x 650 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 |
| Net Generation | MWh / year | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 844 | 985 | 1,266 | 1,407 | 1,126 | 1,126 | 1,126 | 1,126 |
| EPC Price | $1000s | **727,230** | 727,230 | 727,230 | 727,230 | 727,230 | 545,423 | 636,327 | 818,134 | 909,038 | 727,230 | 727,230 | 727,230 | 727,230 |
| Fixed O&M Costs | $1000 / year | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 |
| Fixed O&M Costs | $ / kW | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 |
| Variable O&M Costs | $1000 / year | 18,063 | 13,547 | 15,805 | 20,321 | 22,578 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 |
| Variable O&M Costs | cents / kWh | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Total O&M Costs | cents / kWh | 0.61 | 0.68 | 0.64 | 0.59 | 0.57 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.15 | 2.87 | 2.46 | 1.91 | 1.72 | 1.61 | 1.88 | 2.42 | 2.69 | 2.15 | 2.15 | 2.15 | 2.15 |
| Fixed O&M | | 0.21 | 0.29 | 0.24 | 0.19 | 0.17 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Fuel | | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 0.84 | 0.98 | 1.27 | 1.41 |
| Total | | 3.89 | 4.68 | 4.23 | 3.63 | 3.42 | 3.35 | 3.62 | 4.16 | 4.43 | 3.61 | 3.75 | 4.03 | 4.17 |

| Parameter | Units | Case PC-2 - 1 x 650 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 | 646,080 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 | 37.9 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 | 8997 |
| Net Generation | MWh / year | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 | 4,527,729 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 |
| EPC Price | $1000s | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 | 727,230 |
| Fixed O&M Costs | $1000 / year | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 | 9,684 |
| Fixed O&M Costs | $ / kW | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 | 14.99 |
| Variable O&M Costs | $1000 / year | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 | 18,063 |
| Variable O&M Costs | cents / kWh | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Total O&M Costs | cents / kWh | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 2.01 | 2.08 | 2.22 | 2.29 | 2.09 | 2.12 | 2.19 | 2.23 | 1.80 | 1.97 | 2.34 | 2.53 |
| Fixed O&M | | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Fuel | | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 |
| Total | | 3.74 | 3.82 | 3.96 | 4.03 | 3.82 | 3.86 | 3.93 | 3.96 | 3.54 | 3.71 | 4.08 | 4.27 |

### 7.4.3 Case PC-3 – 1 x 660 MW PC Fired Steam Plant with SCR

Results for the Case PC-3 COE sensitivity study are shown in Figure 7.4.3 and summarized in Table 7.4.3. The levelized COE for the base parameter values is 3.8 cents per kWh. Levelized COE ranges from a low of 3.3 to a high of 4.6 cents per kWh.

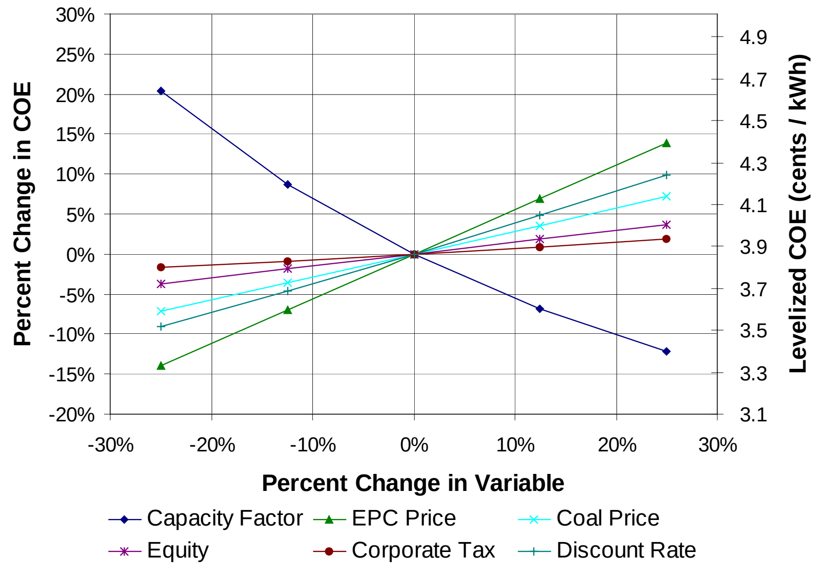



**Figure 7.4. 3: Case PC-3 – 1 x 660 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results**

## Table 7.4. 3: Case PC-3 – 1 x 660 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results

| Parameter | Units | Case PC-3 - 1 x 660 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 |
| Net Generation | MWh / year | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 831 | 970 | 1,247 | 1,386 | 1,109 | 1,109 | 1,109 | 1,109 |
| EPC Price | $1000s | **734,879** | 734,879 | 734,879 | 734,879 | 734,879 | 551,160 | 643,020 | 826,739 | 918,599 | 734,879 | 734,879 | 734,879 | 734,879 |
| Fixed O&M Costs | $1000 / year | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 |
| Fixed O&M Costs | $ / kW | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 |
| Variable O&M Costs | $1000 / year | 18,406 | 13,805 | 16,105 | 20,707 | 23,008 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 |
| Variable O&M Costs | cents / kWh | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Total O&M Costs | cents / kWh | 0.61 | 0.68 | 0.64 | 0.58 | 0.56 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.12 | 2.83 | 2.42 | 1.88 | 1.70 | 1.59 | 1.86 | 2.39 | 2.65 | 2.12 | 2.12 | 2.12 | 2.12 |
| Fixed O&M | | 0.21 | 0.28 | 0.24 | 0.19 | 0.17 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Fuel | | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 0.82 | 0.96 | 1.23 | 1.37 |
| Total | | 3.82 | 4.60 | 4.15 | 3.56 | 3.36 | 3.29 | 3.56 | 4.09 | 4.35 | 3.55 | 3.68 | 3.96 | 4.10 |

| Parameter | Units | Case PC-3 - 1 x 660 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 | 662,936 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 | 8768 |
| Net Generation | MWh / year | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 | 4,645,856 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 |
| EPC Price | $1000s | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 | 734,879 |
| Fixed O&M Costs | $1000 / year | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 | 9,722 |
| Fixed O&M Costs | $ / kW | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 |
| Variable O&M Costs | $1000 / year | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 | 18,406 |
| Variable O&M Costs | cents / kWh | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Total O&M Costs | cents / kWh | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 | 0.61 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.98 | 2.05 | 2.19 | 2.26 | 2.06 | 2.09 | 2.16 | 2.19 | 1.78 | 1.94 | 2.30 | 2.50 |
| Fixed O&M | | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Fuel | | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 |
| Total | | 3.68 | 3.75 | 3.89 | 3.96 | 3.76 | 3.79 | 3.86 | 3.90 | 3.48 | 3.65 | 4.01 | 4.20 |

### 7.4.4 Case PC-4 – 1 x 680 MW PC Fired Steam Plant with SCR

Results for the Case PC-4 COE sensitivity study are shown in Figure 7.4.4 and summarized in Table 7.4.4. The levelized COE for the base parameter values is 3.8 cents per kWh. Levelized COE ranges from a low of 3.2 to a high of 4.5 cents per kWh.

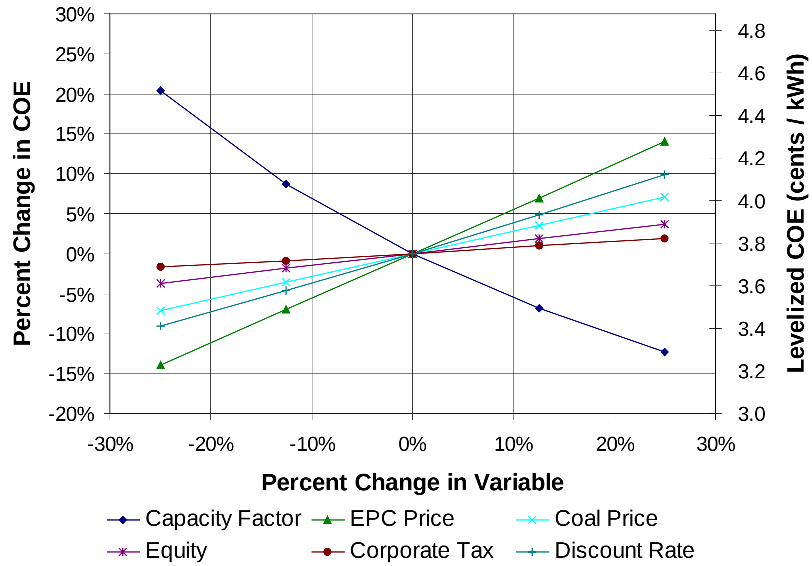



**Figure 7.4. 4: Case PC-4 – 1 x 680 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results**

## Table 7.4. 4: Case PC-4 – 1 x 680 MW PC Fired Steam Plant with SCR Sensitivity Analysis Results

| Parameter | Units | Case PC-4 - 1 x 680 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 |
| Net Generation | MWh / year | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 823 | 961 | 1,235 | 1,372 | 1,098 | 1,098 | 1,098 | 1,098 |
| EPC Price | $1000s | **743,861** | 743,861 | 743,861 | 743,861 | 743,861 | 557,896 | 650,879 | 836,844 | 929,827 | 743,861 | 743,861 | 743,861 | 743,861 |
| Fixed O&M Costs | $1000 / year | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 |
| Fixed O&M Costs | $ / kW | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 |
| Variable O&M Costs | $1000 / year | 18,143 | 13,607 | 15,875 | 20,410 | 22,678 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 |
| Variable O&M Costs | cents / kWh | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 |
| Total O&M Costs | cents / kWh | 0.59 | 0.66 | 0.62 | 0.56 | 0.55 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.10 | 2.80 | 2.40 | 1.87 | 1.68 | 1.58 | 1.84 | 2.36 | 2.63 | 2.10 | 2.10 | 2.10 | 2.10 |
| Fixed O&M | | 0.21 | 0.27 | 0.24 | 0.18 | 0.16 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 |
| Fuel | | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 0.80 | 0.94 | 1.21 | 1.34 |
| Total | | 3.76 | 4.53 | 4.09 | 3.50 | 3.30 | 3.24 | 3.50 | 4.02 | 4.29 | 3.49 | 3.63 | 3.89 | 4.03 |

| Parameter | Units | Case PC-4 - 1 x 680 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 | 677,479 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 | 8580 |
| Net Generation | MWh / year | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 | 4,747,773 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 | 1,098 |
| EPC Price | $1000s | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 | 743,861 |
| Fixed O&M Costs | $1000 / year | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 | 9,767 |
| Fixed O&M Costs | $ / kW | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 |
| Variable O&M Costs | $1000 / year | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 | 18,143 |
| Variable O&M Costs | cents / kWh | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 |
| Total O&M Costs | cents / kWh | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.96 | 2.03 | 2.17 | 2.24 | 2.04 | 2.07 | 2.14 | 2.17 | 1.76 | 1.93 | 2.28 | 2.47 |
| Fixed O&M | | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 | 0.38 |
| Fuel | | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 |
| Total | | 3.62 | 3.69 | 3.83 | 3.90 | 3.70 | 3.73 | 3.80 | 3.83 | 3.42 | 3.59 | 3.94 | 4.13 |

### 7.4.5 Case PC-5 $20 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $20 per Pound High Temperature Alloy

Results for the Case PC-5 COE sensitivity study are shown in Figure 7.4.5 and summarized in Table 7.4.5. The levelized COE for the base parameter values is 3.7 cents per kWh. Levelized COE ranges from a low of 3.2 to a high of 4.5 cents per kWh.

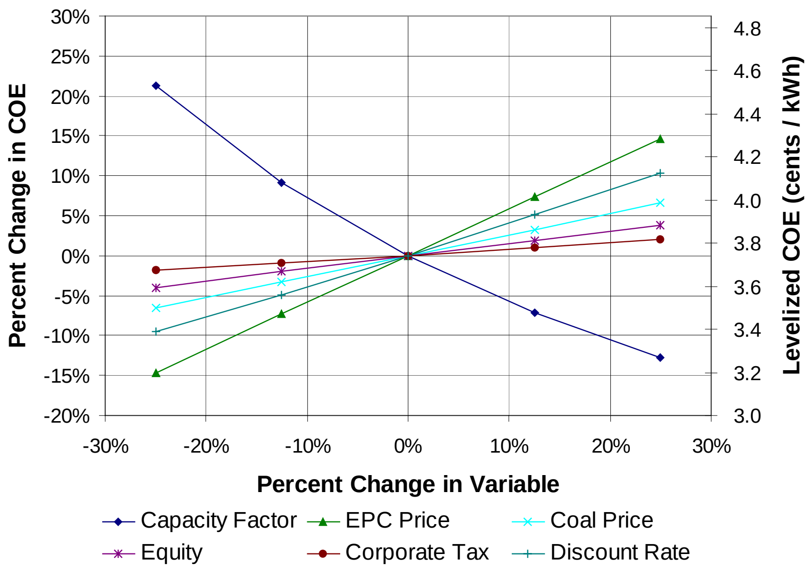



**Figure 7.4. 5: Case PC-5 20 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $20 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4. 5: Case PC-5 20 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $20 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Case PC-5 - 1 x 740 MW PC Fired Steam Plant; $20/lb Nickel | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 |
| Net Generation | MWh / year | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 854 | 997 | 1,282 | 1,424 | 1,139 | 1,139 | 1,139 | 1,139 |
| EPC Price | $1000s | **844,808** | 844,808 | 844,808 | 844,808 | 844,808 | 633,606 | 739,207 | 950,409 | 1,056,010 | 844,808 | 844,808 | 844,808 | 844,808 |
| Fixed O&M Costs | $1000 / year | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 |
| Fixed O&M Costs | $ / kW | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 |
| Variable O&M Costs | $1000 / year | 18,627 | 13,970 | 16,299 | 20,955 | 23,284 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 |
| Variable O&M Costs | cents / kWh | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Total O&M Costs | cents / kWh | 0.56 | 0.62 | 0.58 | 0.53 | 0.52 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.18 | 2.91 | 2.49 | 1.94 | 1.74 | 1.63 | 1.91 | 2.45 | 2.72 | 2.18 | 2.18 | 2.18 | 2.18 |
| Fixed O&M | | 0.20 | 0.26 | 0.23 | 0.18 | 0.16 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.73 | 0.86 | 1.10 | 1.22 |
| Total | | 3.71 | 4.51 | 4.05 | 3.45 | 3.24 | 3.17 | 3.44 | 3.99 | 4.26 | 3.47 | 3.59 | 3.84 | 3.96 |

| Parameter | Units | Case PC-5 - 1 x 740 MW PC Fired Steam Plant; $20/lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 |
| Net Generation | MWh / year | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 | 1,139 |
| EPC Price | $1000s | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 | 844,808 |
| Fixed O&M Costs | $1000 / year | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 | 10,272 |
| Fixed O&M Costs | $ / kW | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 | 13.85 |
| Variable O&M Costs | $1000 / year | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 | 18,627 |
| Variable O&M Costs | cents / kWh | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Total O&M Costs | cents / kWh | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 2.03 | 2.11 | 2.25 | 2.32 | 2.11 | 2.14 | 2.22 | 2.25 | 1.83 | 2.00 | 2.37 | 2.56 |
| Fixed O&M | | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Total | | 3.57 | 3.64 | 3.79 | 3.86 | 3.65 | 3.68 | 3.75 | 3.79 | 3.36 | 3.53 | 3.90 | 4.10 |

### 7.4.6 Case PC-5 $28 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $28 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Case PC-5 COE sensitivity study are shown in Figure 7.4.6 and summarized in Table 7.4.6. The levelized COE for the base parameter values is 3.8 cents per kWh. Levelized COE ranges from a low of 3.2 to a high of 4.6 cents per kWh.

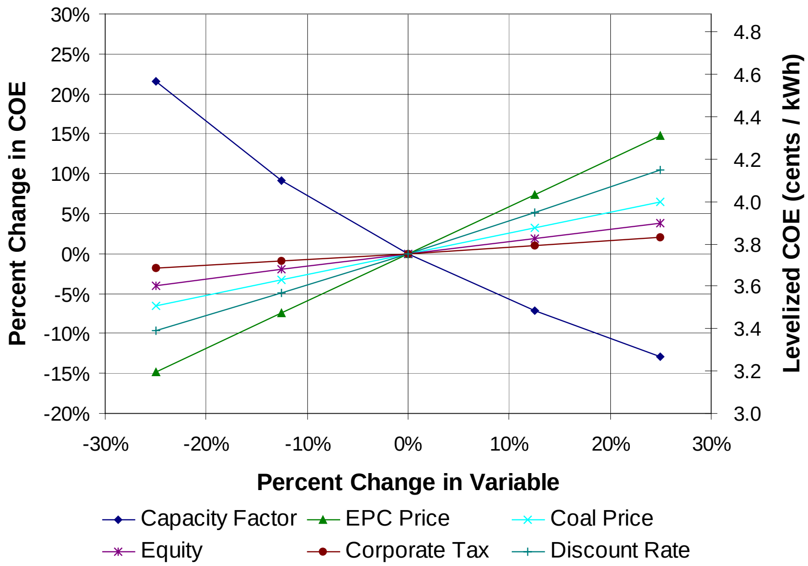



**Figure 7.4. 6: Case PC-5 $28 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $28 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4. 6: Case PC-5 $28 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $28 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Case PC-5 - 1 x 740 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 |
| Net Generation | MWh / year | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 876 | 1,022 | 1,314 | 1,460 | 1,168 | 1,168 | 1,168 | 1,168 |
| EPC Price | $1000s | **866,303** | 866,303 | 866,303 | 866,303 | 866,303 | 649,728 | 758,016 | 974,591 | 1,082,879 | 866,303 | 866,303 | 866,303 | 866,303 |
| Fixed O&M Costs | $1000 / year | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 |
| Fixed O&M Costs | $ / kW | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 |
| Variable O&M Costs | $1000 / year | 18,730 | 14,048 | 16,389 | 21,072 | 23,413 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 |
| Variable O&M Costs | cents / kWh | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Total O&M Costs | cents / kWh | 0.56 | 0.63 | 0.59 | 0.54 | 0.52 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.23 | 2.98 | 2.55 | 1.99 | 1.79 | 1.68 | 1.95 | 2.51 | 2.79 | 2.23 | 2.23 | 2.23 | 2.23 |
| Fixed O&M | | 0.20 | 0.27 | 0.23 | 0.18 | 0.16 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.73 | 0.86 | 1.10 | 1.22 |
| Total | | 3.77 | 4.59 | 4.12 | 3.50 | 3.29 | 3.22 | 3.49 | 4.05 | 4.33 | 3.53 | 3.65 | 3.90 | 4.02 |

| Parameter | Units | Case PC-5 - 1 x 740 MW PC Fired Steam Plant w/ SCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 |
| Net Generation | MWh / year | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 | 1,168 |
| EPC Price | $1000s | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 | 866,303 |
| Fixed O&M Costs | $1000 / year | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 | 10,379 |
| Fixed O&M Costs | $ / kW | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 |
| Variable O&M Costs | $1000 / year | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 | 18,730 |
| Variable O&M Costs | cents / kWh | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Total O&M Costs | cents / kWh | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 2.08 | 2.16 | 2.31 | 2.38 | 2.17 | 2.20 | 2.27 | 2.31 | 1.87 | 2.05 | 2.43 | 2.63 |
| Fixed O&M | | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Total | | 3.62 | 3.70 | 3.85 | 3.92 | 3.71 | 3.74 | 3.81 | 3.85 | 3.41 | 3.59 | 3.97 | 4.17 |

### 7.4.7 Case PC-5 $32.9 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Case PC-5 COE sensitivity study are shown in Figure 7.4.7 and summarized in Table 7.4.7. The levelized COE for the base parameter values is 3.8 cents per kWh. Levelized COE ranges from a low of 3.2 to a high of 4.6 cents per kWh.

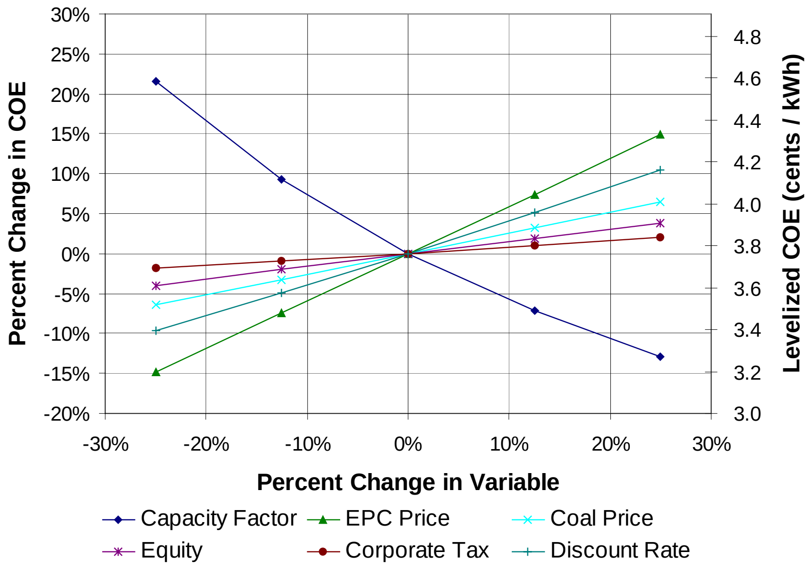



**Figure 7.4. 7: Case PC-5 $32.9 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4. 7: Case PC-5 $32.9 Nickel - 1 x 740 MW PC Fired Steam Plant with SCR and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Case PC-5 - 1 x 740 MW PC Fired Steam Plant; $32.90/lb Nickel | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 |
| Net Generation | MWh / year | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 889 | 1,038 | 1,334 | 1,482 | 1,186 | 1,186 | 1,186 | 1,186 |
| EPC Price | $1000s | **879,468** | 879,468 | 879,468 | 879,468 | 879,468 | 659,601 | 769,534 | 989,401 | 1,099,335 | 879,468 | 879,468 | 879,468 | 879,468 |
| Fixed O&M Costs | $1000 / year | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 |
| Fixed O&M Costs | $ / kW | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 |
| Variable O&M Costs | $1000 / year | 18,793 | 14,095 | 16,444 | 21,143 | 23,492 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 |
| Variable O&M Costs | cents / kWh | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Total O&M Costs | cents / kWh | 0.56 | 0.63 | 0.59 | 0.54 | 0.52 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.27 | 3.02 | 2.59 | 2.02 | 1.81 | 1.70 | 1.98 | 2.55 | 2.84 | 2.27 | 2.27 | 2.27 | 2.27 |
| Fixed O&M | | 0.20 | 0.27 | 0.23 | 0.18 | 0.16 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.73 | 0.86 | 1.10 | 1.22 |
| Total | | 3.81 | 4.63 | 4.16 | 3.54 | 3.32 | 3.24 | 3.53 | 4.09 | 4.38 | 3.57 | 3.69 | 3.93 | 4.06 |

| Parameter | Units | Case PC-5 - 1 x 740 MW PC Fired Steam Plant; $32.90/lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 | 741,615 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 | 7838 |
| Net Generation | MWh / year | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 | 5,197,238 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 | 1,186 |
| EPC Price | $1000s | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 | 879,468 |
| Fixed O&M Costs | $1000 / year | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 | 10,445 |
| Fixed O&M Costs | $ / kW | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 | 14.08 |
| Variable O&M Costs | $1000 / year | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 | 18,793 |
| Variable O&M Costs | cents / kWh | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Total O&M Costs | cents / kWh | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 2.11 | 2.19 | 2.34 | 2.42 | 2.20 | 2.23 | 2.31 | 2.35 | 1.90 | 2.08 | 2.46 | 2.67 |
| Fixed O&M | | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Total | | 3.66 | 3.73 | 3.89 | 3.96 | 3.74 | 3.77 | 3.85 | 3.89 | 3.44 | 3.62 | 4.01 | 4.21 |

### 7.4.8 Case CFB-2 - 1 x 650 MW CFB Steam Plant with SNCR Economic Sensitivity Results

Results for the Case CFB-2 COE sensitivity study are shown in Figure 7.4.8 and summarized in Table 7.4.8. The levelized COE for the base parameter values is 3.6 cents per kWh. Levelized COE ranges from a low of 3.1 to a high of 4.4 cents per kWh.

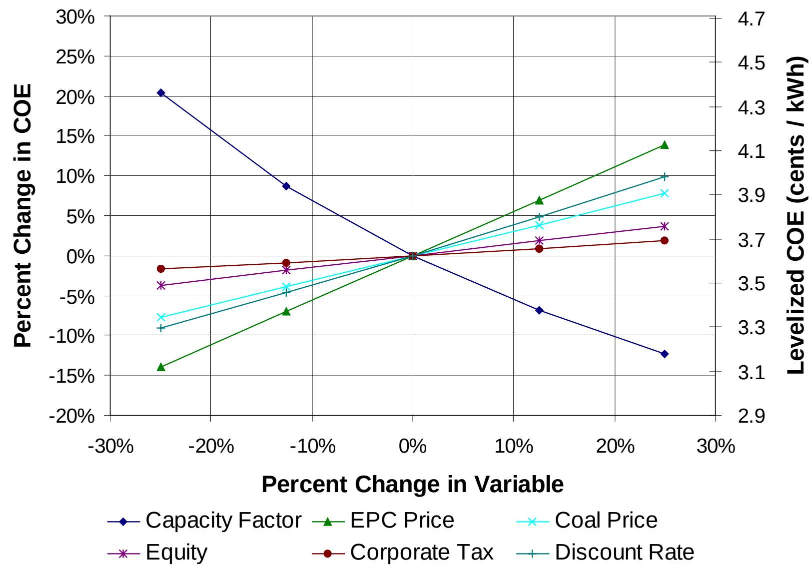



**Figure 7.4. 8: Case CFB-2 - 1 x 650 MW CFB Steam Plant with SNCR Economic Sensitivity Results**

# Table 7.4. 8: Case CFB-2 - 1 x 650 MW CFB Steam Plant with SNCR Economic Sensitivity Results

| Parameter | Units | Case CFB-2 - 1 x 650 MW CFB Steam Plant, SNCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 |
| Net Generation | MWh / year | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 788 | 920 | 1,182 | 1,314 | 1,051 | 1,051 | 1,051 | 1,051 |
| EPC Price | $1000s | **680,579** | 680,579 | 680,579 | 680,579 | 680,579 | 510,434 | 595,507 | 765,652 | 850,724 | 680,579 | 680,579 | 680,579 | 680,579 |
| Fixed O&M Costs | $1000 / year | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 |
| Fixed O&M Costs | $ / kW | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 |
| Variable O&M Costs | $1000 / year | 12,724 | 9,543 | 11,133 | 14,314 | 15,905 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 |
| Variable O&M Costs | cents / kWh | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 |
| Total O&M Costs | cents / kWh | 0.49 | 0.56 | 0.52 | 0.47 | 0.45 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.01 | 2.68 | 2.30 | 1.79 | 1.61 | 1.51 | 1.76 | 2.26 | 2.51 | 2.01 | 2.01 | 2.01 | 2.01 |
| Fixed O&M | | 0.21 | 0.28 | 0.24 | 0.19 | 0.17 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 |
| Fuel | | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 0.84 | 0.98 | 1.26 | 1.40 |
| Total | | 3.62 | 4.36 | 3.94 | 3.38 | 3.18 | 3.12 | 3.37 | 3.87 | 4.13 | 3.34 | 3.48 | 3.76 | 3.90 |

| Parameter | Units | Case CFB-2 - 1 x 650 MW CFB Steam Plant, SNCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 | 647,587 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 | 38.0 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 | 8976 |
| Net Generation | MWh / year | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 | 4,538,290 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 | 1,051 |
| EPC Price | $1000s | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 | 680,579 |
| Fixed O&M Costs | $1000 / year | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 | 9,532 |
| Fixed O&M Costs | $ / kW | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 | 14.72 |
| Variable O&M Costs | $1000 / year | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 |
| Variable O&M Costs | cents / kWh | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 |
| Total O&M Costs | cents / kWh | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.87 | 1.94 | 2.08 | 2.14 | 1.95 | 1.98 | 2.04 | 2.08 | 1.68 | 1.84 | 2.18 | 2.37 |
| Fixed O&M | | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 | 0.28 |
| Fuel | | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 |
| Total | | 3.49 | 3.56 | 3.69 | 3.75 | 3.56 | 3.59 | 3.66 | 3.69 | 3.30 | 3.46 | 3.80 | 3.98 |

### 7.4.9 Case CFB-3 - 1 x 660 MW CFB Steam Plant with SNCR Economic Sensitivity Results

Results for the Case CFB-3 COE sensitivity study are shown in Figure 7.4.9 and summarized in Table 7.4.9. The levelized COE for the base parameter values is 3.6 cents per kWh. Levelized COE ranges from a low of 3.1 to a high of 4.3 cents per kWh.

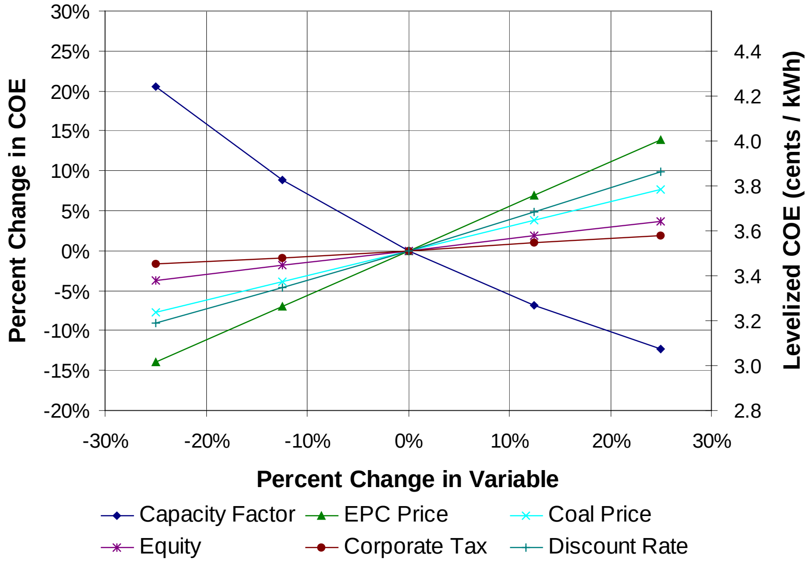



**Figure 7.4. 9: Case CFB-3 - 1 x 660 MW CFB Steam Plant with SNCR Economic Sensitivity Results**

## Table 7.4. 9: Case CFB-3 - 1 x 660 MW CFB Steam Plant with SNCR Economic Sensitivity Results

| Parameter | Units | Case CFB-3 - 1 x 660 MW CFB Steam Plant, SNCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 |
| Net Generation | MWh / year | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 778 | 908 | 1,167 | 1,297 | 1,038 | 1,038 | 1,038 | 1,038 |
| EPC Price | $1000s | **688,776** | 688,776 | 688,776 | 688,776 | 688,776 | 516,582 | 602,679 | 774,873 | 860,970 | 688,776 | 688,776 | 688,776 | 688,776 |
| Fixed O&M Costs | $1000 / year | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 |
| Fixed O&M Costs | $ / kW | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 |
| Variable O&M Costs | $1000 / year | 12,763 | 9,572 | 11,168 | 14,359 | 15,954 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 |
| Variable O&M Costs | cents / kWh | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Total O&M Costs | cents / kWh | 0.48 | 0.55 | 0.51 | 0.46 | 0.44 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 1.98 | 2.65 | 2.27 | 1.76 | 1.59 | 1.49 | 1.74 | 2.23 | 2.48 | 1.98 | 1.98 | 1.98 | 1.98 |
| Fixed O&M | | 0.21 | 0.27 | 0.24 | 0.18 | 0.16 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Fuel | | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 0.82 | 0.96 | 1.23 | 1.37 |
| Total | | 3.56 | 4.29 | 3.87 | 3.32 | 3.12 | 3.06 | 3.31 | 3.81 | 4.06 | 3.29 | 3.42 | 3.70 | 3.83 |

| Parameter | Units | Case CFB-3 - 1 x 660 MW CFB Steam Plant, SNCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 | 663,823 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 | 8756 |
| Net Generation | MWh / year | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 | 4,652,072 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 |
| EPC Price | $1000s | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 | 688,776 |
| Fixed O&M Costs | $1000 / year | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 | 9,572 |
| Fixed O&M Costs | $ / kW | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 | 14.42 |
| Variable O&M Costs | $1000 / year | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 | 12,763 |
| Variable O&M Costs | cents / kWh | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Total O&M Costs | cents / kWh | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.85 | 1.92 | 2.05 | 2.11 | 1.92 | 1.95 | 2.02 | 2.05 | 1.66 | 1.82 | 2.16 | 2.34 |
| Fixed O&M | | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| Variable O&M | | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Fuel | | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 | 1.09 |
| Total | | 3.43 | 3.49 | 3.62 | 3.69 | 3.50 | 3.53 | 3.59 | 3.63 | 3.24 | 3.39 | 3.73 | 3.91 |

### 7.4.10 Case CFB-4 - 1 x 680 MW CFB Steam Plant with SNCR Economic Sensitivity Results

Results for the Case CFB-4 COE sensitivity study are shown in Figure 7.4.10 and summarized in Table 7.4.10. The levelized COE for the base parameter values is 3.5 cents per kWh. Levelized COE ranges from a low of 3.0 to a high of 4.3 cents per kWh.

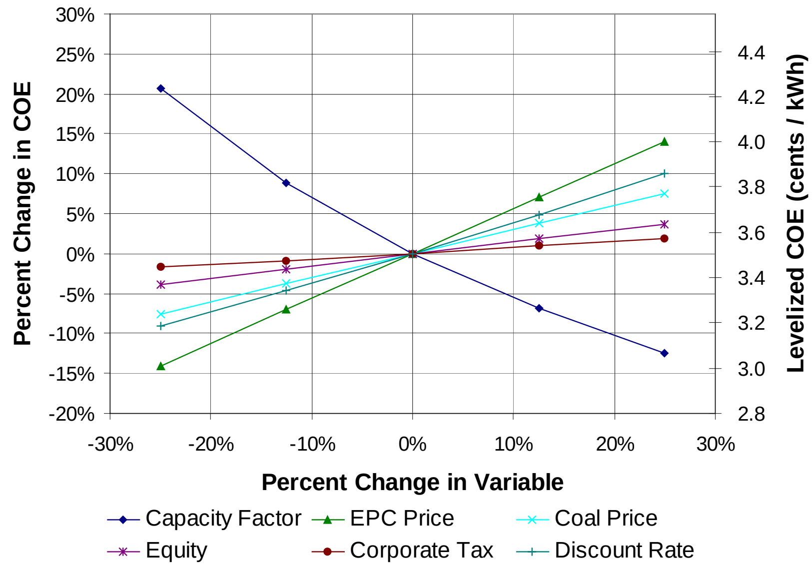



**Figure 7.4.10: Case CFB-4 - 1 x 680 MW CFB Steam Plant with SNCR Economic Sensitivity Results**

## Table 7.4.10: Case CFB-4 - 1 x 680 MW CFB Steam Plant with SNCR Economic Sensitivity Results

| Parameter | Units | Case CFB-4 - 1 x 680 MW CFB Steam Plant, SNCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 |
| Net Generation | MWh / year | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 780 | 910 | 1,169 | 1,299 | 1,039 | 1,039 | 1,039 | 1,039 |
| EPC Price | $1000s | **705,135** | 705,135 | 705,135 | 705,135 | 705,135 | 528,851 | 616,993 | 793,277 | 881,419 | 705,135 | 705,135 | 705,135 | 705,135 |
| Fixed O&M Costs | $1000 / year | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 |
| Fixed O&M Costs | $ / kW | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 |
| Variable O&M Costs | $1000 / year | 12,842 | 9,631 | 11,237 | 14,447 | 16,052 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 |
| Variable O&M Costs | cents / kWh | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Total O&M Costs | cents / kWh | 0.47 | 0.54 | 0.50 | 0.45 | 0.43 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 1.99 | 2.65 | 2.27 | 1.77 | 1.59 | 1.49 | 1.74 | 2.24 | 2.49 | 1.99 | 1.99 | 1.99 | 1.99 |
| Fixed O&M | | 0.20 | 0.27 | 0.23 | 0.18 | 0.16 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Fuel | | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 0.80 | 0.94 | 1.20 | 1.34 |
| Total | | 3.53 | 4.26 | 3.85 | 3.29 | 3.09 | 3.04 | 3.28 | 3.78 | 4.03 | 3.26 | 3.40 | 3.67 | 3.80 |

| Parameter | Units | Case CFB-4 - 1 x 680 MW CFB Steam Plant, SNCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 | 678,366 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 | 39.8 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 | 8568 |
| Net Generation | MWh / year | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 | 4,753,989 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 | 1,039 |
| EPC Price | $1000s | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 | 705,135 |
| Fixed O&M Costs | $1000 / year | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 | 9,654 |
| Fixed O&M Costs | $ / kW | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 | 14.23 |
| Variable O&M Costs | $1000 / year | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 | 12,842 |
| Variable O&M Costs | cents / kWh | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Total O&M Costs | cents / kWh | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.85 | 1.92 | 2.05 | 2.12 | 1.93 | 1.96 | 2.02 | 2.06 | 1.67 | 1.82 | 2.16 | 2.34 |
| Fixed O&M | | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Fuel | | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 | 1.07 |
| Total | | 3.40 | 3.47 | 3.60 | 3.66 | 3.47 | 3.50 | 3.57 | 3.60 | 3.21 | 3.37 | 3.70 | 3.88 |

### 7.4.11 Case CMB-3 - 1 x 670 MW CMB Steam Plant with SNCR Economic Sensitivity Results

Results for the Case CMB$^{TM}$ -3 COE sensitivity study are shown in Figure 7.4.11 and summarized in Table 7.4.11. The levelized COE for the base parameter values is 3.5 cents per kWh. Levelized COE ranges from a low of 3.0 to a high of 4.2 cents per kWh.

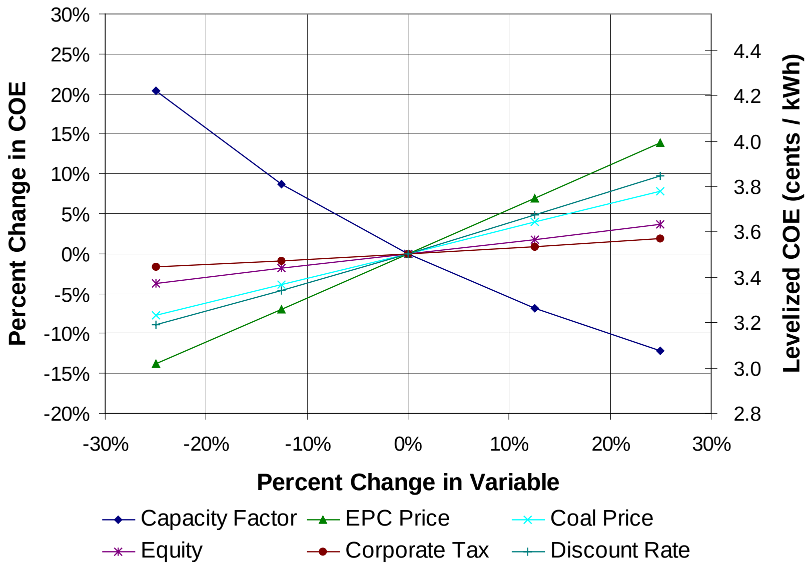



**Figure 7.4.11: Case CMB-3 - 1 x 670 MW CMB Steam Plant with SNCR Economic Sensitivity Results**

## Table 7.4.11: Case CMB-3 - 1 x 670 MW CMB Steam Plant with SNCR Economic Sensitivity Results

| Parameter | Units | Case CMB-3 - 1 x 670 MW CMB Steam Plant, SNCR | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 |
| Net Generation | MWh / year | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 764 | 891 | 1,145 | 1,273 | 1,018 | 1,018 | 1,018 | 1,018 |
| EPC Price | $1000s | **677,549** | 677,549 | 677,549 | 677,549 | 677,549 | 508,162 | 592,856 | 762,243 | 846,936 | 677,549 | 677,549 | 677,549 | 677,549 |
| Fixed O&M Costs | $1000 / year | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 |
| Fixed O&M Costs | $ / kW | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 |
| Variable O&M Costs | $1000 / year | 12,724 | 9,543 | 11,134 | 14,315 | 15,906 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 |
| Variable O&M Costs | cents / kWh | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Total O&M Costs | cents / kWh | 0.48 | 0.54 | 0.51 | 0.45 | 0.44 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 1.95 | 2.60 | 2.23 | 1.73 | 1.56 | 1.46 | 1.70 | 2.19 | 2.43 | 1.95 | 1.95 | 1.95 | 1.95 |
| Fixed O&M | | 0.20 | 0.27 | 0.23 | 0.18 | 0.16 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Fuel | | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 0.82 | 0.96 | 1.23 | 1.37 |
| Total | | 3.52 | 4.24 | 3.83 | 3.28 | 3.09 | 3.03 | 3.28 | 3.77 | 4.01 | 3.25 | 3.38 | 3.66 | 3.80 |

| Parameter | Units | Case CMB-3 - 1 x 670 MW CMB Steam Plant, SNCR | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 | 665,552 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 | 38.9 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 | 8781 |
| Net Generation | MWh / year | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 | 4,664,188 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 | 1,018 |
| EPC Price | $1000s | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 | 677,549 |
| Fixed O&M Costs | $1000 / year | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 | 9,516 |
| Fixed O&M Costs | $ / kW | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 | 14.30 |
| Variable O&M Costs | $1000 / year | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 | 12,724 |
| Variable O&M Costs | cents / kWh | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Total O&M Costs | cents / kWh | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.82 | 1.88 | 2.01 | 2.07 | 1.89 | 1.92 | 1.98 | 2.01 | 1.63 | 1.79 | 2.12 | 2.29 |
| Fixed O&M | | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |
| Variable O&M | | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 | 0.27 |
| Fuel | | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 |
| Total | | 3.39 | 3.46 | 3.59 | 3.65 | 3.46 | 3.49 | 3.55 | 3.59 | 3.21 | 3.36 | 3.69 | 3.87 |

### 7.4.12 Case CMB-5 20 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $20 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Case CMB$^{TM}$ -5 COE sensitivity study are shown in Figure 7.4.12 and summarized in Table 7.4.12. The levelized COE for the base parameter values is 3.4 cents per kWh. Levelized COE ranges from a low of 2.9 to a high of 4.1 cents per kWh.

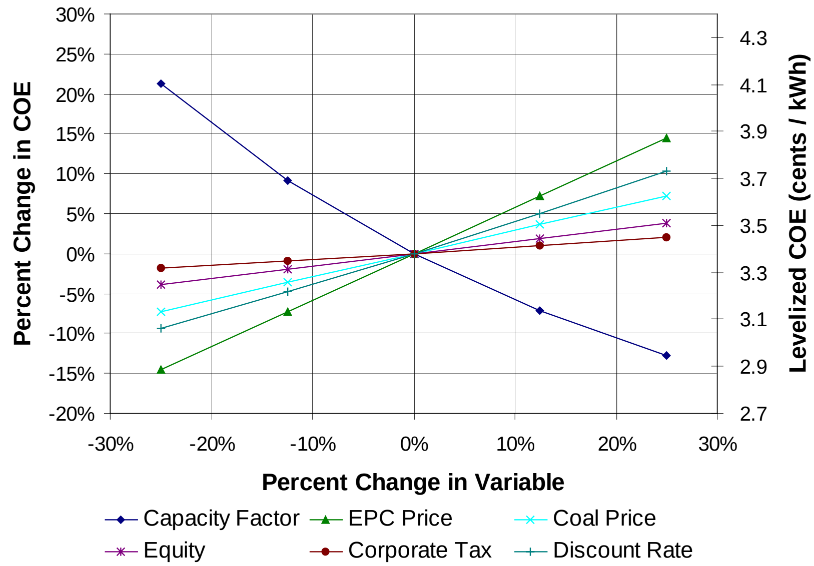



**Figure 7.4.12: Case CMB-5 20 Alloy - 1 x 670 MW CMB Steam Plant with SNCR and $20 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.12: Case CMB-5 20 Alloy - 1 x 670 MW CMB Steam Plant with SNCR and $20 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Case CMB-5 - 1 x 750 MW CMB Steam Plant; $20/lb Nickel | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 |
| Net Generation | MWh / year | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 773 | 902 | 1,160 | 1,289 | 1,031 | 1,031 | 1,031 | 1,031 |
| EPC Price | $1000s | **767,329** | 767,329 | 767,329 | 767,329 | 767,329 | 575,497 | 671,413 | 863,245 | 959,161 | 767,329 | 767,329 | 767,329 | 767,329 |
| Fixed O&M Costs | $1000 / year | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 |
| Fixed O&M Costs | $ / kW | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 |
| Variable O&M Costs | $1000 / year | 13,155 | 9,867 | 11,511 | 14,800 | 16,444 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 |
| Variable O&M Costs | cents / kWh | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Total O&M Costs | cents / kWh | 0.44 | 0.51 | 0.47 | 0.42 | 0.41 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 1.97 | 2.63 | 2.25 | 1.75 | 1.58 | 1.48 | 1.73 | 2.22 | 2.47 | 1.97 | 1.97 | 1.97 | 1.97 |
| Fixed O&M | | 0.19 | 0.25 | 0.22 | 0.17 | 0.15 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 |
| Variable O&M | | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.74 | 0.86 | 1.10 | 1.23 |
| Total | | 3.40 | 4.12 | 3.71 | 3.16 | 2.96 | 2.90 | 3.15 | 3.64 | 3.89 | 3.15 | 3.27 | 3.52 | 3.64 |

| Parameter | Units | Case CMB-5 - 1 x 750 MW CMB Steam Plant; $20/lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 |
| Net Generation | MWh / year | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 | 1,031 |
| EPC Price | $1000s | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 | 767,329 |
| Fixed O&M Costs | $1000 / year | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 | 9,965 |
| Fixed O&M Costs | $ / kW | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 | 13.39 |
| Variable O&M Costs | $1000 / year | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 | 13,155 |
| Variable O&M Costs | cents / kWh | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Total O&M Costs | cents / kWh | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.84 | 1.91 | 2.04 | 2.10 | 1.91 | 1.94 | 2.01 | 2.04 | 1.65 | 1.81 | 2.14 | 2.32 |
| Fixed O&M | | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 |
| Variable O&M | | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Total | | 3.26 | 3.33 | 3.46 | 3.53 | 3.34 | 3.37 | 3.43 | 3.47 | 3.08 | 3.23 | 3.57 | 3.75 |

### 7.4.13 Case CMB-5 28 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $28 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Case CMB™ -5 COE sensitivity study are shown in Figure 7.4.13 and summarized in Table 7.4.13. The levelized COE for the base parameter values is 3.4 cents per kWh. Levelized COE ranges from a low of 2.9 to a high of 4.1 cents per kWh.

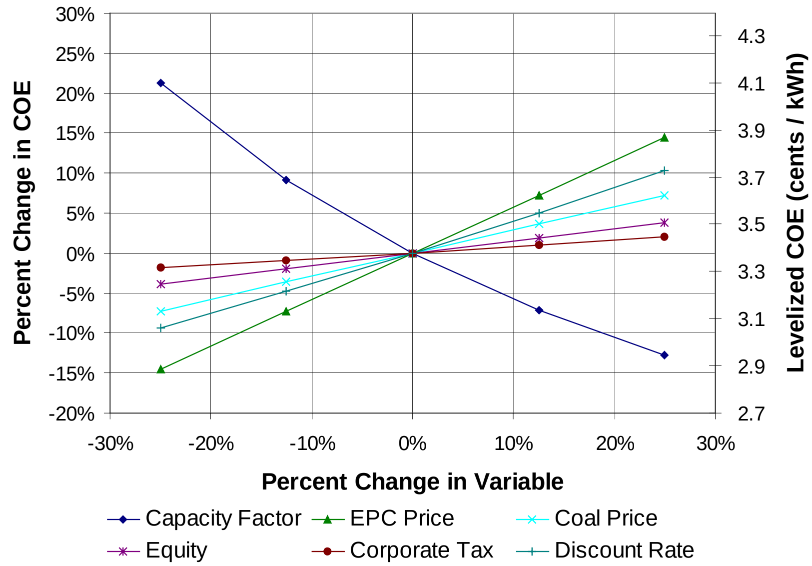



**Figure 7.4.13: Case CMB-5 28 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $28 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.13: Case CMB-5 28 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $28 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Case CMB-5 - 1 x 750 MW CMB Steam Plant; $28/lb Nickel | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 |
| Net Generation | MWh / year | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 772 | 900 | 1,158 | 1,286 | 1,029 | 1,029 | 1,029 | 1,029 |
| EPC Price | $1000s | **767,144** | 767,144 | 767,144 | 767,144 | 767,144 | 575,358 | 671,251 | 863,037 | 958,930 | 767,144 | 767,144 | 767,144 | 767,144 |
| Fixed O&M Costs | $1000 / year | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 |
| Fixed O&M Costs | $ / kW | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 |
| Variable O&M Costs | $1000 / year | 13,097 | 9,823 | 11,460 | 14,734 | 16,371 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 |
| Variable O&M Costs | cents / kWh | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Total O&M Costs | cents / kWh | 0.44 | 0.51 | 0.47 | 0.42 | 0.40 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 1.97 | 2.62 | 2.25 | 1.75 | 1.57 | 1.48 | 1.72 | 2.21 | 2.46 | 1.97 | 1.97 | 1.97 | 1.97 |
| Fixed O&M | | 0.19 | 0.25 | 0.22 | 0.17 | 0.15 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 |
| Variable O&M | | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.73 | 0.86 | 1.10 | 1.22 |
| Total | | 3.39 | 4.11 | 3.70 | 3.15 | 2.96 | 2.90 | 3.14 | 3.64 | 3.88 | 3.14 | 3.27 | 3.51 | 3.63 |

| Parameter | Units | Case CMB-5 - 1 x 750 MW CMB Steam Plant; $28/lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 | 745,555 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 | 7839 |
| Net Generation | MWh / year | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 | 5,224,849 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 | 1,029 |
| EPC Price | $1000s | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 | 767,144 |
| Fixed O&M Costs | $1000 / year | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 | 9,994 |
| Fixed O&M Costs | $ / kW | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 | 13.40 |
| Variable O&M Costs | $1000 / year | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 | 13,097 |
| Variable O&M Costs | cents / kWh | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Total O&M Costs | cents / kWh | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.84 | 1.90 | 2.03 | 2.10 | 1.91 | 1.94 | 2.00 | 2.04 | 1.65 | 1.80 | 2.14 | 2.32 |
| Fixed O&M | | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 |
| Variable O&M | | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Total | | 3.26 | 3.32 | 3.45 | 3.52 | 3.33 | 3.36 | 3.42 | 3.46 | 3.07 | 3.23 | 3.56 | 3.74 |

### 7.4.14 Case CMB-5 32.9 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Case CMB$^{TM}$ -5 COE sensitivity study are shown in Figure 7.4.14 and summarized in Table 7.4.14. The levelized COE for the base parameter values is 3.4 cents per kWh. Levelized COE ranges from a low of 2.9 to a high of 4.2 cents per kWh.

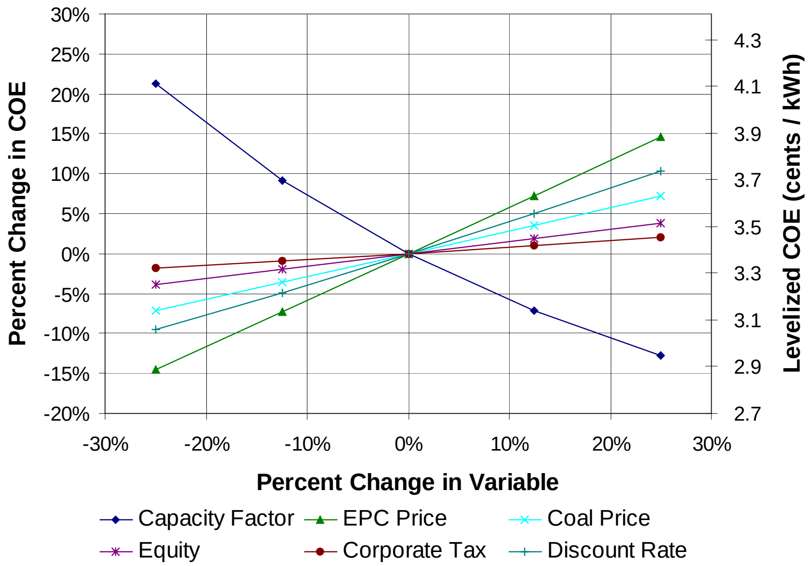



**Figure 7.4.14: Case CMB-5 32.9 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.14: Case CMB-5 32.9 Alloy - 1 x 750 MW CMB Steam Plant with SNCR and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Case CMB-5 - 1 x 750 MW CMB Steam Plant, 32.9 Nickel | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | | |
| Net Output | kW | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 |
| Availability Factor | % | **80** | 60 | 70 | 90 | 100 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 5,256 | 6,132 | 7,884 | 8,760 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 |
| Net Generation | MWh / year | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 |
| **Costs** | | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 783 | 913 | 1,174 | 1,304 | 1,043 | 1,043 | 1,043 | 1,043 |
| EPC Price | $1000s | **776,526** | 776,526 | 776,526 | 776,526 | 776,526 | 582,395 | 679,460 | 873,592 | 970,658 | 776,526 | 776,526 | 776,526 | 776,526 |
| Fixed O&M Costs | $1000 / year | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 |
| Fixed O&M Costs | $ / kW | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 |
| Variable O&M Costs | $1000 / year | 13,199 | 9,900 | 11,550 | 14,849 | 16,499 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 |
| Variable O&M Costs | cents / kWh | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Total O&M Costs | cents / kWh | 0.45 | 0.51 | 0.47 | 0.42 | 0.41 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.25** | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 0.94 | 1.09 | 1.41 | 1.56 |
| **Financing Assumptions** | | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **10** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | | |
| Financial Component | | 2.00 | 2.66 | 2.28 | 1.77 | 1.60 | 1.50 | 1.75 | 2.25 | 2.49 | 2.00 | 2.00 | 2.00 | 2.00 |
| Fixed O&M | | 0.19 | 0.26 | 0.22 | 0.17 | 0.15 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 |
| Variable O&M | | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.74 | 0.86 | 1.10 | 1.23 |
| Total | | 3.42 | 4.15 | 3.73 | 3.18 | 2.98 | 2.92 | 3.17 | 3.67 | 3.92 | 3.18 | 3.30 | 3.54 | 3.67 |

| Parameter | Units | Case CMB-5 - 1 x 750 MW CMB Steam Plant, 32.9 Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 | 744,230 |
| Availability Factor | % | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Actual Operating Hours | hours / year | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 | 7,008 |
| Net Efficiency, HHV | % | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 | 43.5 |
| Net Plant Heat Rate, HHV | Btu / kWh | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 | 7853 |
| Net Generation | MWh / year | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 | 5,215,564 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 | 1,043 |
| EPC Price | $1000s | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 | 776,526 |
| Fixed O&M Costs | $1000 / year | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 | 10,011 |
| Fixed O&M Costs | $ / kW | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 | 13.45 |
| Variable O&M Costs | $1000 / year | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 | 13,199 |
| Variable O&M Costs | cents / kWh | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Total O&M Costs | cents / kWh | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 | 1.25 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 9 | 11 | 13 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.86 | 1.93 | 2.06 | 2.13 | 1.93 | 1.96 | 2.03 | 2.06 | 1.67 | 1.83 | 2.17 | 2.35 |
| Fixed O&M | | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 |
| Variable O&M | | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| Fuel | | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Total | | 3.29 | 3.36 | 3.49 | 3.55 | 3.36 | 3.39 | 3.46 | 3.49 | 3.10 | 3.26 | 3.60 | 3.78 |

### 7.4.15 Case Base Phillip Sporn Unit 4 – Base Phillip Sporn Unit 4 Economic Sensitivity Results

Results for the Base Case Phillip Sporn Unit 4 COE sensitivity study are shown in Figure 7.4.15 and summarized in Table 7.4.15. The levelized COE for the base parameter values is 1.9 cents per kWh. Levelized COE ranges from a low of 1.6 to a high of 2.0 cents per kWh.

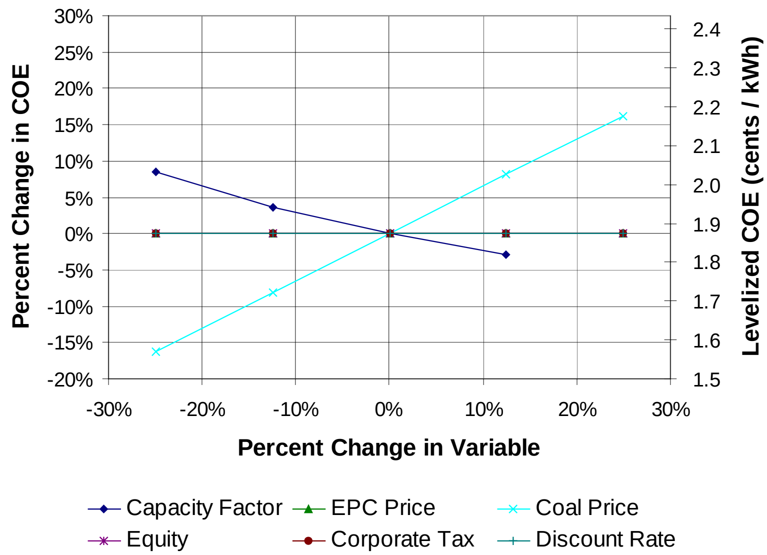



**Figure 7.4.15: Case Base Phillip Sporn Unit 4 – Base Phillip Sporn Unit 4 Economic Sensitivity Results**

## Table 7.4.15: Case Base Phillip Sporn Unit 4 – Base Phillip Sporn Unit 4 Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Base | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 |
| Net Plant Heat Rate, HHV | Btu / kWh | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 |
| Net Generation | MWh / year | 1,165,433 | 874,075 | 1,019,754 | 1,311,112 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EPC Price | $1000s | **0** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fixed O&M Costs | $1000 / year | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 |
| Fixed O&M Costs | $ / kW | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 |
| Variable O&M Costs | $1000 / year | 2,138 | 1,603 | 1,870 | 2,405 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 |
| Variable O&M Costs | cents / kWh | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 |
| Total O&M Costs | cents / kWh | 0.66 | 0.82 | 0.73 | 0.61 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fixed O&M | | 0.48 | 0.63 | 0.54 | 0.42 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| Variable O&M | | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 |
| Fuel | | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 0.91 | 1.06 | 1.37 | 1.52 |
| Total | | 1.87 | 2.03 | 1.94 | 1.82 | 1.87 | 1.87 | 1.87 | 1.87 | 1.57 | 1.72 | 2.03 | 2.18 |

| Parameter | Units | Sporn Unit #4 - Base | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 |
| Net Plant Heat Rate, HHV | Btu / kWh | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 |
| Net Generation | MWh / year | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EPC Price | $1000s | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fixed O&M Costs | $1000 / year | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 |
| Fixed O&M Costs | $ / kW | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 |
| Variable O&M Costs | $1000 / year | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 | 2,138 |
| Variable O&M Costs | cents / kWh | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 |
| Total O&M Costs | cents / kWh | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 | 0.66 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fixed O&M | | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| Variable O&M | | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 |
| Fuel | | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 |
| Total | | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 | 1.87 |

### 7.4.16 Case Base Phillip Sporn Unit 4 Purchase $NO_x$ Credits – Base Phillip Sporn Unit 4 with Purchase of \$5k per Ton $NO_x$ Credits Economic Sensitivity Results

Results for the Base Case Phillip Sporn plant with $NO_x$ credits purchased at \$5k per ton COE sensitivity study are shown in Figure 7.4.16 and summarized in Table 7.4.16. The levelized COE for the base parameter values is 2.3 cents per kWh. Levelized COE ranges from a low of 2.0 to a high of 2.5 cents per kWh.

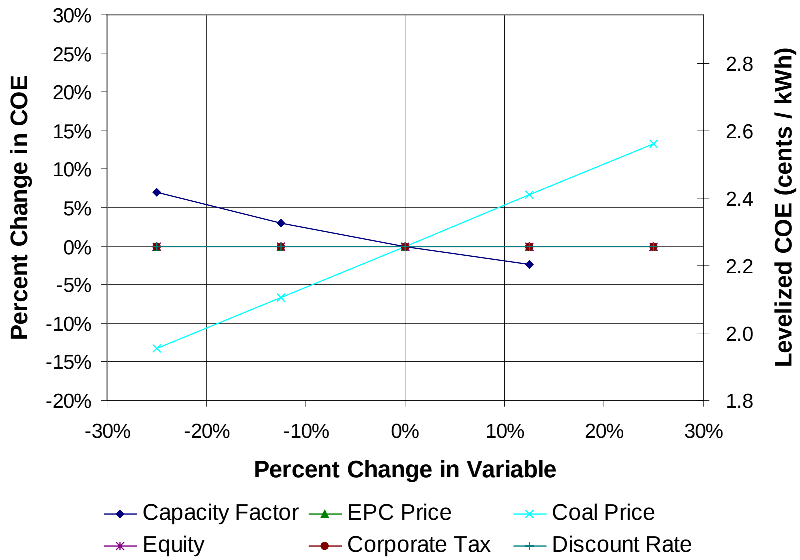



**Figure 7.4.16: Case Base Phillip Sporn Unit 4 Purchase $NO_x$ Credits – Base Phillip Sporn Unit 4 with Purchase of \$5k per Ton $NO_x$ Credits Economic Sensitivity Results**

## Table 7.4.16: Case Base Phillip Sporn Unit 4 Purchase $NO_x$ Credits – Base Phillip Sporn Unit 4 with Purchase of \$5k per Ton $NO_x$ Credits Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Base, Purchase NOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 |
| Net Plant Heat Rate, HHV | Btu / kWh | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 |
| Net Generation | MWh / year | 1,165,433 | 874,075 | 1,019,754 | 1,311,112 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | \$ / kW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EPC Price | \$1000s | **0** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fixed O&M Costs | \$1000 / year | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 |
| Fixed O&M Costs | \$ / kW | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 |
| Variable O&M Costs | \$1000 / year | 7,011 | 5,259 | 6,135 | 7,888 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 |
| Variable O&M Costs | cents / kWh | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 |
| Total O&M Costs | cents / kWh | 1.08 | 1.24 | 1.15 | 1.02 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | \$ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fixed O&M | | 0.48 | 0.63 | 0.54 | 0.42 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| Variable O&M | | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 |
| Fuel | | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 0.91 | 1.06 | 1.37 | 1.52 |
| Total | | 2.29 | 2.45 | 2.36 | 2.24 | 2.29 | 2.29 | 2.29 | 2.29 | 1.99 | 2.14 | 2.44 | 2.60 |

| Parameter | Units | Sporn Unit #4 - Base, Purchase NOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 | 156,518 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 |
| Net Plant Heat Rate, HHV | Btu / kWh | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 | 9561 |
| Net Generation | MWh / year | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 | 1,165,433 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | \$ / kW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EPC Price | \$1000s | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Fixed O&M Costs | \$1000 / year | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 | 5,544 |
| Fixed O&M Costs | \$ / kW | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 | 35.42 |
| Variable O&M Costs | \$1000 / year | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 | 7,011 |
| Variable O&M Costs | cents / kWh | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 |
| Total O&M Costs | cents / kWh | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | \$ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fixed O&M | | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 | 0.48 |
| Variable O&M | | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 |
| Fuel | | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 |
| Total | | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 | 2.29 |

### 7.4.17 Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $20 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Phillip Sporn Unit 4 Repowering Case COE sensitivity study are shown in Figure 7.4.17 and summarized in Table 7.4.17. The levelized COE for the base parameter values is 2.8 cents per kWh. Levelized COE ranges from a low of 2.5 to a high of 3.3 cents per kWh.

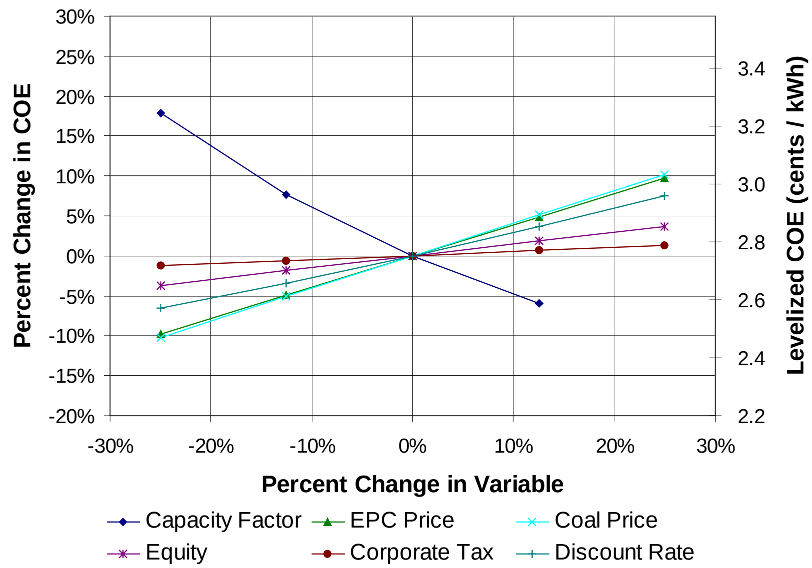



**Figure 7.4.17: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $20 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.17: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $20 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Repowering; $20 per lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 |
| Net Generation | MWh / year | 1,373,690 | 1,030,268 | 1,201,979 | 1,545,401 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 400 | 400 | 400 | 400 | 300 | 350 | 451 | 501 | 400 | 400 | 400 | 400 |
| EPC Price | $1000s | **73,880** | 73,880 | 73,880 | 73,880 | 55,410 | 64,645 | 83,115 | 92,350 | 73,880 | 73,880 | 73,880 | 73,880 |
| Fixed O&M Costs | $1000 / year | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 |
| Fixed O&M Costs | $ / kW | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 |
| Variable O&M Costs | $1000 / year | 2,130 | 1,597 | 1,864 | 2,396 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 |
| Variable O&M Costs | cents / kWh | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Total O&M Costs | cents / kWh | 0.56 | 0.69 | 0.61 | 0.51 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.08 | 1.44 | 1.23 | 0.96 | 0.81 | 0.94 | 1.21 | 1.35 | 1.08 | 1.08 | 1.08 | 1.08 |
| Fixed O&M | | 0.40 | 0.53 | 0.46 | 0.36 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Fuel | | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 0.85 | 0.99 | 1.27 | 1.41 |
| Total | | 2.76 | 3.25 | 2.97 | 2.60 | 2.49 | 2.63 | 2.90 | 3.03 | 2.48 | 2.62 | 2.90 | 3.04 |

| Parameter | Units | Sporn Unit #4 - Repowering; $20 per lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 |
| Net Generation | MWh / year | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 |
| EPC Price | $1000s | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 | 73,880 |
| Fixed O&M Costs | $1000 / year | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 | 5,495 |
| Fixed O&M Costs | $ / kW | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 | 29.78 |
| Variable O&M Costs | $1000 / year | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 | 2,130 |
| Variable O&M Costs | cents / kWh | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Total O&M Costs | cents / kWh | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 0.97 | 1.03 | 1.13 | 1.18 | 1.04 | 1.06 | 1.09 | 1.11 | 0.90 | 0.98 | 1.18 | 1.28 |
| Fixed O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Fuel | | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 |
| Total | | 2.66 | 2.71 | 2.81 | 2.86 | 2.73 | 2.74 | 2.78 | 2.80 | 2.58 | 2.67 | 2.86 | 2.97 |

### 7.4.18 Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Phillip Sporn Unit 4 Repowering Case COE sensitivity study are shown in Figure 7.4.18 and summarized in Table 7.4.18. The levelized COE for the base parameter values is 2.8 cents per kWh. Levelized COE ranges from a low of 2.5 to a high of 3.3 cents per kWh.

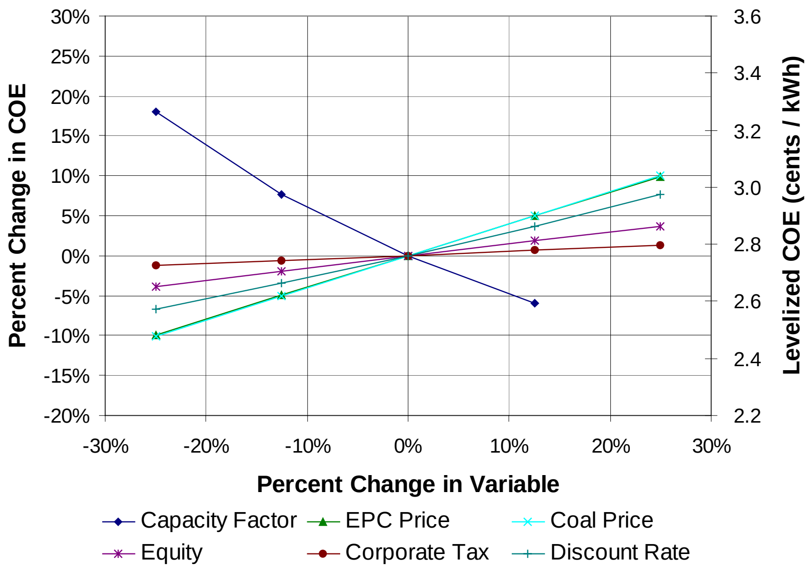



**Figure 7.4.18: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.18: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Repowering; $28 per lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 |
| Net Generation | MWh / year | 1,373,690 | 1,030,268 | 1,201,979 | 1,545,401 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 414 | 414 | 414 | 414 | 310 | 362 | 466 | 517 | 414 | 414 | 414 | 414 |
| EPC Price | $1000s | **76,344** | 76,344 | 76,344 | 76,344 | 57,258 | 66,801 | 85,887 | 95,430 | 76,344 | 76,344 | 76,344 | 76,344 |
| Fixed O&M Costs | $1000 / year | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 2,168 | 1,626 | 1,897 | 2,439 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 |
| Variable O&M Costs | cents / kWh | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Total O&M Costs | cents / kWh | 0.56 | 0.69 | 0.62 | 0.52 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.11 | 1.48 | 1.27 | 0.99 | 0.83 | 0.97 | 1.25 | 1.39 | 1.11 | 1.11 | 1.11 | 1.11 |
| Fixed O&M | | 0.40 | 0.54 | 0.46 | 0.36 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Fuel | | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 0.85 | 0.99 | 1.27 | 1.41 |
| Total | | 2.80 | 3.31 | 3.02 | 2.63 | 2.52 | 2.66 | 2.94 | 3.08 | 2.52 | 2.66 | 2.94 | 3.08 |

| Parameter | Units | Sporn Unit #4 - Repowering; $28 per lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 |
| Net Generation | MWh / year | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 414 | 414 | 414 | 414 | 414 | 414 | 414 | 414 | 414 | 414 | 414 | 414 |
| EPC Price | $1000s | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 | 76,344 |
| Fixed O&M Costs | $1000 / year | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 | 5,532 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 | 2,168 |
| Variable O&M Costs | cents / kWh | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Total O&M Costs | cents / kWh | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.00 | 1.06 | 1.17 | 1.22 | 1.08 | 1.10 | 1.13 | 1.15 | 0.93 | 1.02 | 1.22 | 1.33 |
| Fixed O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Fuel | | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 |
| Total | | 2.69 | 2.75 | 2.85 | 2.91 | 2.77 | 2.78 | 2.82 | 2.84 | 2.61 | 2.70 | 2.91 | 3.02 |

### 7.4.19 Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Phillip Sporn Unit 4 Repowering Case COE sensitivity study are shown in Figure 7.4.19 and summarized in Table 7.4.19. The levelized COE for the base parameter values is 2.8 cents per kWh. Levelized COE ranges from a low of 2.5 to a high of 3.3 cents per kWh.

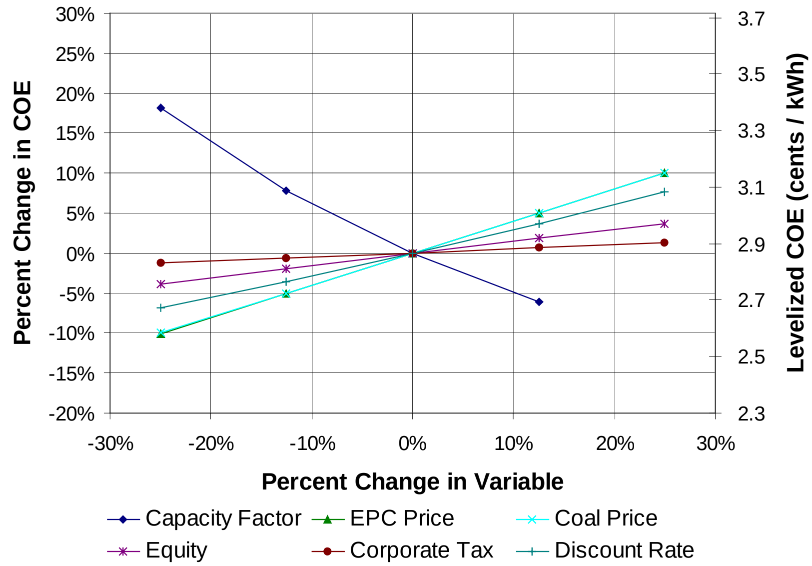



**Figure 7.4.19: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.19: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with No Emissions Credits Sold and $32.90 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Repowering; $32.90 per lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 |
| Net Generation | MWh / year | 1,373,690 | 1,030,268 | 1,201,979 | 1,545,401 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 422 | 422 | 422 | 422 | 316 | 369 | 475 | 527 | 422 | 422 | 422 | 422 |
| EPC Price | $1000s | **77,831** | 77,831 | 77,831 | 77,831 | 58,373 | 68,102 | 87,560 | 97,289 | 77,831 | 77,831 | 77,831 | 77,831 |
| Fixed O&M Costs | $1000 / year | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 |
| Fixed O&M Costs | $ / kW | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 |
| Variable O&M Costs | $1000 / year | 2,190 | 1,643 | 1,917 | 2,464 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 |
| Variable O&M Costs | cents / kWh | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Total O&M Costs | cents / kWh | 0.56 | 0.70 | 0.62 | 0.52 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.13 | 1.51 | 1.30 | 1.01 | 0.85 | 0.99 | 1.28 | 1.42 | 1.13 | 1.13 | 1.13 | 1.13 |
| Fixed O&M | | 0.40 | 0.54 | 0.46 | 0.36 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Fuel | | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 0.85 | 0.99 | 1.27 | 1.41 |
| Total | | 2.83 | 3.34 | 3.05 | 2.66 | 2.54 | 2.69 | 2.97 | 3.11 | 2.55 | 2.69 | 2.97 | 3.11 |

| Parameter | Units | Sporn Unit #4 - Repowering; $32.90 per lb Nickel | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 | 184,487 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 | 8889 |
| Net Generation | MWh / year | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 | 1,373,690 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 422 | 422 | 422 | 422 | 422 | 422 | 422 | 422 | 422 | 422 | 422 | 422 |
| EPC Price | $1000s | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 | 77,831 |
| Fixed O&M Costs | $1000 / year | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 | 5,554 |
| Fixed O&M Costs | $ / kW | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 | 30.11 |
| Variable O&M Costs | $1000 / year | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 | 2,190 |
| Variable O&M Costs | cents / kWh | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Total O&M Costs | cents / kWh | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.02 | 1.08 | 1.19 | 1.24 | 1.10 | 1.12 | 1.15 | 1.17 | 0.94 | 1.04 | 1.24 | 1.35 |
| Fixed O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Fuel | | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 | 1.13 |
| Total | | 2.72 | 2.77 | 2.88 | 2.93 | 2.79 | 2.81 | 2.85 | 2.87 | 2.64 | 2.73 | 2.93 | 3.04 |

### 7.4.20 Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $2k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Phillip Sporn Unit 4 Repowering Case COE sensitivity study are shown in Figure 9.4.20 and summarized in Table 9.4.20. The levelized COE for the base parameter values is 2.8 cents per kWh. Levelized COE ranges from a low of 2.5 to a high of 3.3 cents per kWh.

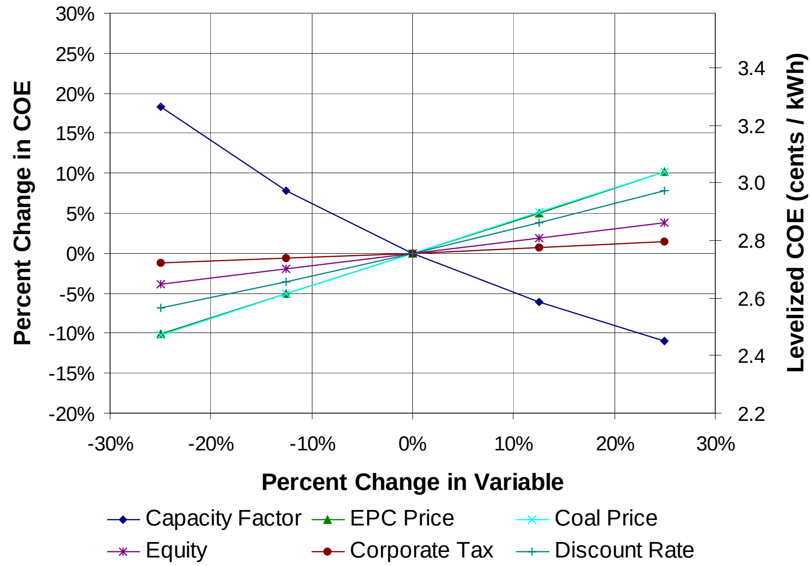



**Figure 7.4.20: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $2k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.20: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with \$2k per Ton $NO_x$ and \$200 per Ton $SO_x$ Emissions Credits Sold and \$28 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Repowering; $2k/ton NOx & $200/ton SOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 |
| Net Generation | MWh / year | 1,372,946 | 1,029,709 | 1,201,327 | 1,544,564 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 419 | 419 | 419 | 419 | 315 | 367 | 472 | 524 | 419 | 419 | 419 | 419 |
| EPC Price | $1000s | **77,344** | 77,344 | 77,344 | 77,344 | 58,008 | 67,676 | 87,012 | 96,680 | 77,344 | 77,344 | 77,344 | 77,344 |
| Fixed O&M Costs | $1000 / year | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 1,586 | 1,189 | 1,388 | 1,784 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 |
| Variable O&M Costs | cents / kWh | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 |
| Total O&M Costs | cents / kWh | 0.52 | 0.65 | 0.58 | 0.47 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.13 | 1.50 | 1.29 | 1.00 | 0.85 | 0.99 | 1.27 | 1.41 | 1.13 | 1.13 | 1.13 | 1.13 |
| Fixed O&M | | 0.40 | 0.54 | 0.46 | 0.36 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 |
| Fuel | | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 0.85 | 0.99 | 1.28 | 1.42 |
| Total | | 2.78 | 3.29 | 3.00 | 2.61 | 2.50 | 2.64 | 2.92 | 3.06 | 2.50 | 2.64 | 2.92 | 3.07 |

| Parameter | Units | Sporn Unit #4 - Repowering; $2k/ton NOx & $200/ton SOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 |
| Net Generation | MWh / year | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 |
| EPC Price | $1000s | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 |
| Fixed O&M Costs | $1000 / year | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 | 1,586 |
| Variable O&M Costs | cents / kWh | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 |
| Total O&M Costs | cents / kWh | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.02 | 1.07 | 1.18 | 1.23 | 1.09 | 1.11 | 1.15 | 1.17 | 0.94 | 1.03 | 1.23 | 1.34 |
| Fixed O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 |
| Fuel | | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 |
| Total | | 2.67 | 2.73 | 2.84 | 2.89 | 2.75 | 2.77 | 2.80 | 2.82 | 2.59 | 2.68 | 2.89 | 3.00 |

### 7.4.21 Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $5k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Phillip Sporn Unit 4 Repowering Case COE sensitivity study are shown in Figure 9.4.21 and summarized in Table 9.4.21. The levelized COE for the base parameter values is 2.8 cents per kWh. Levelized COE ranges from a low of 2.5 to a high of 3.3 cents per kWh.

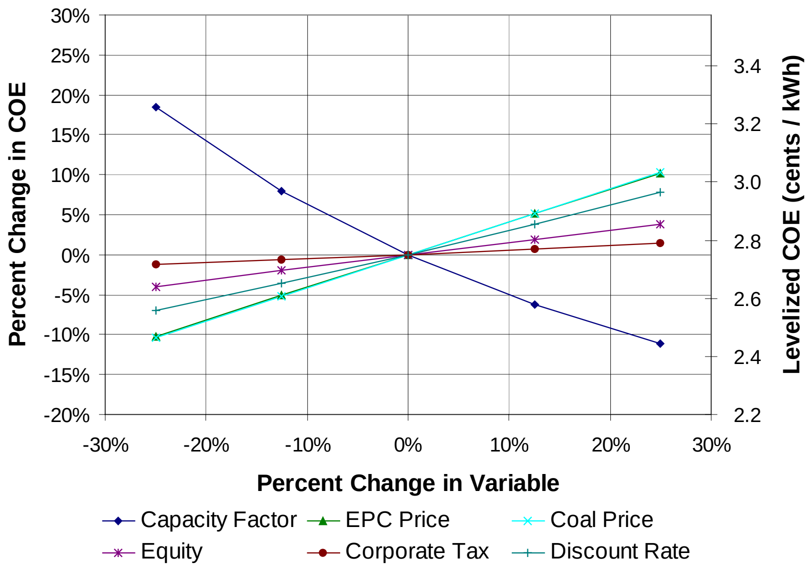



**Figure 7.4.21: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $5k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.21: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with \$5k per Ton $NO_x$ and \$200 per Ton $SO_x$ Emissions Credits Sold and \$28 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Repowering; $5k/ton NOx & $200/ton SOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 |
| Net Generation | MWh / year | 1,372,946 | 1,029,709 | 1,201,327 | 1,544,564 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 419 | 419 | 419 | 419 | 315 | 367 | 472 | 524 | 419 | 419 | 419 | 419 |
| EPC Price | $1000s | **77,344** | 77,344 | 77,344 | 77,344 | 58,008 | 67,676 | 87,012 | 96,680 | 77,344 | 77,344 | 77,344 | 77,344 |
| Fixed O&M Costs | $1000 / year | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 1,203 | 903 | 1,053 | 1,354 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 |
| Variable O&M Costs | cents / kWh | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Total O&M Costs | cents / kWh | 0.49 | 0.62 | 0.55 | 0.45 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.13 | 1.50 | 1.29 | 1.00 | 0.85 | 0.99 | 1.27 | 1.41 | 1.13 | 1.13 | 1.13 | 1.13 |
| Fixed O&M | | 0.40 | 0.54 | 0.46 | 0.36 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Fuel | | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 0.85 | 0.99 | 1.28 | 1.42 |
| Total | | 2.75 | 3.26 | 2.97 | 2.58 | 2.47 | 2.61 | 2.90 | 3.04 | 2.47 | 2.61 | 2.90 | 3.04 |

| Parameter | Units | Sporn Unit #4 - Repowering; $5k/ton NOx & $200/ton SOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 |
| Net Generation | MWh / year | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 |
| EPC Price | $1000s | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 |
| Fixed O&M Costs | $1000 / year | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 |
| Variable O&M Costs | cents / kWh | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Total O&M Costs | cents / kWh | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.02 | 1.07 | 1.18 | 1.23 | 1.09 | 1.11 | 1.15 | 1.17 | 0.94 | 1.03 | 1.23 | 1.34 |
| Fixed O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 |
| Fuel | | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 |
| Total | | 2.65 | 2.70 | 2.81 | 2.86 | 2.72 | 2.74 | 2.77 | 2.79 | 2.56 | 2.66 | 2.86 | 2.97 |

### 7.4.22 Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $8k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results

Results for the Phillip Sporn Unit 4 Repowering Case COE sensitivity study are shown in Figure 9.4.22 and summarized in Table 9.4.22. The levelized COE for the base parameter values is 2.1 cents per kWh. Levelized COE ranges from a low of 1.8 to a high of 2.6 cents per kWh.

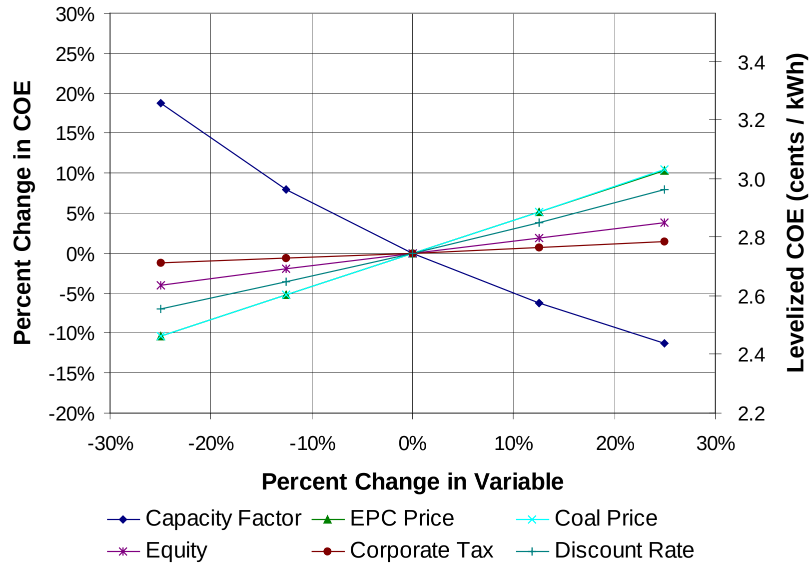



**Figure 7.4.22: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $8k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results**

## Table 7.4.22: Case Repowering Phillip Sporn Unit 4 – Repowering Phillip Sporn Unit 4 with $8k per Ton $NO_x$ and $200 per Ton $SO_x$ Emissions Credits Sold and $28 per Pound High Temperature Alloy Economic Sensitivity Results

| Parameter | Units | Sporn Unit #4 - Repowering; $8k/ton NOx & $200/ton SOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 |
| Availability Factor | % | **85** | 64 | 74 | 96 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 558,450 | 651,525 | 837,675 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 |
| Net Generation | MWh / year | 1,372,946 | 1,029,709 | 1,201,327 | 1,544,564 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 419 | 419 | 419 | 419 | 315 | 367 | 472 | 524 | 419 | 419 | 419 | 419 |
| EPC Price | $1000s | **77,344** | 77,344 | 77,344 | 77,344 | 58,008 | 67,676 | 87,012 | 96,680 | 77,344 | 77,344 | 77,344 | 77,344 |
| Fixed O&M Costs | $1000 / year | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 821 | 616 | 718 | 924 | 821 | 821 | 821 | 821 | 821 | 821 | 821 | 821 |
| Variable O&M Costs | cents / kWh | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Total O&M Costs | cents / kWh | 0.46 | 0.60 | 0.52 | 0.42 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | **1.27** | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 0.95 | 1.11 | 1.43 | 1.59 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | **50** | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | **20** | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| Discount Factor | % | **15** | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.13 | 1.50 | 1.29 | 1.00 | 0.85 | 0.99 | 1.27 | 1.41 | 1.13 | 1.13 | 1.13 | 1.13 |
| Fixed O&M | | 0.40 | 0.54 | 0.46 | 0.36 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Fuel | | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 0.85 | 0.99 | 1.28 | 1.42 |
| Total | | 2.73 | 3.24 | 2.95 | 2.56 | 2.44 | 2.59 | 2.87 | 3.01 | 2.44 | 2.58 | 2.87 | 3.01 |

| Parameter | Units | Sporn Unit #4 - Repowering; $8k/ton NOx & $200/ton SOx Credits | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Power Generation** | | | | | | | | | | | | | |
| Net Output | kW | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 | 184,387 |
| Availability Factor | % | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Actual Operating Hours | hours / year | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 | 744,600 |
| Net Efficiency, HHV | % | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 |
| Net Plant Heat Rate, HHV | Btu / kWh | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 | 8947 |
| Net Generation | MWh / year | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 | 1,372,946 |
| **Costs** | | | | | | | | | | | | | |
| EPC Price | $ / kW | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 | 419 |
| EPC Price | $1000s | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 | 77,344 |
| Fixed O&M Costs | $1000 / year | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 | 5,529 |
| Fixed O&M Costs | $ / kW | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Variable O&M Costs | $1000 / year | 821 | 821 | 821 | 821 | 821 | 821 | 821 | 821 | 821 | 821 | 821 | 821 |
| Variable O&M Costs | cents / kWh | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Total O&M Costs | cents / kWh | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 |
| **Fuel Cost Calculation** | | | | | | | | | | | | | |
| Coal Price | $ / MMBtu | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 | 1.27 |
| **Financing Assumptions** | | | | | | | | | | | | | |
| Equity | % | 38 | 44 | 56 | 63 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Corporate Tax | % | 20 | 20 | 20 | 20 | 15 | 18 | 23 | 25 | 20 | 20 | 20 | 20 |
| Discount Factor | % | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 11 | 13 | 17 | 19 |
| **Levelized Cost of Electricity (cents / kWh)** | | | | | | | | | | | | | |
| Financial Component | | 1.02 | 1.07 | 1.18 | 1.23 | 1.09 | 1.11 | 1.15 | 1.17 | 0.94 | 1.03 | 1.23 | 1.34 |
| Fixed O&M | | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 | 0.40 |
| Variable O&M | | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Fuel | | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 | 1.14 |
| Total | | 2.62 | 2.67 | 2.78 | 2.83 | 2.69 | 2.71 | 2.75 | 2.77 | 2.54 | 2.63 | 2.83 | 2.94 |