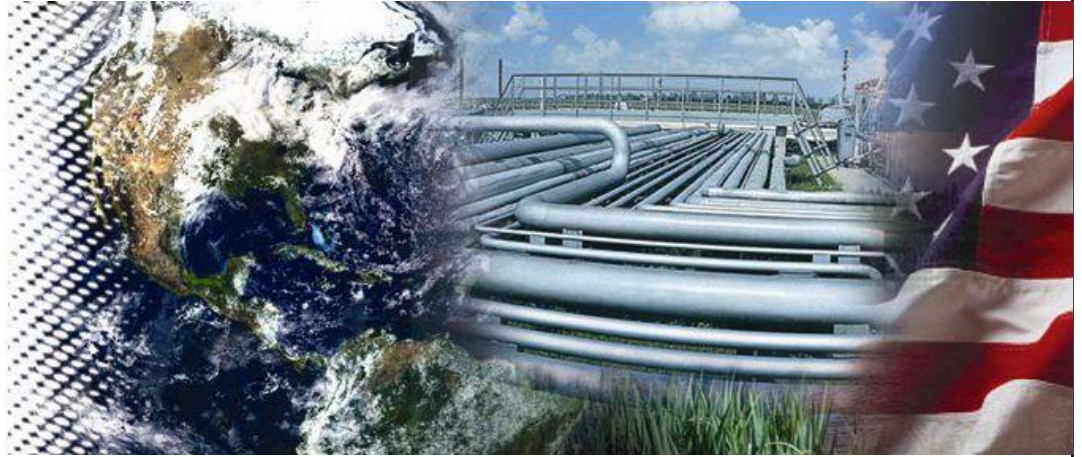




NATIONAL ENERGY TECHNOLOGY LABORATORY



Power Plant Flexible Model Technical Documentation and User's Manual

November 8, 2013

DOE/NETL-2013/1607



**U.S. DEPARTMENT OF
ENERGY**

OFFICE OF FOSSIL ENERGY

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Final Report

November 8, 2013

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Acronyms and Abbreviations

Acfm	Actual cubic feet per minute	h, hr	Hour
ACI	Activated carbon injection	H ₂	Hydrogen
Ar	Argon	H ₂ O	Water
ASU	Air separation unit	Hg	Mercury
atm	Atmosphere (14.696 psi)	HHV	Higher heating value
BAH	Booz Allen Hamilton	hp	Horsepower
BEC	Bare erected cost	HP	High pressure
BFW	Boiler feedwater	HSS	Heat stable salts
Bpd	Barrels per day	IECM	Integrated Environmental Control Model
Btu	British thermal unit	ID	Induced draft
Btu/hr	British thermal units per hour	in. H ₂ O	Inch water
Btu/kWh	British thermal units per kilowatt hour	kg/GJ	Kilograms per gigajoule
Btu/lb	British thermal units per pound	kg/hr	Kilograms per hour
Btu/lbm	British thermal units per pound mass	kg/s	Kilograms per second
Btu/scf	British thermal units per standard cubic foot	kJ	Kilojoule
CaCO ₃	Calcium carbonate (limestone)	kJ/hr	Kilojoules per hour
CaSO ₄	Calcium sulfate	kJ/kg	Kilojoules per kilogram
CCS	Carbon capture and sequestration	kPa	Kilopascal
CDR	cf Cubic feet	kW, kWe	Kilowatt electric
CF	Capacity factor	kWh	Kilowatt-hour
CFB	Circulating fluidized bed	kWt	Kilowatt thermal
CFBC	Circulating fluidized bed combustor/combustion	lb	Pound
CFM	Cubic feet per minute	lb/hr	Pounds per hour
CO	Carbon monoxide	lb/ft ²	Pounds per square foot
CO ₂	Carbon dioxide	lb/MMBtu	Pounds per million British thermal units
DB	Dry basis	lbmol	Pound mole
DB	Daily barrel	lbmol/hr	Pound moles per hour
EPA	Environmental Protection Agency	lb/MWh	Pounds per megawatt hour
ESP	Electrostatic precipitator	lb/TBtu	Pounds per trillion British thermal units
ESPA	Energy Sector Planning and Analysis	LHV	Lower heating value
FD	Forced draft	LNB	Low NO _x burner
FE	Fossil energy	LP	Low pressure
FG	Flue gas	m	Meter
FGD	Flue gas desulfurization	m ³ /min	Cubic meters per minute
ft	Foot, Feet	M	Thousand
ft, w.g.	Feet of water gauge	MAC	Main air compressor
gal	Gallon	Mcf	Thousand cubic feet
gal/MWh	Gallons per megawatt hour	MEA	Monoethanolamine
GJ	Gigajoule	MM	Million
GJ/hr	Gigajoules per hour	MMBtu	Million British thermal units
GHG	Greenhouse gas	MMBtu/hr	Million British thermal units per hour
gpm	Gallons per minute		

MMscf	Million standard cubic feet	psig	Pound per square inch gage
Mol	Mole	PSFM	Power systems financial model
mol/s	Moles per second	S	Sulfur
mol/kg	Moles per kilogram	SC	Supercritical
mole%	Mole percent (percent by mole)	scf	Standard cubic feet
MPa	Megapascal	scfd	Standard cubic feet per day
MW,MWe	Megawatt electric	scfh	Standard cubic feet per hour
MWh	Megawatt-hour	scfm	Standard cubic feet per minute
MWt	Megawatt thermal	Sch.	Schedule
N ₂	Nitrogen	SCPC	Supercritical pulverized coal
N/A	Not applicable	SCR	Selective catalytic reduction process or equipment
NETL	National Energy Technology Laboratory	SDA	Spray dryer absorber
NO	Nitrogen oxide	SEAP	Office of Strategic Energy Analysis & Planning
NO _x	Oxides of nitrogen	SO ₂	Sulfur dioxide
O ₂	Oxygen	SO ₃	Sulfur trioxide
O&M	Operation and maintenance	SO _x	Oxides of sulfur
PA	Primary air	TPD	Ton per day
PC	Pulverized coal	TPH	Tons per hour
PM	Particulate matter	U.S.	United States
ppb	Parts per billion	USC	Ultra-supercritical
PPFM	Power Plant Flexible Model	USCPC	Ultra-supercritical pulverized coal
ppm	Parts per million	vol%	Volume percent
ppmv	Parts per million volume	WB	Wet bulb
PRB	Powder River Basin coal region	°C	Degrees Celsius
psi	Pounds per square inch	°F	Degrees Fahrenheit
psia	Pound per square inch absolute		

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1 Introduction

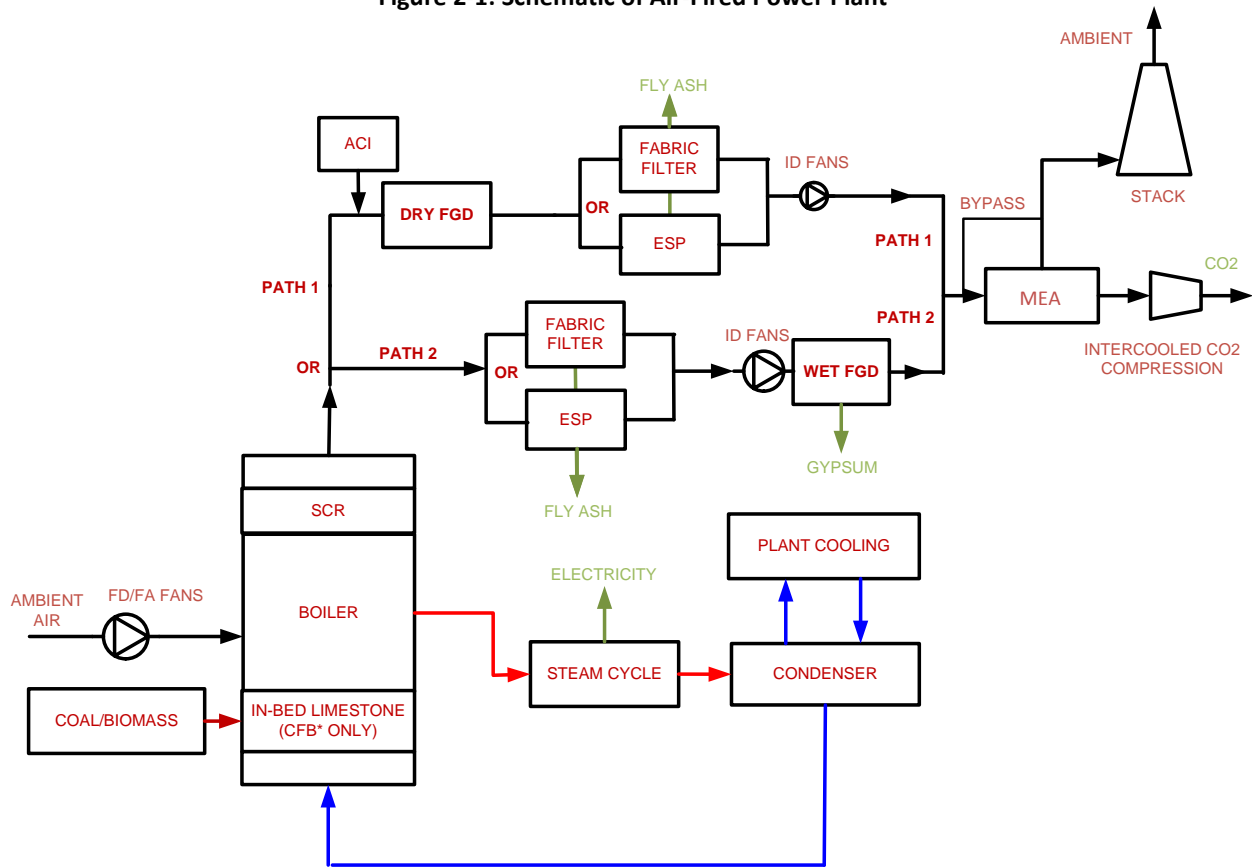
The Power Plant Flexible Model (PPFM) simulates combustion-based power plant electrical output, emissions, material usage, and costs for a fully-configurable mix of boiler and steam plant types, feedstocks, and emissions control equipment. The model can be combined with upstream and downstream process information to provide a cradle-to-gate life cycle analysis (LCA) of various power scenarios.

This document provides a description of the model, validation results, and a user's guide. The description of the model documents the data sources, assumptions, and equations used to construct the model, and is meant to supplement the information available in the model spreadsheet. The validation results show the ability of the model to replicate plant performance parameters, emissions, and costs from models built using Aspen Plus® (Aspen).

2 Model Description

The PPFM is a Microsoft® Excel-based model that was built using plant configurations and performance data from models that were built using Aspen to support a series of National Energy Technology Laboratory (NETL) power plant performance reports (NETL, 2010a, 2010b, 2011a, 2012b). The equations, assumptions, and references used in the model are discussed below. To facilitate the discussion, **Figure 2-1** shows a schematic of an air-fired power plant, and **Figure 2-2** shows a schematic of an oxygen-fired power plant. Each is shown with all of the available equipment and emissions controls.

Figure 2-1: Schematic of Air-Fired Power Plant



ACI (Activated Carbon Injection) - Injects activated carbon which captures mercury

Boiler - Combusts coal to generate steam

CFB (Circulating Fluidized Bed) - A boiler type that suspends feedstock particles in a turbulent, upward flow of air as it combusts them.

CO₂ Compression - Compresses CO₂ to 2200 psig for pipeline transportation

Condenser - Heat exchanger that cools steam turbine exhaust with cooling water or air

Carbon Capture System – Amine (MEA) -based carbon capture system

ESP (Electrostatic Precipitator) and Fabric Filter - Flue gas ash and particulate matter capture

FD/PA Fans (Forced Draft/Primary Air Fans) - Provide ambient air to boiler

ID Fans (Induced Draft Fans) - Ensures low pressure on exhaust side of boiler

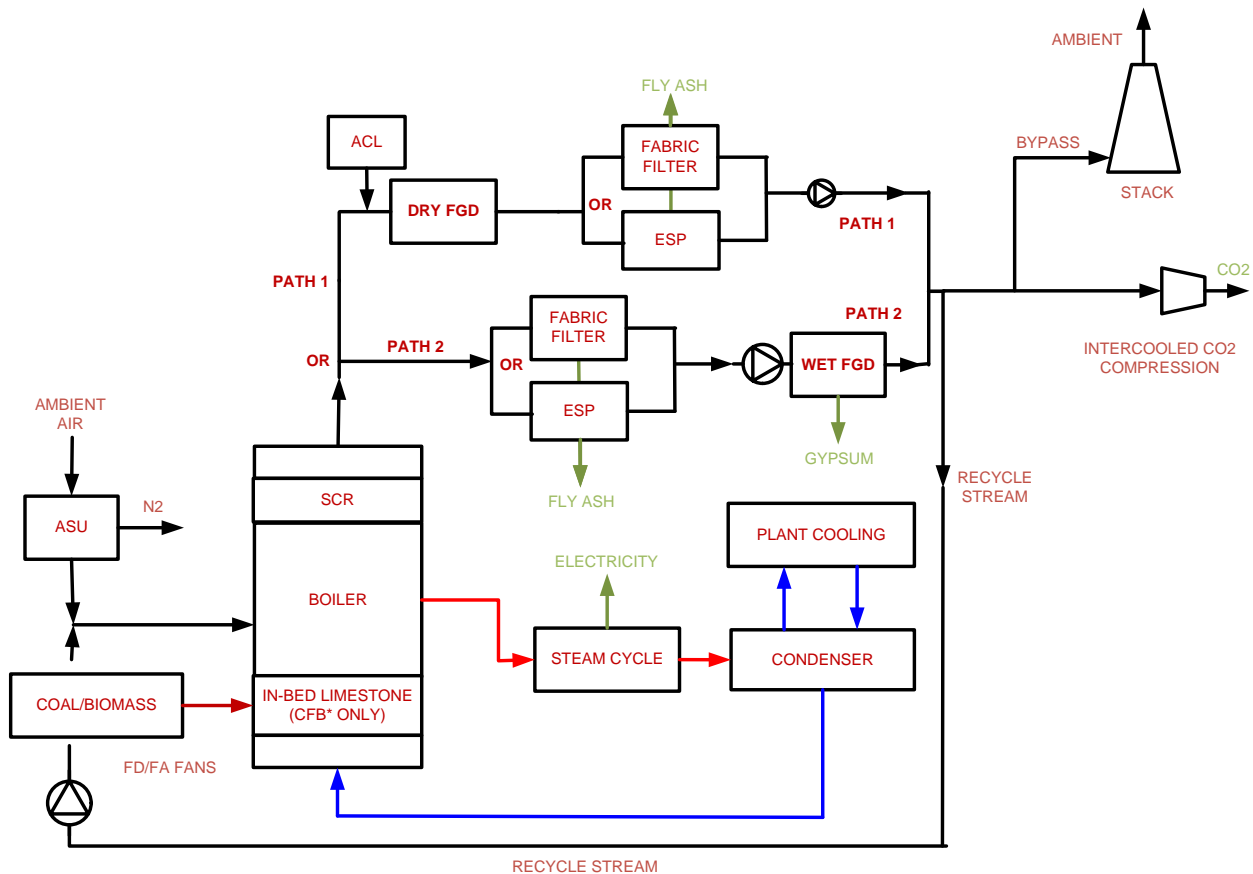
In-bed limestone injection and Wet and Dry FGD (Flue Gas Desulfurization) - Converts SO_x into CaSO₃, CaSO₄, or CaSO₄·H₂O (gypsum).

Plant Cooling - Provides cooling water to condenser and other plant processes

SCR (Selective Catalytic Reduction) - Converts NO_x to N₂ and H₂O

Steam Cycle - Converts steam produced by boiler into electricity using steam turbines

Figure 2-2: Schematic of Oxygen-fired Power Plant



ACI (Activated Carbon Injection) - Injects activated carbon which captures mercury

Air Separation Unit (ASU) - Separates O₂ from ambient air for combustion

Boiler - Combusts coal to generate steam

CFB (Circulating Fluidized Bed) - A boiler type that suspends feedstock particles in a turbulent, upward flow of air as it combusts them.

CO₂ Compression - Compresses CO₂ to 2200 psig for pipeline transportation

Condenser - Heat exchanger that cools steam turbine exhaust with cooling water or air

ESP (Electrostatic Precipitator) and Fabric Filter - Flue gas ash and particulate matter capture

FD/PA Fans (Forced Draft/Primary Air Fans) - Provides recycled flue gas to boiler to control combustion temperature

ID Fans (Induced Draft Fans) - Ensures low pressure on exhaust side of boiler

In-bed limestone injection and Wet and Dry FGD (Flue Gas Desulfurization) - Converts SO_x into CaSO₃, CaSO₄, or CaSO₄·H₂O (gypsum).

Plant Cooling - Provides cooling water to condenser and other plant processes

SCR (Selective Catalytic Reduction) - Converts NO_x to N₂ and H₂O

Steam Cycle - Converts steam produced by boiler into electricity using steam turbines

2.1 Boiler Parameters and Load Factors

Each boiler type has a set of performance parameters that are stored within the “Flow_Chart” worksheet. These performance parameters are used in various calculations throughout the model. Also, most plant emissions controls and auxiliary equipment have an electrical or steam load associated with them and have defined load factors. The boiler parameters and load factors are pulled directly from NETL reports, are calculated using data from NETL reports, or yield results consistent with NETL reports. The boiler parameters are provided in **Table 2-1**, and the load factors are provided in **Table 2-2**.

The steam conditions for the various plant types are not directly modeled, but are provided below for reference (NETL, 2010a, 2010b, 2011a, 2012b):

- Subcritical PC: 17.9 MPa/574°C/574°C (2,600 psig/1,065°F/1,065°F)
- Supercritical PC and CFB: 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)
- Ultra-supercritical PC: 27.6 MPa/649°C/649°C (4,000 psig/1,200°F/1,200°F)

Table 2-1: Boiler Parameters

Parameter	Units	Sub-critical PC (PC)	Supercritical PC (SCPC)	Ultra-SC PC (USCPC)	Circulating Fluidized Bed (CFB)
Steam cycle efficiency	N/A	0.4410	0.4695	0.4850	0.4695
Condensate pump to steam power	hp/kW	0.001936	0.001747	0.001647	0.001936
HP feed flow to steam power	(kg/s)/MWt input	0.3528	0.3704	0.3800	0.3500
Steam blowdown	%	1%	0%	0%	1%
Condenser cooling duty factor	(MMBtu/hr)/MW gross gen	0.00417	0.00373	0.00355	0.00362
Emission Factor NOx	lbm NOx/MMBtu input	0.5	0.5	0.5	0.13
Pulverizer load factor	kW/(ton coal/hr)	13.6	13.6	13.6	0.5
Excess air	mass% more than req'd	8.2%	8.2%	8.2%	12.8%
Oxy excess air	mass% more than req'd	11%	11%	11%	8%
Carbon in refuse	mass%	0%	0%	0%	11%
Overhead ash fraction	%mass ash	80%	80%	80%	70%
Percent NOx NO	%NOx	95%	95%	95%	95%
Fuel sulfur in ash	%mass	0%	0%	0%	0%
Sulfur dioxide	%SOx	100%	100%	100%	100%
Carbon mono	%total carbon mole	0%	0%	0%	0%
Primary forced fan factor	kW/(m ³ /s)	7.0	7.0	9.0	11.1
Primary forced fan oxy	kW(m ³ /s)	5.5	5.5	7.5	32.0
Boiler air in ambient temp	C	15	15	15	30
Boiler air in oxy temp	C	35	35	35	30
Boiler flue gas temp	C	150	150	150	150
Latent heat vaporization	kJ/kg	2261	2261	2261	2261
Boiler flue gas pressure	psia	14.4	14.4	14.4	14.4
Oxy flue gas recycle	%	72%	72%	58%	55%
Infiltration air	%	1.79%	1.79%	1.79%	1.76%
Steam feed enthalpy diff	kJ/kg	2,380	2,222	2,112	2,222
First pass percent ¹	N/A	0.811	0.823	0.85	0.808
Notes: 1: First pass percent is the percentage of total boiler flow that is coming from the feedwater system to be sent to the high-pressure turbine.					

Table 2-2: Electrical and Steam Load Factors for Various Plant Auxiliary Loads

Parameter	Load Factor
Coal Pulverizer	Pulverized Coal Boilers: 13.6 kWe/(ton/hr-coal flow rate) CFB: Boiler: 0.5 kWe/(ton/hr-coal flow rate)
Biomass grinder	177.8 kWe/(kg/s-biomass flow rate)
Biomass dryer	230 kWe/(kg/s-moisture removal rate)
Air Separating Unit Electricity	25.91 kWe/(mol of O ₂ /s) (230 kWh/tonne O ₂)
Air Separating Unit Steam	$4.7388 \cdot 10^{-4}$ kg steam/mol of O ₂
Bottom Ash Handling	106.3 kWe/(kg/s bottom ash flow rate)
In-bed Limestone Injection and Dry Flue Gas Desulfurization Sorbent Handling	20 kWe/(kg/s sorbent flow rate)
Fabric Filter and Electrostatic Precipitator Ash Handling	106.3 kWe/(kg/s ash removed)
Fabric Filter Ash Removal	17.44 kWe/(kg/s ash removed)
Wet Flue Gas Desulfurization Auxiliary Loads	Co-firing biomass with amine capture: 2000 kWe/(kg/s SO ₂ removed) All other cases: 1250 kWe/(kg/s SO ₂ removed)
Wet Flue Gas Desulfurization Sorbent Handling and Preparation	Co-firing biomass with amine capture: 600 kWe/(kg/s limestone) All other cases: 163.73 kWe/(kg/s limestone)
Amine Capture Steam	100% Coal: 1.3 kg/(kg CO ₂ entering vessel) Co-firing biomass: 1.32 kg/(kg CO ₂ entering vessel)
Amine Capture Auxiliary Loads	5.3411 kWe/(mol/s CO ₂ entering vessel)
Amine Capture CO ₂ Compression	13.08 kWe/mol/s CO ₂ captured
Oxygen-fired CO ₂ Compression	19.49 kWe/ mol/s CO ₂ captured

2.2 Feedstock Types

There are eight feedstocks available in the PPFM:

1. Bituminous coal – Illinois #6
2. Sub-bituminous coal – Powder River Basin
3. Lignite – North Dakota Beulah-Zap Lignite
4. Custom coal
5. Hybrid poplar
6. Switchgrass
7. Corn stover
8. Forest residue

As shown above, the coal types, with the exception of custom coal, are defined by the as-received ultimate analysis for each coal type in NETL baseline reports (NETL, 2010a, 2011a). The as-received ultimate analyses show coal composition, specifically carbon, oxygen, water, sulfur, nitrogen, chlorine, and ash as mass percentages, and mercury as a trace element in parts per million

(ppm). However, the custom coal default is an average of different coals to be combusted at the Virginia City Hybrid Energy Center (Moore, 2008). The coal properties in PPFM are summarized in **Table 2-3**.

Table 2-3: Properties of Coal Used in PPFM

Parameter	Bituminous	Sub-bituminous	Lignite	Custom
Higher Heating Value (kJ/kg)	27,135	19,920	15,391	20,636
Water (mass %)	11.12	25.77	36.08	5.98
Carbon (mass %)	63.75	50.07	39.55	48.83
Hydrogen (mass %)	4.50	3.38	2.74	3.33
Nitrogen (mass %)	1.25	0.71	0.63	1.02
Chlorine (mass %)	2.90E-01	1.00E-02	0.00E00	3.92E-06
Sulfur (mass %)	2.51	0.73	0.63	0.74
Ash (mass %)	9.70	8.19	9.86	35.7
Oxygen (mass %)	6.88	11.14	10.51	4.41
Mercury (ppb)	150	81	116	2.98

Untorrefied biomass properties are from dry-basis ultimate analyses contained in NETL reports and are adjusted to as-received moisture content (NETL, 2012a, 2012b; Ortiz). Forest residue properties are the same as hybrid poplar (NETL, 2012c). For untoorrefied feedstocks, the dry-basis analyses are changed to as-received (i.e., including moisture) through the use of **Equation (2-1)** for each component of the feedstock, including HHV. The as-received moisture content is 50 percent, 15 percent, 15 percent, and 50 percent for hybrid poplar, corn stover, switchgrass, and forest residue, respectively. **Table 2-4** shows the dry-basis and as-received properties for the biomass feedstocks.

Torrefied biomass dry-basis properties for hybrid poplar, and by extension forest residue, are based on an ultimate analysis for Georgia Southern Pine from an unpublished report (White et al., 2012). Torrefaction is a process that dries biomass and also results in chemical composition changes both of which increase energy content per mass. Ultimate analyses for torrefied corn stover and switchgrass are not available, but the delivery of dried biomass to the ECF provides a rough estimation of torrefied corn stover and switchgrass. If the biomass is torrefied, the moisture content is 5.7 percent, and **Equation (2-1)** is again used to adjust the properties to an as-received basis. **Table 2-5** shows the dry-basis and as-received properties for torrefied hybrid poplar and forest residue.

$$m_{carbon_{new}} = \frac{m_{carbon_{dry}}}{\sum_i m_{i_{dry}} \cdot \left(1 + \frac{m_{h2o}}{1 - m_{h2o}}\right)} \quad (2-1)$$

where,

m_i is the dry-basis mass fraction of component i (kg of i per kg of biomass)

Table 2-4: Properties of Dry-basis and As-received Biomass used in PPFM

Parameter	Hybrid Poplar		Switchgrass		Corn Stover		Forest Residue	
	Dry	As-rec.	Dry	As-rec.	Dry	As-rec.	Dry	As-rec.
Higher Heating Value (kJ/kg)	19,627	9,814	18,113	15,396	17,510	14,884	19,627	9,814
Water (mass %)	0.00	50.00	0.00	15.00	0.00	15.00	0.00	50.00
Carbon (mass %)	52.36	26.18	42.60	36.21	44.50	37.83	52.36	26.18
Hydrogen (mass %)	5.60	2.80	6.55	5.57	5.56	4.73	5.6	2.80
Nitrogen (mass %)	0.37	0.19	1.31	1.11	0.61	0.52	0.37	0.19
Chlorine (mass %)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfur (mass %)	0.03	0.02	0.01	0.01	0.01	0.01	0.03	0.02
Ash (mass %)	1.48	0.74	7.45	6.33	6.01	5.11	1.48	0.74
Oxygen (mass %)	40.16	20.08	42.08	35.77	43.31	36.81	40.16	20.08
Mercury (ppb)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 2-5: Properties of Torrefied Hybrid Poplar and Forest Residue Used in PPFM

Parameter	Hybrid Poplar	
	Dry	As-rec.
Higher Heating Value (kJ/kg)	24,051	22,675
Water (mass %)	0.00	5.72
Carbon (mass %)	63.52	59.89
Hydrogen (mass %)	5.42	5.11
Nitrogen (mass %)	0.44	0.41
Chlorine (mass %)	0.00	0.00
Sulfur (mass %)	0.00	0.00
Ash (mass %)	0.54	0.51
Oxygen (mass %)	30.08	28.36
Mercury (ppb)	0.00	0.00

The user defines the as-received mass percent of each feedstock to be combusted in the power plant in the “Summary_Sheet.” These mass percentages are used in the pulverizer and grinding processes to aggregate the feedstock compositions into separate generic coal and biomass feedstocks.

2.3 Pulverizer

Coal and torrefied biomass feedstocks are passed to the pulverizer process by combining all of them using a weighted average. For example, assuming a user-defined mix of 80 percent lignite and 20 percent bituminous, the carbon contents of both will be passed into a single parameter in the pulverizer process using **Equation (2-2)**. Pulverizer electricity use is calculated using a load factor of either 13.6 or 0.5 kWe per ton/hour coal mass flow rate, depending on the boiler type. The load factors result in electricity loads similar to NETL baseline reports (NETL, 2010a, 2011a). Circulating fluidized bed boilers do not require coal to be as small as pulverized coal boilers, resulting in a lower pulverizer load factor. Coal mass flow rate is determined in a downstream equation and passed to the pulverizer process. Pulverizer electricity usage is the product of load factor and coal flow rate.

$$m_{C_{combined}} = 0.8 \cdot m_{C_{lignite}} + 0.2 \cdot m_{C_{bituminous}} \quad (2-2)$$

where,

m_c is the mass fraction of carbon (kg of carbon per kg of coal)

2.4 Biomass Grinder

Biomass flows are passed to the biomass grinder by passing the weighted average of feedstocks just as described in the pulverizer process. Grinder electricity use is calculated using a load factor of 177.8 kW per kg/s biomass mass flow rate. The load factor results in electricity loads similar to a previous NETL report (NETL, 2012b). The biomass flow rate is determined in a downstream equation and passed to the biomass grinder process. Biomass grinder electricity usage is the product of load factor and biomass flow rate.

2.5 Biomass Dryer

Biomass flow to the dryer comes from the biomass grinder, so all feedstocks have already been combined into an aggregated biomass flow. As a result, while different feedstocks have different moisture content, their weighted average moisture content is what is passed to the drying process. The final water content is a user-defined parameter in percent mass water. The “Summary Sheet” will not restrict user input (e.g., setting a moisture level of 100 percent), but it does show the limits next to the cell. Dryer electricity use is calculated using a load factor of 230 kWe per kg/s of moisture removed from biomass. The load factor results in electricity loads similar to a previous NETL report (NETL, 2012b) and is based on drying biomass to 10 percent moisture using fluidized-bed drying with internal waste heat utilization. Because moisture content is changing, the mass fractions of biomass components will need to be adjusted using **Equation (2-3)**. The amount of moisture removed in kg/s is the as-received biomass flow rate times the difference in moisture percentage, and the electricity usage is the product of the load factor times the moisture removed in kg/s. The output from the process is normalized to 1 kg of biomass.

This process also calculates the dried mass as a percent of 1 kg of aggregated biomass. This is done by keeping the mass fraction of each component constant while reducing the moisture content to the target percentage using **Equation (2-3)**. The mass fractions for each component of 1 kg of dried biomass are summed to show the total dried mass. The ratio of dried mass to as-received mass is the “Percent of original weight” parameter that will be used in the fuel mixing process. Additionally, the as-fired biomass mass flow rate is divided by “Percent of original weight” to determine the as-received biomass mass flow rate.

$$m_{h2o_{new}} = \sum_i m_{i_{dry}} \cdot \frac{\%_{h2o_{new}}}{1 - \%_{h2o_{new}}} \quad (2-3)$$

where,

m_i is the dry-basis mass fraction of component i (kg of i per kg of biomass)

$\%_{h2o}$ is the mass percent of H₂O after drying

2.6 Fuel Mixing

The aggregated coal and biomass fuel flows are combined in the fuel mixing process. The first step is to determine what mass percent of each flow is delivered to the mixer, because initial, user-defined feedstock percentages are for as-received mass and moisture can be removed from the biomass. The percent of as-fired biomass flow is calculated using the “Percent of original mass” parameter from the drying process and **Equation (2-4)**. Once the as-fired mass percent of biomass is calculated, mass percent of coal is 100 percent minus the as-fired mass percent of biomass. An aggregated feedstock is created by taking a weighted sum of the coal and biomass feedstock compositions using **Equation (2-2)** and the as-fired mass percents. This aggregated feedstock composition is passed on to the “Energy Conversion” process.

$$\%_{biomass\ as-fired} = \frac{(1 - \%_{coal}) \cdot \%_{original\ mass}}{\%_{coal} + (1 - \%_{coal}) \cdot \%_{original\ mass}} \quad (2-4)$$

where $\%_{coal}$ is the as-received mass percent of aggregated coal flow

Using the aggregated feedstock HHV, a feedstock flow rate is determined by dividing the user-defined thermal input by the HHV using **Equation (2-5)**. The aggregated feedstock flow rate is multiplied by the as-fired mass percentages to determine the as-fired mass flow rates of coal and biomass, which are used in the dryer and pulverizing processes to determine electricity usages.

$$\dot{m}_{aggregated\ feedstock} = \frac{\dot{Q}_{thermal}}{HHV_{aggregated\ feedstock}} \quad (2-5)$$

where,

\dot{m} is the mass flow rate (kg/s)

\dot{Q} is the user-defined thermal input (kW)

HHV is the higher heating value (kJ/kg)

Each component of coal is converted to both a mass flow rate and molar flow rate to be used in downstream calculations, so there are mass and molar flow rates for carbon, hydrogen, and others.

2.7 Coal and Biomass Handling

The electricity usages for coal and biomass handling (such as receive/unload facilities and conveyors) are calculated using **Equation (2-6)** from equations used to develop the same electricity usage in NETL reports (NETL, 2010a, 2011a, 2012b). The parameters for coal and biomass are the same.

$$\text{Reclaim rate} = \frac{\text{Flow margin} \cdot \dot{m}_{\text{coal}} \cdot 24}{\text{Reclaim operating hours}} \quad (2-6)$$

$$P_{\text{handling}} = \frac{318 + 7.547 + \text{Reclaim rate} \cdot 0.77231882}{1.341}$$

where ,

Reclaim rate is a dimensionless parameter used in the handling power equation

Flow margin is 1.1

\dot{m}_{coal} is the as-received coal mass flow rate (ton/hr)

Reclaim operating hours is 16 (hours/day)

P_{handling} is the electricity usage of the coal (or biomass) handling system

318, 7.547, 0.77231882, 1.341 are static parameters in the equation to scale power usage (NETL, 2010a).

2.8 Air Separation Unit

The air separation unit (ASU) portion in the model performs the calculations to define the oxidant content for oxygen-firing and ambient air boilers and also power and steam requirements for the air separating unit.

2.8.1 Normal Air Calculations

The first step in determining the oxidant content for the boiler is to determine the stoichiometric requirement for oxygen during combustion. This is done using **Equation (2-7)**.

$$\dot{m}ol_{O_2} = \dot{m}ol_C + \frac{\dot{m}ol_H}{4} + \dot{m}ol_S - \frac{\dot{m}ol_O}{2} \quad (2-7)$$

where ,

$\dot{m}ol_i$ is the molar flow rate of component i (mol/s of i)

The required molar flow rate of oxygen (O_2) is divided by the molar concentration of oxygen in ambient air, statically defined as 0.2074 moles O_2 per mole of air, to determine the required molar flow rate of ambient air. However, each boiler requires excess air to ensure complete combustion. The amount of excess air is defined per boiler as a molar percentage that is added to the required air flow rate. The excess air requirements were set to match the combustion air delivered to the boilers in NETL reports (NETL, 2010a, 2011a, 2012b). The molar concentration of each component in air is multiplied by the air molar flow rate to define the molar flow rates of each component, which are passed on to the energy conversion calculations. The molar concentrations of each air component are shown in **Table 2-6** and the molar percent of excess air for each boiler type is shown in **Table 2-7**.

Table 2-6: Molar Concentrations of Air Components

Component	Molar Concentration
Argon (Ar)	0.009248
Carbon dioxide (CO ₂)	0.000327
Hydrogen (H ₂)	0.000000
Water (H ₂ O)	0.009870
Nitrogen (N ₂)	0.773152
Oxygen (O ₂)	0.207403
Sulfur dioxide (SO ₂)	0.000000

Table 2-7: Amount of Excess Air or Oxygen for Different Boiler Types

Boiler Type	Excess Air/Oxygen
Subcritical	8.2%-mol air
Oxy-fired subcritical	11.0%-mass O ₂
Super critical	8.2%-mol air
Oxy-fired super critical	11.0%-mass O ₂
Ultra super critical	8.2%-mol air
Oxy-fired super critical	11.0%-mass O ₂
Circulating fluidized bed	12.8%-mol air
Oxy-fired circulating fluidized bed	8.0%-mass O ₂

2.8.2 ASU (oxygen-firing) Calculations

An ASU provides an oxidant with a high concentration of oxygen largely by separating nitrogen from ambient air. The ASU does this by cryogenic separation. The electricity usage of this process is largely driven by the main air compressors (MAC) upstream of the rectification column. Additionally, the use of oxygen-rich oxidant requires the recycling of flue gas to control the combustion temperature, so the oxidant composition is dynamic and dependant on the fuel and emission controls (NETL, 2012b).

The electricity used by the ASU as a whole is calculating by multiplying an ASU load factor of 25.91 kWe per mol/s of oxygen delivered. An additional 1000 kWe of auxiliary loads are added to the ASU electricity as is done for other NETL models.

The oxidant air composition is calculated using different equations for each air component. Argon (Ar), nitrogen (N₂), and hydrogen (H₂) enter the system through the ASU in very small percentages and also through boiler infiltration air, which is significant for N₂. Combustion products and trace elements such as mercury (Hg) will vary according to the fuel type and feed rate. For O₂, each boiler has a parameter for an excess oxygen requirement in mass percent similar to the excess air requirement discussed in **Section 2.8.1**. The excess oxygen requirements are shown in **Table 2-7**. The equations for calculating air components are in **Equations (2-8) through (2-14)**, except for O₂, which is discussed above. The molar and mass flow rates are passed to the energy conversion process.

$$\dot{mol}_{Ar} = \left[\dot{mol}_{O_2 reqd} + \frac{\dot{mol}_{O_2 reqd} \cdot (1 - \%_{inf air}) \cdot \%_{O_2 excess} \cdot \%_{recycle}}{\%_{O_2 purity}} \cdot m_{Ar in ASU} + \frac{\dot{mol}_{O_2 reqd} \cdot \%_{inf air}}{m_{O_2 in air}} \cdot m_{Ar in air} \right] \cdot \frac{1}{1 - \%_{recycle}} \quad (2-8)$$

$$\dot{mol}_{N_2} = \left[\dot{mol}_{O_2 reqd} + \frac{\dot{mol}_{O_2 reqd} \cdot (1 - \%_{inf air}) \cdot \%_{O_2 excess} \cdot \%_{recycle}}{\%_{O_2 purity}} \cdot m_{N_2 in ASU} + \frac{\dot{mol}_{O_2 reqd} \cdot \%_{inf air}}{m_{O_2 in air}} \cdot m_{N_2 in air} \right] \cdot \frac{1}{1 - \%_{recycle}} \quad (2-9)$$

$$\begin{aligned} \dot{mol}_{CO_2} &= \left[\dot{mol}_{C fuel} \cdot (1 - m_{C unburned} - \%_{C to CO}) \right. \\ &\quad \left. + IF \left(Wet FGD is on, \frac{\%_{WFGD SOx Eff} \cdot \dot{mol}_{S fuel} \cdot \%_{S in fly ash} \cdot (1 - \%_{Sto SO_2})}{mw_S}, 0 \right) \right] \\ &\quad \cdot \frac{\%_{recycle}}{1 - \%_{recycle}} \end{aligned} \quad (2-10)$$

$$\dot{mol}_{H_2O} = (\dot{mol}_{H fuel} + \dot{mol}_{H_2O fuel}) \cdot \left(\frac{1}{\%_{recycle}} - 1 \right) \cdot IF(Wet FGD is on, 0.34, 1) \quad (2-11)$$

$$\begin{aligned} \dot{mol}_{SO_2} &= \frac{\dot{mol}_{S fuel} \cdot \%_{S in fly ash} \cdot (1 - \%_{Sto SO_2})}{mw_S} \\ &\quad \cdot IF[Wet FGD is on, \%_{WFGD SOx Eff} \cdot \%_{recycle} \\ &\quad \cdot IF(boiler is CFB, 0.15, 0.02), IF(Dry FGD is on, \%_{DFGD SOx Eff} \\ &\quad \cdot \%_{recycle} \cdot IF(boiler is CFB, 0.2, 0.02), 2.5)] \end{aligned} \quad (2-12)$$

$$\dot{mol}_{Hg} = \dot{mol}_{Hg fuel} \cdot [1 - OR(Status_{fabric filter}, Status_{ESP}) \cdot \%_{filter Hg Eff}] \cdot (1 - Status_{WFGD} \cdot \%_{WFGD Hg Eff}) \cdot \%_{recycle} \quad (2-13)$$

$$\dot{mol}_{H_2} = 0 \quad (2-14)$$

where,

$\dot{m}ol_i$ is the molar flow rate of component i (mol/s of i)

m_i is the mass fraction of component i (kg of i/kg of parent)

$\%_{inf\ air}$ is the mass percent of oxidant that is infiltration air

$\%_{O2excess}$ is the excess oxygen requirement (mass %)

$\%_{recycle}$ is the fraction of flue gas that is recycled for CFB (molar %)

$\%_{O2purity}$ is the fraction of the ASU output that is oxygen (molar %)

$m_{C\ unburned}$ is the mass fraction of carbon that is not burned (kg unburned/kg C)

$\%_{CtoCO}$ is the percent of carbon that is oxidized to carbon monoxide

(0 molar % in all cases)

$\%_{FGD\ SOx\ Eff}$ is the SO₂ removal efficiency of a given FGD process (molar %)

$\%_{S\ in\ fly\ ash}$ is the sulfur contained in fly ash (0 molar % in all cases)

$\%_{StoSO2}$ is the percent of sulfur that is oxidized to SO₂ instead of SO₃ (100

molar % all cases)

$Status_x$ is the boolean status of an emission control (1-on; 0-off)

Note: All percentages are treated as their decimal equivalent in calculations, so 74% is 0.74.

There is also a small steam requirement for the ASU. The steam requirement is calculated using a steam load factor of $4.7388 \cdot 10^{-4}$ kg steam per mole of O₂, which is multiplied by the molar flow rate of oxygen provided by the ASU. This steam is taken from between the intermediate-pressure and low-pressure steam turbines resulting in lower electricity production from the steam plant. This penalty is calculated by multiplying the steam flow in kg/s by 1163 kJ/kg to represent the lost energy in kWt which is subtracted from the energy available for conversion to electricity in the energy conversion gross electrical power calculations. The factor of 1163 kJ/kg is loosely tied to the enthalpy across the low pressure turbine but is mostly set to achieve gross power outputs consistent with oxy-fired cases in other NETL reports (NETL, 2010b, 2012b).

2.9 Energy Conversion Calculations

The energy conversion calculations convert the oxidant and fuel inputs into electricity and emissions, auxiliary loads associated with the boiler, transformer losses, and water usage.

2.9.1 Electricity Conversion

2.9.1.1 Thermal input to steam

The user defines the thermal input to the boiler in MW. Thermal input must first be turned into steam. The steam feeds not only the turbine steam generators but also the process steam for the ASU and the MEA carbon capture system. The model calculates the heat turned into steam by deducting losses from the total thermal input (BEE, 2005). The air in and flue gas temperatures for the equations are boiler parameters, except for oxygen-fired plants without FGD which have higher

recycled flue gas temperatures and a higher boiler efficiency as a result. In this case, a correction factor is added based on the boiler flue gas temperature. The losses are:

Heat loss to dry flue gas – The amount of energy used to heat dry flue gas depends largely on the temperature of oxidant into and the flue gas from the boiler. The oxidant inlet temperature is ambient temperature for normal cases and elevated temperatures in oxy-fired cases due to the recycled flue gas. The flue gas temperature is specified for each boiler with a temperature decrease given depending on the mass percent of sub-bituminous and lignite used as feedstock. The equation to calculate heat loss to dry flue gas is **Equation (2-15)**.

Heat loss to evaporation of water formed from combustion – Water is formed from the hydrogen in the fuel and available oxygen. The water forms as sub-cooled, so it is first evaporated and then heated up to the same temperature as the flue gas. **Equation (2-16)** calculates heat loss due to evaporation of water formed.

Heat loss due to evaporation of moisture in fuel – All of the fuels in PPFM contain some amount of moisture. As with the water formed from combustion, this water must be evaporated first and then heated to flue gas temperature. **Equation (2-17)** calculates heat loss due to evaporation of moisture in fuel.

Heat loss to heating moisture in air – The air used for the oxidant contains some amount of moisture. This water is superheated and so only needs to be heated up to flue gas temperature. **Equation (2-18)** calculates heat loss due to heating of moisture in air.

Heat loss due to radiation and other sources – Heat loss due to radiation and other sources is assumed to be 2 percent of the total thermal input.

$$\dot{Q}_{heat\ to\ flue\ gas} = \dot{m}_{dry\ flue\ gas} \cdot cp_{dry\ flue\ gas} \cdot (T_{out} - T_{in}) \quad (2-15)$$

$$\dot{Q}_{heat\ to\ H_2O\ formed} = \frac{m_{H_2\ in\ fuel}}{mw_{H_2}} \cdot mw_{H_2O} \cdot [L_{water} + cp_{steam} \cdot (T_{out} - T_{in})] \quad (2-16)$$

$$\dot{Q}_{heat\ to\ H_2O\ in\ fuel} = m_{H_2O\ in\ fuel} \cdot [L_{water} + cp_{steam} \cdot (T_{out} - T_{in})] \quad (2-17)$$

$$\dot{Q}_{heat\ to\ H_2O\ in\ air} = \dot{m}_{H_2O\ in\ air} \cdot cp_{steam} \cdot (T_{out} - T_{in}) \quad (2-18)$$

where ,

$\dot{Q}_{heat\ to\ flue\ gas}$ is the rate of heat lost to heating up dry flue gas (kW)

$\dot{m}_{dry\ flue\ gas}$ is the mass flow rate of boiler flue gas constituents Ar, CO₂, CO, SO₂, SO₃, NO, NO₂, N₂, and O₂ at the boiler (kg/s)

$cp_{dry\ flue\ gas}$ is the specific heat of flue gas (estimated to be 0.962964 kJ/kg-C)

$\dot{Q}_{heat\ to\ H_2O\ formed}$ is the rate of heat lost to evaporating formed water (kW)

$\dot{m}_{H_2\ in\ fuel}$ is the mass flow rate of hydrogen in fuel (kg/s)

mw_x is the molecular weight of component x (kg/mol)

L_{water} is the latent heat of vaporization of water (2260.9 kJ/kg-C)

cp_{steam} is the specific heat of steam (1.88406 kJ/kg-C)

$\dot{Q}_{heat\ to\ H_2O\ in\ fuel}$ is the rate of heat lost to evaporating water in fuel (kW)

$\dot{m}_{H_2O\ in\ fuel}$ is the mass flow rate of water in fuel (kg/s)

$\dot{Q}_{heat\ to\ H_2O\ in\ air}$ is the rate of heat lost to heating up air moisture (kW)

$\dot{m}_{H_2O\ in\ air}$ is the mass flow rate of water in air (kg/s)

cp_{steam} is the specific heat of steam (1.88406 kJ/kg-C)

T_{in} is the temperature of air provided to the boiler (°C)

T_{out} is the temperature of the flue gas leaving the boiler (°C)

The steam power available to the steam plant and other processes is determined by **Equation (2-19)**. This method of calculating boiler steam output results in gross electrical powers consistent with models in NETL reports (NETL, 2010a, 2010b, 2011a, 2012b).

$$P_{steam} = \dot{Q}_{thermal\ input} - \dot{Q}_{heat\ to\ flue\ gas} - \dot{Q}_{heat\ to\ H_2O\ formed} - \dot{Q}_{heat\ to\ H_2O\ in\ fuel} - \dot{Q}_{heat\ to\ H_2O\ in\ air} - 0.02 \cdot \dot{Q}_{thermal\ input}$$

where, (2-19)

P_{steam} is the total steam power generated by boiler (kW)

$\dot{Q}_{thermal\ input}$ is the total thermal input (kW)

2.9.1.2 Steam to electricity

To calculate the electricity generated from the steam turbines, the total steam power less auxiliary steam loads (i.e., ASU or MEA CO₂ capture) is multiplied by the steam cycle efficiency, which is a defined parameter for each boiler type. The default steam cycle efficiencies were calculated using data from NETL reports (NETL, 2010a, 2010b, 2011a, 2012b). Note that the steam cycle efficiencies are not turbine efficiencies.

$$P_{gross} = (P_{steam} - P_{ASU\ steam} - P_{Econamine\ steam}) \cdot \eta_{steam\ cycle}$$

where,

P_{gross} is the gross electric power generated by the turbine generators (kW)

P_{steam} is the total available steam power (kW)

$P_{ASU\ steam}$ is the parasitic steam load of the ASU (kW)

$P_{Econamine\ steam}$ is the parasitic steam load of the MEA carbon capture system (kW)

$\eta_{steam\ cycle}$ is the steam cycle efficiency

The various power plant electric loads are subtracted from the gross electrical power to provide the net power.

2.9.2 Combustion chemistry

During combustion, oxygen forms with several coal components to form new material streams. **Table 2-8** provides the combustion products. The combustion chemistry calculations determine molar or mass flow rates of affected component streams according to plant parameters (see **Table 2-1**). **Equations (2-21)** through **(2-29)** show how the combustion products are calculated and are from the Integrated Environmental Control Model (IECM) (Rubin, et al., 1991).

Once the combustion chemistry is determined, all component flows, including those unaffected by combustion such as Argon, are passed on to subsequent processes.

Table 2-8: Combustion Products

Component	Products
Carbon (C)	Carbon dioxide (CO ₂) and Carbon monoxide (CO)
Hydrogen (H ₂)	Water (H ₂ O)
Sulfur (S)	Sulfur dioxide (SO ₂) and Sulfur trioxide (SO ₃)
Nitrogen (N ₂)	Nitrogen oxide (NO) and Nitrogen dioxide (NO ₂)

$$\dot{mol}_{N2inFG} = \dot{mol}_{N2inAir} + \frac{\dot{mol}_{NinFuel}}{2 \frac{mol_O}{mol_{O_2}}} - \frac{EF_{NOx} \cdot \dot{Q}_{thermal\ input}}{2 \cdot mw_{NO2}} \quad (2-21)$$

$$\begin{aligned} \dot{mol}_{O2inFG} = & \dot{mol}_{O2inAir} + \frac{\dot{mol}_{OinFuel}}{2} - \frac{\dot{mol}_C\ fuel}{mw_C} \cdot (1 - m_{C\ unburned} - 0.5 \cdot \%_{CtoCO}) \\ & - \frac{\dot{mol}_{HinFuel}}{2 \frac{mol_H}{mol_{H_2}} \cdot mw_{H2}} \\ & - \left[\frac{\dot{mol}_{SinFuel}}{mw_S} \cdot (1 - \%_{S\ in\ fly\ ash}) \cdot (\%_{StoSO2} + 1.5 - 1.5 \cdot \%_{StoSO2}) \right] \\ & - \frac{EF_{NOx} \cdot \dot{Q}_{thermal\ input} \cdot (1 - 0.5 \cdot \%_{NtoNO})}{mw_{NO2}} \end{aligned} \quad (2-22)$$

$$\dot{mol}_{H2OinFG} = \dot{mol}_{H2OinAir} + \frac{\dot{mol}_{HinFuel}}{2 \frac{mol_H}{mol_{H_2}}} + \dot{mol}_{H2OinFuel} \quad (2-23)$$

$$\dot{mol}_{CO2inFG} = \dot{mol}_{CO2inAir} + \frac{\dot{m}_{CinFuel}}{mw_C} \cdot (1 - m_{C\ unburned} - \%_{CtoCO}) \quad (2-24)$$

$$\dot{mol}_{CO2inFG} = \frac{\dot{m}_{CinFuel}}{mw_C} \cdot \%_{CtoCO} \quad (2-25)$$

$$\dot{mol}_{SO2inFG} = \dot{mol}_{SO2inAir} + \frac{\dot{mol}_S^{fuel}}{mw_S} \cdot \%_{StoSO2} \cdot (1 - \%_{S in fly ash}) \quad (2-26)$$

$$\dot{mol}_{SO3inFG} = \frac{\dot{mol}_S^{fuel}}{mw_S} \cdot (1 - \%_{StoSO2}) \cdot (1 - \%_{S in fly ash}) \quad (2-27)$$

$$\dot{m}_{NOinFG} = EF_{NOx} \cdot \dot{Q}_{thermal input} \cdot \%_{NtoNO} \quad (2-28)$$

$$\dot{m}_{NO2inFG} = EF_{NOx} \cdot \dot{Q}_{thermal input} \cdot (1 - \%_{NtoNO}) \quad (2-29)$$

where,

\dot{mol}_{XinFG} is the molar flow rate of component X in the flue gas (mol/s)

\dot{mol}_{XinAir} is the molar flow rate of component X in the oxidant air (mol/s)

$\dot{mol}_{XinFuel}$ is the molar flow rate of N in the fuel (mol/s)

\dot{m}_{XinFG} is the mass flow rate of component X in the flue gas (kg/s)

$\dot{m}_{XinFuel}$ is the mass flow rate of component X in the fuel (kg/s)

EF_{NOx} is the boiler emission factor for NO_x (kg/kW)

$\dot{Q}_{thermal input}$ is the total thermal input to the boiler (kW)

mw_X is the molecular weight of X (mol/kg)

$m_{C unburned}$ is the mass fraction of carbon that is not burned (kg unburned/kg C)

$\%_{CtoCO}$ is the percent of carbon that is oxidized to carbon monoxide

(0 molar % in all cases)

$\%_{S in fly ash}$ is the sulfur contained in fly ash (0 molar % in all cases)

$\%_{StoSO2}$ is the percent of sulfur that is oxidized to SO₂ instead of SO₃ (100

molar % all cases)

2.9.3 Primary air and forced draft fan power

Primary air and forced draft fans deliver most of the oxidant to the boiler in the case of air firing and the recycled flue gas in the case of oxygen-firing. As a result, the power usage of the fans are a function of the volumetric flow rate of the air flow into the boiler and are dependent on the boiler type (see **Table 2-1** parameters Primary forced fan factor and Primary forced fan oxy) and air temperature, which is significantly increased for the oxygen-firing cases. Volumetric flow rate is calculated using the ideal gas law and molar flow rates of the incoming air, as shown by **Equation (2-30)**.

$$\dot{V}_X = \frac{R \cdot \dot{mol}_X \cdot T}{P} \quad (2-30)$$

where,

\dot{V}_X is the volumetric flow rate of component X (m³/s)

R is the ideal gas constant (8.3144721 J/mol-K)

\dot{mol}_X is the molar flow rate of component X (mol/s)

T is the temperature of the oxidant (K)

P is the pressure of the oxidant (Pa)

2.9.4 Condenser heat load

After the low-pressure turbine in the steam cycle, low-quality steam is sent to a condenser to be cooled to subcooled water prior to being sent back through the boiler. This large heat load is removed by the power plant cooling system (discussed below). The heat load is determined using a cooling load factor, which is a boiler parameter (see **Table 2-1** parameter Condenser cooling duty factor). The product of total thermal input to the boiler in kW and cooling load factor in MMbtu/hr per kWt gives the cooling duty heat load. An additional 100 MMbtu/hr is added to this number to account for miscellaneous steam plant heat loads.

2.9.5 Condensate pump power

Condensate pumps are used after the condenser to push water through the rest of the steam plant. The electricity usage of the pumps is calculated using **Equation (2-31)**. **Equation (2-31)** subtracts the MEA and ASU steam powers from the gross power to account for the fact that these auxiliary steam loads bypass the condenser and thus condensate pumps. Also included in the equation is an assumed 95 percent efficiency of the electric motor used to drive the pump.

$$P_{condensate\ pumps} = \theta_{cond\ pump} \cdot (P_{gross} - P_{Econaminesteam} - P_{ASUsteam})/0.95 \quad (2-31)$$

where,

$P_{condensate\ pumps}$ is the electricity usage of the condensate pumps (kW)

$\theta_{cond\ pump}$ is the percent of feedwater that is blowdown (hp/kW)

P_{gross} is the gross electric power generated by the turbine generators (kW)

$P_{ASU\ steam}$ is the parasitic steam load of the ASU (kW)

$P_{Econaminesteam}$ is the parasitic steam load of the MEA carbon capture system (kW)

2.9.6 Power plant recycled water

A few power plant processes discharge water, which is sent to the cooling system to offset water withdrawal for a wet cooling tower or in the case of once-through cooling is simply discharged. The processes are boiler feed water blowdown, flue gas desulfurization gypsum dewatering, and carbon

capture product stream dehydration. Boiler feed water blowdown is calculated using **Equation (2-32)**. The rest of the recycle streams are calculated in the applicable section. The sum of the streams is calculated in this section to be passed on to the water summary. Additionally the boiler feedwater blowdown becomes a water demand for the boiler. The values for these parameters are from NETL report models (NETL, 2010a, 2010b, 2011a, 2012b).

$$\dot{m}_{BFW} = \%_{steamblowdown} \cdot \theta_{feedflowtosteam} \cdot \dot{Q}_{thermal\ input} \quad (2-32)$$

where,

\dot{m}_{BFW} is the mass flow rate of water from boiler feedwater blowdown (kg/s)

$\%_{steamblowdown}$ is the percent of feedwater that is blowdown (kg/s)

$\theta_{feedflowtosteam}$ is a factor defining the amount of feedwater per thermal input
 $[(kg/s)/MW]$

$\dot{Q}_{thermal\ input}$ is the total thermal input to the boiler (MW)

2.9.7 Bottom ash handling electricity

Ash from the feedstock exits the boiler through either the bottom or with the flue gas. A boiler factor (**Table 2-1** parameter Overhead ash fraction) determines how much of the ash is in the flue gas. The removal and handling of the remaining “bottom ash” is an auxiliary electrical load for the plant. The electrical load is calculated using a load factor (106.3 kWe per kg ash/s) and the bottom ash flow rate. The value for the load factor was taken from unpublished data from models used in NETL reports (NETL, 2010a, 2010b, 2011a, 2012b).

2.9.8 Transformer losses

Transformers are used within the plant to support auxiliary electrical loads and also to step up voltage for the grid, and each transformer efficiency is less than 100 percent, resulting in decrease in net power. The losses are calculated by first categorizing the types of transformers used in the plant and assigning efficiencies, which are shown in **Table 2-9**. The low voltage loads are assumed to be 15 percent of the auxiliary loads without transformer losses. All of the losses are summed and subtracted from the net power output. The efficiencies and application are from NETL report models (NETL, 2010a, 2010b, 2011a, 2012b).

Table 2-9: Transformer Types, Efficiencies, and Applicable Electrical Load

Transformer Rating	Efficiency	Electrical Load
24/345 kV	0.997	Net power output w/o transformer losses
24/4.16 kV	0.995	Auxiliary loads w/o transformer losses
4160/480 V	0.995	Low voltage auxiliary loads

2.9.9 Feedwater requirements

Feedwater is the sub-cooled water provided to the boiler and is calculated to support boiler cost scaling. Note that since water is largely recycled in this loop it is not a water demand. The factors and equations were developed using data from NETL reports (NETL, 2010a, 2010b, 2011a, 2012b). All of the boilers use two stages of steam generation, a high-pressure first pass, and an intermediate pressure second pass, which are used to feed three steam turbine generators. The high-pressure first pass goes to the high-pressure turbine, and the second pass goes to the intermediate-pressure turbine followed by the low-pressure turbine. As a result, the feedwater flow (which is the high-pressure feed) represents a fraction of the total steam power available to the steam generators and auxiliary loads. The “first pass percent” boiler parameter was determined by using NETL models to calculate the percent of steam power sent to the high-pressure turbine vs. the power sent to the intermediate- and low-pressure turbines for each boiler type. The enthalpy difference across the boiler is also determined by averaging the enthalpy difference across the boilers in the NETL models. The feedwater calculation is provided in **Equation (2-33)**.

$$\dot{m}_{feedwater} = P_{steam} \cdot \%_{power\ first\ pass} \cdot H_{first\ pass} \quad (2-33)$$

where,

$\dot{m}_{feedwater}$ is the mass flow rate of feedwater to the boiler(kg/s)

P_{steam} is the total available steam power (kW)

$\%_{power\ first\ pass}$ is the percentage of total steam power that is sent to high-pressure turbine

$H_{first\ pass}$ is the enthalpy difference across the boiler (kJ/kg)

2.10 In-bed Limestone Injection (SO_x control)

In-bed limestone injection is a method of flue gas desulfurization for circulating fluidized bed boilers only because of the lower combustion temperature. Limestone (CaCO₃) is injected to the fluidized bed and reacts with SO₂ and SO₃ to form gypsum (CaSO₄·H₂O), which exits with the flue gas as fly ash to be collected at the fabric filter or electrostatic precipitator. The in-bed limestone injection efficiency is a user-defined parameter, but the calculations and costs are based on a default value of 94 percent. The only electrical load for in-bed limestone injection is for sorbent handling and reagent preparation, which is a function of limestone flow rate. Limestone flow is calculated according to **Equation (2-34)** and sorbent handling and reagent electrical usage according to **Equation (2-35)**. The equations are from NETL report models (NETL, 2010b, 2011a).

$$\dot{m}_{limestone} = \frac{\%_{inbed\ SOx\ Eff} \cdot (\dot{mol}_{SO_2} + \dot{mol}_{SO_3}) \cdot \theta_{CaCO_3\ to\ SOx} \cdot mw_{CaCO_3}}{\theta_{CaCO_3\ in\ Lime}} \quad (2-34)$$

where,

$\dot{m}_{limestone}$ is the mass flow rate of limestone to the boiler(kg/s)

$\%_{inbed\ SOx\ Eff}$ is the in-bed limestone injection removal efficiency, user-defined parameter (molar %)

\dot{mol}_X is the molar flow rate of X(mol/s)

$\theta_{CaCO_3\ to\ SOx}$ is the stoichiometric ratio of $CaCO_3$ to S (2.53 mol $CaCO_3$ /mol S)

mw_{CaCO_3} is the molecular weight of $CaCO_3$ (100.086 kg/mol)

$\theta_{CaCO_3\ in\ Lime}$ is the mass percent of $CaCO_3$ in the limestone (mass %)

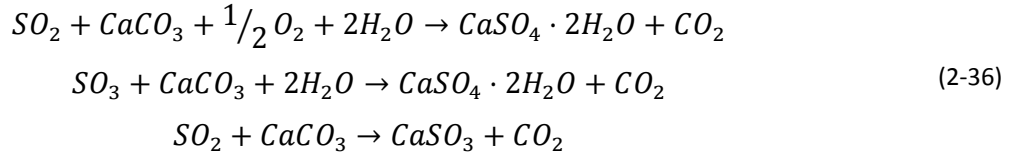
$$P_{inbed} = \theta_{limestone} \cdot \dot{m}_{limestone} \quad (2-35)$$

where,

P_{inbed} is the electrical power usage of in-bed limestone injection (kW)

$\theta_{limestone}$ is the electrical load factor for sorbent handling and reagent (20 kW/(kg lime/s))

The chemical reactions are shown in **Equation (2-36)**. **Equations (2-37)** through **(2-41)** show the calculations for the individual molar flow rates.



$$\dot{mol}_{O_2out} = \dot{mol}_{O_2in} + 0.5 \cdot \%_{CaSO_3\ to\ CaSO_4} \cdot \dot{mol}_{SO_2} \cdot \%_{inbed\ SOx\ Eff} \quad (2-37)$$

$$\dot{mol}_{CO_2} = \frac{\dot{m}_{limestone}}{mw_{CaCO_3} \cdot \theta_{CaCO_3\ to\ SOx}} \quad (2-38)$$

$$\dot{mol}_{SO_2out} = \dot{mol}_{SO_2in} \cdot \%_{inbed\ SOx\ Eff} \quad (2-39)$$

$$\dot{mol}_{SO_3out} = \dot{mol}_{SO_3in} \cdot \%_{inbed\ SOx\ Eff} \quad (2-40)$$

$$\begin{aligned}
\dot{m}_{ashout} = & \dot{m}_{ashin} + (\dot{m}ol_{SO2in} + \dot{m}ol_{SO3in}) \cdot \%_{inbed_SOx_Eff} \\
& \cdot [(1 - \%_{CaSO3toCaSO4}) \cdot mw_{CaSO3} + \%_{CaSO3toCaSO4} \cdot mw_{gypsum}] \\
& + (\dot{m}ol_{SO2in} + \dot{m}ol_{SO3in}) \cdot (1 - \%_{inbed_SOx_Eff}) \cdot mw_{CaCO3} \\
& + \dot{m}_{limestone} \cdot (1 - \theta_{CaCO3inLime})
\end{aligned} \tag{2-41}$$

where,

$\dot{m}ol_{Xin}$ is the molar flow rate of component X into the reaction (mol/s)

$\dot{m}ol_{Xout}$ is the molar flow rate of component X out of the reaction (mol/s)

\dot{m}_{Xin} is the mass flow rate of component X into the reaction (kg/s)

\dot{m}_{Xout} is the mass flow rate of component X out of the reaction (kg/s)

$\%_{inbed_SOx_Eff}$ is the in-bed limestone injection removal efficiency, user-defined parameter (molar %)

$\%_{CaSO3toCaSO4}$ is the percent of $CaSO_3$ that is oxidized to $CaSO_4$

$\theta_{CaCO3\ to\ SOx}$ is the stoichiometric ratio of $CaCO_3$ to S (2.53 mol $CaCO_3$ /mol S)

$\theta_{CaCO3inLime}$ is the mass percent of $CaCO_3$ in the limestone (mass %)

2.11 Selective Catalytic Reduction (NO_x control)

Selective catalytic reduction (SCR) uses ammonia and a catalyst to react with NO_x to form water and diatomic nitrogen. In NETL reports, the SCR reactor is built into the boiler, making it a hot-side SCR reactor, and only contains a stream of ammonia solution. The SCR efficiency is a user-defined parameter, but the calculations and costs are based on a default value of 86-percent. The calculations to determine ammonia feed rate and electrical power loads are from unpublished model data used in NETL reports (NETL, 2010a, 2010b, 2011a, 2012b).

The ammonia requirement is first calculated based on the molar flow rates of NO and NO₂ in the flue gas from the boiler. This is done using **Equation (2-42)**.

$$\dot{m}_{NH3} = \dot{m}ol_{NO} \cdot \%_{SCR\ NOx\ eff} \cdot 17 + 2 \cdot \dot{m}ol_{NO2} \cdot 17$$

where,

\dot{m}_{NH3} is the mass flow rate of ammonia to SCR (lbm/hr)

$\dot{m}ol_X$ is the molar flow rate of component X (lb-mol/s)

$\%_{SCR\ NOx\ eff}$ is the percentage of NO_x removed in the SCR, a user-defined parameter (molar %)

The ammonia is an aqueous solution that is assumed to be 19 percent concentration. The total reagent flow rate is the mass flow rate of ammonia divided by 19 percent. The solution is delivered to a vaporizer by an injection pump, and the vaporizer uses a dilution blower to vaporize the solution.

Both the injection pump and dilution blower use electricity. The formulas and factors to determine the electrical load are from NETL report model data (NETL, 2010a, 2010b, 2011a, 2012b). **Equation (2-43)** provides the injection pump electric power calculation with an electric motor efficiency of 95 percent, and **Equation (2-44)** provides the dilution blower electricity usage with a motor efficiency of 95 percent.

$$P_{NH3\ inj\ pump} = \frac{\dot{m}_{aq\ NH3} \cdot h_{inj\ pump} \cdot g}{\eta_{inj\ pump} \cdot 0.95} \quad (2-43)$$

where,

$\dot{m}_{aq\ NH3}$ is the mass flow rate of aqueous ammonia to SCR (kg/s)

$h_{inj\ pump}$ is the head developed by the pump (m)

g is the acceleration due to gravity (9.81 m/s²)

$\eta_{inj\ pump}$ is the injection pump efficiency (0.8)

$$P_{NH3\ blower} = \frac{\dot{m}_{aq\ NH3}}{\theta_{NH3\ to\ air} \cdot \eta_{fan} \cdot 0.95 \cdot 550 \frac{ft \cdot lb}{hp}} \cdot \left[\frac{P_{in} \cdot \gamma}{(\gamma - 1) \cdot \rho_{air}} \cdot \left(\frac{P_{out}}{P_{in}}^{1-\frac{1}{\gamma}} - 1 \right) \right] \quad (2-44)$$

where,

$P_{NH3\ blower}$ is the blower fan electrical power usage (hp)

$\dot{m}_{aq\ NH3}$ is the mass flow rate of aqueous ammonia to SCR (lbm/hr)

$\theta_{NH3\ to\ air}$ is mass ratio of aqueous ammonia to air (0.03)

η_{fan} is the blower fan efficiency (0.75)

γ is the ratio of air specific heats (1.4)

P_{in} is the absolute pressure at the fan inlet (2299 lb/ft² = 14.7psia + 35 in WG)

P_{out} is the absolute pressure at the fan outlet (2117 lb/ft² = 14.7 psia)

ρ_{air} is the density of air (0.076 lbm/ft³)

The SCR reaction chemistry is calculated according to **Equations (2-45)** through **(2-48)**.

$$\dot{m}_{NOout} = \dot{m}_{NOin} \cdot (1 - \%_{NOX\ eff}) \quad (2-45)$$

$$\dot{m}_{NO2out} = \dot{m}_{NO2in} \cdot (1 - \%_{NOX\ eff}) \quad (2-46)$$

$$\dot{m}_{H2Oout} = \dot{m}_{H2Oin} + \frac{6}{4} \cdot \%_{NOX\ eff} \cdot \dot{m}_{NOin} + \frac{6}{2} \cdot \%_{NOX\ eff} \cdot \dot{m}_{NO2in} \quad (2-47)$$

$$\dot{mol}_{N_2out} = \dot{mol}_{N_2in} + \%_{NOX\ eff} \cdot \dot{mol}_{NOin} + \frac{2}{3} \cdot \%_{NOX\ eff} \cdot \dot{mol}_{NO_2in} \quad (2-48)$$

where,

\dot{mol}_X is the molar flow rate of component X (mol/s)

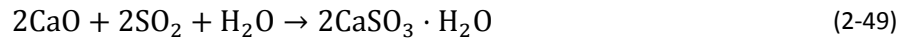
$\%_{SCR\ NOx\ eff}$ is the percentage of NO_x removed in the SCR, a user-defined parameter
(molar %)

2.12 Air Heater Leakage

For non-oxygen-fired plants, some of the air delivered by the forced draft and primary air fans leak across the combustion air preheater into the exiting flue gas. For all boiler types, the air heater leakage is 6 percent of the mass of the oxidant provided to the boiler, and the composition is the same.

2.13 Dry Flue Gas Desulfurization (SO_x control)

Dry FGD injects calcium oxide (CaO) and water into the reactor vessel, which reacts with SO₂ to form hydrated calcium sulfite (CaSO₃·H₂O), according to **Equation (2-49)**. The hydrated calcium sulfite exits with the flue gas as fly ash to be collected at the fabric filter or electrostatic precipitator. The dry FGD SO_x removal efficiency is a user-defined parameter, but the calculations and costs are based on a default value of 93 percent. As a result, model cost and electrical load accuracies are not guaranteed for different efficiencies. The electrical loads for dry FGD are for sorbent handling and reagent preparation and auxiliary loads, which are functions of slurry flow rate. To determine the slurry flow rates, water use must first be determined, because water is used to control the heat of the reaction in addition to the stoichiometric need for water (NETL, 2010b, 2011a).



2.13.1 Chemistry

Equation (2-50) used to calculate molar flow rates of affected flue gas streams out of the dry FGD. All water that goes into the dry FGD leaves with the flue gas stream and is discussed in more detail below.

$$\dot{mol}_{SO_2out} = \dot{mol}_{SO_2in} \cdot (1 - \%_{DFGD\ eff}) \quad (2-50)$$

where,

\dot{mol}_{SO_2} is the molar flow rate of component X (mol/s)

$\%_{DFGD\ eff}$ is the percentage of SO_x removed in the dry FGD, a user-defined parameter
(molar %)

2.13.2 Water Requirements

In order to determine the temperature of the reaction, the enthalpies of the major flue gas constituents are calculated using equations to calculate the isobaric specific heat (c_p) for each constituent and for the inlet and outlet temperatures. The coefficients (A_X , B_X , and others) for **Equation (2-51)** are provided in **Table 2-10**. The inlet temperature depends on the boiler type and the outlet temperature is fixed at 180°F. The molar flow rates of each constituent are multiplied by the inlet and outlet specific heats to calculate enthalpy differences, which are summed to show a total heat loss. The heat loss is the result of adding water to the vessel, which absorbs the heat and vaporizes. The incoming flue gas is a part of the heat to dissipate. The other part of heat to dissipate comes from the chemical reaction. The heat of formation for the reactants and products are shown in **Table 2-11**, and **Equation (2-52)** is the calculation for the heat of reaction. **Equation (2-52)** results in a negative value, which represents a reaction that adds heat to the system (exothermic), so the heat from the reaction is added to the flue gas enthalpy change, resulting in additional heat to evaporate water. The flue gas heat and reaction heat are summed and divided by the energy needed to heat and vaporize 1 kg of water, shown by **Equation (2-53)**.

Table 2-10: Isobaric Specific Heat Calculation Coefficients

	CO ₂	H ₂ O	O ₂	Ar	N ₂	SO ₂
A	24.9974	30.0920	31.3223	20.7860	28.9864	21.4305
B	55.1870	6.8325	-20.2353	2.8259E-07	1.8540	74.3509
C	-33.6914	6.7934	57.8664	-1.4642E-07	-9.6475	-57.7522
D	7.9484	-2.5345	-36.5062	1.0921E-08	16.6354	16.3553
E	-0.1366	0.0821	-0.0074	-3.6614E-08	1.1700E-4	0.0867

$$c_{pX} = A_X + B_X \cdot \frac{T}{1000} + C_X \cdot \frac{T^2}{1000} + D_X \cdot \frac{T^3}{1000} + E_X \cdot \frac{T^4}{1000} \quad (2-51)$$

where,

c_{pX} is the isobaric specific heat of component X (J/mol-K)

$A_X, B_X \dots E_X$ are coefficients from **Table 2-9**

T is the temperature (K)

Table 2-11: Heats of Formation

	H (kJ/mol)
CaO	-635.5
SO ₂	-296.7
H ₂ O	-285.8
CaSO ₃ ·H ₂ O	-1,333

$$Q_{reaction} = \dot{m}_{CaSO_3H_2O} \cdot [(h_{CaSO_3H_2O}) - (h_{SO_2} + h_{CaO} + 0.5 \cdot h_{H_2O})] \quad (2-52)$$

where,

$Q_{reaction}$ is the heat of reaction the reaction (kJ)

$\dot{m}_{CaSO_3H_2O}$ is the molar flow rate of hydrated calcium sulfite (mol/s)

h_X is the heat of formation for component X (kJ/mol)

$$\Delta h_{H_2O} = h_{fH_2O} + c_{pH_2O} (T_{out} + T_{h_2o\ in}) \quad (2-53)$$

where,

Δh_{H_2O} is the heat required to heat and evaporate water (kJ/kg)

h_{fH_2O} is the latent heat of vaporization for water (2260 kJ/kg)

c_{pH_2O} is the specific heat of water (2.32601 kJ/kg-K)

T_{out} is the temperature of the flue gas at the outlet (355.37K = 180°F)

T_{in} is the temperature of the slurry water (284.82K = 53°F)

$$P_{dryFGDhandle} = \theta_{dryFGDhandle} \cdot \dot{m}_{slurry} \quad (2-54)$$

where,

P_{inbed} is the electrical power usage of in-bed limestone injection (kW)

$\theta_{dryFGDhandle}$ is the electrical load factor for sorbent handling and reagent
(20 kW/(kg lime/s))

2.13.3 Dry FGD vessel air flow

Dry FGD vessel volumetric flow is also calculated using **Equation (2-30)** for cost scaling.

2.14 Activated Carbon Injection

Activated carbon is injected into flue gas streams to remove mercury. Mercury is adsorbed by the activated carbon, which is then captured at a fabric filter or an electrostatic precipitator (ESP). This model only accounts for the activated carbon use and resulting addition of ash in the flue gas. The activated carbon injection rates for sub-bituminous and lignite coal, 1.0 and 1.5 lbm activated carbon per MMscf of flue gas are from NETL reports and are representative of systems that remove 90+ percent of mercury at the fabric filter (NETL, 2010b, 2011a). For simplicity, the injection rate for bituminous is assumed to be the same as lignite, because bituminous mercury content is close to lignite, and custom coal is assumed to be the same as sub-bituminous, again, due to similar mercury content. The amount of activated carbon injected is a weighted average of the injection flow rates

based on the as-received percentages of total feedstock, similar to **Equation (2-2)**. No carbon injection is needed for biomass, because the biomass feedstocks do not contain mercury.

To determine the volumetric flow rate of the flue gas, **Equation (2-30)** is again used for the inlet flue gas. No electricity loads are given, because previous NETL models do not account for any, and the loads are likely to be similar to in-bed limestone injection or SCR handling loads and thus negligible compared to other plant electrical loads.

2.15 Fabric Filter (particulate matter and ash control)

Fabric filters remove fly ash, particulate matter (PM), and oxidized mercury (co-benefit capture) from flue gas through physical obstruction. The fabric filter is based on the technology described in other NETL reports (NETL, 2010a, 2012b). PPFM treats all fly ash as unspecified PM (i.e., not distinguished by size). The user defines removal efficiencies for the fly ash and for mercury, which are directly applied to the incoming fly ash and mercury flows. To more accurately model PM removal, the ultimate analyses of the coal and biomass ash would have to be known, and more detailed calculations of combustion products would need to be performed to generate a particle size distribution. The model also provides electricity usages for ash handling and auxiliary loads. Both electrical loads are directly proportional to the fly ash removed, 106.3 kWe per kg/s ash removed for handling and 17.44 kWe per kg/s ash removed. Model cost and performance are based on 99.8 percent efficient fly ash removal and 70.2 percent mercury removal. As a result, model cost and electrical load accuracies are not guaranteed for different efficiencies. The stated mercury removal efficiency is based on a combined 90 percent removal for the fabric filter and wet FGD. Fabric filter volumetric flow is also calculated using **Equation (2-30)** for cost scaling.

2.16 Electrostatic Precipitator (PM and ash control)

ESPs remove fly ash, particulate matter, and oxidized mercury (co-benefit capture) from flue gas through the use of a strong electrostatic charge. The ESP is based on publicly available information (EPA, n.d.; Mihelcic et al., 2009), but again PPFM only models the removal of the fly ash and mercury for reasons discussed in **Section 2.15**. The user defines removal efficiencies for the fly ash and mercury, which are directly applied to the incoming fly ash and mercury flows. To more accurately model PM removal, the ultimate analyses of the coal and biomass ash would have to be known, and more detailed calculations of combustion products would need to be performed to generate ash resistance values that affect the performance of the ESP (Berkenpas et al., 1999). The model also provides electricity usages for ash handling and ESP corona power. Handling is directly proportional to the fly ash removed, 106.3 kWe per kg/s ash removed. ESP corona power is discussed below. Model cost and performance are based on 99.8 percent efficient fly ash removal and 70.2 percent mercury removal. As a result, model cost and electrical load accuracies are not guaranteed for different efficiencies.

The ESP develops a corona to charge the incoming particles. As a result, the corona power is a function of the desired removal efficiency and the amount of air flowing through the ESP. ESP volumetric flow is also calculated using **Equation (2-30)** for each component of the incoming flue gas. To determine the electrical power, **Equation (2-55)** is used for less than 99 percent ash removal efficiency, and **Equation (2-56)** is used for removal efficiencies greater than 99 percent. The piecewise approach is used to mesh two numeric models, Deutsch-Anderson and Matts-Ohnfeldt (EPA, n.d.), and to reproduce performance consistent with a graph showing the corona power for a

sampling of ESPs (Mihelcic, et al., 2009). Within the model, corona power density is calculated for comparison to the sampling of ESPs. The volumetric flow rate is also used to scale ESP cost.

$$P_{corona} = \frac{\ln(1 - \%_{ESP\ eff}) \cdot \dot{V}_{fluegas}}{-41} \quad (2-55)$$

$$P_{corona} = \frac{\ln(1 - \%_{ESP\ eff})^{\frac{1}{0.28}} \cdot \dot{V}_{fluegas}}{-2081.004} \quad (2-56)$$

where,

P_{corona} is the ESP corona power (kW)

$\%_{ESP\ eff}$ is the ESP ash removal efficiency, a user defined parameter (mass %)

$\dot{V}_{fluegas}$ is the volumetric flow rate of the inlet flue gas (cfm)

-41; -2081.004; and 0.28 are dimensionless factors that result in corona power consistent with a sampling of ESPs (Mihelcic et al., 2009)

2.17 Induced Draft Fan Power

Induced draft (ID) fans are used to move flue gas after the boiler. The induced draft fan electrical load is dependent on the flue gas temperature, inlet pressure, required outlet pressure, flue gas volumetric flow, and mechanical efficiency. The temperature is either the boiler flue gas temperature (see **Table 2-1**) or 180°F if dry FGD is turned on. The inlet pressure is calculated based on the boiler flue gas outlet pressure (see **Table 2-1**) and any control equipment that could cause a pressure drop (dry FGD, fabric filter, or ESP). The pressure drops are shown in **Table 2-12** and estimated from NETL reports (NETL, 2010a, 2010b, 2011a, 2012b). Likewise, the required outlet pressure is a function of what pressure drops are downstream of the FGD. However, unlike the upstream pressure drops, the pressure drops downstream of the ID fan depend on the combination of components; therefore, a required pressure increase across the ID fan is determined for each combination of downstream components, as shown in **Table 2-13**. There is also an assumed 20°F temperature increase across the fan.

With the inlet and outlet temperature and pressure set, the volumetric flow rate is calculated using **Equation (2-30)** with the average inlet/outlet temperature and the inlet pressure. **Equation (2-44)** is used to calculate fan power, except the ratio of specific heats is 1.2, the mass flow rate in the numerator is the mass flow rate of the ID fan inlet air, and the mass ratio of ammonia to air term is removed.

Table 2-12: Pressure Drop Caused by Plant Components

Control Equipment	Pressure Drop (psi)
Fabric filter	0.2
ESP	0.05
Dry FGD	0.4

Table 2-13: Required ID Fan Pressure Increase

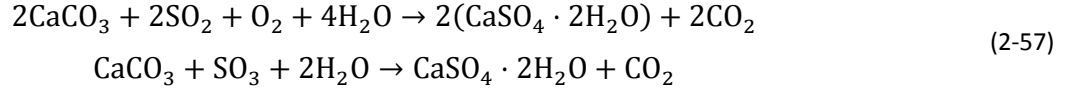
Wet FGD	CO ₂ Capture	ASU Recycle	Boiler Type	Required ID Fan Pressure (psia)
–	–	–	Sub, SCPC	0.60
–	–	–	USCPC, CFB	0.88
X	–	–	All	1.10
X	X	–	All	1.25
X	–	X	All	0.90
X	X	X	All	1.17
–	X	–	All	0.78
–	X	X	All	0.00
–	–	X	Sub, SCPC	0.60
–	–	X	USCPC, CFB	0.88

X: Equipment is on

–: Equipment is off

2.18 Wet Flue Gas Desulfurization (SO_x control)

In wet flue gas desulfurization (FGD) flue gas flows through a slurry of water and limestone (CaCO₃), and the SO₂ and SO₃ combine with the calcium (Ca) in the limestone and oxygen (O₂) to produce gypsum (CaSO₄·H₂O), which releases carbon dioxide (CO₂) and water, according to **Equation (2-57)**. The wet FGD SO_x removal efficiency is a user-defined parameter, but the calculations and costs, which scale according to efficiency, are based on a default value of 93 percent. As a result, model cost and electrical load accuracies are not guaranteed for different efficiencies.



2.18.1 Chemistry

Equations (2-58) through **(2-61)** show the equations used to calculate molar flow rates of affected flue gas streams out of the wet FGD except for water; water is discussed in more detail below. Oxygen for the reaction is provided by the wet FGD system using the same air supply as the boiler (i.e., either ambient air or from the ASU). The gypsum is removed from the reactor vessel as a co-product.

$$\dot{mol}_{\text{SO}_2\text{out}} = \dot{mol}_{\text{SO}_2\text{in}} \cdot (1 - \%_{\text{WFGD eff}}) \tag{2-58}$$

$$\dot{mol}_{\text{SO}_3\text{out}} = \dot{mol}_{\text{SO}_3\text{in}} \cdot (1 - \%_{\text{WFGD eff}}) \tag{2-59}$$

$$\dot{mol}_{\text{O}_2\text{out}} = \dot{mol}_{\text{O}_2\text{FGin}} + \dot{mol}_{\text{O}_2\text{WFGDin}} - 0.5 \cdot \theta_{\text{SO}_2\text{toSO}_4} \cdot \dot{mol}_{\text{SO}_2\text{in}} \cdot \%_{\text{WFGD eff}} \tag{2-60}$$

$$\dot{mol}_{CO2out} = \dot{mol}_{CO2in} + \frac{\dot{mol}_{CaCO3}}{\theta_{CaCO3 \text{ to } SOx}} \quad (2-61)$$

where,

\dot{mol}_X is the molar flow rate of component X (mol/s)

$\%_{WFGD \text{ eff}}$ is the percentage of SO_x removed in the wet FGD, a user-defined parameter (molar %)

$\theta_{CaCO3 \text{ to } SOx}$ is the stoichiometric ratio of $CaCO_3$ to S (1.15 mol $CaCO_3$ /mol S)

2.18.2 Electricity Requirements

There are two electricity loads associated with the wet FGD: a sorbent handling/preparation load and an auxiliary load. The sorbent handling load is calculated using a load factor of either 600 kWe per kg/s limestone flow rate if the plant is co-firing biomass and has amine-based CO_2 capture or 163.73 kWe per kg/s limestone flow rate for all other cases. The auxiliary load uses a load factor of either 2000 kWe per kg/s SO_2 removed if the plant is co-firing biomass and has amine-based capture or 1250 kWe per kg/s SO_2 removed for all other cases. The separate load factors provide results that are consistent with previous NETL reports (NETL, 2010a 2012b).

2.18.3 Water Requirements

As noted above, water is needed in the chemical reaction for gypsum, but much more than the stoichiometric requirement is used for the slurry. While water is lost through evaporation into the flue gas, the product slurry still contains large amounts of excess water. The gypsum product flow is de-watered to allow some of the excess water to be recycled to the cooling tower or discharged for once-through cooling. The resulting FGD water demand is a balance of the wet FGD input water flows (inlet flue gas, limestone slurry, and make-up water) and output flows (outlet flue gas, product slurry).

The amount of water in the product slurry is a fixed ratio to gypsum ($CaSO_4 \cdot 2H_2O$) flow (4.5 kg of excess water per kg of $CaSO_4 \cdot H_2O$). Of this excess water, 50 percent is recycled to the cooling tower.

The amount of water that is evaporated depends on the temperature of the flue gas. If the flue gas is below 212°F, then it is assumed that no water is evaporated. For flue gas flows above 212°F, the amount of water that each flue gas component vaporizes is calculated according to **Equation (2-62)**.

$$\dot{mol}_{X \text{ H}_2O \text{ Evap}} = \frac{c_{p \text{ in}} \cdot \dot{mol}_{X \text{ in}} \cdot (T_{in} - 212^\circ\text{F})}{h_{H_2O}} \quad (2-62)$$

$$h_{\text{h}_2\text{O}} = 7.366 \cdot T_{\text{h}_2\text{O slurry}} + 17593.7 \quad (2-63)$$

where,

$\dot{m}_{\text{X H}_2\text{O Evap}}$ is the amount of water that component X evaporates (lb-mol/s)

$c_{p \text{ in}}$ is the average specific heat capacity of the flue gas mixture [17 btu/(lb-mol·F)]

T_{in} is the temperature of the inlet flue gas (°F)

$\dot{m}_{\text{X in}}$ is the molar flow rate of the component X of inlet flue gas (lb-mol/s)

$h_{\text{h}_2\text{O}}$ is the enthalpy required to evaporate water (btu/lb-mol)

$T_{\text{h}_2\text{O slurry}}$ is the temperature of the water in the slurry (155 °F)

2.18.4 Wet FGD vessel air flow

Fabric filter volumetric flow is calculated using (2-30) for cost scaling.

2.18.5 Co-benefit Mercury Capture

When combined with upstream SCR, some of the oxidized mercury is captured by the wet FGD. The amount of mercury removed at the wet FGD is a user-defined parameter. When combined with 70.2 percent mercury removal at the fabric filter, the default value of 70.2 percent results in a combined co-benefit capture of 95 percent. The mercury would end up in the gypsum, but this is not tracked in the model. Along with mercury, there is a small amount of solid removal (i.e., fly ash) that is set at 2 percent mass.

2.19 Carbon Capture

There are two options available for carbon capture, both of which are discussed in previous NETL reports (NETL, 2010a, 2010b, 2011a, 2012b): monoethanolamine (MEA) and oxygen-firing with compression. The method of capture is determined by whether oxygen firing is selected by the user. Both processes provide high-concentration CO₂ streams, but in practice would likely need upstream processing to ensure the stream is suitable for CO₂ pipeline specifications.

2.19.1 MEA

The first is based on using MEA to absorb CO₂ in a reactor vessel. The CO₂ is stripped in another vessel using steam and sent to a compressor for injection to a pipeline. As a result, there are three major loads: process steam that is removed upstream of the low-pressure turbine, auxiliary loads for the process (pumps and equipment), and electricity for the compressor. There is also a cooling load associated with the compressor and the MEA process. All cooling loads associated with the MEA process and compressor are handled by a wet cooling tower even when hybrid or dry cooling is specified. The model assumes a maximum 90 percent capture rate. Lower capture rates are achieved by allowing flue gas to bypass the process, a user-defined parameter in the model.

2.19.1.1 Steam and electricity loads

Steam demands are calculated using a ratio of kg of steam to kg of CO₂ sent to the process (i.e., minus bypass CO₂). The ratio is 1.3 kg steam/kg CO₂ if the feedstock is 100 percent coal, and 1.32 kg steam/kg of CO₂ if the feedstock contains biomass. The steam mass flow rate is multiplied by the

enthalpy across the low-pressure turbine. The calculation for enthalpy across the low-pressure turbine is shown in **Equation (2-64)**. The steam and enthalpy factors are modeled to provide results that are consistent with previous NETL reports and would not necessarily align with specific values in the reports. The diverted steam energy is subtracted from the steam energy available to the steam cycle, similar to the ASU steam load.

MEA auxiliary loads are calculated using a load factor of 5.3411 kWe per mole/s of CO₂ entering the MEA process.

$$\begin{aligned}\Delta H_{\text{LPTurbine}} &= (\dot{\text{mol}}_{\text{CO}_2 \text{ in}} \cdot 0.03 + 470) \frac{\text{btu}}{\text{lbm}} - \text{for 100\% coal feedstock} \\ \Delta H_{\text{LPTurbine}} &= (\dot{\text{mol}}_{\text{CO}_2 \text{ in}} \cdot 0.003 + 620) \frac{\text{btu}}{\text{lbm}} - \text{for any amount of co-firing biomass}\end{aligned}\quad (2-64)$$

where,

$\Delta H_{\text{LPTurbine}}$ is the enthalpy across the low-pressure turbine (BTU/lbm)

$\dot{\text{mol}}_{\text{CO}_2 \text{ in}}$ is the molar flow rate of CO₂ into the MEA system (i.e., minus bypass)

470 and 620 are factors for adjusting the enthalpy to achieve numbers in agreement with the baseline studies.

The compressor electrical load is based on the volumetric flow rate of CO₂ into the compressor. The flow rate is calculated using **Equation (2-30)** and 0.16 MPa for the pressure and 69°F for the temperature. The electrical load factor is 810 kW per m³/s of captured CO₂.

The cooling load is also calculated using heat load factors of 1420 btu per lbm of CO₂ into the process for hot flue gas (i.e., no upstream SO_x control), and 1310 btu per lbm of CO₂ into the process for low temperature flue gas. This cooling load is passed on to the plant cooling calculations.

2.19.1.2 SO₂ polishing

In the MEA process, SO₂ must be less than 10 parts per million volume (ppmv) to reduce the formation of heat stable salts in the MEA. The first step in this process is to calculate the volumetric flow rate for each component of the flue gas stream using **Equation (2-30)** and 0.1 MPa for the pressure and 150°F for the temperature. Then, **Equation (2-65)** calculates the SO₂ flow to meet 10 ppmv. The volumetric flow rate is converted to a mass flow rate using the ideal gas law and the same temperature and pressure used for the rest of the gas components.

$$\dot{V}_{\text{SO}_2} = (\dot{V}_{\text{gas}} + \dot{V}_{\text{gas}} \cdot 10 \cdot 10^{-6}) \cdot 10 \cdot 10^{-6} \quad (2-65)$$

where,

\dot{V}_{SO_2} is the volumetric flow rate of SO₂ sent to the MEA system (m³/s)

\dot{V}_{gas} is the volumetric flow rate of all other components to the MEA system (m³/s)

2.19.2 Oxygen-fired based capture

When the plant is oxygen-fired, the flue gas stream is mostly CO₂, which allows the flue gas to be sent straight to a compression/drying/treatment system. There are also multiple paths for the flue gas stream coming into the carbon capture equations: capture, recycle, or bypass. The flue gas is first split by the amount defined by the ASU recycle rate, a boiler-specific parameter (see **Table 2-1**). The remaining flue gas is then split between the compressor and the bypass flow, which goes to the stack. The bypass flow is used to achieve less than 100 percent carbon capture.

In previous NETL models, the carbon capture system includes a dryer and treatment system to prepare the CO₂ stream for pipeline specifications. These polishing processes and the associated emissions are approximated in this model by adding 10-bypass to whatever amount the user selects up to 90 percent. At values greater than 90 percent, the user input is used directly. The loads from these steps are assumed to be combined with the compression train because loads aren't specifically listed in the NETL reports. The compressor load factor is 19.49 kWe per mol/s of CO₂ captured.

2.19.3 Water knockout

In both MEA and oxygen-firing, water is knocked out from the flue gas (MEA) or captured stream (oxygen-fired) and then recycled to the wet-cooling tower. The amount of water knockout is based on a specification for the given flue gas streams: 0.0244 kg H₂O/kg flue gas for MEA and 0.000064 kg H₂O/kg oxygen-fired captured gas. The mass flow rate of water in the particular stream is calculated according to **Equation (2-66)**, and then subtracted from the mass flow rate of the incoming water to calculate the mass flow rate of recycled knockout water.

$$\dot{m}_{H_2O} = \frac{\dot{m}_{gas} \cdot \theta_{H_2Oingas}}{1 - \theta_{H_2Oingas}} \quad (2-66)$$

where,

\dot{m}_{H_2O} is the mass flow rate of water in a specific gas stream (kg/s)

\dot{m}_{gas} is the mass flow rate of all components except water in a specific gas stream (kg/s)

$\theta_{H_2Oingas}$ is the fraction of water in the specific gas stream (kg water/kg of gas)

2.20 Plant Cooling

The plant cooling system is responsible for dissipating various heats loads from the plant. There are two options available in the model to do this: hybrid cooling and once-through cooling. The choice of cooling method in the real world would impact condenser temperatures and turbine performance and thus electricity output; however, for simplicity this model assumes that all cooling choices are equal with respect to this interaction.

2.20.1 Hybrid cooling

The hybrid cooling portion of the model calculates electrical loads and water use associated with a water-cooled condenser with circulating water from a wet-cooling tower and an air-cooled condenser. Only the steam plant condenser load can be split between the water- and air-cooled

condensers; all auxiliary loads are assumed to be cooled by a wet-cooling tower. The amount of split between the condensers is fully adjustable, so that the condenser can be 100 percent water- or air-cooled. The 100 percent water-cooled condenser represents a traditional water-cooled condenser/wet-cooling tower.

2.20.1.1 Water-cooled condenser / Wet Cooling Tower

This section of the calculation calculates the circulating water rate needed to dissipate the water-cooled condenser and auxiliary heat loads. The calculations are replicated from NETL report model data (NETL, 2010a, 2012b). It assumes a 20°F change in temperature of the circulating water and a specific heat of 1 btu/lbm-°F. The circulating water pumping power is calculated using **Equation (2-67)**. The circulating water then returns to the wet cooling tower, which draws ambient air, assumed to be 59°F, to cool the heated water at a fixed ratio (0.85 lb water to lb ambient air). The wet cooling tower fan power is calculated using **Equation (2-68)**.

$$P_{CWpump} = \frac{\dot{m}_{CW} \cdot h_{pump}}{\frac{60 \text{ s}}{\text{hr}} \cdot \frac{550 \frac{\text{ft} \cdot \text{lb}}{\text{s}}}{\text{hp}} \cdot \mu_{pump} \cdot 0.95} \quad (2-67)$$

where,

P_{CWpump} is the electrical power required for the circulating water pumps (hp)

\dot{m}_{CW} is the mass flow rate of circulating water (lbm/min)

h_{pump} is the pump discharge head (85 ft)

μ_{pump} is the pump mechanical efficiency (80%)

$$P_{towerfan} = \frac{0.148 \cdot T_{drybulb} \cdot \dot{V}_{air} \cdot \log\left(\frac{P_{out}}{14.7}\right)}{520 \cdot \mu_{fan} \cdot 0.95} \quad (2-68)$$

where,

$P_{towerfan}$ is the electrical power required for the wet cooling tower fans (hp)

$T_{drybulb}$ is the dry bulb temperature of the ambient air (assumed 59°F)

\dot{V}_{air} is the volumetric flow rate of air (scfm)

P_{out} is the fan discharge pressure (14.72 psia assuming 0.5 in of H₂O increase)

μ_{fan} is the fan mechanical efficiency (75%)

The water use associated with the wet cooling tower is calculated based on fixed factors and the circulating water rate (NETL, 2010a). The factors are:

- Drift – 0.0010 percent of the circulating water rate

- Evaporative losses – 0.8 percent of the circulating water flow rate per 10°F change in temperature
- Blowdown losses – Evaporative losses divided by cycles of concentration minus 1, where cycles of concentration is a measure of water re-use in the cooling tower (the default value is 4 cycles of concentration)

The water cooling total water demand is the sum of losses from drift, evaporation, and blowdown.

2.20.1.2 Air-cooled condenser

The only load associated with the air-cooled condenser is fan power. In the model, the air-cooled condenser fan power is 3.5 times the wet-cooling tower fan power assuming 100 percent water cooling (EPA, 2001). As a result, **Equation (2-68)** is used to calculate the wet-cooling tower fan power at 100 percent, which is multiplied by 3.5 and the percent of the condenser load that is air-cooled, a user-defined parameter in the model.

2.20.1.3 Ground and surface water pump power

The user can define the percent of water withdrawal that comes from municipal, surface, and ground water sources. Municipal water sources are assumed to arrive at the needed pressure, but the ground and surface water requires pumping to the facility. The parameters are defined such that the first split is between municipal and ground/surface water in mass percent (0-100 percent municipal). The ground water percentage is then the percent of remaining water withdrawal that comes from ground sources. Ground and surface water pump loads are calculated using **Equations (2-69)** and **(2-70)**.

$$P_{Gnd\ pump} = \frac{\dot{m}_{withdrawal} \cdot (1 - \%_{municipal}) \cdot \%_{gndwater} \cdot (h_{depth} + h_{pump})}{\frac{3600\ s}{hr} \cdot \frac{550\ \frac{ft \cdot lb}{s}}{hp} \cdot \mu_{pump} \cdot 0.95} \quad (2-69)$$

where,

$P_{Gnd\ pump}$ is the electrical power required for the ground water pumps (hp)

$\dot{m}_{withdrawal}$ is the mass flow rate of water withdrawal (lbm/hr from water summary)

$\%_{municipal}$ is the percent of water withdrawal that comes from municipal source (user-defined parameter)

$\%_{gndwater}$ is the percent of the remaining water withdrawal that comes from ground water (user-defined parameter)

h_{pump} is the pump discharge head (230.6 ft)

h_{depth} is the ground water depth (500 ft)

μ_{pump} is the pump mechanical efficiency (80%)

$$P_{Surf\ pump} = \frac{\dot{m}_{withdrawal} \cdot (1 - \%_{municipal}) \cdot (1 - \%_{gndwater}) \cdot (h_{pump})}{\frac{3600\ s}{hr} \cdot \frac{550\ \frac{ft \cdot lb}{s}}{hp} \cdot \mu_{pump} \cdot 0.95} \quad (2-70)$$

where,

$P_{Gnd\ pump}$ is the electrical power required for the ground water pumps (hp)

$\dot{m}_{withdrawal}$ is the mass flow rate of water withdrawal (lbm/hr from water summary)

$\%_{municipal}$ is the percent of water withdrawal that comes from municipal source (user-defined parameter)

$\%_{gndwater}$ is the percent of the remaining water withdrawal that comes from ground water (user-defined parameter)

h_{pump} is the pump discharge head (230.6 ft)

μ_{pump} is the pump mechanical efficiency (80%)

2.20.2 Once-through cooling

Once-through cooling assumes that all cooling loads are dissipated by circulating water through the plant once before discharging. So the circulating water rate is calculated in the same manner as the water-cooled condenser/wet cooling tower scenario. The circulating water rate becomes the water demand for the cooling system and must be met by a combination of municipal, ground, and surface water sources. The only loads associated with the once-through cooling are the ground and surface water pumps, which are calculated using **Equations (2-69) and (2-70)**.

2.21 Stack Emissions Summary

The stack emissions summary converts the flue gas output of the carbon capture calculations and to a number of different units for reference.

2.22 Water Use Summary

The water use summary centralizes all of the water demands of the power plant and breaks them into 5 categories:

- 1) **Demand** – is the water requirement for the process.
- 2) **Internal recycle** – is the water that is recycled in a particular process. Note that all internally recycled water is routed to the wet-cooling tower if the plant uses hybrid cooling. If the plant uses once-through cooling, all water that would be recycled is discharged.
- 3) **Raw water makeup** – is the raw water withdrawal required by the process. It is demand minus internal recycle.

- 4) **Process water discharge** – is the water that is discharged by the process because it is not recyclable or, as mentioned above for once-through cooling, any water that is removed from a process.
- 5) **Raw water consumption** – is the water used by the process. It is raw water makeup minus process water discharge.

The individual values are summed to produce the water requirements for the plant.

2.23 Cost Summary

The cost summary section centralizes the costs developed by the cost model, discussed below. All values are on a June 2011 cost basis.

2.24 Cost Model

The model estimates costs associated with building and operating the power plant. These costs are broken into bare erected cost (BEC), operating and maintenance (O&M) labor cost, and variable operating cost. The BEC is the sum of plant capital costs and the associated engineering costs. The O&M labor cost accounts for the cost of laborers, administrative costs, maintenance labor, and taxes and is independent of the power plant output. The variable operating cost accounts for the cost of consumable material, disposal of material (e.g., ash), and maintenance material costs. Cost estimates are based on data from NETL reports (NETL, 2010a, 2010b, 2011a, 2012b).

2.24.1 Bare Erected Cost and Engineering CM H.O. & Fee

The BEC is calculated by estimating the cost of all the equipment, material, and labor (direct and indirect) associated with different parts of the plant. Costs are calculated for the following categories:

- | | |
|-------------------------------------|-----------------------------|
| • Boiler Capital Costs | • Accessory Electric Plant |
| • Steam Turbine Generator | • Instrumentation & Control |
| • Fuel Handling/Prep | • Fabric Filter |
| • Feedwater & Misc Bop Systems | • ESP |
| • Wet FGD | • CO ₂ Capture |
| • Dry FGD | • ASU |
| • Condenser | • Buildings & Structures |
| • Cooling Water System | • Ducting and Stack |
| • Ash/Spent Sorbent Handling System | • Improvements to Site |

2.24.1.1 Cost model scaling method

The cost model scaling method is generally performed using **Equation (2-71)**.

$$Cost_{new} = Cost_{base} \cdot \left(\frac{Parameter_{new}}{Parameter_{base}} \right)^{Exponent} \quad (2-71)$$

where,

$Cost_{new}$ is the adjusted cost for the component

$Cost_{base}$ is the cost of the component in the reference case

$Parameter_{new}$ is the new value of the plant performance parameter

$Parameter_{base}$ is the value of the plant performance parameter from the base case

$Exponent$ is the scaling exponent that is different for each component

The base case parameters and costs are taken directly from NETL reports, and, when available, 2011 data is used. To that end, base costs are taken from the most recent data if the components are not plant-specific. For example, the ash handling system is based on costs from *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases* (NETL, 2012d) rather than performing separate calculations for each of the plant types (Subcritical, SCPC, USCPC, and CFB). If the components are plant-specific (e.g., subcritical vs. SCPC/CFB vs. USCPC steam plants), then costs are used from the specific report and updated to a 2011 cost basis if necessary. The 2007 base costs are increased by 20 percent to update them to 2011 (NETL, 2012d).

In the model, the scaling parameter is shown to the left of the component, and the exponent is to the right of the component. The exponents are taken from cost model data from NETL reports and are the result of regression analysis for the components.

2.24.1.1.1 Exceptions

The following, **Equations (2-72) through (2-77)** are exceptions to the cost scaling methodology above. With the exception of ESP cost, the formulas are from models used in previous NETL reports. The ESP cost was developed from an Environmental Protection Agency (EPA) fact sheet that provided a capital cost in 2002 dollars (EPA, 2002). The 2002 cost basis (a midpoint of \$21.5/scfm) was escalated to 2011 assuming a 3 percent rate of inflation.

Biomass Receiving & Processing (2-72)

$$cost = \$215.062 \cdot \dot{m}_{biomass}^{0.3724}$$

Biomass Drying (2-73)

$$cost = \$70.428 \cdot \dot{m}_{biomass}^{0.6604}$$

where,

$cost$ is the cost of the component in \$1000

$\dot{m}_{biomass}$ is the mass flow rate of biomass in ton/day

Biomass Pelletization

(2-74)

$$cost = 4611.024 \cdot \left(\frac{\dot{m}_{biomass}}{10 \cdot 1.1} \right)^{0.6604}$$

where,

 $cost$ is the cost of the component in \$1000 $\dot{m}_{biomass}$ is the mass flow rate of biomass in lbm/day

ESP

(2-75)

$$cost = .0281 \cdot \dot{V}_{ESP}$$

where,

 $cost$ is the cost of the component in \$1000 \dot{V}_{ESP} is the volumetric flow rate of glue gas through the ESP (scfm)

Stack

(2-76)

$$cost = \frac{cost_{base}}{20002} \cdot 19.518 \cdot \dot{V}_{stack}^{0.4817}$$

where,

 $cost$ is the cost of the component in \$1000 \dot{V}_{stack} is the volumetric flow rate of glue gas through the stack (scfm)

Duct & Stack Foundations

(2-77)

$$cost = \frac{cost_{base}}{3290} \cdot 471.71 \cdot (\dot{m}_{coal} + \dot{m}_{biomass})^{0.1359}$$

where,

 $cost$ is the cost of the component in \$1000 \dot{m}_{coal} and $\dot{m}_{biomass}$ are the mass flow rates of coal and biomass (lbm/hr)

2.24.2 Operating and Maintenance Labor

The O&M labor costs are pulled directly from NETL's *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases* (NETL, 2012d).

2.24.3 Variable Operating Costs

In the NETL reports, variable operating cost is the sum of maintenance material cost and cost of consumables. The maintenance material cost is replicated from *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases* (NETL, 2012d).

2.24.3.1 Material Costs

Material usage rates are converted directly from the processes when available (e.g., wet FGD limestone usage is converted from kg/s to ton/day). The materials associated with the MEA carbon capture system including SO₂ polishing are scaled from a Fluor test case based on the amount of carbon captured. The yearly cost is calculated by multiplying the daily usage, unit cost, and the number of days per year the plant is operating. The number of operating days is determined by multiplying 365 days by the capacity factor, which is a user-defined parameter. For all reference NETL cases, the capacity factor is 0.85.

3 Model Validation

Throughout model development, previous NETL studies, which are based on ASPEN Plus® (Aspen) models, were used as baseline cases for comparison to the model. Due to the lack of complete thermodynamic and reaction dynamics modeling, complete alignment with the baseline results is an unrealistic expectation. Instead, ranges of deviation from the baseline parameters are allowed, which are shown in **Table 3-1**.

Table 3-1: Model Validation Deviation Targets

Targeted Deviation	Plant Parameters
±1%	Gross Power, Net Power, Coal Feed Rate, Biomass Feed Rate, CO ₂ Emissions, SO ₂ Emissions, Hg Emissions, NO _x Emissions, Captured CO ₂ Flow Rates (for oxygen-fired cases), Argon Stack Flow Rates (indicates accuracy of air input to the plant)
±5%	Raw Water Withdrawal, Water Discharge, Water
±10%	Bare Erected Cost, Total Fixed, and Variable Operating Costs Note that when baseline costs were provided in 2007 dollars, they were adjust to 2011 dollars by increasing the BEC and Fixed O&M costs by 20 percent , and variable operating costs by 50 percent based on cost changes noted in <i>Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases</i> (NETL, 2012d)

The radar graphs presented in the following pages, **Figure 3-1** through **Figure 3-8**, show the percent difference between these baseline cases and the model. Ideally, the graphs would show all cases following the 0% line around the axes, indicating no difference from the baseline cases. When there is a positive deviation (or overestimation by the model) the plot will move to the outside, and to the inside for a negative deviation (or underestimation). Deviations outside of the targeted errors shown in **Table 3-1** are marked with note numbers and discussed below the graph. The cases are divided up by type: air-fired without capture, air-fired with amine capture, and oxygen-fired.

3.1 Validation Cases

Validation cases were chosen to demonstrate agreement across various plant configurations and feedstocks. A summary of the validation case configuration is in **Table 3-2**. The goal is to show that even though a particular configuration isn't explicitly modeled, the close agreement with related cases implies that the model is accurate for the case of interest.

Some of the reference cases used to verify the PPFM had minor errors as published in the original reports. Errata sheets were created after report publication so that these errors can be corrected in the next report iteration. The validations presented below compare to the corrected case values as appropriate. These corrections include:

Cases PA1-PA4 (NETL, 2012b): ammonia consumption for SCR was changed from a constant value of 74 tons per day (TPD) to 128, 114, 109, and 107 TPD for Cases PA1, PA2, PA3, and PA4, respectively, and the municipal water consumption was reduced to one-half the original value (the 50% portion of water supply from ground water is considered free of charge).

Cases PO1-PO4 from (NETL, 2012b): ammonia consumption and SCR catalyst costs were set to zero, and the municipal water consumption was reduced to one-half the original value.

Cases S12A, S12B, L12A, L12B, S13A, S13B, L13A, L13B, S22A, L22A (NETL, 2011a): Recycled water was being double-counted in the report. Once corrected, water withdrawal for these cases increased.

Cases S13F and S22F (NETL, 2010b): At the time of the report, cost reporting methodology did not include owner's costs, so taxes and insurance were not included. For comparison purposes, the PPFM fixed operating costs for these cases do not include taxes and insurance.

Table 3-2: Summary of Validation Case Plant Configurations

Plant Type	Feedstock	Case Name
Subcritical	Bituminous Coal	Case 9, Case 10
Supercritical (SCPC)	Bituminous Coal	Case 11, Case 12
	Bituminous/Hybrid Poplar Co-fire (% Hybrid Poplar)	PN1 (100%), PN2 (60%), PN3 (30%), PN4 (15%)
Ultra-supercritical (USCPC)	Sub-bituminous Coal	S13A
	Lignite Coal	L13A
Circulating Fluidized Bed (CFB)	Sub-bituminous Coal	S22A
	Lignite Coal	L22A
Amine CO ₂ -Capture SCPC	Bituminous/Hybrid Poplar Co-fire (% Hybrid Poplar)	PA1 (100%), PA2 (60%), PA3 (30%), PA4 (15%)
Oxygen-fired SCPC	Bituminous Coal	BO0
	Bituminous/Hybrid Poplar Co-fire (% Hybrid Poplar)	PO1 (100%), PO2 (60%), PO3 (30%), PO4 (15%)
Oxygen-fired USCPC	Sub-bituminous	S13F
Oxygen-fired CFB	Sub-bituminous	S22F

3.1.1 Air-fired performance and scaling

Cases 9, 10, 11, and 12 (NETL, 2010a); PN1, PN2, PN3, PN4, PA1, PA2, PA3, and PA4 (NETL, 2012b); S12A, S12B, L12A, L12B, S13A, S13B, L13A, L13B, S22A, and L22A (NETL, 2011a) demonstrate the model ability to replicate results of air-fired plants for subcritical, SCPC, USCPC, and CFB boiler types using different feed stocks and over a range of thermal inputs. The air-fired plants are considered the basis for the other variations.

3.1.2 Oxygen-fired performance

Cases BO0, PO1, PO2, PO3, and PO4 (NETL, 2012b) demonstrate the model ability to correctly model the ASU and its impact on boiler efficiency. Matching these cases was the priority during development, but in addition to these, general agreement with Cases 13F and S22F gross power shows that the methodology in implementing oxygen-firing is correct.

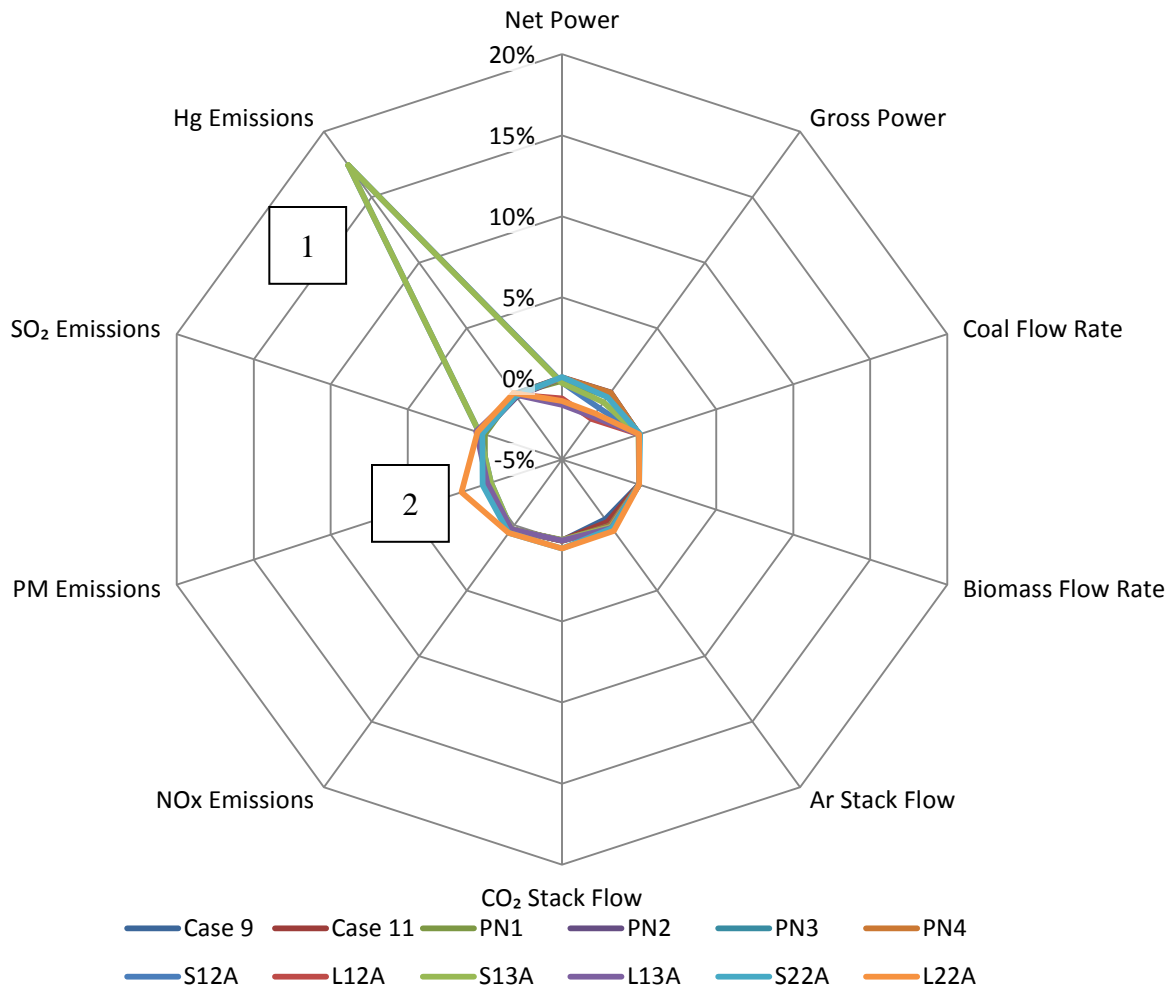
3.1.3 Emission controls impact

There are also cases that demonstrate the difference in performance for different control technologies. By showing close agreement with the different cases, confidence in the model results increases.

Table 3-3: Case Breakdown by Plant Technology

Category	Plant Technology	Cases
NO _x	SCR	Cases 9- 12, BN0, BN1, BA0, BA1, PN1-PN4, PA1-PA4, S22A, L22A (actual process is SNCR for S22A and L22A)
	Oxygen-firing	BO0, PO1-PO4, S13F, S22F
	None	None
SO _x	In-bed limestone injection	S22A, L22A
	Dry FGD	S12A, L12A
	Wet FGD	Cases 9- 12, BN0, BN1, BA0, BA1, PN2-PN4, PA2-PA4, PO2-PO4
	None	PN1, PA1, PO1
PM	Fabric filter	All cases
	ESP	None
	None	None
Mercury	Co-benefit wet FGD	Cases 9- 12, BN0, BN1, BA0, BA1, PN1-PN4, PA1-PA4, PO1-PO4
	Co-benefit fabric filter	Cases 9- 12, BN0, BN1, BA0, BA1, PN1-PN4, PA1-PA4, PO1-PO4, S22A, L22A
	Activated carbon	S12A, S12B, L12A, L12B, S13A, S13B, L13A, L13B
	None	S13F, S22F (report assumes 90% captured in the CO ₂ compression/processing train (NETL, 2010b))
Cooling	Water-cooled condenser/wet cooling tower	Cases 9- 12, BN0, BN1, BA0, BA1, PN1-PN4, PA1-PA4, PO1-PO4
	Hybrid condenser/wet cooling tower	S12A, L12A, S12B, L12B, S13A, L13A, S13B, L13B, S13F, S22A, L22A, S22F
	Once-through	None

Figure 3-1: Comparison of Non-capture Plants - Percent Difference from Baseline Parameter



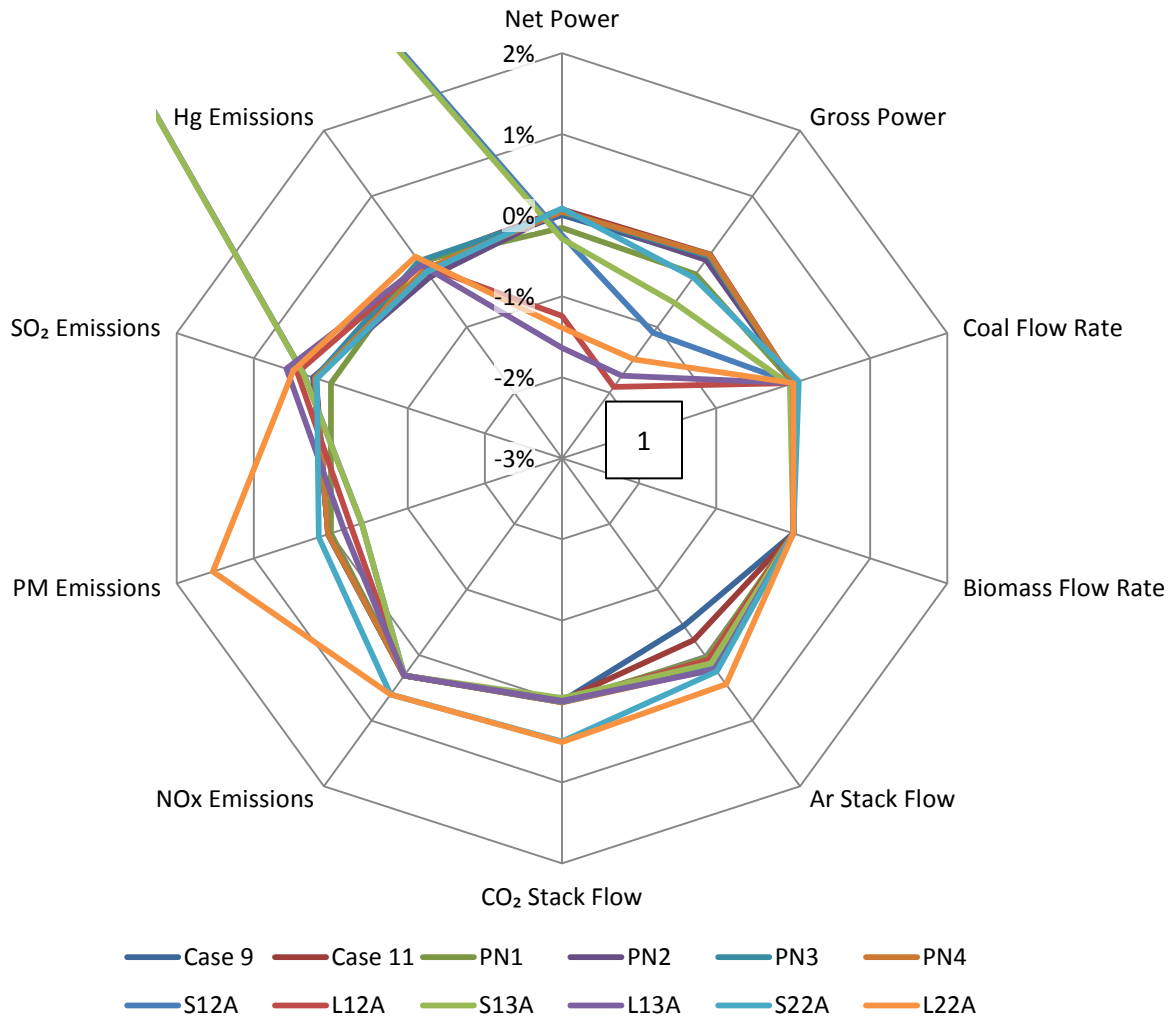
Notes:

1

Mercury emissions are 17.4 percent higher than the baseline for the sub-bituminous cases S12A (SCPC) and S13A (USCPC). The baseline study (NETL, 2011a) assumes an additional mercury capture due to co-benefit capture at the filter resulting from the presence of SCR. The same report assumes that there is no co-benefit capture for lignite PC plants, so cases L12A and L13A are consistent with the report.

2

The PM emissions for L22A are overestimated by 1.5 percent. This deviation is the result of modeling differences for the in-bed limestone injection which results in additional fly ash production compared to the baseline study.

Figure 3-2: Comparison of Non-capture Plants - Percent Difference from Baseline Parameter (re-scaled)**Notes:**

1

Gross and net power are underestimated for S12A, L12A (sub-bituminous and lignite SCPC), S13A, L13A (sub-bituminous and lignite USCPC), S22, and L22A (sub-bituminous and lignite CFB) (NETL, 2011a). The SCPC plants are defined according to the performance of the SCPC plants in the NETL bituminous baseline reports (NETL, 2010). There are different environmental assumptions between the two reports (ambient temperature, pressure, etc.) that result in different steam cycle efficiencies for the SCPC plants (Case 11, PN1-PN4 versus S12A, L12A, S22A, and L22A). The gross power for the sub-bituminous is higher than lignite cases because the calculation for boiler steam production over predicts the steam output for sub-bituminous cases but correctly predicts the lignite cases.

Figure 3-3: Comparison of Non-capture Plants - Percent Difference from Baseline Parameter

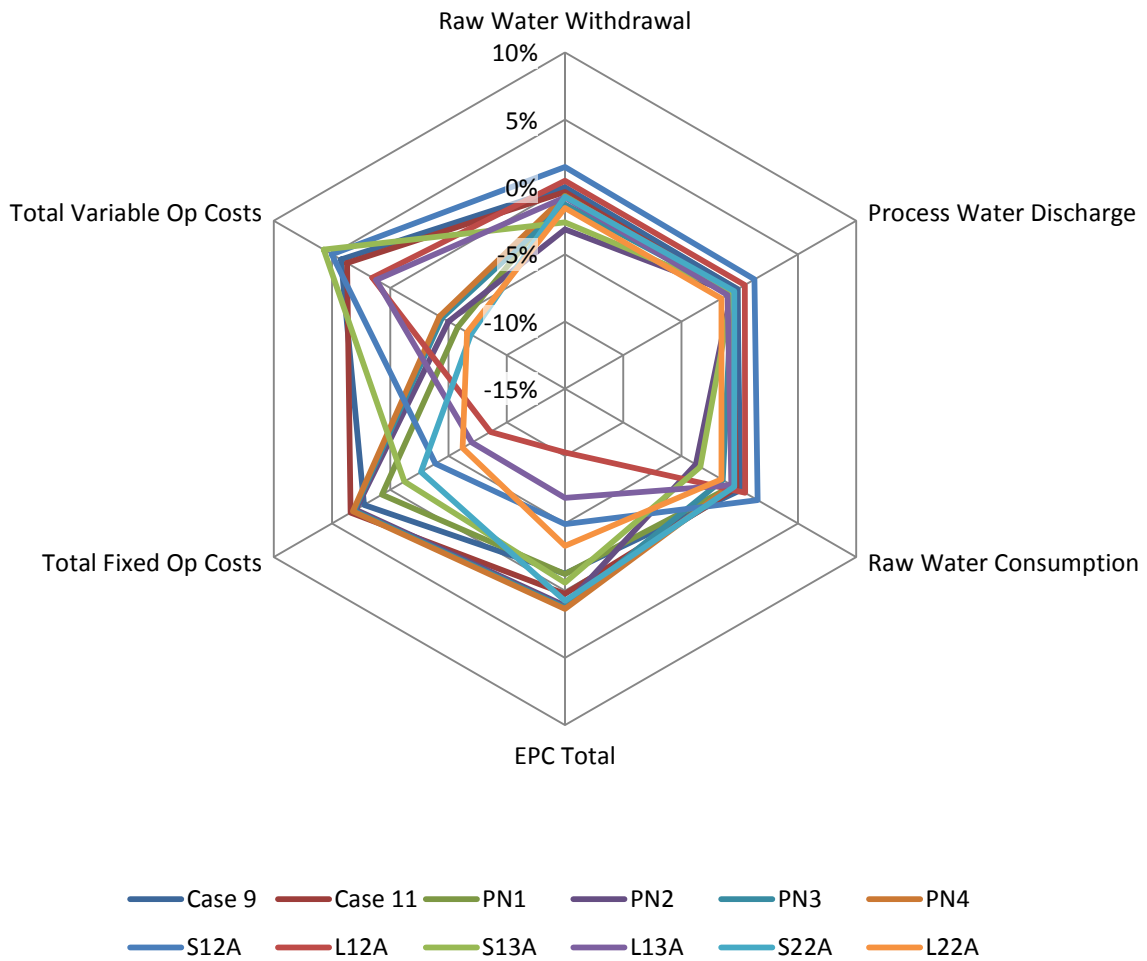
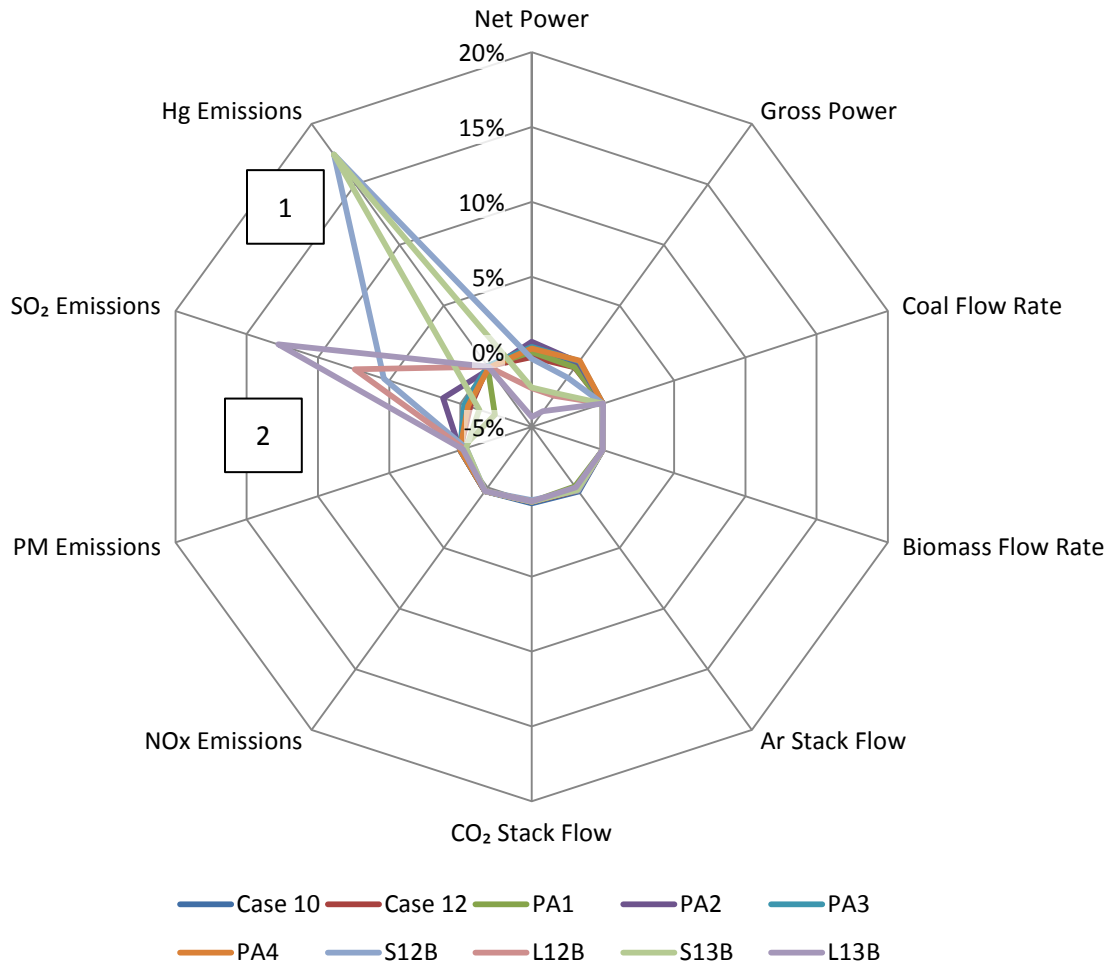


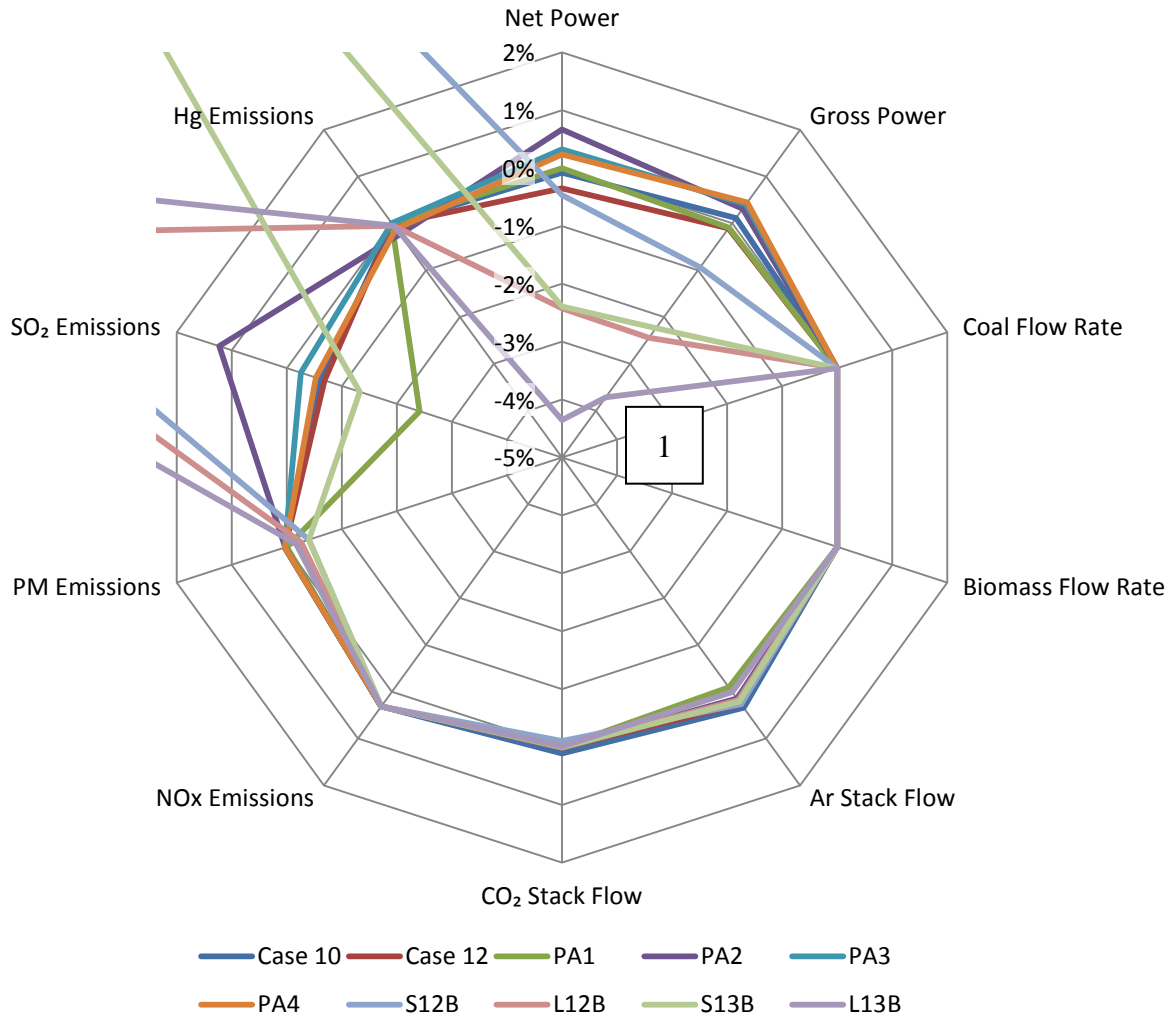
Figure 3-4: Comparison of Amine-capture Plants - Percent Difference from Baseline Parameter**Notes:****1**

The differences in Hg emissions are caused by the same factors as in Note 1 **Figure 3-1**.

2

SO₂ emissions are overestimated by 1.2, 5.4, 7.4, and 12.8 percent for Cases PA2 (SCPC w/ 60% biomass), S12B, L12B (sub-bituminous and lignite SCPC w/ MEA, and L13B, respectively and underestimated by 2.4 and 1.3 percent for PA1 (SCPC with 100% biomass) and S13B (sub-bituminous USCPC w/ MEA), respectively. The source of this error is in the model for SO₂ polishing combined with the very small SO₂ flows that are sent to the stack following the MEA process. The SO₂ polishing is modeled using assumed temperatures and pressures to calculate volumetric flow rate of the flue gas, so only small deviations from the baseline temperature and pressure are needed to cause errors of this magnitude. The errors are considered acceptable given the small flow rates that are involved (PA2 – 0.0015 kg/s, S12B - 0.0014 kg/s, L12B - 0.0015 kg/s, L13B - 0.0014 kg/s, PA1 – 0.0017 kg/s, and S13B - 0.0013 kg/s).

Figure 3-5: Comparison of Amine-capture Plants - Percent Difference from Baseline Parameter (re-scaled)

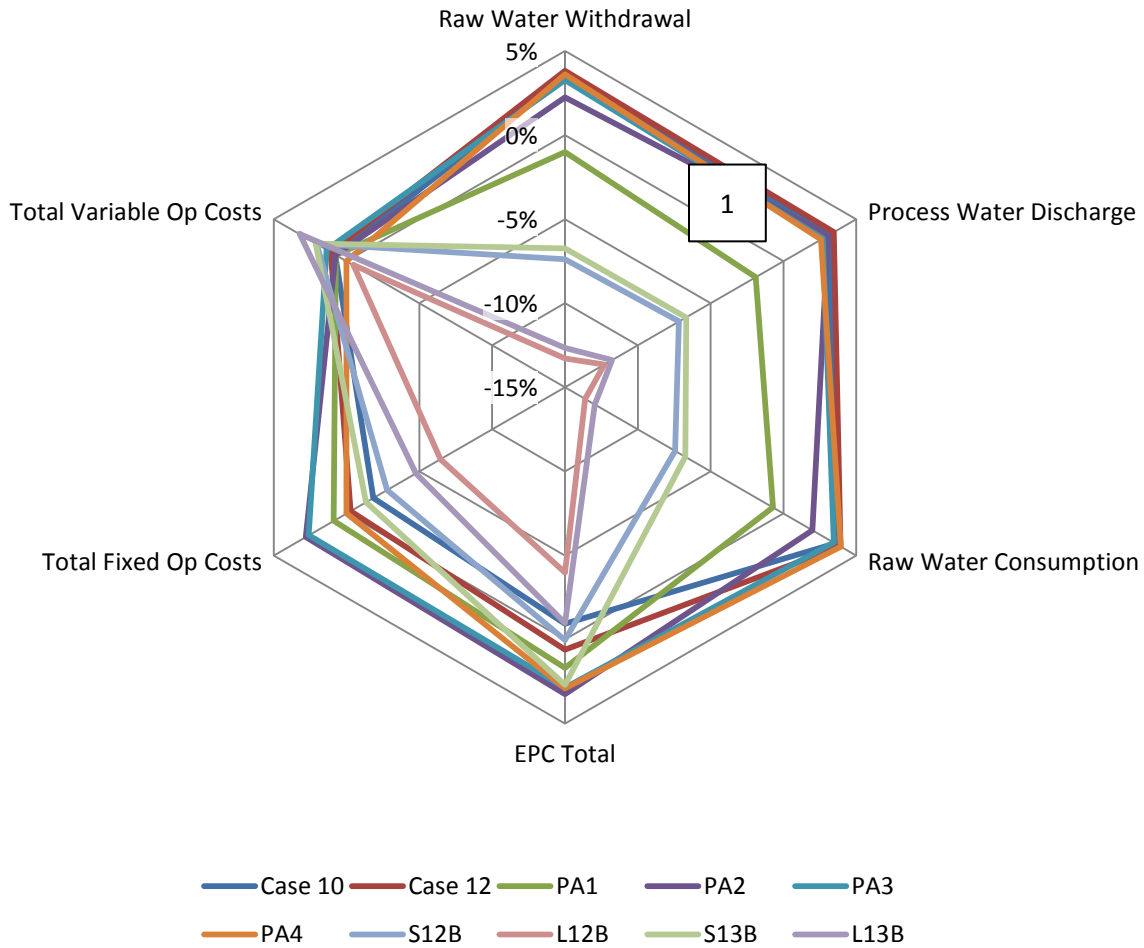


Notes:

1

The gross and net powers are underestimated for the sub-bituminous and lignite cases for the same reasons as discussed in Note 1 of **Figure 3-2**.

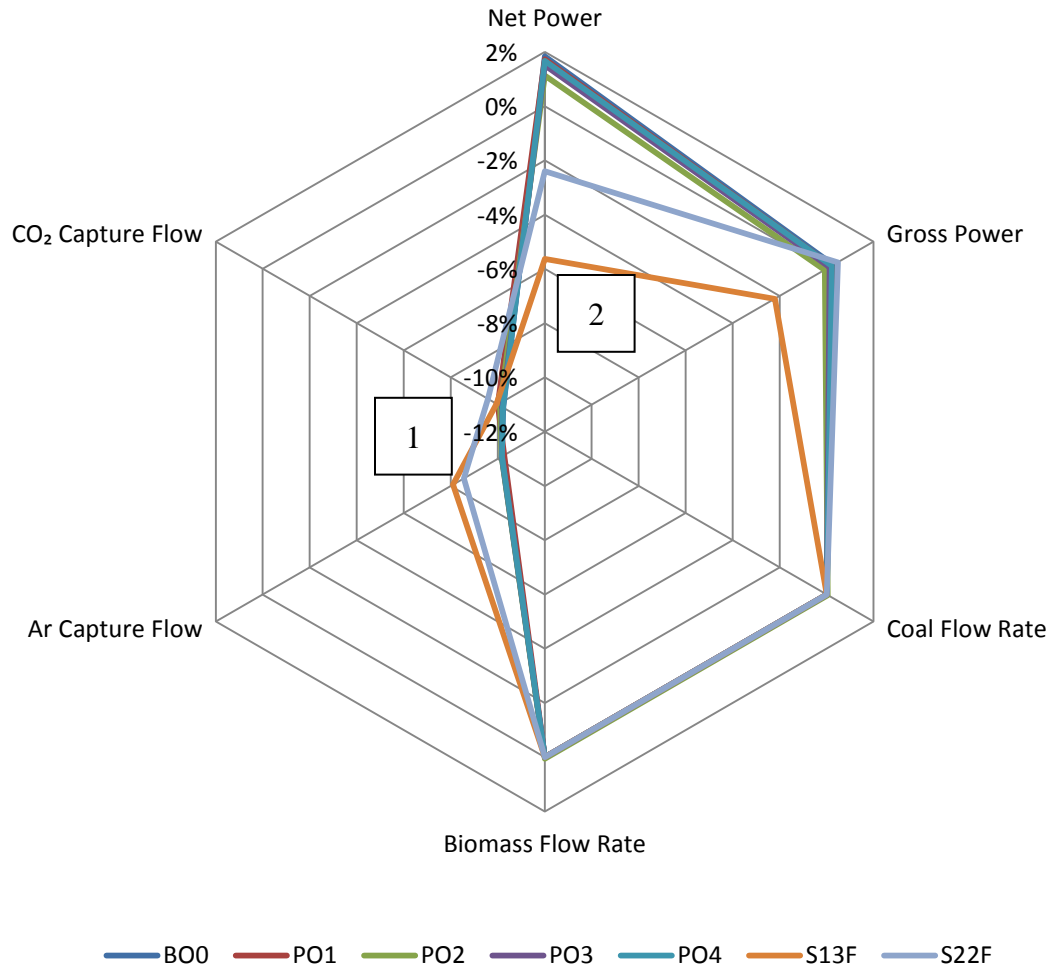
Figure 3-6: Comparison of Amine-capture Plants - Percent Difference from Baseline Parameter



1

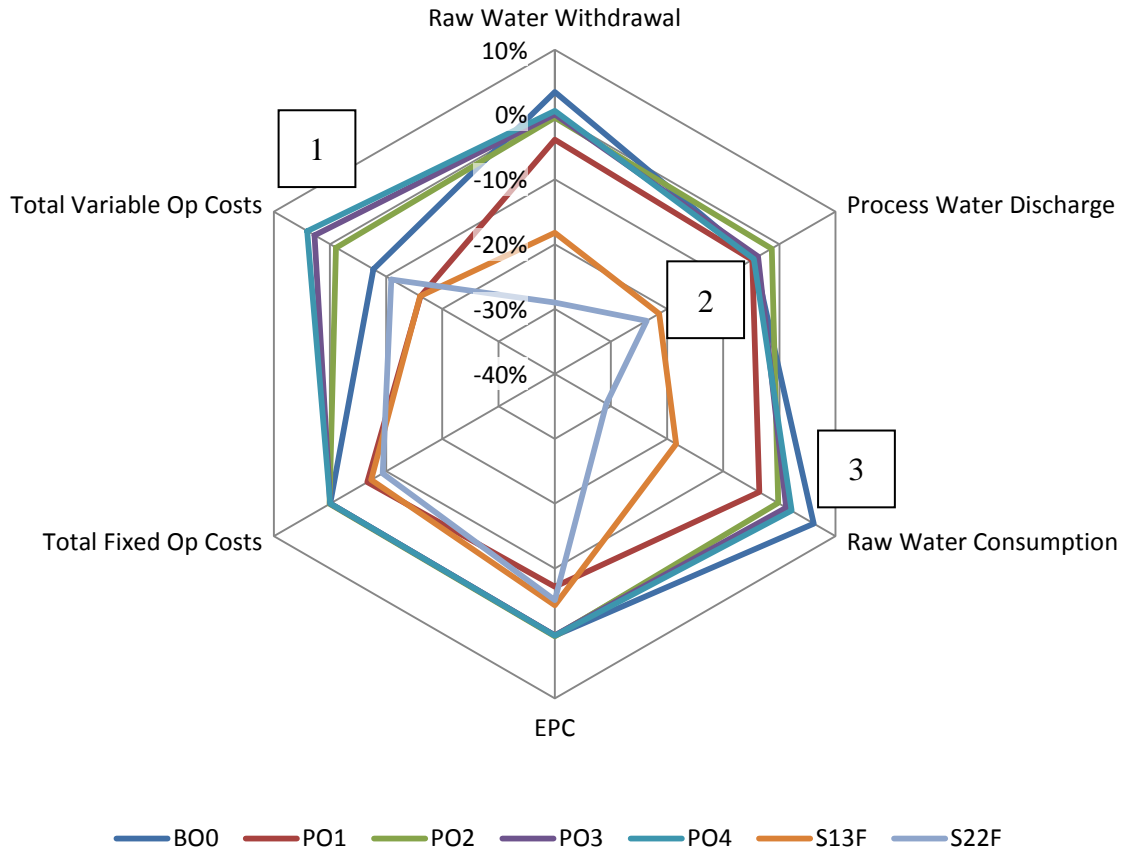
Raw water withdrawal, discharge, and consumption are all underestimated for Cases S12B (sub-bituminous SCPC w/ MEA), L12B (lignite SCPC w/ MEA), S13B (sub-bituminous USCPC w/ MEA), and L13B (lignite USCPC w/ MEA). The main difference between PPFM and these cases is the cooling load associated with the MEA process. Again, the PPFM is tuned to the bituminous plants (Cases 10, 12, and PA1-PA4), so any difference in the ambient conditions between the cases will result in different performance. Another minor part of this difference is caused by the underestimated gross powers for these cases, as the power plant condenser heat load is a function of gross power and a higher heat load induces more water use by the cooling tower.

Figure 3-7: Comparison of Oxygen-fired Plants - Percent Difference from Baseline Parameter



1 The captured CO₂ and argon flows are 8 to 10 percent less than the baseline cases because the PPFM model assumes that 10 percent of the captured flow is released to the atmosphere as part of polishing processes. This assumption results in less compression loads leading to overestimated net power for cases PO1-PO4 (oxy-fired SCPC with 100%, 60%, 30%, and 15% biomass). The argon capture flow for cases S13F and S22F (sub-bituminous, oxy-fired CFB) are only underestimated by 8 percent because the plant configuration for the oxy-fired CFB case (NETL, 2010b) is much different than the oxy-fired SCPC cases (PO1-PO4) (NETL, 2012b), resulting in different recycle/capture stream compositions. Because of the low error associated with the oxy-fired SCPC cases and the different configuration, the difference is acceptable.

2 The net powers for case S13F (sub-bituminous USCPC) and S22F (sub-bituminous CFB) are further underestimated because the ASUs in cases S13F and S22F (NETL, 2010b) use much less electricity than the ASU from oxy-fired SCPC cases (NETL, 2012b), resulting in much less net power despite similar gross power output. The difference in electricity usage between the reports is because the ASUs in cases S13F and S22F do not compress the oxidant stream to the same pressure as cases PO1-PO4 (46 psia vs. 86.6 psia).

Figure 3-8: Comparison of Oxygen-fired Plants - Percent Difference from Baseline Parameter

1 The total variable operating costs are underestimated for the sub-bituminous cases S13F (USCPC) and S22F (CFB) and also bituminous case PO1 (SCPC with 100 percent biomass). This is in part due to the correction factor of 1.5 applied to the 2007-basis costs of these plants. The 1.5 correction factor was calculated using the average price increase of consumables, the biggest changes caused by ammonia and municipal water costs. Because these plants do not use ammonia due to the absence of SCR and also have under-predicted water demand, especially cases S13F and S22F as discussed in Note 2, the cost correction factor is overly conservative.

2 Water use for cases S13F and S22F are underestimated for all three parameters. The source of the deviations is in lower plant cooling loads. There are design differences between the low-rank cases and the bituminous cases, the biggest of which is the presence of a direct contact cooler in the low-rank cases which represents a large cooling load and thus cooling water demand. Other differences are increased cooling loads for the ASU and the CO₂ compression train compared to the cooling loads of cases BO0 and PO1-PO4.

3 The raw water consumption for case BO0 (bituminous, oxy-fired SCPC) is overestimated by 6.1 percent. This is due to the combination of overestimated withdrawal (3.5%) and underestimated process water discharge (4.5%). Because the withdrawal and discharge deviations are within 5 percent of the baseline value, the error in the consumption number is considered acceptable.

4 PPFM User's Guide

PPFM allows users to calculate the emissions, loads, and costs associated with a specific power plant configuration including feed choice, boiler type, and emissions controls. Users can create a custom power plant or choose to view the outputs associated with plants configured based on those modeled in NETL publications. It is important to note that the PPFM outputs for pre-configured NETL cases do not match the published values exactly due to differences in modeling. Also, the cost and performance data were taken from models of base load power plants with expected net outputs of 550 MW. While every effort was made to scale cost and performance with plant size, the model will be most accurate when similarly sized plants are configured.

4.1 Overview of Model Tabs

PPFM is a Microsoft® Excel-based model with eight viewable tabs. Each tab and its corresponding role in the model are discussed in **Table 4-1**.

Table 4-1: PPFM Excel Tab Descriptions

Model Tab	Description
Summary_Sheet	Provides interface for user-customized plant configuration and corresponding outputs (emissions, performance, loads, water usage, and costs)
Flow_Chart	Contains all modeling calculations and intermediate process stream compositions
Mass_Balances	Calculates mass balances (inputs and outputs) for carbon, mercury and sulfur
GaBi_Sheet	Interface sheet for importing specified power plant into GaBi Life Cycle Analysis modeling software
Constants	Constants used throughout PPFM
Refs	References utilized to build PPFM
Justifications	Detailed modeling assumptions
Plant_Configurations	Contains model presets for 39 published power plant simulations in various NETL reports (NETL, 2010a, 2010b, 2011b, 2012b); custom scenarios saved by the user are also stored here for future use

4.2 Operation of the Model

PPFM is operated from the “Summary Sheet” tab in Excel. From that tab, the user has access to all of the model parameters (**Figure 4-1**) and detailed outputs (**Figure 4-3** and **Figure 4-4**). The input cells for the model are denoted by those with an orange fill. As illustrated by **Figure 4-1**, the user can change the composition of feedstock (coal/biomass), turn on/off various pollution control technologies (CO₂, Hg, NO_x, PM, and SO_x), choose the plant type (PC, SCPC, USCPC, CFB), choose the combustion gas composition (air or oxygen), and choose the cooling type. The remainder of this section describes each of the input sections in detail.

The main input to the model is the thermal input to the power plant. All other inputs and outputs are scaled according to that input along with the chosen configuration of the power plant (i.e. the pollution control equipment). Users can also specify other variables (e.g. net power, heat rate, or feed rate), which in turn are used to calculate the thermal input for the power plant.

Figure 4-1: Summary Sheet Screenshot – Inputs

	A	B	C	D	E	F	G	H
1								
2	Feedstock				Air separation unit (oxy-firing)			
3	Bituminous Coal	0%	Total: 100%		Status	1	0 - Off, 1 - On	
4	Sub-bituminous Coal	0%						
5	Lignite Coal	0%						
6	Hybrid Poplar	100%			Plant			
7	Switchgrass	0%			Plant Type	2	1 - Subcritical Pulverized Coal (PC)	
8	Corn Stover	0%					2 - Supercritical Pulverized Coal (SCPC)	
9	Forest Residue	0%					3 - Ultra-supercritical Pulverized Coal (USCPC)	
10	Custom Coal	0%					4 - Circulating Fluidized Bed (CFB)	
11	Torrefied biomass	0	0 - Off, 1 - On		Thermal input (HHV)	2028	MWt	
12	Biomass target moisture level	10%	Range: 0 to 50%			6,918	MMbtu/hr	2,027,546 kWt
13	NOx controls				SOx controls			
14	Selective Catalytic Reduction	0	0 - Off, 1 - On		Wet FGD	0	0 - Off, 1 - On	
15	SCR efficiency	86%	Default: 86%		SOx removal efficiency	0%	molar percent, Default 98%	
16								
17	Fly ash and particulate matter controls				Dry FGD	0	0 - Off, 1 - On	
18	Fabric Filter	1	0 - Off, 1 - On		SOx removal efficiency	0%	molar percent, Default 93%	
19	Ash removal efficiency	99.8%	Default: 99.8%					
20	Electrostatic Precipitator	0	0 - Off, 1 - On		In-bed limestone injection	0	0 - Off, 1 - On (to be used only with CFB boiler)	
21	Ash removal efficiency	0.0%	Default: 99%		SOx removal efficiency	0%	molar percent, Default: 94%	
22								
23	Carbon dioxide capture							
24	Status	1	0 - Off, 1 - On		Plant cooling			
25	If ASU is off, CO2 capture is amine-based.				Wet cooling tower/Hybrid Condenser	1	0 - Off, 1 - On	
26	Capture bypass	0%	Default: 0%			0%	Percentage Air-Cooled Condenser (Default 0%)	
27								
28	Mercury control				Once-through cooling	0	0 - Off, 1 - On	
29	Filter/ESP co-benefit cap. Rate	70.2%	Default: 70.2%		Allowable temperature increase	20	°F, default 60°F	
30	Wet FGD co-benefit cap. Rate	0.0%	Default: 70.2%		Power Plant Capacity Factor	0.85	Capacity factor used for yearly operating costs	
31	Activated Carbon Injection	0	Default: 0		Municipal Water Usage	50%	% water withdrawn from municipal source (Default 0%)	
32					Ground Water Percent	100%	% of remaining water withdrawn from ground (Default 50%)	

4.2.1 Feedstock Options

There are eight feed stock choices including four coal options (bituminous, sub-bituminous, lignite, and custom) and four biomass options (hybrid poplar, switchgrass, corn stover, and forest residue). Users can adjust the mix of the various options in cells B3:B10 on the “Summary Sheet” tab. The custom coal option allows the user to enter a unique composition and heating value for use in the model calculations. This data is entered in cells H98:H109 on the Flow Chart tab as shown in **Figure 4-2**. The user has infinite flexibility for feedstock combinations as shown in **Figure 4-1**. The model allows coal types to be mixed as well as coal/biomass co-firing. The total shown in cells C3:C10 of **Figure 4-1** must equal 100 percent.

Figure 4-2: Custom Coal Input Cells on Flow Chart Tab

	E	F	G	H	I	J	K
93							
94							
95		Custom				Reference [4]	
96			Input		1 kg_cus		
97							
98			Output	As-received			
99				20636 kJ		8871.88	
100							
101				0.0598 kg_H2O			
102				0.4883 kg_C			
103				0.0333 kg_H			
104				0.0102 kg_N			
105				0.0000 kg_Cl			
106				0.0074 kg_S			
107				0.3570 kg_Ash			
108				0.0441 kg_O			
109				2.98E-09 kg_Hg			
110			Total	1.0001			
111							
112							

If either hybrid poplar or forest residue is selected as part of the feedstock mix, the model allows the user to choose torrefaction as a pre-treatment step by entering a value of “1” in cell B11 as shown in **Figure 4-1**. The torrefaction step occurs outside the boundaries of the model, but the heating value and composition of the biomass is adjusted accordingly for use within the model. The torrefied biomass enters the model boundary and proceeds through the same pulverizing process as coal. Due to data limitations, the torrefaction option in the model is restricted to hybrid poplar and forest residue. If the user does not select the torrefaction option, the biomass is dried and ground on-site prior to being mixed with the pulverized coal. With the torrefaction option turned off, the model allows the user to specify the moisture content of dried biomass by entering a percentage into cell B12. If the user selects more than one type of biomass, the specified moisture content is based on the combined stream. The model does not explicitly support combinations of torrefied and un-torrefied biomass, but torrefied biomass properties could be entered into the custom coal section (since torrefied biomass is treated as coal) while also choosing non-torrefied feedstocks.

4.2.2 Plant Type and Cooling

PPFM is configured to model four different types of power plants: Subcritical Pulverized Coal (PC), Supercritical Pulverized Coal (SCPC), Ultra-supercritical Pulverized Coal (USCPC), and Circulating Fluidized Bed (CFB). The plant type is specified by entering the corresponding value in cell F7 on the “Summary Sheet” tab. Each of the different power plants can be fired using either air or oxygen. Oxy-firing requires an on-site ASU, which produces a gas stream that is 95 percent oxygen. The user can specify air- or oxy-firing by entering the corresponding value into cell F3 on the “Summary Sheet” tab as shown in **Figure 4-1**. The model accounts for the additional cooling, electricity, and steam loads that are required when oxy-firing is selected for a plant. All of the inputs and outputs for the model are scaled based on the specified thermal input to the plant. The user can enter this value in cell F11. While the thermal input to the plant is used as the default input to PPFM, the model also allows the user to specify a substitute variable for scaling calculations (e.g. net power, net heat rate, coal flow rate). This functionality is discussed in **Section 4.3**. Users can specify the capacity factor of the power plant in cell F30. The capacity factor is only used in the variable operating cost calculations in the model, and its value will change depending on modeling needs. For example, full capacity (CF of 1.0) costs may be needed for use with other programs like the PSFM (NETL, 2011c).

For power plant cooling, the user has the option of a wet cooling tower with a hybrid condenser or once-through cooling. The switches for the cooling technologies are located in cells F25 and F28. If the wet cooling tower option is chosen, the user can specify the percentage of the condenser load that is air-cooled in cell F26. With the once-through cooling option, the user can set the maximum allowable temperature increase in the cooling water from withdrawal to discharge. Regardless of cooling type, the user specifies the source of water (municipal vs. ground vs. surface). The user-defined mix of water sources for cooling is the same mix that is used for other makeup water required in different areas of the model.

4.2.3 Air Emissions Control

PPFM includes emissions control technologies for CO₂, Hg, NO_x, PM, and SO_x. Each technology can be toggled on or off as desired by the user. The removal efficiencies are parameterized and can be adjusted based on plant design or operation. Some technologies provide co-benefits whereby more than one particular pollutant is removed. These relationships will be discussed further below.

4.2.3.1 Nitrogen Oxides

NO_x control in PPFM is achieved by use of selective catalytic reduction (SCR) technology. The user can toggle SCR on/off by entering the corresponding value into cell B14 on the “Summary Sheet” tab. The user can also adjust the efficiency of the SCR unit by entering a percentage into cell B15. The default removal efficiency is 86 percent. In addition to converted NO_x, SCR also oxidizes mercury, which is required for its removal at downstream processes without activated carbon injection. Therefore, SCR must be turned on for co-benefit mercury capture without activated carbon injection.

4.2.3.2 Fly Ash and Particulate Matter

The model provides two technology options for fly ash and particulate matter control: fabric filters and electrostatic precipitator (ESP). The user can select the type and efficiency of the particulate control devices in cells B18:B21 on the “Summary Sheet” tab. The default ash removal efficiency for

fabric filter technology is 99.8 percent and is 99.0 percent for ESP. Mercury that has been oxidized via the SCR process is also removed at this stage.

4.2.3.3 Carbon Dioxide

Carbon dioxide control in the model can be achieved via CO₂ capture with an MEA-based system or by oxy-firing. Control of carbon dioxide can be turned on by entering a “1” into cell B24 on the “Summary Sheet” tab. If the modeled power plant does not utilize oxy-firing (cell F3), the model assumes that CO₂ is achieved by use of an MEA-based system. If oxy-firing is turned on, the model does not use the MEA system. The capture rate for the MEA technology is 90 percent, while oxy-firing is assumed to capture 100 percent of CO₂. The user can bypass either system by entering the desired percentage into cell B26 to achieve lower levels of capture.

4.2.3.4 Sulfur Oxides

There are three options for sulfur oxide removal included in PPFM: wet flue gas desulfurization (FGD), dry FGD, and in-bed limestone injection. The third option is only applicable to CFB plants. The user can select the desired control technology by entering a “1” into cells B14, B17, or B20 on the “Summary Sheet” tab. The corresponding removal efficiency for each technology can be entered as a percentage in cells B15, B18, and B21.

4.2.3.5 Mercury

As discussed in **Sections 2.18.5, 2.15, and 2.16**, the removal of mercury occurs as a co-benefit of the SO_x (Wet FGD) and particulate removal processes (filter or ESP). The SCR process is required to oxidize the mercury, thereby facilitating removal in the downstream processes. The user can enter the co-benefit capture rates for the filter/ESP in cell B29 and for the Wet FGD in cell B30. The co-capture benefits are additive, so the percentage entered for the Wet FGD is based on the mass of mercury in the flue gas downstream of a filter/ESP (if they exist in the plant configuration).

The math for mercury removal in PPFM does not account for the removal mechanism of mercury via the injection of activated carbon (ACI). If ACI is selected, the model accounts for the cost and creates a tracked input that can be included in the GaBi model, but the user is responsible for choosing the capture rate at the fabric filter. The NETL studies that use activated carbon (NETL, 2010b, 2011a) and an EPA report (EPA, 2010) suggest that mercury capture rates at the fabric filter or ESP can reach 90 percent with low-sulfur coals (sub-bituminous and lignite) and specialized sorbents (activated carbon). The EPA document also shows that high-sulfur coals in plants with a dry FGD and fabric filter can achieve removal rates of over 90 percent, and that a plant firing high-sulfur coal may not see much benefit from the addition of activated carbon because SO₃ and Hg tend to compete for the active sites on the activated carbon.

4.2.4 Model Outputs

The other half of the summary sheet, as shown in **Figure 4-3** and **Figure 4-4**, provides the detailed outputs from the model based on the parameter inputs in **Figure 4-1**. The modeling outputs include a performance summary, fuel feed rates, auxiliary loads, water usage, air emissions, and plant costs. All outputs are updated dynamically based on changes to the input parameters on the “Summary Sheet.”

Figure 4-3: Summary Sheet Screenshot – Outputs: Emissions

	A	B	C	D	E	F	G	H	I
33	Emissions								
34	CO2								
35		kg/hr	kg/MWh_gross	kg/GJ	kg/MWh_net	lbm/hr	lbm/MWh_gross	lbm/MMbtu	lbm/MWh_net
36	Stack	59,813	79	9	112	131,866	174	21	246
37	Captured	538,321	710	82	1004	1,186,795	1,566	191	2,213
38	Recycled	730,463	964	118	1362	1,610,395	5,469,777	259	3,003
39	SO ₂								
40	Stack	35	0.0468	0.0054	0.0661	78	0.1031	0.0126	0.1457
41	NOx								
42	Stack	16	0.0218	0.0025	0.0308	36	0.0480	0.0059	0.0678
43	Particulate Matter								
44	Stack	59	0.078	0.0090	0.1097	130	0.1711	0.0209	0.2418
45	Mercury								
	Stack	0.001	1.82E-06	2.11E-07	2.58E-06	0.003	4.02E-06	4.90E-07	5.68E-06

Figure 4-4: Summary Sheet Screenshot – Outputs: Plant Performance, Loads, Water Usage, and Costs

	K	L	M	N	O	P
1						
2	Performance Summary					
3						
4	Gross power	856.161 MW	Yearly power generation		4,168,833 MWh	
5	Net power	559.492 MW	Default steam cycle efficiency		46.95%	
6	Net plant efficiency (HHV)	27.6%	Default steam cycle heat rate		7279 btu/kWh	
7	Net plant heat rate (HHV)	13,046 kJ/kWh	Modified steam cycle efficiency		46.95%	
8		12,365 btu/kWh	Modified steam cycle heat rate		7279 btu/kWh	
9						
10	As-received coal/torrefied biomass feed rate	0 kg/hr				
11		0 lbm/hr				
12	As-received biomass feed rate	743,788 kg/hr				
13		1,639,773 lbm/hr				
14						
15	Auxiliary loads					
16	Coal Handling and Conveying	0 kW				
17	Pulverizers	0 kW				
18	Biomass Processing	57,855 kW				
19	Biomass Handling	444 kW				
20	Baghouse/ESP	21 kW				
21	Ash Handling	162 kW				
22	Primary/Forced Draft Fans	4,629 kW				
23	Induced Draft Fans	0 kW				
24	SCR	0 kW				
25	FGD	0 kW				
26	FGD Sorbent Handling and Reagent Prep	0 kW				
27	Amine Capture Plus Auxiliaries	0 kW				
28	CO2 Compression	79,004 kW				
29	ASU Compressor & Aux	135,514 kW				
30	Misc Balance of Plant	2,000 kW				
31	Steam Turbine Auxiliaries	400 kW				
32	Condensate Pumps	1,003 kW				
33	Circulating Water Pumps	8,225 kW				
34	Ground/Surface Water Pumps	674 kW				
35	Cooling Tower and Air-cooled Cond Fans	4,362 kW				
36	Transformer Losses	3,375 kW				
37	Total	297,669 kW				
38						
39	Water usage					
40	Raw Water Makeup	28 m ³ /min	5.03E-02 m ³ /min/MWnet			
41		7,439 gpm	13.30 gpm/MWnet			
42	Process Water Discharge	7 m ³ /min	1.27E-02 m ³ /min/MWnet			
43		1,871 gpm	3.34 gpm/MWnet			
44	Water Consumption	21 m ³ /min	3.77E-02 m ³ /min/MWnet			
45		5,568 gpm	9.95 gpm/MWnet			
46						
47	Procure Construct Cost (BEC + Eng'g CM HO & Fee)	\$1,655,697	x\$1000 - 2011 basis			
48	Operating and Maintenance Labor	\$62,573	x\$1000/yr - 2011 basis			
49	Total Variable Operating Costs (minus feedstock)	\$25,422	x\$1000/yr - 2011 basis			

4.3 Built-in Model Functions

In addition to the parameters available on the Summary Sheet, the user can access several functions in the PPFM tab of the ribbon as shown in **Figure 4-5**. Instead of specifying the thermal input to the power plant on the Summary Sheet tab, a number of functions have been created to allow users to specify other plant characteristics (e.g. net power, heat rate, and coal feed rate). For example, a user can use the net heat rate and coal flow rate buttons to model an actual plant. Other functions are available for users to select existing cases and save new cases. All of the ribbon functions will be described below.

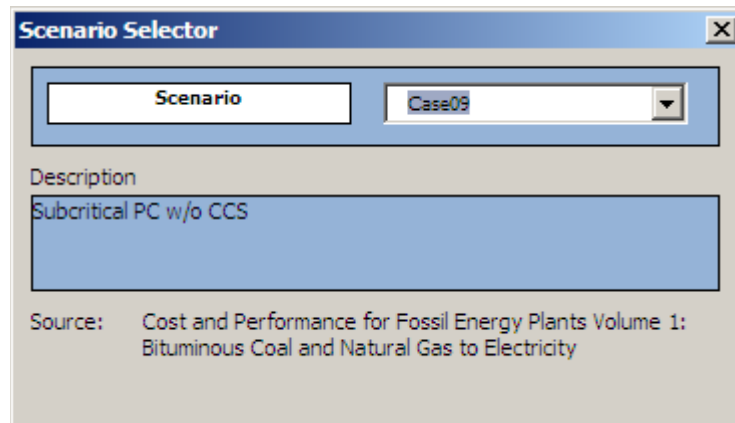
Figure 4-5: Ribbon Screenshot



4.3.1 Scenario Selector Button

The “Scenario Selector” button preloads the Summary Sheet with the appropriate values to model the NETL documented plant case studies. Scenarios are listed by the unique identifier specified based on the referenced report. Upon selection, the dialog box, as shown in **Figure 4-6**, displays a description of the case as well as the source document for that case. The inputs and outputs on the Summary Sheet update automatically to match the documented scenario.

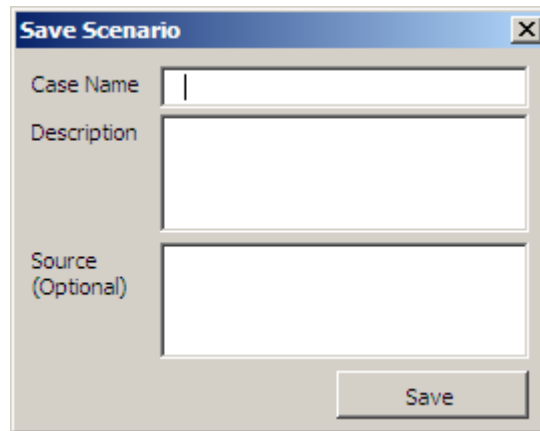
Figure 4-6: Dialog Box for Scenario Selector Button



4.3.2 Save Scenario Button

After users have configured a plant on the “Summary Sheet”, the unique configuration can be saved by using the “Save Scenarios” button. Upon selection, the dialog box, as shown in **Figure 4-7**, allows the user to choose a unique case name, description, and source. If users have saved custom scenarios, they will also appear in the scenario selector dropdown list (**Figure 4-6**). To delete a case, the whole column of data can be deleted from the “Plant Configurations” tab. Note that the baseline scenarios are write protected.

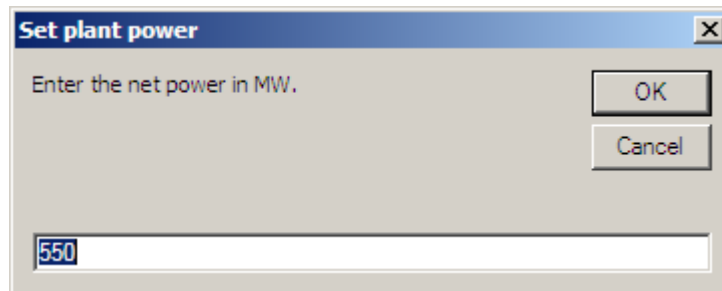
Figure 4-7: Dialog Box for Save Scenario Button

A dialog box titled "Save Scenario" with a close button (X) in the top right corner. It contains three text input fields: "Case Name" (a single-line field), "Description" (a multi-line field), and "Source (Optional)" (a multi-line field). A "Save" button is located at the bottom right of the dialog box.

4.3.3 Plant Net Power – Feedstock and Plant Net Power – Heat Rate Buttons

The next two functions (“Plant Net Power – Feedstock” and “Plant Net Power – Heat Rate”) allow the user to specify the net power output. Depending on which function is selected, the model adjusts either the feed rate or heat rate. If the “Plant Net Power – Heat Rate” function is used, the steam cycle efficiency changes for the plant, and the original and modified steam plant efficiencies are highlighted on the “Summary Sheet”. The net power is entered in the dialog box as shown in **Figure 4-8** in units of MW.

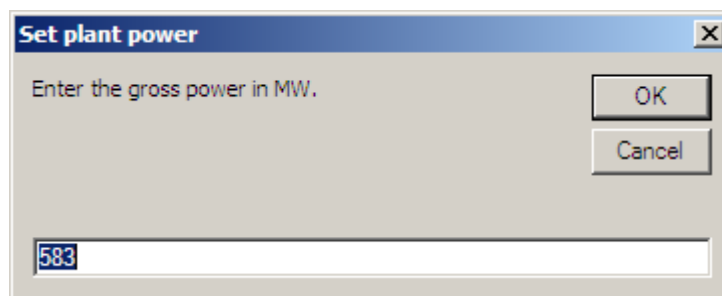
Figure 4-8: Dialog Box for Plant Net Power Heat Rate and Feedstock Buttons

A dialog box titled "Set plant power" with a close button (X) in the top right corner. It contains the text "Enter the net power in MW." and two buttons: "OK" and "Cancel". At the bottom, there is a text input field with the value "550" entered.

4.3.4 Plant Gross Power – Feedstock Button

With the “Plant Gross Power –Feedstock” button, the model adjusts the feed rate to the plant based on the user specification in the dialog box as shown in **Figure 4-9** in units of MW.

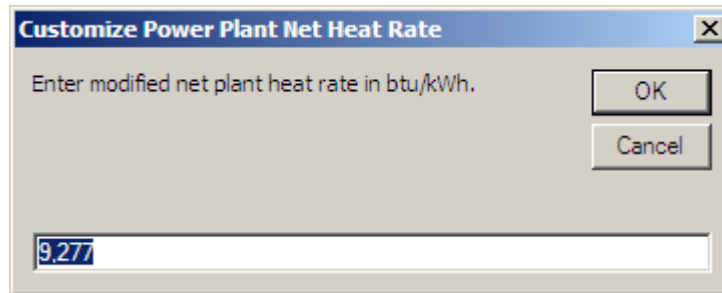
Figure 4-9: Dialog Box for Plant Gross Power Feedstock Button

A dialog box titled "Set plant power" with a close button (X) in the top right corner. It contains the text "Enter the gross power in MW." and two buttons: "OK" and "Cancel". At the bottom, there is a text input field with the value "583" entered.

4.3.5 Net Heat Rate Button

The “Net Heat Rate” button allows the user to enter a custom value for the variable. The use of this function results in a change in the steam cycle efficiency for the plant. Again, the steam cycle efficiency is changed and highlighted in the “Summary Sheet.” The net heat rate is entered in the dialog box as shown in **Figure 4-8** in units of Btu/kWh.

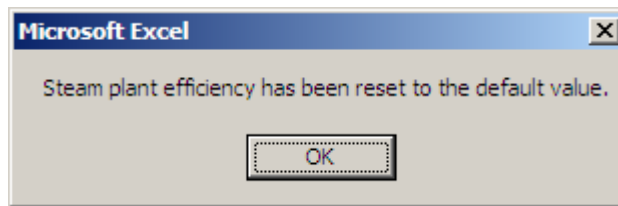
Figure 4-10: Dialog Box for Net Heat Rate Button



4.3.6 Reset Net Heat Rate Button

When either the “Plant Net Power – Heat Rate” or “Net Heat Rate” functions are used, the default steam cycle efficiency is changed as part of the calculation. In order to reset the model to the default value, users should select the “Reset Net Heat Rate” button from the ribbon. Upon selection, the dialog box shown in **Figure 4-11** appears, informing the user that the value has been reset.

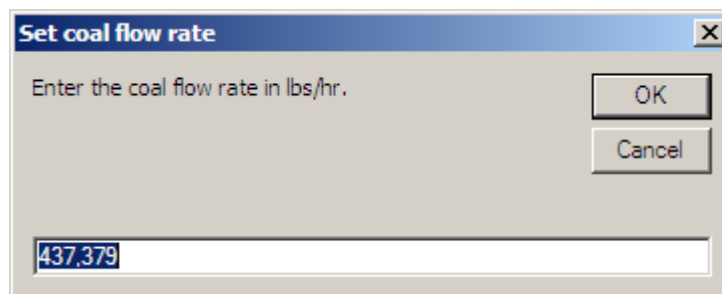
Figure 4-11: Dialog Box for Reset Net Heat Rate Button



4.3.7 Coal Flow Rate Button

Users can specify the coal feed rate to the plant by selecting the “Coal Flow Rate” button in the ribbon. Depending on the coal type specified on the summary sheet, the model calculates the thermal input to the plant based on the feed rate entered in the dialog box shown in **Figure 4-12** in units of lbs/hr.

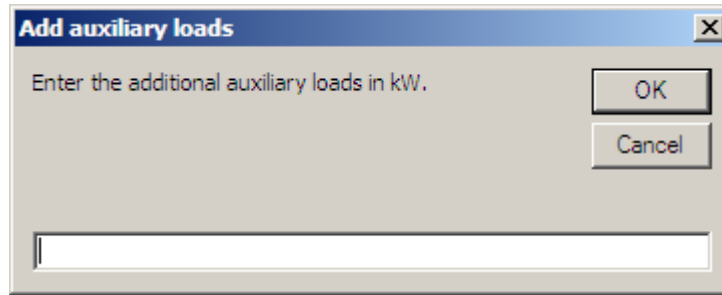
Figure 4-12: Dialog Box for Coal Flow Rate Button



4.3.8 Additional Auxiliary Loads Button

As shown by **Figure 4-4**, the model accounts for an extensive set of auxiliary loads at the plant. The “Additional Auxiliary Loads” function allows users to specify supplemental loads on top of those already considered in the model. These additional loads are entered in the dialog box in units of kW as shown in **Figure 4-13** and are added to the “Misc balance of plant” loads, which becomes highlighted upon being modified.

Figure 4-13: Dialog Box for Additional Auxiliary Loads Button



4.3.9 Generate GaBi Import Button

The final button in the PPFM tab of the ribbon allows users to export a configured plant as a unit process for modeling in the GaBi Life Cycle Assessment software package. The function generates the unique format required by GaBi from the data on the “GaBi_sheet” tab. The process name and description provide the information regarding the configuration and operation of the power plant. A user can add more tracked inputs or outputs by inserting rows and providing the necessary information.

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