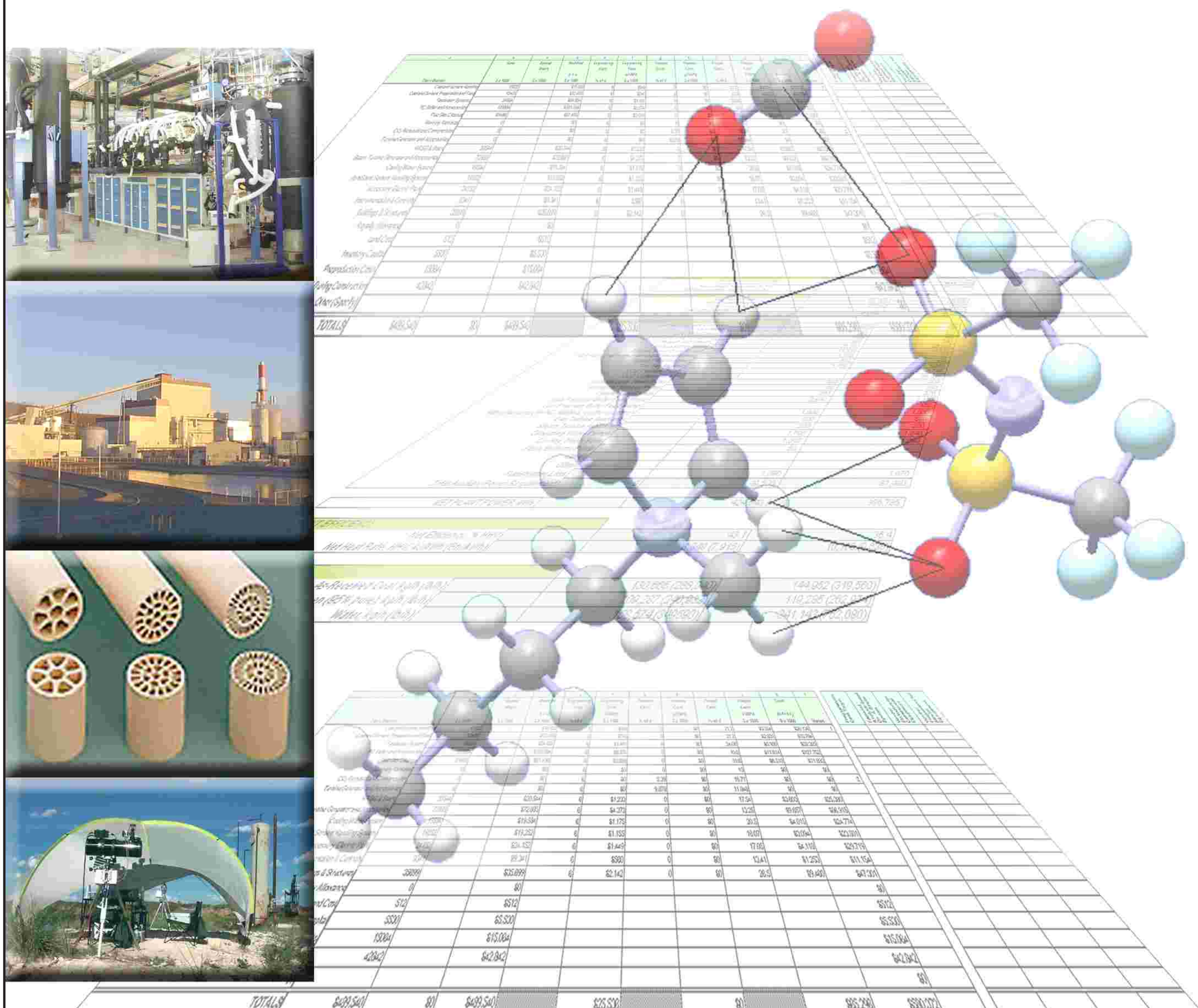
U.S. Department of Energy • Office of Fossil Energy

National Energy Technology Laboratory

Carbon Capture and Sequestration Systems Analysis Guidelines



April 2005

DESCRIPTIONS OF GRAPHICS ON COVER PAGE:

First Graphic on Top Left:

Project Title: CO_2 Hydrate Process for Gas Separation from a Shifted Synthesis Gas Stream, NT40248

Illustration depicts a continuous flow Engineering Test Module (ETM) for demonstrating carbon dioxide (CO_2) capture from mixed gas streams using gas hydrates. Gas and water are contacted in a venturi mixer followed by downstream finned heat exchanger sections for removing the heat of formation. The hydrate slurry is then physically separated from the remaining gas.

Second Graphic down from Top Left:

Title: AES Warrior Run Power Plant; Cumberland, MD

Illustration depicts the AES Warrior Run power plant which is a 180-MWe (net), coal-fired electric generating facility located in the Allegany County Industrial Park in Cumberland, MD. One of the newest coal-fired power plants in the United States, it achieved commercial operations on February 10, 2000. As a cogenerator, steam from the power plant is also used for the on-site production of food-grade liquid CO_2.

Third Graphic down from Top Left:

Project Title: In-house project on Hybrid Membranes for CO_2 Removal

Illustration depicts ceramic membranes showing various pore structures. As the stabilization of CO_2 concentrations in the atmosphere becomes increasingly important, the capture and sequestration of CO_2 emissions from advanced power generation will become a necessity. Currently, separation and capture represent the greatest expense in the overall reduction of CO_2 emissions. Improvements in capture have a great potential to affect the cost of CO_2 mitigation, and membrane technology holds significant promise in this area.

Fourth Graphic down from Top Left:

Project Title: Development of Comprehensive Monitoring Techniques to Verify the Integrity of Geologically Sequestered Carbon Dioxide, NT10244

Illustration depicts spectroscopic measurements being taken at the West Pearl Queen Field located in New Mexico. One of the most critical research areas is aimed at monitoring the long-term storage stability and integrity of CO_2 in geologic formations. Research aimed at monitoring the integrity of CO_2 sequestered in geologic formations is certainly one of the most pressing areas of need if geologic sequestration is to become a significant factor in meeting stated objectives of the U.S. to reduce greenhouse gas emissions.

Center Page – Molecular Structure Graphic:

Project Title: Design and Evaluation of Ionic Liquids as Novel Absorbents, NT42122

Illustration depicts results of *ab initio* calculation for CO_2 association with 1-n-butyl-3-methylpyridinium bis (trifluorosulfonyl) amide.

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1.0 Background

The intent of this document is to provide guidance to projects awarded by the U.S. Department of Energy (DOE), Office of Fossil Energy (FE), National Energy Technology Laboratory (NETL) that are developing carbon dioxide (CO_2) capture and separation technologies and conducting systems and economic analyses. These guidelines are applicable to both pre-and post-combustion CO_2 capture and separation technologies and are a requirement to research projects recently awarded by NETL. For those projects awarded that do not have the requirement to conform to this document, it is recommended that they do, if they have not yet performed a systems and economic analysis according to their statement of project objectives.

It is the intent of NETL to conform all systems analysis work performed by its contractors to these guidelines whether the Contractor was required to comply or not. This document is based on and extends the guidance provided in the "Quality Guidelines for Energy System Studies," which was issued by NETL in February 2004. NETL expects to periodically evaluate this document to meet the needs of the program.

Each year, carbon sequestration system studies are undertaken by the U.S. Department of Energy, Office of Fossil Energy, and NETL. Some of these studies are conducted by NETL personnel; others are implemented under research and development funding instruments managed by FE or NETL. Technologies that have been studied range from ideas at a conceptual stage to processes evaluated at an advanced pilot scale. Carbon sequestration research areas have included capture and separation related projects; monitoring, mitigation, and verification projects; geologic sequestration; terrestrial sequestration; and novel concepts.

One of the goals of this effort is to develop cost-effective and environmentally sound technologies, which will help to stabilize overall atmospheric concentrations of CO_2 and reduce greenhouse gas emissions. This is a challenging program of critical national importance that has been established to identify, support, and develop new or breakthrough technologies, which can be successfully implemented.

In addition, there is a substantial requirement for technological improvements to increase efficiency and lower costs, because currently available power plant CO_2 capture and separation technologies do not meet the carbon sequestration program goal of capturing 90% of the CO_2 emitted with only a 10% and 20% increase in the cost of electricity for pre-combustion and post-combustion systems, respectively. Systems analyses and economic modeling of potential new processes are crucial to providing sound guidance to the research and development (R&D) effort, which is investigating a wide range of CO_2 capture options. It is critically important that the reported performance characteristics or advantages of one system over another be legitimate, transparent, and not simply the result of different assumptions or methods used by the process model.

2.0 Purpose

A primary objective of NETL's CO_2 capture and separation systems studies is the ability to assess potential technical and economic merits for an assortment of technologies. In order to do this, it is useful to compare the results of novel CO_2 capture technologies that are incorporated into similar energy systems. The results are used to identify barriers to deployment and to help the process developers establish system performance targets. Occasionally, however, problems originate with these analyses due to inadequate description of the methodology, insufficient documentation of the data, errors in the mass and energy balance, inconsistent reference state conditions, etc. Further, conducting fair and rational comparisons between studies is often complicated by one of two factors:

2.1 Fundamental Differences in Study Scope: Substantial differences in scope are to be expected among energy system studies that are independently planned and implemented. For example, studies of a certain type of energy system that are independently sponsored are bound to have differences in their system configurations and/or specifications of feedstocks and products. Furthermore, various levels of rigor are often used to model and analyze similar energy systems.

2.2 Incongruities in Modeling, Documentation, Analysis, and Reporting: The absence of any quality guidelines for energy system studies has led to incongruities in the energy system studies sponsored by FE and NETL. Incongruities related to process modeling, documentation, analysis, and reporting have often complicated or prevented any attempts to perform rational comparisons among energy system studies.

3.0 Guidance

To help alleviate the obstacles identified in Section 2.0, the following guidance is being provided to each CO_2 capture technology developer that is under FE NETL award. It is anticipated that these guidelines will provide greater clarity and uniformity to the process of completing systems analyses for carbon sequestration projects. However, these guidelines are not intended to minimize the level of detail that some contractors are capable of performing. Greater detail and information is always preferred over less but it is understood that contractor capabilities vary.

3.1 "Quality Guidelines for Energy System Studies"

"Quality Guidelines for Energy System Studies" (provided for reference in Section I) were issued by NETL on February 24, 2004 and were established to improve the quality of NETL-sponsored energy system studies and to ensure that they are objective, transparent, and comparable with one another. These guidelines offer a menu of technical suggestions and proven approaches for conducting an energy system study. In order for NETL to perform a system analysis of CO_2 capture technologies, it needs a certain quantity and quality of data for each project. The guidelines provide guidance on specifications for feedstocks, products, and processes, estimating performance, documentation of assumptions and methodology, definitions of measures, cost estimation guidance based on industry practices, and guidelines for reporting overall economic performance. To ensure consistency and transparency, these guidelines should be consulted prior to providing technology cost and performance data to NETL.

3.2 Additional Guidelines

In addition to the NETL's Quality Guidelines, there are supplementary guidelines that are requested specifically for the systems analysis of CO_2 capture and separation projects.

Additional Guidelines for Carbon Capture and Sequestration Systems Analysis	
Process Flow Diagrams (PFD)	**Include a PFD that shows how process streams flow among all the major components in the overall energy system**. As appropriate for detail and clarity, show streams and components that are confined to certain subsystems on separate process flow diagrams. Every stream in the system should be labeled with a unique name.
Stream Table	**A stream table that lists, by stream number, the significant properties of each stream at design point conditions should accompany each process flow diagram**. At a minimum, the following properties should be included: temperature, pressure, vapor fraction, enthalpy, volumetric flow (for gases), total mass flow (for liquids and solids), and chemical composition [component mass fraction, component mass flow (for liquids and solids) or component mole fraction (for gases)].
Component Descriptions	**Complete the tables provided in the attached Microsoft Excel® workbook in Section II**. For the purpose of illustrating the intent of these information requests, portions of the spreadsheet tables have been completed. Additional data should be entered as necessary.
Capital and O&M Costs	**Tabulate the capital cost estimates for each major component or subsystem, including the project and/or process contingency applied to each. Complete the tables provided in the attached Microsoft Excel® workbook**. The table should also indicate the basis for each estimate, e.g., a programmatic cost target; a factored analysis based on a similar system, vendor estimates for commercial equipment, or vendor projections for conceptual equipment. Include any underlying or supporting assumptions that were used in completing the Excel® tables. Fuel costs and fixed/variable operating and maintenance (O&M) costs should also be tabulated by major plant section.
CO_2 Quality	**Tabulate the CO_2 gas composition.** The following constituents will be provided as a minimum: % CO_2, H_2S (ppm), oxygen (ppm), water (lbs/MMCF), glycol (gal/MMCF), nitrogen (minimum miscibility pressure or MMP), hydrocarbons (MMP), and temperature (Fahrenheit).
Techno-economic Performance	**Tabulate the system's technical and economic performance (e.g., products, efficiency, capital cost).** Determine the economic and performance impact of CO_2 capture on a power

	plant by calculating \$/ton of CO_2 avoided, \$/ton of CO_2 removed, % parasitic load, % increase in cost of electricity (COE), etc. The economic and performance data of the power plant without CO_2 capture (i.e., "baseline") will be required to carry out these calculations. Identify major equipment components that have been specified as part of a sparing strategy (e.g., a spare gasifier) and describe how spares affect the assumptions made regarding plant availability and capacity factor. Include sensitivity scaling curves for plant sizes between 200 and 1,000 MW that illustrate the impact of implementing this capture technology relative to the cost of electricity (mills/kWh) for specified capacity factors (multiple curves expected for capacity factors within the 65% to 85% range in 5% increments), plant efficiency, capture system footprint (ft^2), plant capital cost, \$/ton of CO_2 avoided, % CO_2 captured, and % COE increase over baseline case. If the capture technology has multi-pollutant capabilities in addition to CO_2 capture, then trade-off sensitivity studies with other pollution control systems (e.g., to handle SO_2 and H_2S) will be performed to optimize the efficiency and cost of the power cycle (credits at prevailing rates for pollutants with sensitivity cost curves are to be used).
Environmental Performance	**Tabulate the environmental performance of the system**, including: • a characterization of any liquid or solid waste streams, and • a listing of air emissions on the basis of mass per unit of input fuel energy, e.g., kg/MWh.
Expected Year of Commercialization	**Provide an estimated year that the capture technology will be available for commercial installation**. Also, to support this projection: • provide a brief narrative describing the current development status of the capture technology and timeline (e.g., concept, bench-scale, pilot-scale, demonstration plant, pre-commercialization unit, etc.), • provide any relevant data from prior scale or demonstration testing regarding operating experience, technical and cost performance, etc., • indicate whether a commercialization plan has been prepared and identify the organization with the lead responsibility for implementing the plan, and • describe how financial challenges and regulatory requirements are being met or addressed to help ensure commercialization success.

3.3 Excel® Spreadsheet with Templates

As a supplement to the NETL Systems Analysis Guidelines, several result tables were developed and can be used as templates for any given systems analysis. These spreadsheet templates have been provided in Section II. Note that these templates are not necessarily all inclusive—additional information required to fully describe the complete engineering analysis should be added as expanded or supplemental tables. Note that these tables are examples of an Integrated Gasification Combined Cycle (IGCC) with CO_2 capture and a Pulverized Coal (PC) power plant. An analogous approach is recommended for other power plant analyses, e.g., Natural Gas Combined Cycle (NGCC). These tables are included in the attached Microsoft Excel® electronic file and the NETL website.

Section I

Quality Guidelines for Energy System Studies

Quality Guidelines for Energy System Studies

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Disclaimer

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Foreword

Each year, dozens of energy system studies are undertaken by the U.S. Department of Energy (DOE) Office of Fossil Energy (FE) and the National Energy Technology Laboratory (NETL). Some of these studies are conducted by NETL personnel; others are implemented under research and development contracts funded and managed by NETL or FE. It is useful to compare results of those studies that feature similar energy systems. Unfortunately, conducting fair and rational comparisons is often complicated by one of two factors:

(1) **Fundamental Differences in Study Scope**: Substantial differences in scope are to be expected among energy system studies that are planned and implemented independently. For example, studies of a certain type of energy system that are independently sponsored are bound to have differences in their system configurations and/or specifications of feedstocks and products. Furthermore, various levels of rigor are often used to model and analyze similar energy systems. These scope-related obstacles to study comparisons can be avoided if FE and NETL plan and coordinate the energy system studies they sponsor. If well-planned, a methodical progression of energy system studies would be highly conducive to numerous internal comparisons that would yield valuable additional knowledge. Although outlining such a progression of systems studies is not within the scope of the present guidelines, we do recommend some standard specifications for certain feedstocks, products, and processes that are commonly encountered in energy system studies sponsored by FE or NETL.

(2) **Incongruities in Modeling, Documentation, Analysis, and Reporting**: The absence of any quality guidelines for energy system studies has led to incongruities in the energy system studies sponsored by FE and NETL. Incongruities related to process modeling, documentation, analysis, and reporting have often complicated or prevented any attempts to perform rational comparisons among energy system studies. Examples of these include:

- Accepted industry standards for basic energy components and processes were not followed.
- Process models were inadequately documented.
- Proprietary models were not validated.
- Key data or model software were not made accessible.
- Different equations and definitions were used to quantify the same performance measures.
- Different techniques and methodologies were used to estimate costs and measure overall economic performance.
- No confidence intervals were reported for quantitative results.
- Different bases were employed in analysis.
- Process boundaries were not clearly defined.

These quality guidelines were assembled to aid the development of NETL-sponsored energy system studies that are objective, transparent, and comparable with one another. The guidelines were written to represent the consensus view of the following NETL elements, all of which contributed to their development: the Office of Systems and Policy Support, the Office of Coal and Environmental Systems, and the Strategic Center for Natural Gas.

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1 Introduction

1.1 Purpose and Application

These guidelines are offered to project managers and systems analysts to aid the development of NETL-sponsored energy system studies that are objective, transparent, and comparable with one another.

Project managers are encouraged to consult and reference these guidelines when preparing statements of work for help in determining appropriate requirements for analytical rigor, model validation, model documentation, uncertainty analysis, project deliverables, and reporting.

System analysts and modelers are encouraged to use this document for guidance on feedstock/product specifications, process modeling, cost estimation, and economic analysis.

1.2 Overview

These non-mandatory guidelines are generally outcome-based and do not prescribe a "one-size-fits-all" approach on how energy system studies should be done. After all, project managers and modelers must retain discretion on how to tailor their methodology to fit a given situation. Instead, these guidelines offer a menu of technical suggestions and proven approaches for conducting an energy system study.

Specifications for Selected Feedstocks, Products, and Processes—*Section 2 provides "default" specifications for various feedstocks (e.g., analyses of Illinois #6 coal), products (e.g., purity and pressure of hydrogen gas), byproducts and processes (e.g., sulfur,* CO_2*) that are commonly found in such studies. The purpose is to enhance the consistency of NETL-sponsored energy system studies,*

Modeling Process Performance—*Section 3 offers technical suggestions for modeling overall energy systems as well as common process components, based on recognized industry practices for process design and modeling.*

Documenting Process Models—*Section 4 presents guidelines for documenting the data sources, assumptions, and methodology used for system- and component-level process models, and provides multiple options for validating proprietary models.*

Reporting Process Performance—*Section 5 provides guidelines for reporting the process performance of overall energy systems and provides precise definitions and equations for measures of process performance.*

Estimating Capital, Operating and Maintenance Costs—*Section 6 offers guidance for cost estimating based on recognized industry practices.*

Reporting Overall Economic Performance—*Section 7 provides guidelines for computing and reporting measures of overall economic performance, such as total capital investment, return on investment, and cost of electricity.*

These guidelines attempt to describe the elements and attributes that an energy system study should possess to demonstrate that the information presented is both **objective and transparent**. At a minimum, reports should be transparent enough to allow analytical results to be fairly and easily compared with the analytical results of reasonably similar studies.

Appendix A contains a more detailed discussion of information quality and the ability of energy system studies to be compared and reproduced. It also provides an overview of relevant public law and agency guidelines, including those issued by the Office of Management and Budget and DOE. Appendix B is a list of abbreviations used in these guidelines and Appendix C is a list of references.

2 Specifications for Selected Feedstocks, Products, and Processes

This section provides "default" specifications for various feedstocks, products, byproducts, and processes that are commonly found in such studies. These default specifications should enhance the consistency of NETL-sponsored energy system studies. Follow these guidelines in the absence of any compelling market-, project- or site-specific requirements.

2.1 Fuel Feedstocks

A short list of commonly used feedstocks are described below. Other fuels are to be treated with the same rigor of analysis and documentation as the fuels presented below.

2.1.1 Natural Gas

When natural gas is the required fuel, use the composition shown in Table 1, which is based on the mean of over 6,800 samples of pipeline quality natural gas taken in 26 major metropolitan areas of the United States (Liss et al. 1992.).

Table 1. Natural Gas Composition

Component	Volume Percentage	
Methane, CH_4	93.1	
Ethane, C_2H_6	3.2	
Propane, C_3H_8	0.7	
n-Butane, C_4H_{10}	0.4	
Carbon Dioxide, CO_2	1.0	
Nitrogen, N_2	1.6	
	LHV	**HHV**
MJ/scm	34.71	38.46
Btu/scf	932	1032

Notes:

1. The reference data reported the mean volume percentage of higher hydrocarbons (C_4 +) to be 0.4%. For simplicity, the above composition represents all the higher hydrocarbons as *n*-butane (C_4H_{10}).
2. The reference data reported the mean volume percentage of CO_2 and N_2 (combined) to be 2.6%. The above composition assumes that the mean volume percentage of CO_2 is 1.0%, with the balance (1.6%) being N_2.
3. LHV = lower heating value; HHV = higher heating value

2.1.2 Coal

Table 2 shows ultimate, proximate, and sulfur analyses for five specific U.S. coals ranging in rank from lignite to low-volatile bituminous. We recommend that NETL-sponsored studies of coal-fueled systems be based upon one of these coal types and their analyses. Additional information on the coal types (including ash and mineral matter analyses, maceral analysis, optical reflectance, ash fusion properties, free-swelling indices, plasticity, and dilatometry) is available from the Argonne Premium Coal Sample Program (Vorres 1989).

Table 2. Analysis of Selected Coals

Rank	Lignite		Sub-bituminous		High-volatile Bituminous		Medium-volatile Bituminous		Low-volatile Bituminous	
Seam	Beulah-Zap		Wyodak-Anderson (PRB)		Illinois #6 (Herrin)		Upper Freeport		Pocahontas #3	
Sample Location	Mercer Co., ND		Campbell Co. WY		St. Clair Co., IL		Indiana Co., PA		Buchanan Co., VA	
	Proximate Analyses (weight %)									
	AR	Dry	AR	Dry	AR	Dry	AR	Dry	AR	Dry
Moisture	32.24	0	28.09	0	7.97	0	1.13	0	0.65	0
Ash	6.59	9.72	6.31	8.77	14.25	15.48	13.03	13.18	4.74	4.77
Volatile Matter	30.45	44.94	32.17	44.73	36.86	40.05	27.14	27.45	18.48	18.6
Sulfur	0.54	0.8	0.45	0.63	4.45	4.83	2.29	2.32	0.66	0.66
Fixed Carbon (BD)	30.18	44.54	32.98	45.87	36.47	39.64	56.41	57.05	75.47	75.97
HHV, kJ/kg	17338	25588	19599	27254	25584	27798	30971	31324	34718	34946
HHV, Btu/lb	7454	11001	8426	11717	10999	11951	13315	13467	14926	15024
LHV, kJ/kg	15894	24625	18135	26176	24528	26864	30052	30423	33774	34012
LHV, Btu/lb	6833	10587	7796	11254	10545	11549	12920	13080	14520	14622
	Ultimate Analysis (weight %)									
	AR	Dry	AR	Dry	AR	Dry	AR	Dry	AR	Dry
Moisture	32.24	0	28.09	0	7.97	0	1.13	0	0.65	0
Carbon	44.62	65.85	49.21	68.43	60.42	65.65	73.39	74.23	86.15	86.71
Hydrogen	2.95	4.36	3.51	4.88	3.89	4.23	4.03	4.08	4.2	4.23
Nitrogen	0.70	1.04	0.73	1.02	1.07	1.16	1.33	1.35	1.26	1.27
Chlorine	0.03	0.04	0.02	0.03	0.05	0.05	0.00	0.00	0.19	0.19
Sulfur	0.54	0.8	0.45	0.63	4.45	4.83	2.29	2.32	0.66	0.66
Ash	6.59	9.72	6.31	8.77	14.25	15.48	13.03	13.18	4.74	4.77
Oxygen (BD)	12.32	18.19	11.67	16.24	7.91	8.60	4.79	4.84	2.15	2.17
	Sulfur Analysis (weight %)									
	AR	Dry	AR	Dry	AR	Dry	AR	Dry	AR	Dry
Pyritic	--	0.14	--	0.17	--	2.81	--	1.77	--	0.15
Sulfate	--	0.03	--	0.03	--	0.01	--	0.01	--	0.03
Organic	--	0.63	--	0.43	--	2.01	--	0.54	--	0.48

Notes: Data reproduced/derived from Argonne National Laboratory, premium coal sample analytical data.
AR = as received; PRB = Powder River Basin; BD = by difference
HHV (gross) measured experimentally; LHV (net) derived from the corresponding HHVs.

2.2 Non-Fuel Feedstocks

2.2.1 Limestone

When limestone is required as a feedstock, use the analysis in Table 3 for studies that are not site specific (U.S. Department of Energy and EPRI 2002):

Table 3. Greer Limestone Analysis

Component	Dry Basis %
Calcium Carbonate, $CaCO_3$	80.40
Magnesium Carbonate, $MgCO_3$	3.50
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

2.3 Chemical and Fuel Products

The following specifications for chemical products apply at the point at which the products are packaged for delivery or cross the plant boundary.

2.3.1 Hydrogen

Hydrogen products must be of ultra-high purity (approaching 100 percent hydrogen content). The fuel cell market is interested in hydrogen for transportation use, and mandates that the product stream be free of sulfur, chlorine, potassium, and particulate matter. Delivery pressure via pipeline transport should be 20.7 to 27.6 bar (300-400 psia). Hydrogen turbines typically run at around 50 percent hydrogen content to help control nitrogen oxides (NO_X) in the exhaust stream. For refining and chemical processing markets, hydrogen is typically recycled to other processes rather than burned as fuel. This recycled hydrogen has to be free of sulfur and water to prevent cross contamination in the chemical process.

2.3.2 F-T Fuels

Fischer-Tropsch (F-T) fuels, also known as gas-to-liquid fuels, are formed from gaseous hydrocarbons. F-T fuels should have zero sulfur content and be ultra-low in aromatics and toxics. An F-T fuel should be delivered as a liquid as it crosses the plant boundary.

2.3.3 Methanol

Methanol should be supplied as a liquid at a purity of 99.85 weight percent (DOE Office of Fossil Energy, 1999). Because of its potential use in fuel cell systems, methanol fuel must have zero sulfur content. Processes that produce higher alcohols should be avoided, or steps should be taken to reform higher alcohols, when supplying methanol to direct methanol fuel cells. The higher alcohols will act as diluents at the anode and will not react in the system.

2.4 Byproducts and Wastes

The following specifications for byproducts apply at the point at which the products are packaged for delivery or cross the plant boundary.

2.4.1 Carbon Dioxide

Carbon dioxide (CO_2), whether being sold for chemical processing or being sequestered, is to be supplied as a liquid and must meet the pipeline specification shown in Table 4 (Bock et al, 2002:

Table 4. Carbon Dioxide Pipeline Specification

Pressure	152 bar
Water Content	233 K (-40 °F) dew point
N_2	<300 ppmv
O_2	< 40 ppmv
Ar	<10 ppmv

2.4.2 A Note on "Sequestration Ready" Processes

At the time these guidelines were written, there was little to no economic benefit in the United States for avoiding emissions of greenhouse gases, of which CO_2 is the most significant. Nevertheless, DOE is devoting considerable effort to developing processes for generating electricity and chemicals from fossil fuels with reduced CO_2 emissions. A new approach to reducing carbon emissions is to capture CO_2 within a process, pressurize it, and transport it to a site where it can be disposed of in a manner that would keep it out of the atmosphere for a very long time. Providing for CO_2 capture and pressurization entails extra capital and operating costs compared to venting it to the atmosphere. Processes that provide for carbon capture will appear to have poorer economic performance than comparable processes that do not, yet we can argue that a process that provides for carbon capture is actually superior.

One notion suggested for dealing with this problem is to describe plants that are "sequestration ready." This means that a version of the process has been conceived that would capture carbon, but that version is not the one being modeled. For instance, oxygen-blown integrated gasification combined-cycle (IGCC) systems can be fitted with shift reactors, solvent absorbers, and recovery units; water condensers and separators; gas compressors; and other equipment needed to recover CO_2. In anticipation that at some future time capture of CO_2 may have economic value (apart from its sale, which may not be possible at all plant locations), it has been suggested that project developers may wish to construct plants in a “sequestration ready” mode. Space at the plant site would be left unoccupied in anticipation that at a later date the equipment necessary for capturing carbon would be installed as a retrofit. Thus, it is asserted, capital and operating costs for carbon capture would be deferred until it was economic to do so.

Time will tell whether this idea will be adopted by project developers. However, if process modelers choose to describe their process as being “sequestration ready,” they will be expected to explain the basis of their claim in some detail. A plant that is “sequestration ready” as defined here would be more expensive to build than one that was not. More land would be required, and runs of piping would pass through unoccupied areas of the plant. You will be expected to describe both how costs of the ”sequestration ready” plant were adjusted relative to a similar plant not designed for carbon capture, and how at a later time the necessary equipment to effect capture could be brought in and installed. You should also include discussion of how heat balances would change after refitting for carbon capture, and how these changes could be made without disruption to the plant. You should provide plot plans, process flow diagrams, and stream tables (see Section 5.3) for both the “sequestration ready” and “carbon capture” system configurations.

2.4.3 Sulfur

Sulfur byproducts are to be in solid elemental form. The purities achieved via various Claus processes are sufficient for most sulfur markets.

3 Modeling Process Performance

When evaluating competing power systems amid today's concerns about efficiency and greenhouse gas emissions, it is more important than ever to have confidence that the reported performance advantage of one system over another is legitimate and not simply caused by differences in assumptions or methods used by the process model. The comparability of energy system studies can be enhanced if certain recognized industry practices for process design and modeling are followed.

The six largest problems encountered in systems analysis are: (1) erroneous, inconsistent, or fallacious bases or reference state conditions; (2) inaccurate models; (3) failure to achieve convergence to a closed mass and energy balance; (4) infeasible operating conditions (e.g., excessive pressures, temperature crosses); (5) inadequate documentation of the data and methodology; and (6) over-interpretation of results because error bars are not reported. Following the guidelines offered in Sections 3 and 4 will help to address these problems.

3.1 Modeling the Overall System

Model performance of an energy system using a predictive computer simulation technique. Use a recognized heat and mass balance code, such as Aspen Plus®, ChemCad, or other equivalent process simulator, that has been shown to be capable of reproducing baseline results within a reasonable margin of error for various power systems published on the NETL website.

A spreadsheet-type analysis may be acceptable in some special cases, as long as it is predictive in nature and capable of reproducing previously established baseline results, and not a "cut and paste" exercise, where the results of earlier simulations are simply repackaged in a non-predictive manner.

The development of graphical user interfaces in current versions of Aspen Plus® and similar process simulators has made setting up and running power plant simulations on a standard PC far faster and easier than it was in the past, reducing the motivation to use spreadsheet models. Moreover, with Aspen Plus® or an equivalent process simulator, a modeler can change the system arrangement quickly and easily, while being assured of a correct heat and mass balance and proper accounting for all chemical species and physical properties every time. With a special-purpose spreadsheet simulation, none of these things are automatically ensured, and changes in system arrangement can be difficult to accommodate. In either case, you must be properly trained to ensure proper knowledge of the system being modeled. You must also thoroughly understand correct thermodynamics and chemical reactions.

Aspen Plus® can be integrated with Microsoft Excel® to run simulations. The integration process can be performed in either direction, i.e., information can be fed to an Excel® spreadsheet from an Aspen Plus® simulation, or values in an Aspen Plus® simulation can be changed by an Excel® spreadsheet. The method of control is through a Visual Basic program, written in the spreadsheet macros environment. Although quite laborious, such integration can be useful for sensitivity analysis or model validation.

The following specific modeling guidelines are applicable to the overall energy system:

- In accordance with recognized industry practice, unless otherwise indicated in the design basis of the report, predicted performance should always be calculated for International Organization for Standardization (ISO) conditions: 288 K (59 °F) sea level ambient site conditions, 60 percent relative humidity, and without duct losses.
- Process models should generate sufficient information to generate a complete process flow diagram and a stream property table. (Also see Section 5.3.)
- Process variables (e.g., heat loss, blowdown amount, entrance loss, mechanical efficiency, auxiliary and miscellaneous power requirement), should be reported for each piece of equipment or section.
- For power systems that sequester CO_2, performance and cost calculations must account for the energy and process equipment required to compress the CO_2 and liquefy it for storage/transport. (Also see Sections 1.3 and 2.4.1)
- Model results should indicate the level of confidence of convergence in the model analysis. The results should point out any errors or warnings that occur, with explanations as to the cause of such problems.

3.2 Modeling Specific Process Components

3.2.1 Condensing Steam Turbines

Absent site-specific requirements to the contrary (such as using air-cooled condensers), all power systems incorporating condensing steam turbines should be analyzed, assuming the condenser coolant is at a temperature consistent with the use of a plume-abated wet/dry mechanical draft cooling tower for standard ambient conditions, i.e. 280 K (45 °F) wet-bulb temperature.

In no case should you assume a steam-turbine-exhaust pressure lower than 4.55 kPa (0.66 psia) for simulation studies at the above standard ambient conditions with a plume-abated mechanical draft cooling tower.

3.2.2 Heat Exchangers

Various types of heat exchangers are routinely used in energy systems, including intercoolers, recuperators and heat recovery boilers. Since assuming extremely large, uneconomic heat exchangers can result in predictions of misleadingly high efficiencies for a power plant, recognized industry practice should be followed in selecting key thermodynamic parameters, (e.g., effectiveness, approach, and pinch point temperatures) for input to the systems analysis.

Normal design practice limits heat exchanger effectiveness for gas-to-gas heat exchangers to 85 percent or less. For heat recovery boilers, pinch-point temperature differences are normally 14 K (25 °F) or more and superheater approach temperature differences are normally 56 K (100 °F) or more.

3.2.3 Other Common Components

More common components of energy systems are addressed here. Examples of these components are:

- Rotating equipment:
  - Blowers
  - Fans
  - Compressors
  - Expanders
  - Gas turbines
  - Steam turbines
  - Pumps
  - Generators
  - Engines
    - IC
    - Diesel
    - Stirling
- Material preparation:
  - Solid transport
  - Crusher
  - Grinder
  - Conveyor
  - Hopper
  - Classification
- Heat exchange units
  - Cooling tower
  - Boilers
  - Chiller
  - Condenser
  - Reboiler
  - Heat exchangers
- Cleanup units:
  - Filters
    - High and low pressure
    - Baghouse
  - Electrostatic precipitators
  - Flue gas scrubbers
  - Waste treatment equipment
  - Cyclone
  - Settler
  - Decanter
- Process units:
  - Selective catalytic reduction (SCR)
  - Selective noncatalytic reduction (SNCR)
  - Air Separation Unit

- Fuel cell
- Combustor
- Fired heater
- Quench
- Mixer
- Splitter
- Flash drum
- Deaerator
- Absorber
- Stripper
- Distillation
- Air/N_2 saturator
- Guard bed
- Fuel gas scrubber

Common component information may include: efficiencies (mechanical, electrical, speed control); spare/sizing issues; stack heights; gas velocities; pressure drops; distribution in ductwork and vessels; conveyor arrangement; silo sizing; etc.

4 Documenting Process Models

This section presents guidelines for documenting the data sources, assumptions, and methodology used in system- and component-level process models. We also offer multiple options for validating proprietary models. Although no format is prescribed for this information, it is recognized that much of it would most appropriately be provided in appendices to energy system study reports.

Energy system reports should identify and describe all the process models that were used to simulate the energy system, including those at each of three levels:

- The executive interface (i.e., calculation engines such as AspenPlus®, Microsoft Excel),
- All component-level models (e.g., unit operation blocks), and
- Any noteworthy sub-level models that are required by the executive interface or component models.

The nature of each description should depend upon the level of the model and whether the model being described is based on

- **Commercially-available process modeling software,**
- **Non-commercial modeling software, or**
- **Spreadsheet software.**

The amount of descriptive detail recommended for various situations is outlined in Sections 4.1, 4.2, and 4.3.[1]

In addition, energy system reports should identify and describe all the **physical property data sets** that were used to simulate the energy system, in accordance with the guidance outlined in Section 4.4.

These recommendations do not prescribe a format for reporting model descriptions; rather, their intention is to establish the minimal information that a report should include in some fashion.

Obviously, various overriding factors, such as cost or time constraints or intellectual property issues, will prevent some model descriptions from conforming to the recommendations listed below. In the case of non-disclosable proprietary information, the validation guidelines provided in Section 4.5 should be considered.

[1] Energy system studies may depend upon an array of process models, some of which are based on commercially-available process modeling software, others on non-commercial modeling or spreadsheet software. However, since these guidelines suggest that individual descriptions be provided for every process model in the system, every process model should be placed into one of these categories and the corresponding guidelines for documentation should be followed.

4.1 Commercially-Available Process Modeling Software

Many process models are created using process modeling software that is commercially available to the general public at no cost or is actively marketed for sale/licensing at a standard commercial price. Examples of commercially available process modeling software include Aspen Plus® (Aspentech), FLUENT (Fluent, Inc.), GT PRO (Thermoflow) and ChemCAD®. In general, descriptions of process models that are based on commercially available software require less detail, since much of the pertinent information can be referenced to the software's publicly available documentation.

4.1.1 Executive Interfaces

For commercially-available executive interfaces (i.e., calculation engines), an overview of the interface should be provided, and an electronic copy of the master input file or worksheet file should be included with the report.[2] At a minimum, the overview should include:

- A brief description of the executive interface, including its vendor and version number;

- An explanation of how the executive interface converges on a solution, including:
    - a description of the convergence criteria and a list of assumptions and design specifications,
    - a description of the algorithms used for simultaneously solving the model equations,
    - a list of the tolerances specified for convergence, and
    - a statement verifying that convergence to a feasible solution was achieved.

- An explicit statement of the average chemical composition and thermodynamic properties of all feedstocks (e.g., proximate and ultimate analyses for coal); and

- A list of technical assumptions or input parameters that are commonly applicable to all the models composing the energy simulation, e.g., ambient atmospheric conditions.

4.1.2 Component-Level Models and Sub-Level Models

For commercial, component-level, and noteworthy sub-level models,[3] including "off the shelf" models offered within a public, executive interface package, a brief overview of the model, including its scientific basis and underlying data and assumptions, should be given (or referenced). In addition, provide a description of how the model's input requirements were satisfied, including any assumptions that were made. If noteworthy, justify why a particular model has been chosen from among multiple model options, e.g., kinetic versus non-kinetic, steady-state versus dynamic, empirical versus mechanistic.

[2] If the master input file contains components with proprietary information that cannot be divulged, such components should be replaced with "sanitized" versions that still allow the model to be exercised. However, such proprietary models should still be described and validated in accordance with Section 4.6.

[3] When multiple sub-level models are used together to model a major process component or unit operation, a single description should usually suffice for the entire group.

More specific guidelines for describing process models of various energy system components include:

Heat Exchangers. Various types of heat exchangers are routinely used in energy systems, including intercoolers, recuperators, and heat recovery boilers. When describing a heat exchanger process model, list its key thermodynamic assumptions as appropriate for the type of exchanger, such as effectiveness, approach temperature, and pinch-point temperature.

Condensing Steam Turbines. Explicitly state the cooling tower approach-temperature, the condenser temperature-range, and the terminal temperature-difference assumed for the analysis.

Other Common Components. Other components to be considered would be similar to the list found in Section 3.2.3.

4.2 Non-Commercial Modeling Software

Some process models are based on non-commercial modeling software that is not available to the general public, is not actively marketed for sale/licensing at a standard commercial price, or both. Non-commercial models also include models based on commercially available process modeling software that has been substantially modified.

Examples of models based on non-commercial modeling software include:

- ***NETL-Sponsored Process Models.*** NETL-sponsored process models that are being developed with government funding.

- ***Corporate Process Models.*** In-house models that were developed by a corporation and are usually proprietary.

4.2.1 NETL-Sponsored Process Models

In addition to the level of detail outlined in Section 4.1, descriptions of NETL-sponsored process models that are being developed with government funding should provide:
- A detailed explanation of the scientific basis of the model (e.g., mathematical equations and physics),
- A list of any assumptions and/or measured data that the model is based upon, and
- An explanation of how the model's scientific basis, data and assumptions were translated into expressions used by the computer model.

Furthermore, electronic copies of any government-funded software, along with a complete set of user manuals, should be delivered with the report.[4]

[4] When preparing a contract for the government-funded development of process modeling software, consider whether or not the government will be required to pay software license fees at some point in the future. License fee issues should be resolved, not only for government-funded software but also for any other software that is required to use the government-funded software.

4.2.2 Corporate Process Models

To the extent allowed by proprietary constraints, descriptions of corporate process models should include the level of detail outlined in Section 4.1 and 4.2.1. When substantially less information than this can be revealed, provide a summary of how the model was validated for accuracy and objectivity. Section 4.5 outlines various approaches for validating proprietary models.

4.3 Spreadsheet Software

Sometimes spreadsheet software is used to model an energy system. Since most spreadsheet models can be categorized as either a "corporate process model" or "NETL-sponsored process model," their documentation should follow the guidelines provided above in Section 4.2. In addition, documentation for spreadsheet-based models should also include descriptions of:

- The general assumptions and solution method on which the model is based,
- The method(s) used to ensure correct heat and mass balances and proper accounting of all chemical species,
- The physical property data sets and equations of state used in the model's calculations, and
- Model validation(s), e.g., correlation of model predictions to test data, reproduction of standard reference simulation cases, or other substantiation of the model's reproducibility and/or predictive accuracy (see Section 4.5).

4.4 Physical Property Data Sets

Provide a brief overview for each physical property data set that is used in the energy system study. Also provide explanations for how each data set was applied in the energy system simulation, including a list of the process models that used it and any assumptions that were made. In addition, you should explain instances in which a physical property data set is overridden.

When physical property data is developed with government funds, deliver an electronic copy of the data set along with detailed documentation with the report.

4.5 Validation of Proprietary Models

Proprietary issues will greatly constrain descriptions of non-commercial corporate models. When such descriptions reveal substantially less information than is suggested for commercial models, provide a summary of how the corporate model was validated for accuracy and objectivity.

Use various methods to validate process models, including the following, which are listed in increasing order of rigor. Usually use more than one of the following methods for validation.

References. This method validates the model by providing references that lend credibility to it, such as:

- A description of other noteworthy projects or studies that have depended on the model, and/or

- Testimony that vouches for the model's objectivity and accuracy from competent and credible sources independent of the model's corporate owner.

Engineering Checks. This method verifies that the model does not violate fundamental scientific laws, such as conservation of mass, or conservation of energy.

Replication of Results. This method validates the subject model by demonstrating that it is capable of replicating, within an acceptable degree of error, the analytical results of another, publicly available, well-established process model using the same input data. In many cases, the level of rigor employed by a proprietary model (such as an OEM model) may be greater than that of the established validation model. In such cases, acknowledge each model's confidence interval when comparing results for validation. In situations where the level of rigor of a known model is unreported, results should be reported as meeting the level of the previous results, with detailed discussion of your assumptions versus the known models assumptions.

Experimental Results. This method can be used to validate a *predictive* process model by demonstrating that the model's analytical results conform to measured experimental data. (This method would not be appropriate for validating correlative process models that are based on experimental data.)

Regardless of the method you choose, you should attach a statement from the model developer that indicates how the model has been validated.

5 Reporting Process Performance

This section offers guidelines for reporting the process performance of overall energy systems. Precise definitions and equations are offered for certain measures of process performance.

5.1 Design Basis

An overview of the energy system design basis should be provided. The design basis should include a brief description of the plant, to be further developed in the analysis, which should include plant size, capacity factor, and primary fuel.

The overview should also indicate whether the analysis is performed for a "generic" or specific location. A site-specific analysis should note the location of the site and describe its utility access, transportation infrastructure and environmental restrictions.

5.2 SI and English Units of Measure

Throughout energy system study reports, the International System of Units (SI)[5], including non-SI units accepted[6] for use with the SI, should be used to express all measurements. For measures that are to be quantified in English units (such as heating values), SI units should be presented first, followed by the corresponding value expressed in English units within parentheses.

5.3 Process Flow Diagrams and Stream Tables

Include a diagram that shows how process streams flow among all the major components in the overall energy system. As appropriate for detail and clarity, show streams and components that are confined to certain subsystems on separate process flow diagrams. Every stream should be labeled with a unique name.

A stream table that lists, by stream number, the significant properties of each stream at design point conditions, should accompany each process flow diagram. At a minimum, the following properties should be included: temperature, pressure, vapor fraction, enthalpy, volumetric flow (for gases), total mass flow (for liquids and solids), and chemical composition [component mass fraction, component mass flow (for liquids and solids) or component mole fraction (for gases)]. Report work and heat streams after the heat and mass balance section. The standard stream tables should report properties using SI units. If requested, provide supplementary stream tables using English units.

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[5] The Omnibus Trade and Competitiveness Act of August 1988 (PL 100-418), 15 CFR 1170 (January 1991) and Executive Order 12770 (July 1991) require Federal agencies and departments to use the SI system of measurement.

[6] Limited to those non-SI units accepted by the International Committee of Weights and Measures (CIPM) for use with the SI.

5.4 Single-Product System Efficiency and Efficacy

Single-product energy systems are those systems that produce only one energy-related product, although multiple non-energy byproducts may also be produced. Energy-related products include electrical power and both liquid and gaseous fuels. Examples of non-energy byproducts include elemental sulfur, sulfuric acid, gypsum, and various aggregate materials.

Net efficiencies/efficacies should reflect estimated losses for all auxiliary systems necessary for operation of the energy system, including controls, fuel preparation and emission control systems**.** Calculate and report net efficiencies/efficacies on the basis of both the lower heating value (LHV) and higher heating value (HHV) of the input fuels.

5.4.1 Power-Only Systems

For systems in which power is the only energy-related product, use the following formula to compute net electrical efficiency:

$$\textbf{Net electrical efficiency} = \frac{\text{net electrical energy}}{\text{total heating value energy of all input fuels}}$$

where:

net electrical energy = the net electrical energy delivered at the required voltage to the plant busbar (whether delivered to a utility grid or to a distributed generation application)

heating value energy = the amount of energy in a fuel, based on its lower or higher heating value (enthalpy of combustion)

5.4.2 Fuel-Only Systems

For systems in which liquid or gaseous fuels are the only energy-related products produced, use the following formula to compute net thermal efficacy:

$$\textbf{Net thermal efficacy} = \frac{\text{total heating value of all product fuels}}{\text{Total heating value energy of all direct and indirect input fuels}}$$

where:

product fuels = the fuels that have been cleaned, purified and compressed to the specifications of the customer

***direct* input fuels** = fuels that are fed directly into, and converted within, the energy system

***indirect* input fuels** = fuels that are converted outside of an energy system to produce a non-fuel energetic stream (e.g., electricity or steam) that is fed into the energy system.

For example, consider a gasification-based energy system that requires coal, electric power from the grid, and steam from "across the fence" to produce a gaseous hydrogen fuel. The coal that is fed directly into the energy system is a direct input fuel. The fuel used by the utility power plant to generate the necessary electric power is an indirect input fuel. Likewise, the fuel used by the steam plant to generate the necessary steam is also an indirect input fuel.

You should always provide a detailed description of the rationale and methodology used to determine the heating value energy of indirect input fuels. Use the guidelines listed in Table 5 to calculate the heating value energy of indirect fuels, unless a compelling rationale is presented to do otherwise.

Table 5. Guidelines for Calculating Heating Value Energy of Indirect Input Fuel

Type of Energetic Input Stream	Guideline
Electrical Energy	Assume that 3.37 kWh (HHV) or 3.17 kWh (LHV) of indirect input fuel energy is required for each kWh of electrical energy consumed by the energy system.[1]
Steam and Hot Water	Assume a boiler efficiency of 88.8% (HHV) or 84.4 (LHV) and that 20% of the steam produced in the boiler is lost in the steam/hot water distribution system.[2]

[1] Reflects losses associated with:
- (a) the average efficiency of fossil-based (coal, petroleum and natural gas) plants in the U.S. electric power sector (electric utilities and independent power producers) in 2001 (HHV efficiency = 32.8%; LHV efficiency = 34.9%). From U.S. DOE EIA. *Annual Energy Outlook 2003*. Table F7.
- (b) the average percentage of net U.S. power generation lost during transmission and distribution between 1990 and 2000 (6.7%). From: U.S. DOE EIA. *Annual Energy Review 2001*. Table 8.1.

[2] Source: Taplin 1998.
- (a) the maximum economically achievable boiler efficiency for fossil-based boilers is reported to be 88.8% (HHV).
- (b) the percentage of steam lost during distribution from the boiler to the point of use is reported to be 20%.

5.5 Multi-Product System Efficacy

This section offers guidelines for calculating and reporting the efficacies of the following types of multi-product energy systems:

- Combined fuel and power systems (CFP),
- Combined heat and power systems (CHP), and
- Combined heat and fuel systems (CHF).

No guidelines are offered here for calculating the efficacies of multi-product energy systems that include chemicals in their product slate.

The term definitions provided in Section 5.4 also apply to the equations presented below for CFP, CHP, and CHF systems.

For all systems, calculate and report net efficacies on the basis of both the lower heating value (LHV) and higher heating value (HHV) of the input fuels. (For systems that co-produce fuels, use the LHV of the output fuel when calculating LHV efficacy, and the HHV of the output fuel when calculating HHV efficacy.)

Because the achievable efficacy of a multi-product energy system is highly dependent upon its product output ratio, the relative merit of various systems cannot be determined by comparing their efficacies alone (unless the systems being compared have identical product output ratios). Therefore, the reported efficacy of a multi-product energy system should always be accompanied by the product output ratio of the system. The product output ratio should be expressed for a given period of time with the same units that are commonly used to measure product output, e.g., MWh/day.

5.5.1 CFP Systems

For energy systems that co-produce fuel and power (CFP), use the following equation to compute net efficacy.

$$\textbf{Net CFP efficacy} = \frac{\text{net electrical energy + total heating value of all product fuels}}{\text{total heating value energy of all direct and indirect input fuels}}$$

5.5.2 CHP and CHF Systems

Use the following two equations to compute net efficacies for energy systems that co-produce heat and power (CHP) and heat and fuel (CHF):

$$\textbf{Net CHP efficacy} = \frac{\text{net electrical energy + externally exchanged heat}}{\text{total heating value energy of all direct and indirect input fuels}}$$

$$\textbf{Net CHF efficacy} = \frac{\text{total heating value of all product fuels + externally exchanged heat}}{\text{total heating value energy of all direct and indirect input fuels}}$$

where:

externally exchanged heat = the quantity of heat exchanged to an external process stream from a thermal energy stream that is exported by the CHP energy system

For example, consider a CHP system that generates power for the utility grid and exports steam to a heat exchanger in a nearby industrial plant. The “externally exchanged heat” would be the amount of heat extracted from the steam by the industrial plant’s heat exchanger over a full production cycle.

Note that the above equations are only applicable when the external process extracts heat from the exported thermal stream through some type of heat exchanger. The equation would not be applicable if the external system physically mixes the exported thermal stream with another process stream with no prior heat exchange.

For CHP and CHF systems that follow a cyclical production schedule because of predictable fluctuations in thermal and electrical demands (such as those arising from building occupation schedules and daily/seasonal temperature fluctuations), each term in the efficacy equation should reflect a full production cycle. Calculating the instantaneous efficacy of a cyclical CHP or CHF system at some favorable time in the production cycle is not appropriate.

5.6 Reporting Emissions

For power-only energy systems, report emissions on the basis of mass per unit of energy produced, e.g., kg/MWh.

For multi-product energy systems, report emissions on the basis of mass per unit of input fuel energy, e.g., kg/kJ.

Other methods of quantifying emissions, such as stack concentrations, should be reported as necessary and appropriate.

5.7 Thermodynamic Diagrams

You can include thermodynamic diagrams to aid in detailing the results. Label such diagrams with an appropriate title, and use a subtitle to define specifications of the results (e.g., flow conditions, temperatures, sorbent types). Since most thermodynamic diagrams would be graphs, label the axes of the graphs and use SI units. There are no required diagrams, so the report developer has full flexibility in use of such.

6 Estimating Capital, Operating, and Maintenance Costs

This section offers guidance for estimating the capital, operating, and maintenance costs of energy systems. In general, cost engineering should be done in accordance with the recognized methods and standards that are promulgated by groups, such as the Association for the Advancement of Cost Engineering (AACE), EPRI Technical Assessment Guide (TAG), and the American National Standards Institute (ANSI).

6.1 Capital Costs

6.1.1 Commercially-Available Equipment

Estimated plant capital costs should reflect full turnkey outlays, including cost allowances for site engineering, permitting and licensing, installation, land, transportation, taxes, contingencies, financial and legal fees, construction, startup, commissioning, spares, and operator training.

You should explicitly state the design basis of estimated capital costs for each major subsystem involved in the estimate, whether known costs for a similar system, a factored analysis based on sizing of major equipment, or a detailed estimate based on full design drawings and vendor quotes**.**

If a sufficiently detailed system definition exists, special-purpose software packages (e.g., ICARUS) are recommended for capital cost estimation.

Break down the plant capital cost by major plant section, with both a process contingency and a project contingency applied to each.

Process Contingency. Process contingency is designed to compensate for uncertainty in cost estimates caused by performance uncertainties associated with the development status of a technology. Apply a process contingency to each plant section based on its technology status at the time the cost estimate is prepared, according to the AACE standards listed in Table 6.

Table 6. AACE Standards for Process Contingency

Technology Status	Process Contingency
New technology, little or no test data	40% +
New technology, prototype test data	20-35%
modifications to commercial technology	5-20%
commercial technology	0-5%

Each process contingency should address the cost uncertainty arising from the use of new technology in the plant section to which it is applied.

Project Contingency. Project contingency is designed to compensate for uncertainty in cost estimates caused by an incomplete technical definition. Project contingencies are typically applied to the entire project, but we recommend that you apply the contingency to each plant section, based on the stage of technical definition at the time the cost estimate is prepared, according to the following AACE standards listed in Table 7. (See Parsons 1999.)

Table 7. AACE Standards for Project Contingency

Design Stage	Level of Project Definition (% of complete definition)	AACE Estimate Class	Project Contingency
Concept Screening	0 - 2	5	50%
Feasibility Study	1 - 15	4	40%
Budget Authorization	10 - 40	3	30%
Project Control	30 - 70	2	15%
Bid Check	50 - 100	1	5%

For many NETL process comparison studies that involve use of equipment and devices still in development, the appropriate AACE Class is 4 for the plant section containing the new technology.

6.1.2 Conceptual Equipment or Equipment Being Developed

AACE International does not have a recommended procedure for estimating conceptual or under development equipment, but there are some reasonable measures that can be made to assess the accuracy of a cost estimate. Report the basis of all equipment items when estimating the capital cost of equipment that is conceptual or under development. You should clearly state the status of the equipment under development, and in turn how this will affect the accuracy of the cost estimate. As a default method to express the uncertainty, you can provide a sensitivity analysis around the major cost driver(s) used to estimate the cost (e.g., pressure, size, temperature). It is very likely that off-the-shelf items will be used along with items being developed. When working with off-the-shelf items, report the source for the information. When working with under-development equipment items, explain the level of definition for the equipment/process and the basis that was used to estimate the cost. The level of definition provides some indication of the expected accuracy of the estimate. AACE International classifies estimates into five levels. Table 8 lists these classifications, provides a range of expected accuracy, and gives the level of definition that is needed per class.

Table 8. Expected Accuracy of Five Estimate Classes

AACE Estimate Class	Expected Accuracy	Level of Project Definition (% of complete definition)
5	+50% to -30%	0 – 2
4	+30% to -15%	1 – 15
3	+20% to -10%	10 – 40
2	+15% to -5%	30 – 70
1	+5% to -5%	50 - 100

The report should document how the cost estimate was developed, what elements it includes, the level of detail used, the source of cost data, etc. An example of such information is how much scaleup or scaledown was involved in estimating the equipment item from the base reference.

6.2 Operating and Maintenance Costs

Explicitly state the basis of operating and maintenance (O&M) cost estimates for each major plant section involved in the estimate, regardless of whether the basis is known costs for similar equipment or a factored analysis based on sizing of major equipment.

Assume a capacity factor of no more than 85 percent for power plant O&M purposes. The assumed capacity factor should be based upon a realistic assumption of system availability and should conform to the definitions provided in Section 6.3.

Explicitly state the cost of consumables (fuels, catalysts, sorbents, water), labor rates, interest rates, etc., used in estimating O&M costs, and refer to recognized sources.

Include byproduct credits and waste disposal costs, including estimated tonnages and assumed rates in O&M costs.

6.3 Capacity Factor and Availability

When forecasting the total output of an energy system and calculating the associated O&M costs, the analyst must fix an annual capacity factor for the energy system:

$$\textbf{annual capacity factor \%} = \frac{\text{total output in one year}}{\text{(rated output capacity) (8760 hours)}} \quad (100\%)$$

The annual capacity factor of an energy system depends upon both its duty cycle and its availability. A baseload energy plant that is dispatched as much as possible could have an annual capacity factor that is nearly equivalent to its availability. On the other hand, the annual capacity factors of “intermediate” or “peaking” energy systems could be much lower than their availabilities, since market demands or other factors limit how often they are required for service.

Unless a compelling rationale is presented to do otherwise, you should assume that the capacity factor for fossil-fueled, baseload energy systems is the lesser of 80 percent or the system availability.

Energy system studies should conform to the following definitions when addressing measures of energy system reliability and availability. (These definitions were originally developed by the Gasification Technologies Council.)

on-stream % + product unrequired % + planned outage % + unplanned outage % = 100%

where:

on-stream % =	percentage of year that the system was operating and supplying product in a quantity useful to the customer.
product unrequired % =	percentage of year that the primary product was not required, and therefore the system was not operated
planned outage % =	percentage of year that the system was not operated because of outages that were scheduled at least one month in advance, including yearly planned outages as well as maintenance outages with more than one month notice
unplanned outage % =	percentage of year that the system was not operated because of forced outages that had less than one month notice, including immediate outages as well as maintenance outages with less than one month notice

$$\textbf{forced outage rate \%} = \frac{\text{(unplanned outage \%)}}{\text{[(on-stream \%) + (unplanned outage \%)]}}\ (100\%)$$

availability % = (on-stream %) + (product unrequired %) [1 - (forced outage rate %) / 100%]

7 Reporting Overall Economic Performance

This section provides guidelines for reporting the overall economic performance of conceptual energy systems, e.g., total capital investment, return on investment (ROI), and cost of electricity (COE). Since these guidelines primarily pertain to energy system studies that compare and/or rank emerging technologies at a conceptual level, they do not address some of the elements required by more detailed measures of economic performance, such as those applied to site-specific studies.

The EPRI TAG method is the preferred method of assessing overall economic performance. The TAG method should be adhered to, but alternative techniques can be used, provided that the alternative is technically sound and as effective as the TAG method.

There is no current guideline mandating default values for financial analysis, e.g., debt/equity ratios, interest rates, taxes, and depreciation. You are given free rein to decide what values to use for financial variables to reflect economic conditions and market expectations that prevail at the time of the study. Document the following elements in reporting economic performance. Some of the elements are percentages of overall section costs, and typical values for these are indicated.

A sensitivity analysis showing variability of values for the standard analysis is not required in the guidelines, but could add beneficial information to your analysis.

7.1 Capital Costs

This section details costs associated with capital expenditures, specifically, anything to do with purchase, siting, and startup of working equipment. The costs are broken down into three areas: total plant cost, total plant investment, and total capital requirement. Costs that should be reported here for each area are indicated below.

7.1.1 Total Plant Cost (TPC)

- Process Plant Cost (PPC)—Plant section subtotal
- Engineering fees—10% of PPC
- Process Contingency—Plant-section dependent (See Section 6.1)
- Project Contingency—Plant-section dependent (See Section 6.1)

7.1.2 Total Plant Investment (TPI)

The TPI is the total of TPC and

- An interest and inflation-adjustment factor (dependent on construction interest rate, inflation rate, and construction time frame) multiplied by the TPC.

7.1.3 Total Capital Requirement (TCR)

The TCR is the total of TPI and:

- Prepaid Royalties—0.5% of PPC for new technology, a capital charge
- Initial Catalyst and Chemical Inventory—30 day inventory
- Startup Costs
  - 2% TPI
  - 30 days chemicals and operating labor
  - 7.5 days fuel inventory
- Spare Parts—0.5% of TPC
- Working Capital
  - 30 days fuel and consumables
  - 30 days byproduct inventory
  - 30 days direct expenses
- Land

7.2 Operating Costs

Operating costs are costs associated with day-to-day operation of the plant. Maintenance and consumables are accounted for in this section. Byproducts and any credits for byproducts are reported in this section. Items of interest for reporting are indicated below.

7.2.1 Total Operating Costs (TOC)

- Consumables—1 year at capacity factor
  - Fuel
  - Chemicals
  - Catalysts Disposal—Cost of ash/sorbent disposal
- Maintenance Costs—2.2% TPC
- Plant Labor
  - Operating labor
  - Supervisory/clerical—30% of operating labor and 12% of maintenance costs

7.2.2 Byproduct Credits—Credit for Salable Materials

Byproduct sales should be fully described and referenced.

- Material description
- Amount per unit time
- Market price per unit amount

7.2.3 Net Operating Costs (NOC)

NOC is the net total of TOC and byproduct credits.

7.3 Economic Assumptions

To enhance the consistency of NETL-sponsored energy system studies, this section provides "default" specifications for certain assumptions that may be required to evaluate the economic performance of energy systems. In the absence of any compelling market-, project- or site-specific requirements, follow these guidelines:

- Project Life—20 years
- Book Life—20 years
- Tax Life—20 years
- Federal and State Income Tax Rate—38%
- Tax Depreciation Method—Accelerated Cost Recovery System (ACRS)
- Investment Tax Credit—0.0%
- Construction Interest Rate—Construction period @ 11.2%
- Financial Structure—both current and constant dollars

  For low-risk projects, the financial structure in Table 9 would be adequate.

Table 9. Financial Structure for Low-Risk Projects

Type of Security	% of Total	Current Dollar Cost %	Current Return %	Constant Dollar Cost %	Constant Return %
Debt	80	9.0	7.2	5.8	4.7
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount Rate (Cost of Capital)			11.2		8.0

For high-risk projects, the financial structure in Table 10 would be adequate:

Table 10. Financial Structure for High-Risk Projects

Type of Security	% of Total	Current Dollar Cost %	Current Return %	Constant Dollar Cost %	Constant Return %
Debt	45	9.0	4.1	5.8	2.6
Preferred Stock	10	8.5	0.9	5.3	0.5
Common Stock	45	12.0	5.4	8.7	3.9
Discount Rate (Cost of Capital)			10.3		7.1

- Inflation Rate—3.0%
- Real Escalation Rates
    - Fuel
        - Coal
          0.5% over inflation, Energy Information Administration (EIA) 2003
        - Natural Gas
          0.3% over inflation, low growth case, EIA 2003
          0.6% over inflation, high growth case, EIA 2003
        - O&M—0% over inflation

7.4 Measures of Economic Performance

This section provides guidelines for measuring the economic performance of power-only and multiple-product energy systems.

7.4.1 Power-Only Energy Systems

Cost of Electricity

- Tenth-year levelized dollars—This is an accepted practice that balances the offset of capital in early years versus fuel cost in later years.

7.4.2 Multiple-Product Energy Systems

It is inherently difficult to assign costs or develop RSPs for co-products in multi-product energy systems. Approaches selected are often somewhat arbitrary and can result in an unreasonable RSP for one of the products. You must both describe and fully justify the approach taken to assigning costs and/or determining the RSP in co-product energy systems. Explain whether the method chosen used a market-based analysis to handle co-product costs, a savings-based analysis to modify operating costs based on the co-product costs, or another method.

Appendix A: Measures of Information Quality

A.1 Relevant Public Law and Agency Guidelines

DOE issued guidelines, effective October 1, 2002, that set forth policy and procedures to maximize the quality, utility, objectivity, and integrity of the information that DOE disseminates to members of the public (RA.1). The DOE information quality guidelines were prepared based on government-wide guidelines issued by the U.S. Office of Management and Budget (OMB) under Section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Pub.L. 106-554; December 21, 2000; 114 Stat. 2763). This Act had directed OMB to issue guidelines that ". . . provide policy and procedural guidance to Federal Agencies for ensuring and maximizing the quality, objectivity, utility, and integrity of information disseminated by Federal Agencies."

Although the quality guidelines contained in this report for energy system studies were not mandated by either the DOE or OMB guidelines, their intent and underlying principles are the same. Nominal adherence to these guidelines should result in energy system studies that conform to the spirit of the public law and DOE guidance.

A.2 Key Traits of Quality Information

The OMB and DOE quality guidelines describe four key traits that underlie quality information: utility, objectivity, transparency, and integrity. The present guidelines largely focus on the latter two quality traits.

Utility is the usefulness of information to its intended users, and encompasses attributes such as pertinence, timeliness, and practicality.

Integrity is the extent to which information has been secured and protected from falsification or corruption.

Objectivity is to the extent to which the information is presented in an accurate, clear, complete, and unbiased manner.

Transparency means clear and concise information on such topics as information sources, survey and analytical methods, accuracy and reliability, and consistency with countervailing considerations such as confidentiality.

Reports that document the data sources, assumptions, and methodology employed for process and economic models enable readers to make judgments on the quality of the data, possible sources of error, and its applicability to their own interests.

Level of Rigor. Since all four of these traits are relative in nature, the overall quality of an energy system study will greatly depend upon how rigorously each trait is pursued.

These guidelines suggest two levels of rigor with regard to transparency: comparability and reproducibility. Most NETL-sponsored energy system studies should aspire to the standard of comparability, while only a few studies are anticipated to warrant the rigor of reproducibility. Regardless of the level of rigor, the transparency of many studies will be limited by the extent to which energy system studies rely on proprietary and/or sensitive information.

A.3 Comparability

"Comparability" is the ability of analytical results to be fairly and easily compared with the analytical results of reasonably similar studies. We recommend comparability as the transparency standard to which most NETL-sponsored energy system studies should aspire. Although comparability demands a lower degree of transparency than reproducibility, it does require a very thorough documentation of assumptions, input data, and performance parameters.

A.4 Reproducibility

"Reproducibility" is the capability of analytical results to be reproduced within an acceptable degree of error by an independent party that applies identical analytical methods to the underlying data. A very high degree of transparency is required to achieve the standard of reproducibility.

Influential Information. Under the OMB quality guidelines, only information that is deemed "influential" must be held to the high standard of reproducibility. The DOE quality guidelines define "influential" information as

- Information that is subject to embargo until the date of its dissemination by DOE because of its potential market effects,
- Information that is the basis for a DOE regulatory action that may result in an annual effect on the economy of $100 million or more, or
- Other information that is designated "influential" on a case-by-case basis.

Very few DOE information products meet this definition. Examples include:

- Certain information products of DOE's Energy Information Administration are routinely embargoed.
- Some of the appliance energy conservation standards rulemakings under the Energy Policy and Conservation Act have $100 million impacts on the economy.

Although few, if any, NETL-sponsored energy system studies are expected to meet DOE's definition of influential information, you should carefully consult the DOE guidelines to determine requirements for any study that is deemed "influential."

In certain circumstances, energy system studies that contain only non-influential information should also be held to the high standard of reproducibility. For example, reproducibility may be warranted for studies that NETL uses for baseline system comparisons or for validation of second-party models.

Appendix B: Abbreviations

AACE	Association for the Advancement of Cost Engineering
ACRS	Accelerated Cost Recovery System
ANSI	American National Standards Institute
AR	as received
ASU	Air Separation Unit
BD	by difference
CFP	combined fuel and power
CHF	combined heat and fuel
COE	cost of electricity
CHP	combined heat and power
CIPM	International Committee of Weights and Measures
CO_2	carbon dioxide
DOE	(U.S.) Department of Energy
EIA	(DOE) Energy Information Administration
FE	(DOE) Office of Fossil Energy
F-T	Fischer-Tropsch
HHV	higher heating value
IGCC	integrated gasification combined-cycle
ISO	International Organization for Standardization
LHV	lower heating value
NETL	(DOE) National Energy Technology Laboratory
NOC	net operating costs
NO_X	nitrogen oxides
O&M	operating and maintenance
OMB	(U.S.) Office of Management and Budget
PPC	process plant cost
PRB	Powder River Basin
ROI	return on investment
RSP	required selling price
SCR	selective catalytic reduction
SI	International System of Units (or Systeme Internationale)
SNCR	selective noncatalytic reduction
TAG	EPRI Technical Assessment Guide
TCR	total capital requirement
TOC	total operating costs
TPC	total plant cost
TPI	total plant investment

Appendix C: References

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Section II

Spreadsheet Templates

Table 1-1: IGCC General Assumptions/Analysis Design Basis

Notes	

		Example
Location		East-West Region
Fuel (Primary/Secondary)		Illinois # 6 Coal
Delivered Cost of Primary/Secondary Fuel ($/ton or $/MM Btu)		$1.24/M Btu
Design/Construction Period (years)		4 years
Plant Start-up Date		Jan-05
Land Area/Unit Cost ($/acre)		$2,000/acre
Capital Cost Year Dollars		2000
Capacity Factor (%)		65%
Levelized Capital Charge Factor (%)		14%
Project Book Life		20 years
Engineering Fees		6%
Process Contingency		2%
Project Contingency		15%

Table 1-2: Supercitical PC General Assumptions/Analysis Design Basis

Notes	

		Example
Location		East-West Region
Fuel (Primary/Secondary)		Illinois # 6 Coal
Delivered Cost of Primary/Secondary Fuel ($/ton or $/MM Btu)		$1.24/M Btu
Design/Construction Period (years)		4 years
Plant Start-up Date		Jan-05
Land Area/Unit Cost ($/acre)		$1,600/acre
Capital Cost Year Dollars		2000
Capacity Factor (%)		65%
Levelized Capital Charge Factor (%)		14%
Project Book Life		20 years
Engineering Fees		6%
Process Contingency		2%
Project Contingency		15%

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.
This report may be downloaded from the following U.S. DOE NETL website:
http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/analysis/Updated%20Costs.pdf

Table 2-1: IGCC Power Plant Performance

Notes	

STEAM CYCLE		w/o CO_2 Capture (Case 3B)	w/ CO_2 Capture (Case 3E)
Throttle Pressure, Mpa (psig)		12.4 (1,800)	12.4 (1,800)
Throttle Temperature, ^{o}C (^{o}F)		538 (1,000)	565.6 (1,050)
Reheat Outlet Temperature, ^{o}C (^{o}F)		538 (1,000)	565.6 (1,050)
2nd Reheat Outlet Temperature, ^{o}C (^{o}F)			
GROSS POWER SUMMARY, kWe			
Gas Turbine Power		337,472	345,355
Steam Turbine Power		143,783	127,207
Generator Loss	( )	(7,215)	(7,088)
Fuel Gas Expander Power		-	8,801
Gross Plant Power	0	474,040	474,275
AUXILIARY LOAD SUMMARY			
Coal Handling and Conveying		330	360
Coal Milling		750	830
Coal Slurry Pumps		200	220
Slag Handling and Dewatering		150	160
Recycle Gas Blower		600	340
Air Separation Plant		23,330	25,560
Oxygen Boost Compressor		11,910	14,820
H2S Plant (May be combined with CO2 capture if Selexol)		1,300	Inc. w/CO2
Claus/TGU/Scrubber		400	410
Tail Gas Recycle		1,410	1,000
CO2 Capture Plant		-	8,590
CO2 Compression		-	25,010
Humidification Tower Pump		100	100
Humidifier Makeup Pump		60	240
Condensate Pumps		280	370
High Pressure Boiler Feed Pump		2,940	3,180
Low Pressure Boiler Feed Pump		-	100
Miscellaneous (HVAC, lighting, control systems)		1,000	1,000
Gas Turbine Auxiliaries		600	600
Steam Turbine Auxiliaries		200	200
Circulating Water Pumps		1,790	1,840
Cooling Tower Fans		1,010	1,090
Flash Bottoms Pump		50	-
Other			
Other			
Transformer Loss		1,090	1,470
Total Auxiliary Power Requirement	0	49,500	87,490
NET PLANT POWER, kWe		424,540	386,785
PLANT EFFICIENCY			
Net Efficiency, % HHV		43.1	35.4
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)		8,349 (7,915)	10,166 (9,638)
CONSUMABLES			
As-Received Coal, kg/h (lb/h)		130,665 (288,040)	144,952 (319,560)
Oxygen (95% pure), kg/h (lb/h)		109,287 (240,932)	119,285 (262,974)
Water, kg/h (lb/h)		158,574 (349590)	341,143 (752,080)

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 2-2: Supercritical PC Power Plant Performance

Notes	

STEAM CYCLE		w/o CO_2 Capture (Case 7C)	w/ CO_2 Capture (Case 7A)
Throttle Pressure, Mpa (psig)		24.1 (3,500)	25.1 (3,500)
Throttle Temperature, ^{o}C (^{o}F)		565.6 (1,050)	565.6 (1,050)
Reheat Outlet Temperature, ^{o}C (^{o}F)		565.6 (1,050)	565.6 (1,050)
2nd Reheat Outlet Temperature, ^{o}C (^{o}F)		565.6 (1,050)	565.6 (1,050)
GROSS POWER SUMMARY, kWe			
Steam Turbine Power		498,319	408,089
Generator Loss	( )	(7,211)	(5,835)
Gross Plant Power	0	491,108	402,254
AUXILIARY LOAD SUMMARY			
Coal Handling and Conveying		390	390
Limestone Handling and Reagent Preparation		920	920
Pulverizers		1,860	1,860
Ash Handling		1,670	1,670
Primary Air Fans		1,220	1,220
Forced Draft Fans		970	970
Induced Draft Fans		5,050	19,880
SCR		100	100
Seal Air Blowers		50	50
Precipitators		1,000	1,000
FGD Pumps and Agitators		3,450	3,450
Condensate Pumps		590	300
Boilers Feed Water Booster Pumps		2,670	3,090
Miscellaneous (HVAC, lighting, control systems)		2,000	2,000
Steam Turbine Auxiliaries		400	400
Circulating Water Pumps		3,540	1,950
Cooling Tower Fans		2,030	1,110
MEA Unit			1,940
CO_2 Compressor			29,730
Other			
Other			
Transformer Loss		1,140	930
Total Auxiliary Power Requirement	0	29,050	72,960
NET PLANT POWER, kWe		462,058	329,294
PLANT EFFICIENCY			
Net Efficiency, % HHV		40.5	28.9
Net Heat Rate, HHV, kJ/kWh (Btu/kWh)		8,882 (8,421)	12,463 (11,816)
Condenser Cooling Duty, GJ (10^6 Btu/hr)		1,914 (1,815)	1,025 (972)
CONSUMABLES			
As-Received Coal, kg/h (lb/h)		151,295 (333,542)	151,295 (333,542)
Sorbent, kg/h (lb/h)		15,535 (34,248)	15,535 (34,248)

Reference: Evaluation of Innovative *Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2000.

Table 3: IGCC w/o CO_2 Capture (Case 3B) Capital Cost Details

a Plant Section	b Base $ x 1000	c Special Mods $ x 1000	d Modified b + c $ x 1000	e Engineering Fees % of d	f Engineering Fees e/100*d $ x 1000	g Process Cont. % of d	h Process Cont. g/100*d $ x 1000	i Project Cont. % of d	j Project Cont. i/100*d $ x 1000	k Total d+f+h+j $ x 1000	l Notes	Programmatic Cost Target	Factored Analysis Based On A Similar System	Vendor Estimates for Commercial Equpment	Vendor Projections for Similar Equipment
Coal Receiving and Handling	$13,643		$13,643	6	$819	0	$0	21.2	$2,892	$17,354	1				
Coal Preparation and Feed	$16,686		$16,686	6	$1,001	3.366	$562	14.395	$2,402	$20,651					
Feedwater Systems	$12,340		$12,340	6	$740	0	$0	23.87	$2,946	$16,026					
Gasifier	$93,885		$93,885	6	$5,633	8.457	$7,940	12.73	$11,952	$119,410					
Air Separation	$36,423		$36,423	6	$2,185	0	$0	10.6	$3,861	$42,469					
Acid Gas Removal (H2S)	$26,496		$26,496	6	$1,590	4.2	$1,113	19.85	$5,259	$34,458					
Elemental Sulfur Plant (Claus, TGCU, SWS)	$13,810		$13,810	6	$829	3.678	$508	15.992	$2,208	$17,355					
Mercury Removal	$0		$0	6	$0	3.5	$0	15	$0	$0					
Intercooled Shift Reactors	$0		$0	6	$0	3.5	$0	15	$0	$0					
CO_2 Capture Process	$0		$0	6	$0	3.5	$0	15	$0	$0	2				
CO2 Compressor/Drier	$0		$0	6	$0	3.5	$0	15	$0	$0					
Combustion Turbine/Generator and Accessories	$61,863		$61,863	6	$3,712	9.878	$6,111	11.848	$7,330	$79,015					
HRSG & Stack	$20,684		$20,684	6	$1,241	0	$0	11.929	$2,467	$24,392					
Steam Turbine Generator and Accessories	$23,650		$23,650	6	$1,419	0	$0	13.302	$3,146	$28,215					
Cooling Water System	$12,968		$12,968	6	$778	0	$0	19.66	$2,550	$16,296					
Ash Handling System	$8,118		$8,118	6	$487	6.705	$544	13.133	$1,066	$10,216					
Accessory Electric Plant	$23,066		$23,066	6	$1,384	0	$0	17.9	$4,129	$28,579					
Instrumentation & Controls	$9,661		$9,661	6	$580	0	$0	14.977	$1,447	$11,688					
Buildings & Structures	$8,504		$8,504	6	$510	0	$0	26.496	$2,253	$11,267					
Royalty Allowance	$0		$0							$0					
Land Cost	$700		$700							$700					
Inventory Capital	$4,293		$4,293							$4,293					
Preproduction Costs	$12,708		$12,708							$12,708					
Allowable Funds Used During Construction	$41,806		$41,806							$41,806					
Other (Specify)										$0					
TOTALS	$441,304	$0	$441,304		$22,908		$16,777		$55,908	$536,897					

1) Costs listed in column c, "Special Mods" account for special modifications required for the Sequestration Ready plant that would not necessarily be required for a commercial plant, e.g., modifications required for the 7FA to burn a hydrogen-rich syngas.

2) CO2 is compressed to 1,200 psia.

3) The 10% fee can be broken down as follows: 6% for engineering, 3% for construction management, and 1% for plant startup. Engineering includes costs for detailed design and contractor permitting. (Project permitting is not included.) Plant startup includes costs for startup engineers and technical support during startup. (All other startup costs are not included.)

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 4: IGCC w/ CO_2 Capture (Case 3E) Capital Cost Details

a	b	c	d	e	f	g	h	i	j	k	l	Programmatic Cost Target	Factored Analysis Based On A Similar System	Vendor Estimates for Commercial Equipment	Vendor Projections for Similar Equipment
Plant Section	Base $ x 1000	Special Mods $ x 1000	Modified b + c $ x 1000	Engineering Fees % of d	Engineering Fees e/100*d $ x 1000	Process Cont. % of d	Process Cont. g/100*d $ x 1000	Project Cont. % of d	Project Cont. i/100*d $ x 1000	Total d+f+h+j $ x 1000	Notes				
Coal Receiving and Handling	$14,537		$14,537	6	$872	0	$0	21.2	$3,082	$18,491	1				
Coal Preparation and Feed	$17,853		$17,853	6	$1,071	3.366	$601	14.395	$2,570	$22,095					
Feedwater Systems	$13,174		$13,174	6	$790	0	$0	23.63	$3,113	$17,077					
Gasifier	$87,969		$87,969	6	$5,278	8.661	$7,619	11.63	$10,231	$111,097					
Air Separation	$40,651		$40,651	6	$2,439	0	$0	10.6	$4,309	$47,399					
Acid Gas Removal (H2S)	$73,607		$73,607	6	$4,416	3.678	$2,707	15.992	$11,771	$92,502					
Elemental Sulfur Plant (Claus, TGCU, SWS)	$6,122		$6,122	6	$367	3.678	$225	15.992	$979	$7,694					
Mercury Removal	$0		$0	6	$0	3.5	$0	15	$0	$0					
Intercooled Shift Reactors	$20,100		$20,100	6	$1,206	3.5	$704	15	$3,015	$25,025					
CO_2 Capture Process	$17,500		$17,500	6	$1,050	3.5	$613	15	$2,625	$21,788	2				
CO2 Compressor/Drier	$26,600		$26,600	6	$1,596	3.5	$931	15	$3,990	$33,117					
Combustion Turbine/Generator and Accessories	$62,161		$62,161	6	$3,730	9.878	$6,140	11.848	$7,365	$79,396					
HRSG & Stack	$20,429		$20,429	6	$1,226	0	$0	11.929	$2,437	$24,092					
Steam Turbine Generator and Accessories	$21,478		$21,478	6	$1,289	0	$0	13.302	$2,857	$25,624					
Cooling Water System	$11,958		$11,958	6	$717	0	$0	19.66	$2,351	$15,026					
Ash Handling System	$8,650		$8,650	6	$519	6.705	$580	13.133	$1,136	$10,885					
Accessory Electric Plant	$27,855		$27,855	6	$1,671	0	$0	18.033	$5,023	$34,549					
Instrumentation & Controls	$9,381		$9,381	6	$563	0	$0	14.977	$1,405	$11,349					
Buildings & Structures	$8,303		$8,303	6	$498	0	$0	26.496	$2,200	$11,001					
Royalty Allowance	$0		$0							$0					
Land Cost	$700		$700							$700					
Inventory Capital	$4,920		$4,920							$4,920					
Preproduction Costs	$15,466		$15,466							$15,466					
Allowable Funds Used During Construction	$51,793		$51,793							$51,793					
Other (Specify)										$0					
TOTALS	$561,207	$0	$561,207		$29,300		$20,120		$70,459	$681,085					

1) Costs listed in column c, "Special Mods" account for special modifications required for the Sequestration Ready plant that would not necessarily be required for a commercial plant, e.g., modifications required for the 7FA to burn a hydrogen-rich syngas.

2) CO2 is compressed to 1,200 psia.

3) The 10% fee can be broken down as follows: 6% for engineering, 3% for construction management, and 1% for plant startup. Engineering includes costs for detailed design and contractor permitting. (Project permitting is not included.) Plant startup includes costs for startup engineers and technical support during startup. (All other startup costs are not included.)

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 5-1: IGCC Consumables and Operating & Maintenance (No Capture Case 3B)

	Units	Est. Quantity	$ x 1000	$/kW-yr	c/kWh	Notes
Consumables						
Chemicals (Specify)						
	$/ton		$270	$0.57	0.01	
	$/ton					
	$/ton					
Other Consumables	$/ton		$0	$0.00	0.00	
Water	$/1000 gal		$237	$0.57	0.01	
Mercury Removal (Activated Carbon)	$/ton		$0	$0.00	0.00	
Waste Disposal	$/ton		$1,306	$2.85	0.05	
By-Product Credits	$/ton		-$876	-$2.28	-0.04	
Fuel Cost	$/ton		$23,725	$55.81	0.98	
Operating & Maintenance						
Operating Labor	$/hr		$5,503	$13	0.23	
Maintenance Labor	$/hr		$3,823	$9	0.16	
Administrative & Support Labor	$/hr		$2,331	$5.5	0.10	
Maintenance Material	$/hr		$5,734	$13.5	0.24	
TOTALS			$42,053	$99	1.73	

Table 5-2: IGCC Consumables and Operating & Maintenance (With Capture Case 3E)

	Units	Est. Quantity	$ x 1000	$/kW-yr	c/kWh	Notes
Consumables						
Chemicals (Specify)						
	$/ton		$256	$0.57	0.01	
	$/ton					
	$/ton					
Other Consumables	$/ton		$0	$0	0	
Water	$/1000 gal		$223	$0.57	0.01	
Mercury Removal (Activated Carbon)	$/ton		$0		0	
Waste Disposal	$/ton		$1,449	$3.99	0.07	
By-Product Credits	$/ton		-$972	-$2.28	-0.04	
Fuel Cost	$/ton		$26,321	$68.34	1.2	
Operating & Maintenance						
Operating Labor	$/hr		$5,503	$14.2	0.25	
Maintenance Labor	$/hr		$4,731	$12.2	0.21	
Administrative & Support Labor	$/hr		$2,559	$6.6	0.12	
Maintenance Material	$/hr		$7,097	$18.3	0.32	
TOTALS			$47,167	$122	2.15	

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 6: IGCC Capital Summary

Capital Cost Summary	No CO_2 Capture (Case 3B) x $1000	With CO_2 Capture (Case 3E) x $1000
Coal Receiving and Handling	$13,643	$14,537
Coal Preparation and Feed	$16,686	$17,853
Feedwater Systems	$12,340	$13,174
Gasifier	$93,885	$87,969
Air Separation	$36,423	$40,651
Acid Gas Removal (H2S)	$26,496	$73,607
Elemental Sulfur Plant (Claus, TGCU, SWS)	$13,810	$6,122
Mercury Removal	$0	$0
Intercooled Shift Reactors	$0	$20,100
CO2 Capture Process	$0	$17,500
CO2 Compressor/Drier	$0	$26,600
Combustion Turbine/Generator and Accessories	$61,863	$62,161
HRSG & Stack	$20,684	$20,429
Steam Turbine Generator and Accessories	$23,650	$21,478
Cooling Water System	$12,968	$11,958
Ash Handling System	$8,118	$8,650
Accessory Electric Plant	$23,066	$27,855
Instrumentation & Controls	$9,661	$9,381
Buildings & Structures	$8,504	$8,303
Process Capital	$381,797	$488,328
Engineering Fees	$22,908	$29,300
Process Contingency	$16,777	$20,120
Project Contingency	$55,908	$70,459
Allowable Funds Used During Construction	$41,806	$51,793
Land Cost	$700	$700
Inventory Capital	$4,293	$4,920
Preproduction Costs	$12,708	$15,466
Total Capital Requirement (TCR)	$536,897	$681,085
Levelized Capital Charge Factor (%)	14%	14%
Capacity Factor (%)	65%	65%
Capital c/kWh	3.11	4.33
Production c/kWh	1.74	2.15
Total c/kWh	4.85	6.48
\$/ton CO_2 Removed	N/A	N/A
\$/ton CO_2 Avoided	N/A	23

Notes

References:

Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, EPRI, 2002.

Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal, EPRI, 2000.

Table 7: PC w/o CO_2 Capture (Case 7C) Capital Cost Details

a	b	c	d	e	f	g	h	i	j	k	l				
Plant Section	Base $ x 1000	Special Mods $ x 1000	Modified b + c $ x 1000	Engineering Fees % of d	Engineering Fees e/100*d $ x 1000	Process Cont. % of d	Process Cont. g/100*d $ x 1000	Project Cont. % of d	Project Cont. i/100*d $ x 1000	Total d+f+h+j $ x 1000	Notes	Programmatic Cost Target	Factored Analysis Based On A Similar System	Vendor Estimates for Commercial Equpment	Vendor Projections for Similar Equipment
Coal and Sorbent Handling	$15,822.0		$15,822	6	$949	0	$0	21.2	$3,354	$20,126	1				
Coal and Sorbent Preparation and Feed	$12,409.0		$12,409	6	$745	0	$0	21.2	$2,631	$15,784					
Feedwater Systems	$24,854.0		$24,854	6	$1,491	0	$0	24.06	$5,980	$32,325					
PC Boiler and Accessories	$109,564.0		$109,564	6	$6,574	0	$0	10.6	$11,614	$127,752					
Flue Gas Cleanup	$61,486.0		$61,486	6	$3,689	0	$0	10.6	$6,518	$71,693					
Mercury Removal	$0.0		$0	6	$0	0	$0	15	$0	$0					
CO_2 Removal and Compression	$0.0		$0	6	$0	5.39	$0	16.71	$0	$0	2				
Turbine/Generator and Accessories	$0.0		$0	6	$0	9.878	$0	11.848	$0	$0					
HRSG & Stack	$20,544.0		$20,544	6	$1,233	0	$0	17.54	$3,603	$25,380					
Steam Turbine Generator and Accessories	$72,885.0		$72,885	6	$4,373	0	$0	13.25	$9,657	$86,915					
Cooling Water System	$19,584.0		$19,584	6	$1,175	0	$0	20.5	$4,015	$24,774					
Ash/Spent Sorbent Handling System	$19,252.0		$19,252	6	$1,155	0	$0	16.07	$3,094	$23,501					
Accessory Electric Plant	$24,152.0		$24,152	6	$1,449	0	$0	17.05	$4,118	$29,719					
Instrumentation & Controls	$9,341.0		$9,341	6	$560	0	$0	13.41	$1,253	$11,154					
Buildings & Structures	$35,699.0		$35,699	6	$2,142	0	$0	26.5	$9,460	$47,301					
Royalty Allowance	$0.0		$0							$0					
Land Cost	$512.0		$512							$512					
Inventory Capital	$5,530.0		$5,530							$5,530					
Preproduction Costs	$15,064.0		$15,064							$15,064					
Allowable Funds Used During Construction	$42,842.0		$42,842							$42,842					
Other (Specify)										$0					
TOTALS	$489,540	$0	$489,540		$25,536		$0		$65,296	$580,372					

1) Costs listed in column c, "Special Mods" account for special modifications required for the Sequestration Ready plant that would not necessarily be required for a commercial plant, e.g., modifications required for the 7FA to burn a hydrogen-rich syngas.

2) CO2 is compressed to 1,200 psia.

3) The 10% fee can be broken down as follows: 6% for engineering, 3% for construction management, and 1% for plant startup. Engineering includes costs for detailed design and contractor permitting. (Project permitting is not included.) Plant startup includes costs for startup engineers and technical support during startup. (All other startup costs are not included.)

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 8: PC w/ CO_2 Capture (Case 7A) Capital Cost Details

a	b	c	d	e	f	g	h	i	j	k	l				
Plant Section	Base $ x 1000	Special Mods $ x 1000	Modified b + c $ x 1000	Engineering Fees % of d	Engineering Fees e/100*d $ x 1000	Process Cont. % of d	Process Cont. g/100*d $ x 1000	Project Cont. % of d	Project Cont. i/100*d $ x 1000	Total d+f+h+j $ x 1000	Notes	Programmatic Cost Target	Factored Analysis Based On A Similar System	Vendor Estimates for Commercial Equpment	Vendor Projections for Similar Equipment
Coal and Sorbent Handling	$15,822		$15,822	6	$949	0	$0	21.2	$3,354	$20,126	1				
Coal and Sorbent Preparation and Feed	$12,409		$12,409	6	$745	0	$0	21.2	$2,631	$15,784					
Feedwater Systems	$23,061		$23,061	6	$1,384	0	$0	23.46	$5,410	$29,855					
PC Boiler and Accessories	$108,954		$108,954	6	$6,537	0	$0	10.6	$11,549	$127,040					
Flue Gas Cleanup	$59,410		$59,410	6	$3,565	0	$0	10.6	$6,297	$69,272					
Mercury Removal	$0		$0	6	$0	0	$0	15	$0	$0					
CO_2 Removal and Compression	$111,769		$111,769	6	$6,706	5.39	$6,024	16.71	$18,677	$143,176	2				
Combustion Turbine/Generator and Accessories	$0		$0	6	$0	9.878	$0	11.848	$0	$0					
HRSG & Stack	$18,014		$18,014	6	$1,081	0	$0	17.54	$3,160	$22,254					
Steam Turbine Generator and Accessories	$62,245		$62,245	6	$3,735	0	$0	13.26	$8,254	$74,233					
Cooling Water System	$17,133		$17,133	6	$1,028	0	$0	20.5	$3,512	$21,673					
Ash/Spent Sorbent Handling System	$19,252		$19,252	6	$1,155	0	$0	16.07	$3,094	$23,501					
Accessory Electric Plant	$31,341		$31,341	6	$1,880	0	$0	17.22	$5,397	$38,618					
Instrumentation & Controls	$8,879		$8,879	6	$533	0	$0	13.41	$1,191	$10,602					
Buildings & Structures	$33,695		$33,695	6	$2,022	0	$0	26.5	$8,929	$44,646					
Royalty Allowance	$0		$0							$0					
Land Cost	$544		$544							$544					
Inventory Capital	$6,316		$6,316							$6,316					
Preproduction Costs	$18,379		$18,379							$18,379					
Allowable Funds Used During Construction	$52,929		$52,929							$52,929					
Other (Specify)										$0					
TOTALS	$600,152	$0	$600,152		$31,319		$6,024		$81,454	$718,950					

1) Costs listed in column c, "Special Mods" account for special modifications required for the Sequestration Ready plant that would not necessarily be required for a commercial plant, e.g., modifications required for the 7FA to burn a hydrogen-rich syngas.

2) CO_2 is compressed to 1,200 psia.

3) The 10% fee can be broken down as follows: 6% for engineering, 3% for construction management, and 1% for plant startup. Engineering includes costs for detailed design and contractor permitting. (Project permitting is not included.) Plant startup includes costs for startup engineers and technical support during startup. (All other startup costs are not included.)

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 9-1: Pulverized Coal Consumables and Operating & Maintenance

(No Capture Case 7C)

	Units	Est. Quantity	$ x 1000	$/kW-yr	c/kWh	Notes
Consumables						
Chemicals (Specify)						
	$/ton		$6,183	$13.7	0.24	
	$/ton					
	$/ton					
Other Consumables	$/ton		$2,909	$6.3	0.11	
Water	$/1000 gal		$537	$1.1	0.02	
Mercury Removal (Activated Carbon)	$/ton		$0	$0.0	0	
Waste Disposal	$/ton		$3,315	$7.4	0.13	
By-Product Credits	$/ton		$0	$0.0	0	
Fuel Cost	$/ton		$27,473	$59.2	1.04	
Operating & Maintenance						
Operating Labor	$/hr		$4,815	$10.4	$0.18	
Maintenance Labor	$/hr		$2,635	$5.7	$0.10	
Administrative & Support Labor	$/hr		$1,863	$4.0	$0.07	
Maintenance Material	$/hr		$3,953	$8.6	$0.15	
TOTALS			$53,683	$116	2.04	

Table 9-2: Pulverized Coal Consumables and Operating & Maintenance

(With Capture Case 7A)

	Units	Est. Quantity	$ x 1000	$/kW-yr	c/kWh	Notes
Consumables						
Chemicals (Specify)						
	$/ton		$10,247	$31.32	0.55	
	$/ton					
	$/ton					
Other Consumables	$/ton		$2,073	$6.26	0.11	
Water	$/1000 gal		$300	$1.14	0.02	
Mercury Removal (Activated Carbon)	$/ton		$0	$0.00	0	
Waste Disposal	$/ton		$3,315	$10.25	0.18	
By-Product Credits	$/ton		$0	$0.00	0	
Fuel Cost	$/ton		$27,427	$83.71	1.47	
Operating & Maintenance						
Operating Labor	$/hr		$5,272	$16.0	0.28	
Maintenance Labor	$/hr		$3,490	$10.6	0.19	
Administrative & Support Labor	$/hr		$2,191	$6.7	0.12	
Maintenance Material	$/hr		$5,235	$15.9	0.28	
TOTALS			$59,550	$182	3.19	

Reference: *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal*, EPRI, 2002.

Table 10: PC Capital Summary

Capital Cost Summary	No CO_2 Capture (Case 7C) x $1000	With CO_2 Capture (Case 7A) x $1000
Coal and Sorbent Handling	$15,822	$15,822
Coal and Sorbent Preparation and Feed	$12,409	$12,409
Feedwater Systems	$24,854	$23,061
PC Boiler and Accessories	$109,564	$108,954
Flue Gas Cleanup	$61,486	$59,410
Mercury Removal	$0	$0
CO_2 Removal and Compression	$0	$111,769
Combustion Turbine/Generator and Accessories	$0	$0
HRSG & Stack	$20,544	$18,014
Steam Turbine Generator and Accessories	$72,885	$62,245
Cooling Water System	$19,584	$17,133
Ash/Spent Sorbent Handling System	$19,252	$19,252
Accessory Electric Plant	$24,152	$31,341
Instrumentation & Controls	$9,341	$8,879
Buildings & Structures	$35,699	$33,695
Process Capital	$425,592	$521,984
Engineering Fees	$25,536	$31,319
Process Contingency	$0	$6,024
Project Contingency	$65,296	$81,454
Allowable Funds Used During Construction	$42,842	$52,929
Land Cost	$512	$544
Inventory Capital	$5,530	$6,316
Preproduction Costs	$15,064	$18,379
Total Capital Requirement (TCR)	$580,372	$718,950
Levelized Capital Charge Factor (%)	14%	14%
Capacity Factor (%)	65%	65%
Capital c/kWh	3.36	4.57
Production c/kWh	2.04	3.19
Total c/kWh	5.41	7.76
$/ton CO_2 Removed	N/A	N/A
$/ton CO_2 Avoided	N/A	23

Notes

References:

Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal, EPRI, 2002.
Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal, EPRI, 2000.

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