

Demonstration Development Project: Assessment of Biomass Repowering Options for Utilities

1022219

Demonstration Development Project: Assessment of Biomass Repowering Options for Utilities

1022219

Technical Update, December 2010

EPRI Project Manager
D. O'Connor
P. Meagher

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

THE FOLLOWING ORGANIZATION, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

ANTARES Group Incorporated

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2010 Electric Power Research Institute, Inc. All rights reserved.

ACKNOWLEDGMENTS

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

ANTARES Group, Incorporated.
4351 Garden City Drive, Suite 301
Landover, MD 20785

Principal Investigator
C. Lindsey

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Demonstration Development Project: Assessment of Biomass Repowering Options for Utilities.
EPRI, Palo Alto, CA: 2010.1022219.

ABSTRACT

This report has been prepared to help organizations with fossil-fired generation assets better understand their options for taking advantage of biomass-derived fuels at existing facilities. It considers plant conversions that completely replace fossil fuels through repowering as well as options that focus on high-percentage cofiring of biomass along with fossil fuels.

Drawing on the experiences of operating facilities that have converted to biomass and from prior work, the analysis underlying this report examines the costs and benefits of implementing various plant conversions. These conversions range from major plant changes (including boiler replacement) to making almost no plant modifications and simply moving to highly processed biomass fuels (which can, in some cases, be fired directly into existing combustion systems).

The analysis covers nine conversion options at a macroscopic level and then focuses on four specific options within the context of individual case studies. These case studies provide detailed insights into what would be involved in such conversions, covering topics such as technologies employed, economics, performance, risk, emissions, and likely conversion schedules.

This analysis also investigates the costs and benefits of using raw wood chips versus using more highly processed, specially engineered fuels (such as torrefied wood pellets). Although the optimal approach for any specific facility would depend on numerous site-specific factors, the analysis suggests that the substantially lower cost of raw wood chips provides an economic advantage sufficient to offset the costs of the plant modifications required to burn the wood chips.

Keywords

Biomass

Biomass repowering

Cofiring

Biomass gasification

Fluidized bed combustion

Torrefied wood pellets

CONTENTS

1 INTRODUCTION AND BACKGROUND	1-1
2 BIOMASS REPOWERING TECHNOLOGY OPTIONS.....	2-1
Coal Boiler Fleet Market Assessment	2-1
Discussion of Target Plants.....	2-8
Environmental Issues and Constraints.....	2-9
EPA Boiler MACT	2-9
EPA CISWI Rules.....	2-10
Tailoring Rule	2-11
Overview of Biomass Repowering Technologies	2-12
Technology Primer	2-12
Stoker Grate Firing.....	2-13
Fluidized Bed Boilers	2-13
Suspension Firing	2-15
Gasification Technologies.....	2-15
Option Discussions: Caveats and Assumptions	2-17
Option 1: Replace existing boiler with turbine-sized new grate boiler	2-18
Technology Description	2-18
Appropriate Fuel Qualities	2-22
Construction Schedule and Permitting.....	2-22
Costs.....	2-23
Technology Status and Development Risks	2-24
Option 2: Replace existing boiler with turbine-sized fluid bed boiler	2-26
Technology Description	2-26
Appropriate Fuel Qualities	2-29
Construction Schedule and Permitting.....	2-29
Costs.....	2-29
Technology Status and Development Risks	2-30

Option 3: Modify existing coal boiler for grate firing.....	2-31
Technology Description	2-31
Appropriate Fuel Qualities	2-34
Construction Schedule and Permitting.....	2-34
Costs.....	2-34
Technology Status and Development Risks	2-35
Option 4: Modify existing coal boiler with fluid bed firing	2-37
Technology Description	2-37
Appropriate Fuel Qualities	2-39
Construction Schedule & Permitting	2-39
Costs.....	2-39
Technology Status and Development Risks	2-39
Option 5: Modify existing gas/oil boiler for grate firing.....	2-40
Technology Description	2-40
Appropriate Fuel Qualities	2-43
Construction Schedule and Permitting.....	2-43
Costs.....	2-43
Technology Status and Development Risks	2-44
Option 6: Modify existing gas/oil boiler with fluid bed firing	2-44
Technology Description	2-44
Appropriate Fuel Qualities	2-47
Construction Schedule and Permitting.....	2-47
Costs.....	2-47
Technology Status and Development Risks	2-48
Option 7: High percentage cofiring	2-48
7a) Direct Cofiring – Suspension Firing of Biomass in Existing Coal Boiler	2-54
Technology Description.....	2-54
Appropriate Fuel Qualities.....	2-57
Costs	2-57
Construction Schedule and Permitting.....	2-58
Technology Status and Development Risk	2-59
7b) and 7c) Indirect Cofiring - Externally gasify biomass and fire in existing fossil fuel boiler	2-60
Technology Description.....	2-60
Appropriate Fuel Qualities.....	2-66

Construction Schedule and Permitting.....	2-66
Costs	2-67
Technology Status and Development Risks	2-68
Discussion and Comparison of Repowering Technologies	2-71
Review of Factors.....	2-72
Deployment Status	2-72
Deployment Opportunity	2-72
Incentives.....	2-74
Other Considerations.....	2-77
Summary of Results	2-78
3 FUEL HANDLING CONSIDERATIONS	3-1
Fuel Handling, Storage, and Processing Considerations.....	3-1
Physical Characteristics	3-1
Chemical Characteristics	3-2
Energy Density	3-2
Amount of Fuel to be Stored on Site	3-2
Risk of Explosions or Fire.....	3-3
Proximity to Existing Transportation Infrastructure/Ease of Transportation	3-3
Level of Automation Desired	3-3
Biomass Fuels to be Considered	3-3
Key Properties: Wood Chips	3-3
Physical Characteristics.....	3-3
Chemical Characteristics	3-4
Energy Density	3-6
Risk of Explosions or Fire	3-6
Key Properties: Wood Pellets.....	3-7
Physical Characteristics.....	3-7
Chemical Characteristics	3-8
Energy Density	3-9
Risk of Explosions or Fire	3-9
Key Properties: Torrefied Wood Pellets	3-10
Physical Characteristics.....	3-10
Chemical Characteristics	3-11
Energy Density	3-11

Risk of Explosions or Fire	3-11
4 CASE STUDY ANALYSES: TECHNICAL DATA	4-1
Baseline Pulverized Coal Plant Facility Description	4-2
Conceptual Plant Modification Diagrams and Overview of Case Studies	4-3
Case 1 – BFB Retrofit to Fire Wood Chips	4-3
Case 2 – Suspension Firing of Pulverized Wood Pellets	4-5
Case 3 – Suspension Firing of Pulverized Torrefied Wood Pellets	4-7
Case 4 – Cofiring of Biomass-derived Syngas with Pulverized Coal	4-9
Performance Modeling	4-11
Key Inputs and Assumptions	4-11
Feedstock Assumptions.....	4-11
Base Case: Coal-fired Operations.....	4-14
Case 1 – BFB Retrofit with Wood Chip Firing	4-15
Boiler Plant Performance	4-15
Fuel Delivery and Storage	4-18
Fuel Processing	4-19
Additional Data	4-20
Case 2 – Suspension firing of pulverized wood pellets	4-21
Boiler Plant Performance	4-21
Particle sizing and residence time.....	4-22
Milling and associated parasitic loads.....	4-23
Additional concerns.....	4-24
Specifications	4-25
Fuel Delivery and Storage	4-27
Fuel Processing	4-29
Fuel firing	4-29
Case 3 – Suspension firing of torrefied wood pellets	4-31
Boiler Plant Performance	4-31
Specifications	4-33
Fuel Delivery and Storage	4-35
Case 3a.....	4-35
Case 3b.....	4-35
Case 3c.....	4-35
Fuel Processing (all cases).....	4-36

Fuel Firing	4-36
Additional Data	4-40
Case 4 – Cofiring of biomass-derived syngas with pulverized coal	4-40
Boiler Plant Performance	4-40
Specifications	4-41
Fuel Delivery and Storage	4-44
Fuel Processing	4-44
Additional Data	4-46
Comparative Analysis: Key Economic Decision Factors and Industry Viewpoint	4-46
Emissions Performance	4-48
Industry Perspectives and Risk Analysis	4-50
Fuel supply issues	4-51
Technology risk	4-52
Explosion hazards / fire	4-53
Project cost	4-53
Environmental compliance	4-53
Future economic benefit cash flow	4-54
Future shifts in government or public perception	4-54
5 CASE STUDY ANALYSIS: ECONOMICS	5-1
Capital Costs	5-1
Scenario Cost Summary	5-2
Case 1 – BFB with wood chips	5-2
Case 2 – Conversion for wood pellet firing	5-2
Case 3 – Conversion for torrefied wood pellet firing	5-3
Case 4 – Gasification Cofiring	5-4
Non-Fuel Operations and Maintenance Costs	5-13
Scope of Analysis	5-13
Labor Costs	5-14
Non-Labor Costs	5-18
O&M Estimation Results	5-18
Fuel Costs	5-19
Other Key Inputs and Assumptions	5-20
Economic Analysis Results	5-22
Discussion	5-27

6 INDUSTRY IMPLICATIONS ANALYSIS.....	6-1
Data Sources	6-1
Analysis of Regional Variation of Key Factors	6-3
Facility Locations for Repowering Candidates	6-3
Biomass Resources and Transportation Modes	6-6
Economic Factors.....	6-10
Property Taxes	6-12
Permitting Lead Times.....	6-12
Incentives and Environmental Standards	6-12
Renewable Portfolio Standards	6-12
Regional Carbon Initiatives.....	6-13
Northeastern Regional Greenhouse Gas Initiative	6-15
Western Climate Initiative (WCI).....	6-15
The Midwest Greenhouse Gas Accord	6-15
Methodology for Qualitative Analysis	6-16
Discussion	6-19
Recommendations for Additional R&D Efforts	6-20
7 CONCLUSIONS	7-1
8 REFERENCES	8-1
A DETAILED TECHNOLOGY OVERVIEW MATRIX.....	A-1
B TRANSPORTATION MODE ANALYSIS.....	B-1
Truck Trailer Transportation Limitations.....	B-1
Modal Analysis	B-2
Truck Transportation	B-2
Rail Transportation	B-3
Barge Transportation.....	B-5
Mode Comparison	B-7
C THERMOFLEX MODELING; MASS BALANCE RESULTS	C-1
D OPERATIONS AND MAINTENANCE DETAILS	D-1
E STATE LEVEL QUALITATIVE ANALYSIS MATRIX	E-1

F CAPITAL COST ANALYSIS METHODOLOGY DETAILS	F-1
Scaling Technique.....	F-1
Contingency and Other Factors	F-1

LIST OF FIGURES

Figure 2-1 Boiler Age Based on Unit (Top). Age Distribution of Installed Boiler Capacity (Bottom).	2-3
Figure 2-2 Average Coal Boiler Size by Age	2-4
Figure 2-3 Boiler Size Based on Number of Units (top). Size Distribution of Boiler Capacity (bottom).	2-5
Figure 2-4 Example Process Diagram for Option 1: Turbine-Sized Repowering using New Grate Boiler (95 MW _{gross})	2-21
Figure 2-5 Example Process Diagram for Option 2: Turbine-Sized Repowering using Fluid Bed Boiler (48.8 MW _{gross})	2-28
Figure 2-6 General Process Flow Diagram for Option 3 – Modified Grate Boiler (95 MW _{gross})	2-33
Figure 2-7 General Process Flow Diagram for Option 4 – Modified BFB Boiler (94 MW _{gross})	2-38
Figure 2-8 Example Process Diagram for Option 5 – Modified Grate Boiler (41 MW _{gross})	2-42
Figure 2-9 Example Process Diagram for Option 6 – Modified Fluid Bed Boiler (39 MW _{gross})	2-46
Figure 2-10 Example Process Diagram for Direct Cofiring	2-51
Figure 2-11 Example Process Diagram for Indirect Cofiring	2-52
Figure 2-12 Example Process Diagram for Parallel Cofiring	2-53
Figure 2-13 Example Process Diagram for Option 7a – Direct Cofiring in Existing Coal Boiler	2-56
Figure 2-14 Example Process Diagram for Option 7b – Indirect Cofiring in Existing Coal Boiler	2-64
Figure 2-15 Example Process Diagram for Option 7c – Indirect Cofiring in Existing Gas/Oil Boiler	2-65
Figure 4-1 Block Flow Diagram for Case 1	4-4
Figure 4-2 Block Flow Diagram for Case 2	4-6
Figure 4-3 Block Flow Diagram for Case 3	4-8
Figure 4-4 Block Flow Diagram for Case 4	4-10
Figure 4-5 Biomass Storage and Reclaim System	4-19
Figure 4-6 Power Plant Layout (Case 1)	4-20
Figure 4-7 Case 1 BFB Retrofit Project Timeline	4-21
Figure 4-8 Biomass Storage and Reclaim System	4-27
Figure 4-9 Cross Section of Biomass Pile in Storage	4-28

Figure 4-10 Power Plant Layout (Case 2).....	4-30
Figure 4-11 Estimated Project Schedule for Case 2.....	4-31
Figure 4-12 Biomass Storage and Reclaim System	4-36
Figure 4-13 Power Plant Layout (Case 3a).....	4-37
Figure 4-14 Power Plant Layout (Case 3b).....	4-38
Figure 4-15 Power Plant Layout (Case 3c).....	4-39
Figure 4-16 Estimated Project Schedule for Case 3.....	4-40
Figure 4-17 Power Plant Layout (Case 4).....	4-45
Figure 4-18 Estimated Project Schedule for Case 4.....	4-46
Figure 5-1 LCOE Results.....	5-22
Figure 5-2 Cost Components; Constant LCOE.....	5-23
Figure 5-3 Case 1 – LCOE (Constant) Sensitivity Analysis	5-24
Figure 5-4 Case 2a – LCOE (Constant) Sensitivity Analysis	5-25
Figure 5-5 Case 2b – LCOE (Constant) Sensitivity Analysis	5-25
Figure 5-6 Case 3a1 – LCOE (Constant) Sensitivity Analysis	5-26
Figure 5-7 Case 3a2 – LCOE (Constant) Sensitivity Analysis	5-26
Figure 5-8 Case 4 – LCOE (Constant) Sensitivity Analysis	5-27
Figure 6-1 Standard Federal Regions.....	6-3
Figure 6-2 Fleet of Coal, Oil, and Natural Gas Fired Boilers.....	6-4
Figure 6-3 Types of Coal-fired Boilers	6-5
Figure 6-4 Summary of Biomass Resource Availability and Transportation	6-8
Figure 6-5 Pellet Plant Locations	6-9
Figure 6-6 Average Retail Pellet Prices	6-10
Figure 6-7 Hourly Median Wage for Power Plant Operators	6-11
Figure 6-8 State Average Cost of Electricity	6-11
Figure 6-9 Status of State RPS Activity	6-13
Figure 6-10 Regional Carbon Initiatives.....	6-14
Figure 6-11 Roads and Railroads used for Transportation Availability Analysis.....	6-17
Figure B-1 Transportation Costs for Biomass Delivered by Truck.....	B-3
Figure B-2 Transportation Costs for Biomass Delivered by Rail.....	B-4
Figure B-3 Transportation Costs for Biomass Delivered by Barge	B-6
Figure B-4 Transportation Mode Comparison for Wood Pellets	B-8
Figure B-5 Transportation Mode Comparison for Torrified Wood Pellets	B-9
Figure B-6 Comparison of Transportation Costs by Fuel Type and Mode.....	B-10
Figure B-7 Comparison of Delivered Fuel Costs by Fuel Type and Mode.....	B-11
Figure C-1 Base Case Coal Model Process Diagram, Part 1	C-2
Figure C-2 Base Case Coal Model Process Diagram, Part 2	C-3
Figure C-3 Wood Chips Repowering Model Process Diagram.....	C-4
Figure C-4 Wood Pellets Repowering Model Process Diagram, Case 2a.....	C-5

Figure C-5 Wood Pellets Repowering Model Process Diagram, Case 2b	C-6
Figure C-6 Torrefied Wood Pellets Scenario 3.1 Repowering Model Process Diagram.....	C-7
Figure C-7 Torrefied Wood Pellets Scenario 3.2 Repowering Model Process Diagram.....	C-8
Figure C-8 Syngas Repowering Model Process Diagram	C-9

LIST OF TABLES

Table 2-1 Status of the Coal Boiler Fleet	2-6
Table 2-2 Primary NO _x Control Technology	2-6
Table 2-3 Boiler Firing Design Type	2-7
Table 2-4 Primary PM Control Technology	2-7
Table 2-5 Proposed Boiler MACT Limits.....	2-10
Table 2-6 Gasifier Characteristics by Type	2-17
Table 2-7 Option 1 Summary: Replace existing boiler with turbine sized new grate boiler	2-25
Table 2-8 Summary for Option 2: Replace existing boiler with turbine sized new fluid bed boiler	2-31
Table 2-9 Summary for Option 3: Modify existing coal boiler for grate firing	2-36
Table 2-10 Summary for Option 4: Modify existing coal boiler for fluid bed firing	2-40
Table 2-11 Summary for Option 5: Modify existing gas/oil boiler for grate firing.....	2-44
Table 2-12 Summary for Option 6: Modify existing gas/oil boiler for fluid bed firing	2-48
Table 2-13 Methods of Direct Co-firing	2-49
Table 2-14 Methods of Indirect Cofiring	2-50
Table 2-15 Comparison of Properties for Different Fuels	2-54
Table 2-16 Biomass Fuel Qualities for Cofiring in a Coal Boiler	2-57
Table 2-17 Commercial Scale Direct Cofiring Project Examples	2-59
Table 2-18 Emissions Data for Lahti Gasification Cofiring.....	2-62
Table 2-19 Summary for Option 7a: Suspension firing of biomass to existing coal boiler	2-70
Table 2-20 Summary for Option 7b: Externally gasify biomass and fire in existing coal boiler	2-70
Table 2-21 Summary for Option 7c: Externally gasify biomass and fire in existing gas/oil boiler	2-71
Table 2-22 U.S. Coal Plant Data Summary	2-73
Table 2-23 U.S. Utility Scale Natural Gas and Oil Boilers	2-73
Table 2-24 Simplified Technology Comparison Matrix	2-79
Table 3-1 Chemical Reactions in Biomass	3-2
Table 3-2 Wood Chips – Chemical Reaction Effects & Preventive Measures	3-5
Table 3-3 Wood Chips – Fire Preventative Measures	3-7
Table 3-4 Wood Pellets – Chemical Reaction Effects & Preventative Measures	3-9
Table 3-5 Wood Pellets – Fire and Explosion Preventative Measures	3-10

Table 4-1 Fuel Properties Used in Analysis	4-12
Table 4-2 Air Requirements by Fuel Type	4-13
Table 4-3 Estimated Performance of Case 1	4-17
Table 4-4 Estimated Performance for Case 2.....	4-26
Table 4-5 Storage and Handling Safety Measures for Wood Pellets.....	4-29
Table 4-6 Estimated Performance of Case 3.....	4-34
Table 4-7 Estimated Performance of Case 4.....	4-43
Table 4-8 Performance Comparison for Repowering Technologies	4-47
Table 4-9 Reference Emissions for Biomass Fluid Bed Operation.....	4-49
Table 4-10 Reference Emissions for Biomass Stoker Operation.....	4-50
Table 5-1 Capital Costs for Case 1 (BFB retrofit with wood chips).....	5-5
Table 5-2 Capital Costs for Case 2a (Wood pellets, mill limit).....	5-6
Table 5-3 Capital Costs for Case 2b (Wood pellets, flue gas limit).....	5-7
Table 5-4 Capital Costs for Case 3a.1 (Torrefied wood pellets with concrete dome storage and mill limit)	5-8
Table 5-5 Capital Cost for Case 3a.2 (Torrefied wood pellets with concrete dome storage and flue gas limit)	5-9
Table 5-6 Capital Costs for Case 3b.1 (Torrefied wood pellets with open pile storage and mill limit)	5-10
Table 5-7 Capital Costs for Case 3c.1 (Torrefied wood pellets with rectangular storage and flue gas limit)	5-11
Table 5-8 Capital Costs for Case 4 (Syngas cofiring).....	5-12
Table 5-9 Plant Personnel Description	5-15
Table 5-10 Plant Staffing Requirements	5-16
Table 5-11 Hourly salaries and assumptions.....	5-17
Table 5-12 O&M Results.....	5-18
Table 5-13 Fuel Cost by Type.....	5-19
Table 5-14 Key Financial Inputs	5-20
Table 5-15 Operating inputs	5-21
Table 5-16 Breakeven Comparison	5-28
Table 6-1 Ranking of Regional Attributes	6-18
Table B-1 Physical Limitations for Walking Floor Trailers.....	B-2

1

INTRODUCTION AND BACKGROUND

As interest in renewable energy technologies has increased, greater attention has been given to the potential for utilizing biomass resources in existing energy production systems. Many options are being proposed for modifying or converting fossil-fired generation systems to use renewable feedstocks, such as wood chips and agricultural residues, instead of their traditional, non-renewable energy sources (most frequently, coal). This interest has been driven by a number of factors, but the emergence of state-based Renewable Portfolio Standards (RPS) and growing concerns regarding future carbon regulation have been the most pressing.

While there are a wide variety of fossil-fired plants in operation today, coal-fired power plants continue to provide approximately half of the electricity used in the United States. Biomass resources, many of which are both plentiful and often available at lower costs than coal, are an appealing substitute.

The purpose of this report is to provide detailed analysis specifically targeted at a subset of the renewable options available to utility companies with existing coal-fired electric generation assets: namely, biomass repowering and high percentage fuel switching. Although repowering¹ and fuel switching are technically different, the intended result within the narrow context examined in this report is the same: leveraging existing coal-fired generation assets to allow for a significant or complete conversion to biomass-derived fuels.

In this report, such conversions range from major plant changes (including boiler replacement) to making almost no plant modifications and simply moving to highly processed biomass fuels (which can, in some cases, be fired directly into existing combustion systems).

This report covers nine different potential configurations at a macroscopic level, and then focuses in on four specific options within the context of individual case studies. These case studies, for example, weigh trade-offs between capital investments to use raw wood chips versus the potential to avoid such investments by using more highly processed, specially engineered fuels (such as torrefied wood and pellets, which have garnered considerable attention from electric utilities).

Using available data from EPRI repowering feasibility studies and reports from operating repowered facilities, this analysis examines the costs and benefits of implementing these various configurations, including impacts on plant performance and energy production efficiency.

¹ The U.S Energy Information Administration (EIA) defines repowering as “refurbishment of a plant by replacement of the combustion technology with a new combustion technology, usually resulting in better performance and greater capacity.”

This report also addresses additional factors, including the impact that a plant's location may have on key variables and project development risks, as well as insight into specific factors that should be considered carefully when applying the lessons derived from this analysis to EPRI members' own coal-fired plant inventories.

2

BIOMASS REPOWERING TECHNOLOGY OPTIONS

This chapter provides an overview of the variety of biomass conversion options available to owners interested in repowering² their existing coal-fired generation assets. Background on the overall U.S. coal-fired fleet is provided for perspective. These data are followed by a high-level review and assessment of current repowering technologies, ranging from complete boiler replacement to high percentage cofiring using biomass gasification.

Coal Boiler Fleet Market Assessment

Understanding the existing U.S. coal boiler fleet helps provide perspective on the overall opportunity for biomass repowering in this country. Available data considered in this analysis include the number and type of plants, their capacities, and the equipment utilized to reduce emissions. It is particularly important to also look at the characteristics of older plants that may be retired from standard operations currently, as these facilities may potentially be reconfigured with new or modified boilers designed to run on biomass fuels.

The National Energy Technology Laboratory (NETL) has a publicly available database which served as the basis for this analysis. As stated by NETL, the Coal Power Plant Database (CPPDB) “contains emissions, generation, location, and firing information for all coal power plants in the United States” (NETL, 2007). The information is compiled from the EIA form 767, EIA form 423, the National Emissions Inventory Database, and the Clean Air Markets Database. This composite database was released in 2007, and is based on data from 2005.

Generally, coal fleet statistics have remained fairly stable over time. Coal-fired generation is a very important contributor to the nation’s energy supply, and it is usually attractively priced compared to alternative sources. The reader should be aware that the data used for this analysis are still representative of the current fleet, although some marginal units have since fallen victim to pricing and legislative changes within the market (or have reached the end of their operational life), and may have changed status since the NETL database was last compiled.

² In context of these options, it is important to re-emphasize that the term “repowering” is being used a bit differently and more narrowly in this report than is typical for the industry. “Repowering” traditionally can refer to any process of replacing or improving existing power plant equipment, whether by changing fuel sources or by simply installing new equipment to improve efficiency and emissions (natural gas-fired combustion turbines are a typical choice). This report focuses solely on repowering conventional energy production systems through biomass technologies. (Advanced biomass gasification systems capable of producing syngas suitable for firing large-scale combustion turbines are still not commercially available, and are therefore not considered within this report.)

There are 605 coal plant sites across the nation, many of which have more than one boiler either in separate buildings or within one facility. There are 1,733 individual boiler units listed in total.³ The characterization below is based on these individual boiler units, as this is how the information was provided in the database. This is also likely to be the most useful information in terms of repowering projects, since plants may choose to use biomass in one or more individual units.

It is also important to note that some of the information in the database is incomplete as a result of differences in how these plants and businesses are regulated, which in turn leads to different reporting requirements. Overall, there were between 300 and 600 units with limited information in some of the categories considered. Many of these facilities are small and, despite the rather large number of them, they represent only a small fraction of the total generating capacity.

Figure 2-1 demonstrates the magnitude of the aging coal fleet, with 94% of the installed capacity being from facilities with boilers installed more than 20 years ago. Additionally, the average age of coal boilers in the current U.S. fleet is 42 years.

Only 6% of the total fleet capacity has been placed in service within the last 20 years, while 16% of the fleet has been on-line for 50 years or more. Most of the boilers are between 25 and 50 years old. The age of the boiler fleet in general suggests that some of these units may be up for replacement, renovations, or closure consideration in the near future, if they aren't already.

³ It is possible that in some cases several boilers feed into a single turbine. As this distinction is not clear in the base data set, it is not possible to accurately assess here.

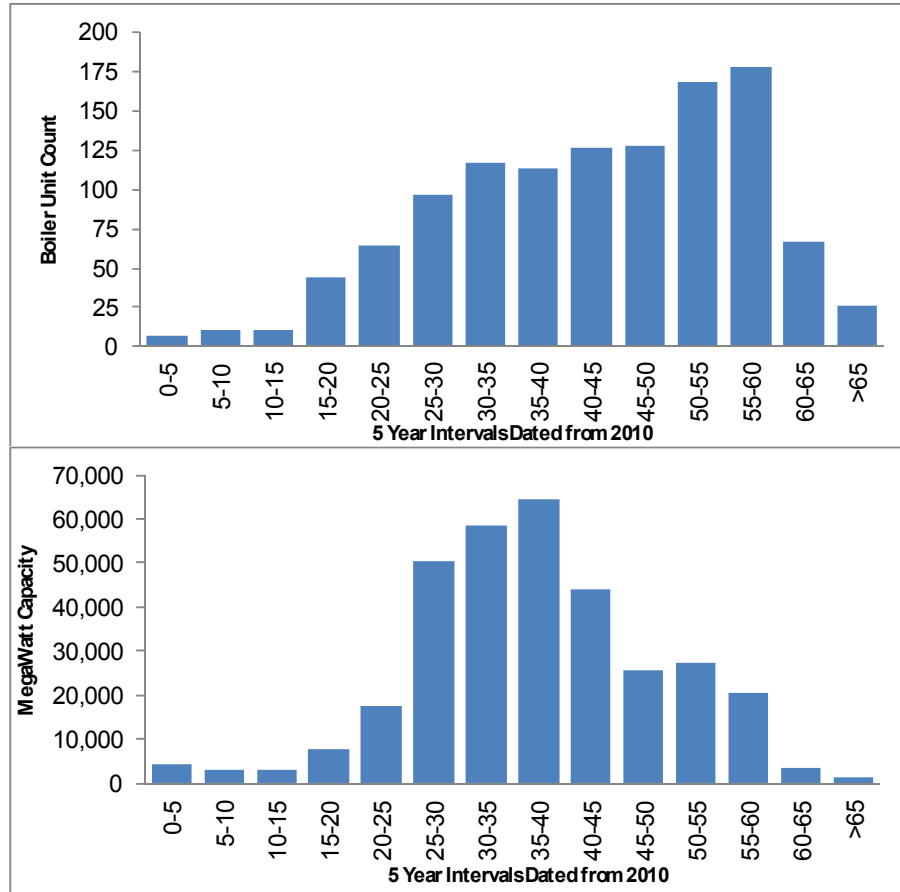


Figure 2-1
Boiler Age Based on Unit (Top). Age Distribution of Installed Boiler Capacity (Bottom).

The average boiler size within each age range is presented in Figure 2-2. The newest facilities, which were either planned or under construction as of 2005, have the largest average size of the group. The facilities that are 5-25 years old are significantly smaller on average, and many of these may have been add-ons to existing facilities. Meanwhile, the units that form the base of the active coal fleet (from 25-40 years old) are of similar average size to the newest ones, with average capacities greater than 500 MW.

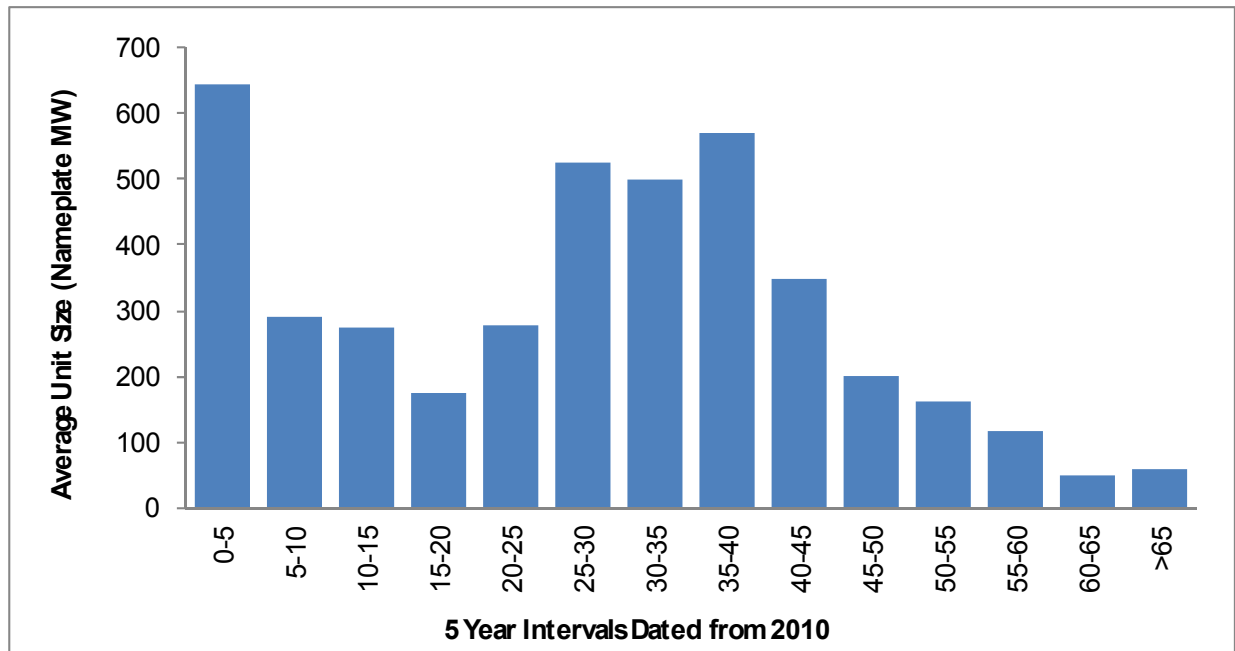


Figure 2-2
Average Coal Boiler Size by Age

The distributions of boiler sizes in terms of number of units and nameplate capacity are shown in Figure 2-3. The average size of coal boilers in the current U.S. fleet is about 300 MW. More than 650 units have capacities under 100 MW. While the boiler units with nameplate capacities greater than 800 MW are comparatively small in number, that segment still has the greatest overall contribution to the total megawatt capacity of the group.

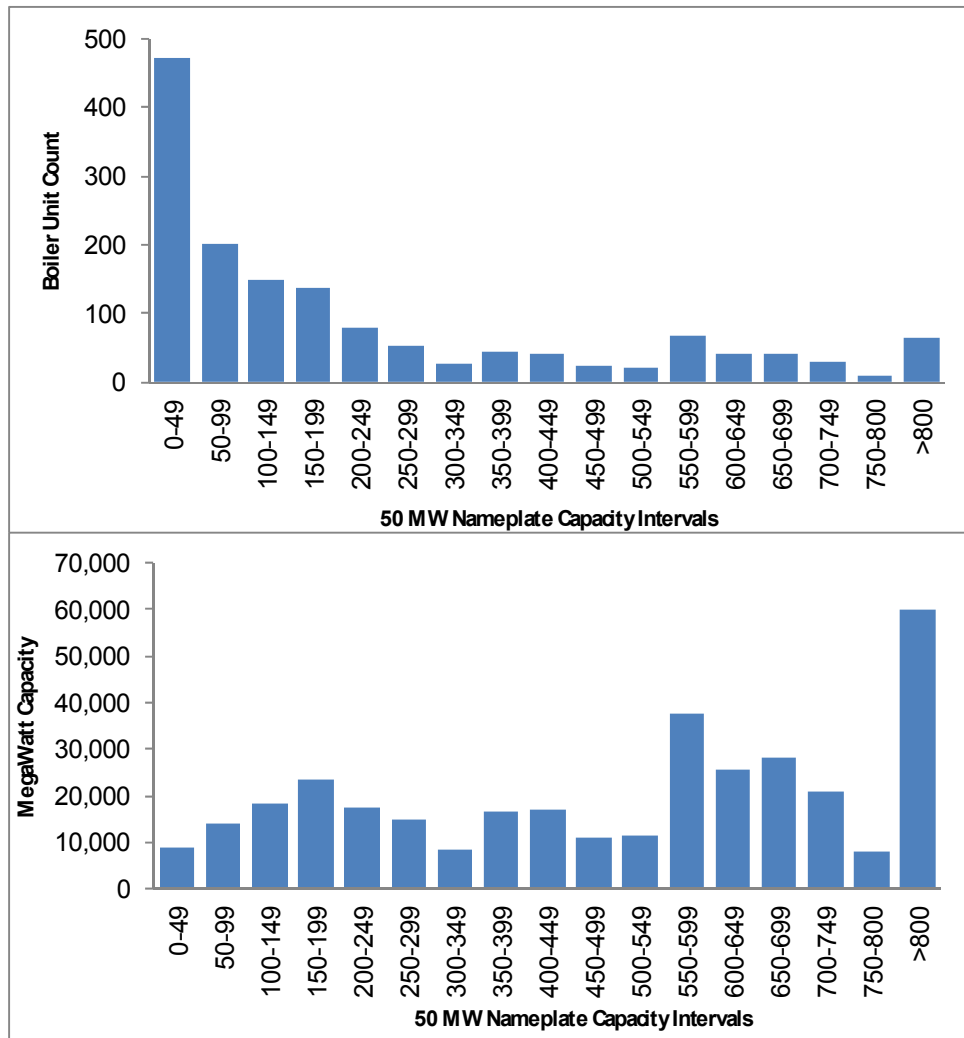


Figure 2-3
Boiler Size Based on Number of Units (top). Size Distribution of Boiler Capacity (bottom).

Table 2-1 shows the status and capacity of the boiler fleet. The boiler status categories are described in greater detail below.

- “Cold Standby (Reserve)” units are operational plants that would take several months to bring online.
- “New units under construction” were listed as currently under construction as of 2005.
- “Operating” units are those that have been fired within the past year.
- “Out of service” plants had not been fired within the last reporting year, but their ultimate fate is unknown.
- “Planned” sites were proposed, but were likely 5 or more years from being operational.
- “Retired” plants are completely out of service, with no plans to bring them back into service.
- “Standby” plants are not normally used, but can be brought into service if needed.

Table 2-1
Status of the Coal Boiler Fleet

Boiler Status	# of Boilers	MW Capacity
Cold Standby (Reserve)	19	1,022
New unit under construction	4	2,986
Operating	1,663	335,117
Out of service	20	559
Planned	3	1,531
Retired	6	184
Standby	18	181
Grand Total	1,733	341,580

Almost all of the reported facilities (96%) are currently operational.

It is interesting to note that while there are six individual boiler units listed as retired, these correspond to just two facilities. Both of these plants are more than 60 years old. Since there are 100 plants overall that are more than 60 years old, this suggests that the majority of these old plants are still operable today (though some had not fired in the reporting year, and a couple are on cold standby). This highlights the longevity of these boilers.

The breakdown of NO_x control practices utilized by the coal boiler fleet is shown in Table 2-2. Low NO_x burners and overfire air strategies are relatively common, and a significant number of larger boilers are also employing selective catalytic reduction (SCR). Based on the age of the underlying data set, it is probable that this number is even higher today.

Table 2-2
Primary NO_x Control Technology

Prevalence of NO_x Control Technologies	Entire Fleet		50-200 MW Units		
	% of	% of MW	% of Boilers	% of MW	% Fleet
Advanced Overfire Air/ Overfire Air	26%	40%	23%	23%	4%
Fluidized Bed Combustion	5%	2%	6%	5%	1%
Low NO _x Burners	45%	69%	52%	57%	10%
Selective Catalytic Reduction	7%	20%	3%	3%	1%
Selective Noncatalytic Reduction	5%	3%	6%	5%	1%
Unknown and N/A	28%	12%	28%	26%	5%
<i>Note: Percentages do not sum to 100% because most boilers employ multiple control technologies.</i>					

Table 2-3 shows the different types of coal boiler designs and their usage within the current fleet. Tangential firing boilers are the most common, making up 39% of the categorized reported units (43% by MW capacity). Cyclone fired boilers and spreader stokers, in comparison, only make up 7% and 4% of the reported boiler fleet, respectively.

In total, approximately 80% of the coal fleet is made of pulverized coal boiler units (which include front firing, opposed firing, rear firing, and tangential firing units). Interestingly, for units with capacities between 50 MW and 200 MW, wall-fired units (front, rear, and opposed) are relatively prevalent.

Table 2-3
Boiler Firing Design Type

Boiler Firing Type	Entire Fleet		50-200 MW Units		
	# of Boilers	MW Capacity	# of Boilers	MW Capacity	% of Category Capacity
Arch firing	8	649	7	649	100%
Concentric firing	1	615	-	-	0%
Cyclone firing	84	25,308	31	3,847	15%
Fluidized bed firing	48	5,921	13	1,768	30%
Front firing	262	35,775	164	20,533	57%
Opposed firing	208	115,228	9	1,191	1%
Rear firing	11	1,179	7	625	53%
Spreader stoker	47	1,005	12	706	70%
Tangential firing	450	141,695	191	23,558	17%
Vertical firing	31	3,764	21	2,314	61%
Unknown	583	10,441	52	4,095	39%

Lastly, Table 2-4 presents data regarding primary particulate matter (PM) control technologies and their utilization within the coal fleet. Overall, about 71% of the units that reported using particulate controls used an electrostatic precipitator (ESP). An additional 19% utilized a baghouse. Multiclones are used in 8% of the units, while only 3% use wet scrubbers.

Table 2-4
Primary PM Control Technology

Primary PM Control Technology	# of Boilers	MW Capacity
Baghouse, pulse	151	10,496
Baghouse, reverse air	129	26,629
Baghouse, shake and deflate	8	1,630
Electrostatic precipitator, cold side, with flue gas conditioning	196	66,186
Electrostatic precipitator, cold side, without flue gas conditioning	678	171,413
Electrostatic precipitator, hot side, with flue gas conditioning	23	7,091
Electrostatic precipitator, hot side, without flue gas conditioning	206	32,899
Multiple cyclone	120	9,926
Single cyclone	3	118
Wet scrubber	42	10,733
Unknown	177	4,459

Discussion of Target Plants

From the discussion above, it was seen that the majority of the coal-fired capacity uses low NO_x burners, though a significant amount of coal-fired capacity also employs additional control via SCR and selective non-catalytic reduction (SNCR) technologies. The units with SCRs also tend to be larger than the overall fleet average (nearly 600 MW on average). This is especially relevant for the following reasons:

1. Given the investment necessary to install SCR, SCR additions are usually made to plants with the expectation that firing coal will remain viable at these sites.
2. The potential operational issues associated with biomass and SCR catalysts will reduce the likelihood that these units are first-tier candidates for biomass-related retrofits. From a technical standpoint, the presence or absence of SCR affects a plant's suitability for biomass repowering. SCR catalysts are sensitive to chemical interference in the form of chemical deactivation (poisoning) and physical deactivation (fouling). DeFusco (2007) suggests that high levels of unburned carbon in fly ash, which is typical of both stoker firing of biomass and suspension firing of wood pellets or wood chips, may also degrade SCR performance. Along those same lines, SCR manufacturers remain reluctant to suggest SCR for plants with high-carbon fly ashes.
3. The fact that these units are larger means that, even accounting for the potential derating due to conversion to biomass, these units would represent very large plants by biomass power standards.

Combined, these factors demonstrate that units currently equipped with SCRs should not be considered prime candidates for biomass repowering.

Beyond the issues associated with SCRs, there are also some additional potential constraints to consider:

- Baghouses have long been avoided for high-loss on ignition (LOI) ashes due to the increased likelihood of fire or explosion. ESPs present a lower combustion hazard for these materials, meaning that they are preferred given the high-carbon ashes typical of stoker firing of biomass (DeFusco, 2007). Plants with existing baghouses are not ideal for stoker repowering, or for suspension firing of wood pellets or wood chips, all of which produce high-LOI ashes. In such cases, capital investments may be required to either replace the baghouse with an ESP or to mitigate the fire hazards associated with keeping the baghouse in place (this would likely be done by using enhanced filter cleaning and expedited ash removal). While this does not completely rule out a facility currently employing baghouses, it does suggest that owners may want to consider such plants as being second-tier targets.
- The existing boiler geometry is also important to consider. For example, pulverized coal fired boilers that are already experiencing short residence times or particle burnout issues are even more likely to have higher levels of unburned combustibles when suspension firing wood pellets (or even torrefied wood). Particle size and residence time are both discussed in more detail in subsequent sections.

On the other hand, units with low capacity factors (including oil or gas units), as well as units that are facing retirement because emission control upgrades are not economically justified, may be excellent targets. As noted in the tables above, there are numerous smaller, older coal-fired units in the U.S. fleet. Given the industry's preference to equip larger units with SCRs, many of these smaller plants may be at risk of being retired, and repowering with biomass may present an attractive alternative.

Environmental Issues and Constraints

The potential environmental and regulatory compliance issues surrounding biomass repowering projects can be both extensive and complicated. There are issues related to the extent of the plant modification, the fuel source, the technology selection, and the project's geographical location. To complicate matters further, the EPA is in the process of issuing new Maximum Achievable Control Technology (MACT) and Commercial and Industrial Solid Waste Incinerator (CISWI) Rules. Depending on the EPA's final guidance, these new rules could have profound implications on the ability of certain technologies to be sited at an existing plant. A summary of the proposed regulations is provided below.

Given the complexity of these issues, this discussion is limited to the direct impacts that new rules may have on equipment choices for a repowering project, specifically with respect to choices for pollution control equipment.

EPA Boiler MACT

In June 2010, the U.S. EPA released its draft changes to MACT regulations for industrial boilers. The initial boiler MACT rules were put in place in 2004, but these were rescinded by a court ruling in 2007 due to concerns that the rules were not stringent enough and required clearer definition. The draft modifications are the EPA's long-anticipated first attempt at revised boiler MACT rules. The EPA accepted comments on the draft rule until August 23, 2010 and had planned to make its final decisions at the end of October 2010 so that the Office of Management and Budget could begin a 60-day review period in early November. The deadline for the final rule to be released was set for January 14, 2011. However, in early December, the EPA asked for a 15 month extension to finalize the boiler MACT rule, until April 13, 2012, to respond to new data and ensure that the final rule appropriately characterizes emissions limits. If this preferred extension is not granted, the EPA has asked for at least a 5 month extension (to June 15, 2011) to complete the rulemaking.

It is unclear how much the current draft will resemble the final rules, but the draft does provide some insight into the EPA's intentions. For example, the rule uses surrogate emissions to help ensure regulation of the 188 target pollutants covered by MACT. Most relevant to this project, carbon monoxide (CO) has been proposed as the surrogate for organic compounds, and hydrochloric acid (HCl) as the surrogate for acid gases.

Of key importance are the limits associated with carbon monoxide. In its draft rule, the EPA proposed CO limits for various boiler technologies, including biomass fluidized beds and stokers. While the EPA views the surrogate emissions approach as reasonable, the CO limits proposed for biomass-fired units appear to be at the lower end of rates permitted in the existing fleet, as well as those in more recent installations.

For reasons including fuel flexibility and improved emissions performance, fluidized bed technologies are increasingly preferred over stoker boilers. However, achieving the CO emission limits listed in Table 2-5 could be a potential concern, since it is difficult to achieve these levels while simultaneously meeting likely NO_x emission requirements without having to resort to SCR technologies. Several vendors supplying quotes for other projects as part of recent feasibility studies have stated that they believed they could meet a 40 parts per million (PPM) CO emission limit (with no exclusion for start-up/shut-down and load changes) and achieve NO_x emission levels in the 0.10-0.15 lb/MMBtu range using SNCR⁴ technologies and best combustion practices. However, this issue will need to be revisited and a firm guarantee must be secured from vendors before a new boiler is installed.

Table 2-5
Proposed Boiler MACT Limits

Boiler Type	PM (lb/MMBtu)	Hg (lb/MMBtu)	CO (PPM)
New Biomass Stoker	0.008	0.0000002	560
New Biomass Fluidized Bed	0.008	0.0000002	40

Additional information has been collected regarding control of other pollutants, including particulate matter (PM) and mercury. Although the PM limits shown above are low, fluidized bed boiler vendors contacted during previous studies have expressed confidence that they could be met using bag filtration. HCl and mercury emissions can be controlled using sodium bicarbonate and activated carbon injection. A number of these vendors indicated that they were comfortable that the emission limits listed above could be met using these technologies.

EPA CISWI Rules

The EPA also had its CISWI rules vacated in 2004, and it has released draft guidance on this regulation as well. For non-exempt units, the CISWI rules govern the emissions of pollutants not explicitly listed in the MACT rules and could impose additional emission control requirements. Although it is difficult to imagine that the EPA or state environmental offices will set forth rules that would classify bark or woodchips as a solid waste, other potential sources of biomass fuels may be affected and reclassified. This could limit potential fuel options for those facilities seeking to avoid CISWI classification (and the additional emission restrictions and reporting requirements that go along with it).⁵

⁴ SNCR is considerably less capital intensive than SCR, but its ability to lower total NO_x emissions is also more limited.

⁵ The EPA has developed a flowchart methodology for determining whether a material is or is not a solid waste, the flowchart is available here: <http://www.epa.gov/epawaste/nonhaz/define/flow-ingredient.htm>.

Tailoring Rule

In May 2010, the EPA issued a final rule defining when greenhouse gas (GHG) emissions from new and existing stationary sources would require New Source Review Prevention of Significant Deterioration (PSD) and Title V operating permits under the Clean Air Act (CAA). The rule tailors the GHG emissions threshold to shield small polluters (such as farms and schools) while regulating the larger stationary sources (power plants, landfills, refineries, and industrial plants). The latter are responsible for an estimated 70 percent of the nation's GHG emissions.

The compliance schedule is implemented in two steps, initially focusing on the largest sources (which already have experience with CAA reporting requirements) and then expanding to cover additional facilities that may not currently be covered by the CAA.

The rule addresses the following six GHGs:

- Carbon dioxide (CO₂)
- Methane (CH₄)
- Nitrous oxide (N₂O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride (SF₆)

Beginning in January 2011, facilities that are currently required to obtain PSD and Title V operating permits must also include GHGs in their permitting requirements if their GHG emissions increase by over 75,000 tons (68,040 tonnes) CO₂ equivalent per year. Beginning in July 2011, these requirements will also apply to all new facilities emitting over 100,000 (90,720) tons of GHGs annually, all existing facilities that emit over 100,000 tons annually, and any facilities that increase their emissions by 75,000 tons annually, even if these projects do not exceed reporting thresholds for other criteria pollutants. Facilities that are subject to these new GHG requirements will be required to install Best Available Control Technology (BACT) equipment to control their GHG emissions. The EPA is currently developing an additional rule that should be complete before July 2012 and would make sources that emit over 50,000 (45,360) tons of GHGs annually subject to these reporting requirements as well. The EPA does not anticipate that this additional rule would take effect before April 2016.

Considerable controversy has arisen over the fact that the final rule does not distinguish between fossil-based CO₂ emissions and biogenic CO₂ emissions. As written, the tailoring rule would include bioenergy and bioprocessing facilities in the permitting process. Stakeholders requested that the EPA allow emissions of biogenic GHGs to be excluded, partially or wholly, for the purposes of the BACT analysis and the PSD program. In July 2010, the EPA requested information on GHG emissions associated with biogenic sources. In the document "PSD and Title V Permitting Guidance for Greenhouse Gases," which was released on November 10, 2010, the EPA described how, in advance of any further action from them, state permitting authorities may independently consider the environmental, energy, and economic benefits of biomass for energy generation when conducting BACT analyses for GHGs. Of particular note is the

statement that, based upon considerations of the potential benefits of biomass, “permitting authorities might determine that, with respect to the biomass component of a facility’s fuel stream, certain types of biomass by themselves are BACT for GHGs” (EPA, 2010).

In January 2011, the EPA expects to issue a suggested technical framework for analyzing the environmental, energy, and economic benefits of biomass, with the intent of allowing permitting authorities to streamline their own processes of determining BACT relative to biomass; the EPA anticipates that this guidance will address specific types of biomass feedstocks. In addition, the EPA plans to determine prior to May 2011 (in advance of the July 2011 implementation date for the second phase of the Tailoring Rule) whether a supplemental rule is sufficient to address the issue of quantifying the net impact of CO₂ emissions from biogenic sources.

Overview of Biomass Repowering Technologies

This section of the chapter will examine the technology options available for a utility-based biomass repowering project. Nine biomass repowering scenarios will be compared at a macroscopic level in terms of operational characteristics, process design implications, technical risk, and cost. These options have been selected based upon industry trends and following consultation with potential utility end-users and original equipment manufacturers that are active in the boiler repowering market.

The biomass repowering scenarios are as follows:

1. Replace existing boiler with turbine-sized new stoker grate boiler (equivalent steam output rate and conditions)
2. Replace existing boiler with turbine-sized fluid bed boiler
3. Modify existing coal boiler for stoker grate firing
4. Modify existing coal boiler with fluid bed firing
5. Modify existing gas/oil boiler for grate firing
6. Modify existing gas/oil boiler with fluid bed firing
7. High percentage cofiring:
 - a. Apply suspension firing of biomass to existing coal boiler
 - b. Externally gasify biomass and fire in existing coal boiler
 - c. Externally gasify biomass and fire in existing gas/oil boiler

Technology Primer

Since the same technical principles apply to a number of the above options (and to avoid repetition), an overview of several major types of biomass conversion are described below prior to the more detailed breakout discussions in the next subsection.

Stoker Grate Firing

Stoker-grate boiler technology is a well-established, traditional solid fuel firing technology. Fuel is propelled either mechanically or pneumatically through chutes on the sides of the boiler and spread across a combustion grate within the boiler. There are several common types of grates available, including rotating, vibrating, and chain/traveling, all of which may or may not be employed in a spreader stoker configuration.

Rotating grates, which have generally been used for smaller biomass systems, feed fuel from the top of a conical surface in the boiler, distributing it along a 360-degree rotation. The fuel's descent along the slope of the cone allows the material to dry before reaching the combustion zone at the perimeter of the boiler.

Vibrating grates use intermittent vibration to distribute fuel evenly after the material has been deposited onto the grate surface. The vibration eliminates fuel piling, thus allowing relatively complete combustion of fuels even in the case of high moisture content. These grates are generally cooled with either air or water, allowing higher under-fire air temperatures (in the case of water cooling) and greater use of over-firing without slag formation or grate damage. This technology is favored for larger biomass boilers.

Chain or traveling grates use a moving grate surface to mechanically convey the fuel distributed onto the grate at one side of the boiler toward the other side of the boiler. The fuel is combusted with air supplied from underneath the grate as it travels along, such that only ash remains by the time the fuel reaches the far side of the boiler. At that point, the ash falls into hoppers for removal. This continuous ash removal means that the combustion and fuel feeding rates must be relatively constant in order to achieve relatively complete combustion with predictable levels of unburned carbon in the removed material.

As noted previously, fuel can be conveyed to the boiler either mechanically or pneumatically. Pneumatic conveyance is specifically used for spreader stoker systems, which combine both stoker and suspension firing techniques to deliver fuel to the grate. Fuel is distributed from above the grate surface, allowing smaller, dryer particles to combust during the fall to the grate surface. Larger, wetter particles, in turn, form a thin layer on the grate surface and undergo combustion there. This spreader stoker type of fuel delivery can be used in combination with any of the grate types noted above.

Fluidized Bed Boilers

Fluidized bed technologies are less prevalently deployed than stoker grate systems but are receiving increased consideration for new and solid-fueled retrofit projects. This is due primarily to their improved emissions characteristics, carbon burnout, and, in some cases, their ability to burn higher moisture content fuels. Fluidized bed boilers are generally classified as either circulating fluidized bed (CFB) or bubbling fluidized bed (BFB), although some subtypes and variations of these designs do exist. These systems can operate either near atmospheric pressure or at elevated pressure.

All fluidized bed technologies use a mass of inert, sand-like material that is suspended along with small fuel particulates by high-velocity under-fire air. This mass of inert particles provides thermal inertia to the system, stabilizing combustion in the face of changing fuel composition or moisture content by ensuring that fuel particles quickly reach combustion temperature. The fluidized state of the bed allows maximum exposure of the fuel particles to air, leading to very complete combustion, generally beginning with a gasification stage in the lower part of the bed and a combustion stage in the upper part of the bed, or above the bed.

Fuel is fed from above the bed and quickly dispersed by the movement of the fluidizing air and inert bed material. The bed material acts as a heat sink during combustion, allowing combustion to occur at comparatively low temperatures, generally 1,472 to 1,652°F (800 to 900° C). These lower temperatures allow, in turn, low levels of excess air, leading to high overall system efficiency. The low temperature also inhibits NO_x formation (which occurs at almost 1,000°F (556°C) higher than this range). After combustion, a mixture of bed material, ash, and flue gas may flow through a cyclone to remove bed material before leaving the boiler. Whether or not this occurs depends upon the type of fluidized bed design used.

Bubbling beds have relatively low fluidization velocities (3.3 to 9.9 ft/s) (1 to 3 m/s) and thus little carryover of bed particles to the cyclones. They are relatively insensitive to changes in fuel sizing and composition. Fluidized bed systems are controlled carefully for temperature, and in the case of bubbling beds, convection pass heat exchange tubing can be suspended as a cantilever into the bed itself to provide a heat sink. Controlling the amount of bed material and fluidizing air allows operators to control the bed height, and thus how many such tubes are acting as heat sinks within the bed itself to control temperature.

Circulating beds use higher-velocity (13.2 to 39.6 ft/s) (4.0 to 12.1 m/s) fluidizing air, leading to extensive bed material carryover out of the furnace. Large cyclones placed just after the economizer (but before the air preheater) are used to capture the bed particles and recycle them to the bottom of the furnace for re-suspension. Some circulating beds use impacting surfaces near the top of the boiler to knock out a large portion of the bed particles entrained in the flue gas, thus reducing the load on the hot cyclones. These particles return via gravity to the bottom of the furnace.

Due to their higher particle velocities, CFBs are vulnerable to erosion problems. For this reason, convection tubes are not suspended within the bed itself, as can be done with BFBs. Instead, the reinsertion rate of the bed material collected by the cyclones and impact surfaces is controlled, allowing the particle loading (and thus the available heat sink for combusting fuel) to be controlled. This in turn controls boiler temperature.

As noted above, BFBs and CFBs can operate at either atmospheric or elevated pressure. If operated at elevated pressure, the outlet flue gas is of high enough pressure to be used in a gas turbine, making high-pressure systems of interest for gasification rather than combustion applications.

Both CFBs and BFBs generally use flue gas recirculation (FGR) to control both NO_x formation and boiler/bed temperature. Both types of systems also have low levels of unburned carbon in their ash, and ash collection is almost exclusively collected as fly ash rather than bottom ash. A 99:1 fly ash to bottom ash ratio is typical of fluid bed systems, compared to the approximately 80:20 ratio seen in stoker grate systems.

Excess air ranges from 20-25% for BFBs and 10-20% for CFBs. Turndown ratios for CFBs and BFBs are 3:1 and 4:1, respectively, compared to 4:1 for stoker grate systems.

Suspension Firing

Suspension firing is a technology commonly used to combust relatively dry particulate fuels in utility-scale boilers. Pulverized coal boilers are the most common example of suspension firing of solid fuels, using fans to blow pressurized mixtures of combustion air and finely milled fuel particles into the boiler through an array of burners that are mounted through the boiler wall(s). These particles combust while suspended within the boiler furnace. This suspended firing allows combustion to take place in a three-dimensional volume, allowing smaller boiler dimensions than are possible in pile or grate firing, which must spread the fuel over a two-dimensional surface. Suspension firing also allows low levels of excess air (10-18%), as the small size of the fuel particles and their thorough mixing with combustion air exposes maximal surface area for combustion.

Fuels for this firing method should ideally be relatively dry (less than 25% moisture) and less than 0.25 inches (0.64 cm) in any dimension. The smaller the particle size and the drier the fuel, the more rapid and complete the combustion process. Fine particle sizing requires significant pretreatment (milling and/or drying), as well as caution in fuel purchasing to avoid extremely high-moisture fuels.

With proper fuel sizing, fuel properties, and furnace conditions, suspension firing typically leads to ash generation at an approximate ratio of 80:20 fly ash to bottom ash (similar to stoker grate systems).

Gasification Technologies

Gasification can be defined as the process of converting a solid fuel into a gaseous fuel by any of a variety of biological, chemical, and thermochemical processes. However, the term “gasification” typically refers to the thermochemical process of oxidizing solid fuel in the presence of substoichiometric amounts of oxygen at moderate temperatures. This generates a syngas⁶ or producer gas containing hydrogen, carbon monoxide, carbon dioxide, and lesser amounts of oxygen and hydrocarbons. This low- to medium-Btu gas can be used as a fuel to replace natural gas in many applications, depending on purity requirements. A co-product of gasification is char, a high-carbon solid that can be combusted for further energy recovery.

⁶ “Syngas” technically refers to a mixture of two moles H_2 per mole CO , as required by the methanol synthesis reaction. However, in common usage, the term “syngas” has come to be synonymous with “producer gas,” referring to any hydrogen- and carbon monoxide-rich mixture of gases. “Syngas” will be used in this more general sense throughout this report.

Gasification technologies can be grouped into either close-coupled or stand-alone types. Close-coupled gasifiers use staged combustion, with a sub-stoichiometric zone in which a solid fuel is gasified, and a stoichiometric zone in either the same vessel or a directly connected unit where the resulting producer gas is combusted. Stand-alone types of gasifiers are usually distinguished by their need for syngas cleanup processes, as the tar and alkali content of raw syngas is often detrimental to downstream uses, such as in a reciprocating engine or a gas turbine generator.

Stand-alone gasifiers can generally be divided into two major categories: fixed- and fluidized-bed systems. The former is an air-starved, lower-temperature, shaft-like grate furnace, while the latter is an air-starved, lower-temperature, fluidized bed furnace. The mechanical aspects of these technologies are discussed above and in the subsections below. There are several other less conventional gasification technologies currently in a demonstration phase, including plasma arc gasification (which is currently applied only to small-scale commercial waste or medical waste processing units) and low temperature hydrothermal gasification (which uses high-moisture fuels in the presence of water and a catalyst). Only fixed- and fluidized-bed gasifiers will be discussed here due to their significantly higher commercial advancement.

When used as gasifiers, fixed beds produce a lower-Btu syngas (100 Btu/ft^3 , $3,726 \text{ kJ/m}^3$) than fluidized beds, though at lower complexity and lower cost. Fluidized bed gasifiers can handle a wider range of biomass fuels, as well as average moisture contents up to 30%. Fixed bed systems (classified as updraft, downdraft, or crossflow, depending on the orientation of the flow of air or oxygen through the gasifier) are commercially dominant, but tend to be limited to smaller district heating and cogeneration projects, generally less than 5 MW_e . This is because the nature of the shaft reactor limits the diameter and thus the throughput. Developers have seen a good match between these smaller gasifiers and small-scale power generation equipment. Fluidized bed gasifiers represent an alternate option, especially for larger scales, and both bubbling and circulating fluidized bed gasifiers have been used commercially in larger utility-scale projects to generate electricity from the producer gas, using a separate boiler to raise steam (Antares, 2003).

Apart from the bed type, gasifiers can also be classified based upon their operating pressure. Many gasifiers are atmospheric, but operation at higher pressures can be used to increase the throughput, albeit with an increase in gasifier complexity and cost. The composition of the oxidizing gases that are used to react with the solid fuel to produce syngas is another useful classification. Air-blown gasifiers are simplest, but the presence of nitrogen and inert gases in the air dilutes the product gas, leading to low heating values. Oxygen-blown gasifiers lead to elevated heating values, but come at the expense of additional equipment to concentrate oxygen for reaction. A third type is the steam-injected gasifier, which uses the hydrogen, oxygen, and heat from medium-pressure steam to react with the fuel, producing syngas with heating values as large as 315 Btu/ft^3 ($11,737 \text{ kJ/m}^3$).

An overall technical comparison of fixed and fluidized bed gasification technologies is provided in Table 2-6 (EPRI, 2010f), which summarizes the types of gasification that will be considered in the following subsections.

Table 2-6
Gasifier Characteristics by Type

	Fixed Bed Types			Fluidized Beds	
	Updraft	Downdraft	Side-Draft	Bubbling	Circulating
Sensitivity to:					
fuel specification	moderate	specific	moderate	flexible	flexible
fuel size	very good	good	good	fair	fair
moisture content	very good	fair	good	good	good
Ash content	poor	poor	poor	very good	very good
Reaction temperature	1000 °C	1000 °C	900 °C	850 °C	850 °C
Fuel mixing	poor	poor	poor	very good	excellent
Gas exit temperature	250 °C	800 °C	900 °C	800 °C	850 °C
Tar in gas	very high	very low	very high	moderate	low
Dust in gas	good	moderate	high	very high	very high
Turndown ration	good	fair	good	very good	good
Scale-up potential	good	poor	poor	good	very good
Start-up facility	poor	poor	poor	good	good
Control facility	fair	fair	fair	very good	very good
Carbon conversion	very good	very good	poor	fair	very good
Thermal efficiency	excellent	very good	good	good	very good
LHV of gas	poor	poor	poor	poor	fair

Option Discussions: Caveats and Assumptions

The analyses of different repowering options presented below are based on data collected from the public sector as well as prior work conducted by the authors and EPRI. The authors have attempted to normalize comparisons to avoid presentation of biased information, but important details are not always clearly presented in the original data sources. This is particularly important with respect to a few key metrics, including net plant heat rate. For example, a plant's heat rate before and after a repowering project will depend on a number of factors, including the configuration of the steam cycle (such as reheat/non-reheat). These factors clearly extend well beyond the change in fuel and are the primary reason for the additional effort spent on the case studies presented later in this report. Therefore, the reader is discouraged from drawing hard and fast conclusions with respect to the suitability of one technology over another, except as provided for in later portions of the report or where explicitly stated.

Similar caveats are appropriate with respect to cost data. Published cost data vary with time, and the scope of retrofits can greatly differ. Wood yards, for example, can range in cost from very low to very high depending on the level of automation and the individual vendor. That said, the authors of this report suspect that some of the reported data in the literature are too low, and the reader will note that the case studies presented later in this report suggest capital costs that are generally at the high end of the ranges reported for some of the proposed retrofits. Again, the purpose of the case studies presented later in this report is to eliminate some of these uncertainties by making normalizing assumptions with respect to equipment selection and vendors.

One additional point of information may be helpful in reviewing the costs associated with the proposed retrofits. The authors conducted an informal analysis using data from a variety of sources, which suggested that, on a rule of thumb basis, repowering projects that involve significant boiler work tend to have capital costs in the range of 40-70% of the cost of an equivalently sized greenfield project. For less intense retrofits (high percentage cofiring or fuel switching), the costs will be lower.

Option 1: Replace existing boiler with turbine-sized new grate boiler

Technology Description

In this scenario, an existing fossil fuel-fired utility boiler is replaced with a biomass grate boiler sized to maintain the electrical generation capacity rating of the existing unit. Steam flow to the steam turbine(s) at full load boiler operation must match the existing full load steam rate to maintain the existing electrical capacity. As biomass fuels such as green wood can have a moisture content of 50% or more, the higher heating value (HHV) is often as low as 4,500 Btu/lb (10,467 kJ/kg). In contrast, coal is a far more energy-dense fuel, and maintaining the same boiler steam output after repowering may require an amount of biomass three or four times the mass of fuel previously required when operating with coal.

Efficiently combusting this much greater mass requires a significant increase in combustion surface area. If a stoker grate firing technology is selected, an increase in combustion surface means larger grates, and thus laterally larger boilers. For this reason, any turbine-sized biomass repowering project would almost always require either a new boiler or a retrofit that would completely replace and expand the bottom of the existing boiler. Many power plants have limited available space around the existing boiler, so even if the existing boiler is removed, the boiler house would likely need to be modified structurally (if feasible) and/or have some major equipment moved in order to accommodate the additional size of the replacement boiler.

Furthermore, biomass also generally requires a larger amount of excess air than coal because of its higher moisture content and larger particle size. Because the new boiler is generating the same amount of steam as the previous boiler, with a lower-heating value fuel that requires higher percentages of excess air, flue gas and combustion air requirements will increase over their existing values. New induced draft (ID) and forced draft (FD) fans may be required to handle the much larger volumes of flue gas and air, respectively. Unless these fans are currently well oversized in the existing facility, they will probably need to be replaced. This increased gas flow and the relatively high unburned carbon content of the fly ash also may require replacement or modification of existing pollution control equipment, such as the addition of new multiclones (to remove large unburned carbon particles upstream of air heaters) and upgrade or modification of existing ESPs.

With respect to air heaters, it is preferable if the units are equipped with tubular air heaters and not regenerative heaters, the latter being more common. A detailed evaluation of the existing regenerative air heater, space availability, and anticipated gas flow and heat exchange conditions when operating on biomass should determine whether the existing regenerative air heater can be used to provide all or a portion of the air heating requirements after the retrofit. Otherwise, a new tubular air heater may be required to provide all or a supplemental portion of the air heating.

The altered pressure profile of the flue gas train, which will now include some flue gas recirculation, may also necessitate augmentation or replacement of the rotary air heater. Most pulverized coal facilities are equipped with regenerative air heaters whose design makes some degree of leakage between the flue gas side and the air side inevitable. In the case of a BFB, the pressure differential between the two sides of the heat exchanger will increase, thus also increasing leakage. Depending on the exact pressure differential and the degree of over-size of the existing air preheater, a tubular design that allows no leakage may be used as an addition or replacement to produce the full-design primary air temperature rise without excessive leakage.

Additional fuel handling and conveying equipment is also necessary, in order to accommodate the larger mass flow of biomass and to screen it for size and for contaminants like metals and stone. Fuel storage areas will likely need to be expanded in order to maintain an acceptable on-site fuel reserve due to the increased fuel flow per hour and the significantly reduced energy density of typical biomass relative to coal. Further, since biomass fuel is generally shipped by truck from distributed sources, rather than by rail, new on-site equipment for truck receiving, weighing, and unloading will likely need to be installed.

Unburned carbon in the ash is another factor that needs to be considered. Stoker grate systems tend to have high loss on ignition in the ash exiting the boiler with the flue gas, which may necessitate reburn systems to reduce the amount of unburned carbon in the fly ash before collection. The fly ash may be deemed combustible depending on the presence or absence of such systems, the total amount of unburned carbon, and the temperature of the fly ash when it reaches the particulate collection devices (DeFusco et al, 2007). For this reason, the fabric filters used in baghouses may be considered a fire hazard in stoker grate applications. Electrostatic precipitators in combination with multicyclones are thus often used instead of baghouses for stoker grate plants (*Ibid.*).

In general, biomass boilers provide significant emissions reduction benefits compared to coal operations on a lb/MMBtu and ton/year basis for NO_x and SO₂. However, biomass firing tends to increase CO, volatile organic compounds (VOC), and particulate emissions compared to coal for boilers sized to equivalent steam outputs.

Nitrous oxides are generated during combustion in a boiler, as the nitrogen in the combustion air and fuel is oxidized. NO_x formation can be minimized by limiting the amount of oxygen available to the fuel. Post-combustion emissions reduction technologies such as SCR or SNCR systems can also be employed to further reduce the NO_x released in the flue gas. However, unburned carbon may limit the economic viability of SCR systems being used to reduce NO_x emissions. According to DeFusco (2007), SCR manufacturers have suggested that high levels of unburned carbon may reduce catalyst life, significantly increasing the total lifecycle cost of an SCR system. If true, and if a NO_x control system is necessary (especially under potential new industrial boiler MACT rules), the cost gap between non-catalytic and catalytic reduction methods may increase.

Uncontrolled NO_x emissions from a 50 to 100 MW biomass-fired stoker boiler are estimated to be on the order of 0.15-0.3 lb/MMBtu. With an SNCR, the NO_x emissions may be effectively reduced by as much as 60%, to about 0.1-0.2 lb/MMBtu.

CO and VOC emissions depend upon how well the mixing of air and fuel achieves complete combustion in the boiler. These emissions can be minimized by a properly designed overfire air system. A mechanical dust collector downstream of the economizer outlet is required to minimize particulate flow and protect downstream air heaters and pollution control equipment, as well as to minimize the fire hazards associated with relatively high levels of unburned carbon. With multicyclones and an ESP, particulate emissions from a biomass-fired stoker boiler could be around 0.005 lb/MMBtu, significantly lower than typical permit limits of 0.02 lb/MMBtu. Based on actual biomass stoker units in operation, VOCs may range from around 0.01 to 0.09 lb/MMBtu. CO emissions typically range from around 0.01 to 0.4 lb/MMBtu. Since sulfur emissions are directly related to the sulfur content in the fuel, biomass-fired systems inherently generate significantly less SO₂ than coal-fired units.

A simple, example process diagram of a biomass-fired power plant using a new stoker-grate boiler is presented in Figure 2-4 below. Major equipment items requiring replacement in a repowering project are highlighted to indicate the scope of the plant's modifications. Material flows indicated on the diagram are taken from boiler modeling in a recent feasibility study published by EPRI for a modified coal plant with a capacity of about 95 MW gross power generation when operating on biomass.

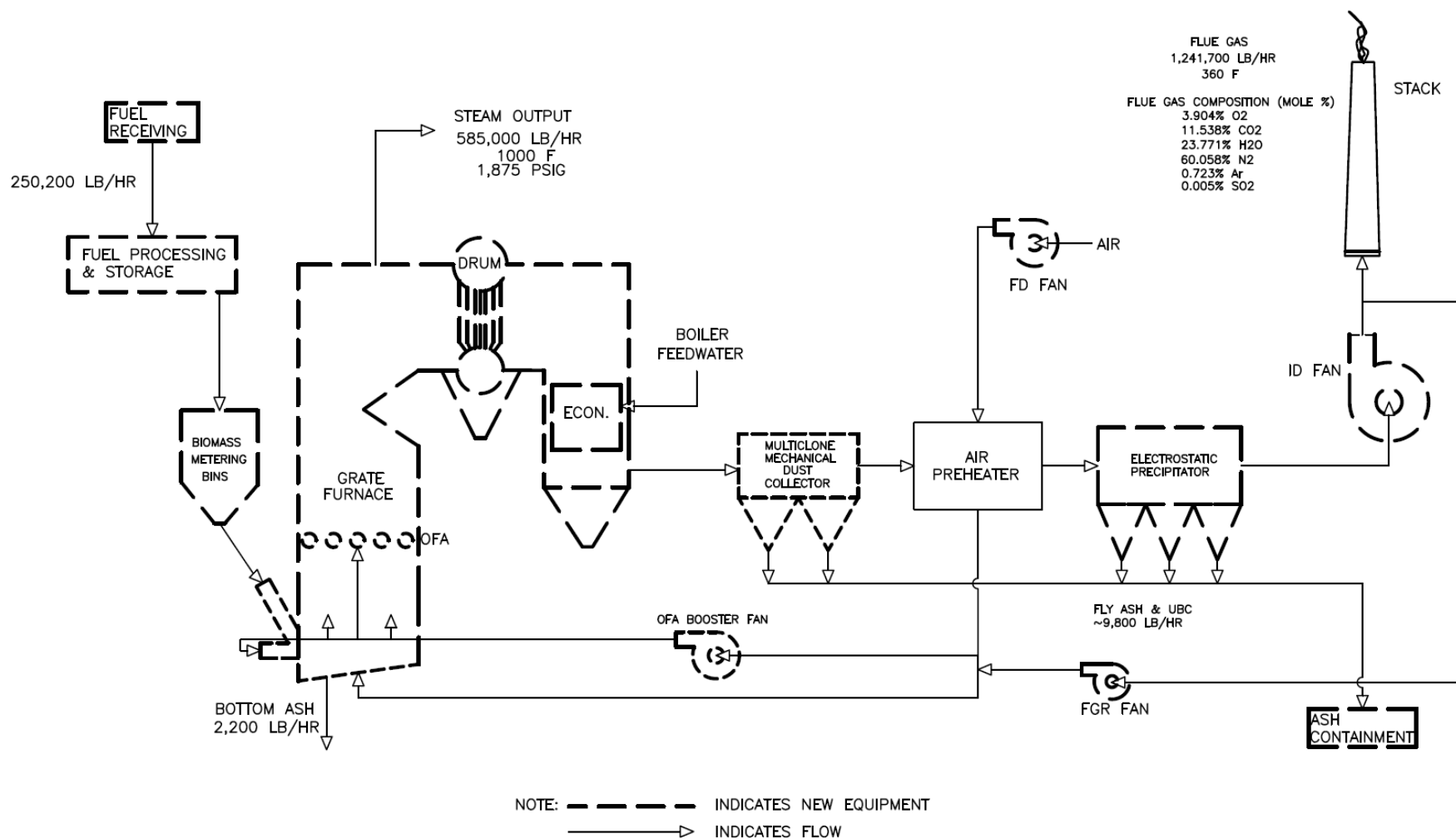


Figure 2-4
Example Process Diagram for Option 1: Turbine-Sized Repowering using New Grate Boiler (95 MW_{gross})

Appropriate Fuel Qualities

A stoker grate boiler, whether a replacement or a retrofit, is somewhat inflexible in fuel characteristics. Stoker grates can be designed for any of a wide variety of fuels, ranging from municipal solid waste to high-moisture biomass, but large deviations from the design fuel specification can lead to unstable combustion. Van den Broek (1995) indicates that fuel moisture content must be kept within 10% of the design point, or heat transfer rates and flue gas flows begin to vary dramatically.

A further constraint is that at the high operating temperatures of stoker grate boilers (2200°F to 3000°F, 1204 to 1649°C), the combustion of fuels with low ash melting temperatures can lead to slagging. This prevents the use of these fuels, such as agricultural wastes, at high cofiring percentages (*Ibid.*).

Construction Schedule and Permitting

Because a turbine-sized boiler replacement project will likely involve consideration of significant increases in one or more criteria pollutants, or installation of new emissions controls to mitigate potential increases, the associated permitting process will be a significant time investment. A general estimated timeline for a biomass repowering project involving boiler replacement is three to four years (Hoeflich, 2009).

Many examples of biomass-fired stoker grate boilers exist. However, nearly all of these boilers were constructed as part of new, greenfield facilities rather than as plant modifications. This limits the amount of data available in terms of construction timelines for this type of facility. The following list illustrates some example timelines for greenfield facilities that have been constructed over the last three decades. It should be noted that, because these new construction projects were more extensive than a repowering project, their timelines will likely be longer.

- Okeelanta Cogeneration facility in South Bay, Florida:
 - 74.9 MW_e cogeneration facility with three water-cooled vibrating grate boilers
 - 2 years to obtain financing
 - 1.5 years of construction
 - 3 months of commissioning
- Plant McNeil in Burlington, Vermont:
 - 50 MW_e electricity generator with a traveling grate boiler
 - 1 year to move from obtaining financing to contracting a developer
 - 2 years to obtain permits and prepare for site work
 - 2.25 years of construction (7 months elapsed between the start of boiler construction and hydrotesting)
 - 6 months of commissioning

- Wheelabrator Shasta in Anderson, California:
 - 50 MW_e electricity generator with three traveling grate boilers
 - 5 months equipment procurement and detailed engineering
 - 13 months of construction

Other points of reference that should be considered are the timelines presented for turbine-sized fluidized bed boiler replacement projects. These are described in the following subsection.

Costs

Based on the discussion above, a sample list of required equipment for replacement of an existing utility boiler with a stoker grate biomass boiler sized to maintain the plant's generation capacity would require the following major equipment investments:

- Boiler house modifications/equipment rearrangement, or new boiler house construction,
- Replacement stoker grate boiler,
- FD, ID, and overfire air booster fans,
- Stacker-reclaimers (wood yard),
- Truck dumpers and walking floor unloading pits,
- Conveyors, chip hogs, and scalping screens,
- Multiclone(s) for large particulate removal,
- Baghouse or electrostatic precipitator, and
- NO_x control system (SNCR).

The authors were unable to identify any specific cost data for this particular repowering scenario due to the fact that (1) repowering projects have apparently been more rare than greenfield construction of complete new biomass-fired power stations, and (2) in the case of complete boiler replacement projects, rather than boiler retrofits, the boiler type chosen has most commonly been a fluidized bed rather than a stoker grate. The most applicable cost data found were either for the greenfield construction of a new power station using a stoker grate boiler or for a retrofit of an existing boiler to stoker firing (rather than replacement). The former scenario will incur a much higher capital cost than a boiler replacement, due to more extensive site and foundation work, plus the installation and purchase of complete plant steam piping, turbine generator, condenser, and cooling equipment. The latter scenario is discussed in detail in later subsections.

Due to the absence of data specific to this scenario, greenfield biomass power stations using stoker grate boilers are used for reference. One such example is Williams Lake Generating Station in British Columbia. This 60 MW_e plant uses a water-cooled vibrating grate boiler fueled by sawmill residues, which cost \$174 million (in 2010 dollars) to construct, equivalent to \$2,900 per kW capacity. Based on recent feasibility studies and technology characterization reports, it is estimated that the costs for a repowering project involving replacement of the existing boiler

would be about 50-60% of the Greenfield construction costs. This would correspond to \$1,450/kW to \$1,740/kW for a 60 MW facility. McNeil Generating Station is another sample plant that was noted above in the construction timeline discussion. This 50 MW_e facility was constructed in 1984, with an installed cost of about \$118 million (in current dollars). This is equivalent to \$2,364/kW for the greenfield project, which would translate to about \$1,180/kW to \$1,420/kW for a repowering project. Costs up to about \$4000/kW have been stated for more recently announced greenfield biomass plant construction projects.

Operating and fuel cost data are also available for these two plants. Williams Lake in 2001 reported that its non-fuel O&M costs averaged less than \$0.01 per kWh at a nearly 100% capacity factor (Wiltsee, 2000). Its fuel costs, due to an environmental liability disposal arrangement with local sawmills, were negligible and were composed of mostly transportation fees for short-haul trucking to the plant. During the same survey, McNeil Station reported operating costs of \$0.026 per kWh and fuel costs of \$0.016 to \$0.024 per kWh. In 2010 dollars, these equate to \$0.032 and \$0.020 to \$0.030 per kWh, respectively. During the season reported, McNeil was firing exclusively wood fuel, despite its dual-fuel capability (it is equipped to cofire natural gas).

Other large wood-fired stoker boiler facilities have reported non-fuel O&M costs of about \$0.018/kWh. Based on a recent feasibility study, the estimated non-fuel O&M costs for a 75 MW (net) facility is \$0.014 to \$0.017/kWh (EPRI, 2010b).

Another indication of the cost of a turbine-sized stoker grate repowering project is given by the cost of a turbine-sized fluidized bed repowering project as described in the next subsection. As the boiler type is different, the cost will not apply exactly to the current scenario, but the overall scope of supply will be similar.

Technology Status and Development Risks

As noted above, stoker grate technology is a well-established, thoroughly deployed technology. McNeil Generating Station in Burlington, Vermont is a modern, utility-scale example of a biomass-fired stoker grate boiler. The travelling grate boiler was constructed in 1984, and has since operated at 50 MW_e generating capacity with few subsequent modifications. The most significant change has been the installation of cofiring capacity for natural gas and additional wood fuels to enable fuel switching in response to fuel price fluctuations.

Other utility-scale grate boilers installed new (rather than as retrofits) include:⁷

- Måbjergværket CHP facility in Denmark (vibrating grate)
- Enköping CHP facility in Sweden (vibrating grate)
- Kettle Falls Station in Washington (traveling grate)
- Wheelabrator Shasta in California (traveling grate)
- Stratton Energy in Maine (traveling grate)

⁷ Sources: (van den Broek, 1995; NREL, 2000)

- Tracy Biomass Plant in California (water cooled vibrating grate)
- Grayling Station in Michigan (traveling grate)
- Multitrade Project in Virginia (fixed grate)
- Williams Lake Station in Canada (water cooled vibrating grate)
- Ridge Station in Florida (traveling grate)
- Camas Cogeneration Plant in Washington (water cooled vibrating grate)
- Snohomish Plant in Washington (sloping grate)
- Okeelanta Cogeneration Plant in Florida (water cooled vibrating grate)

This wide degree of deployment and OEM experience suggests that there should be a relatively low technical risk involved with a stoker grate boiler replacement project. However, there is some difference between technology risk and application risk. As noted previously, there are not many examples of this type of repowering, and the learning curve of implementing such a retrofit will be non-trivial, especially if the integration goes beyond re-use of steam equipment or if there is a substantial deviation from the initial steam operating conditions.

A summary of key factors for this option is provided below.

Table 2-7

Option 1 Summary: Replace existing boiler with turbine sized new grate boiler

Example Capital Cost Estimate	\$2,364-\$2,900/kW for 50-60 MW <u>greenfield</u> facilities; corresponds to about \$1,180-\$1,740/kW for repowering
Non-fuel O&M Cost Estimate	\$0.01-\$0.02/kWh
Feedstock Requirements	Fuel moisture content must be w/in 10% of design fuel specs. No fuels with low ash melting temps.
Project Development Timeline⁸	3-4 years. Need revised air permits. Estimate 1-2 yrs financing/permits, 1-3 yrs construction & commissioning.
Emissions Performance Summary	Reduce SO _x , NO _x , Hg, and GHG relative to coal; increase CO and VOCs

⁸ The project development timeline corresponds to the expected timeframe for permitting and construction. There is a difference between this project development time and plant outage time, which is the amount of time a facility will need to be offline while the biomass configuration is being installed. This issue is discussed in more detail at the end of Chapter 4, including a more detailed discussion of timelines, but different repowering technologies will have very different outage requirements, even if their overall project development period is similar. Replacing a boiler bottom will require considerably more downtime than simply switching fuels. In the case of the latter, most of the work is likely to be focused on the fuel yard and can be conducted in parallel with existing operations. This would clearly not be the case for a boiler replacement or significant boiler modification.

Option 2: Replace existing boiler with turbine-sized fluid bed boiler

Technology Description

This scenario considers replacing an existing fossil fuel-fired utility boiler with a biomass fluid bed boiler sized to maintain the electrical generation capacity rating of the existing power plant. The general complications inherent in any biomass repowering project sized to maintain current electrical generation capacity are discussed above in the context of stoker grate boilers, and many of these will also apply to a fluid bed replacement boiler project. For example, biomass fuel flow rates will greatly increase in this configuration, as will combustion air and flue gas flow rates in order to accommodate biomass combustion.

However, there are also significant differences. Because devolatilization/gasification and combustion in a fluidized bed boiler take place in and above a flexible, three-dimensional volume of the suspended bed particles, rather than on a grate, fluidized bed boiler dimensions are more flexible than stoker grates. This is further enhanced by the ability of BFBs and CFBs to feed fuel from any wall of the boiler, rather than having to conform to the direction of grate travel (as in stoker firing) (DeFusco, 2007). This means that if the boiler footprint is limited by existing structures and major equipment (or any other constraints), the boiler may be designed to some extent to have a tall but laterally narrow combustion bed zone that sources fuel from all sides of the boiler.⁹ A stoker grate, on the other hand, can only combust as much material as can be spread laterally, making the boiler design more subject to footprint limitations.

Fluidized beds also require lower levels of excess air than stoker boilers, due to their more effective exposure of biomass surface area to air and to the heat sink of the inert particles (although the higher volume of biomass fuel from repowering will require more air than the coal-fired unit). As such, some ductwork and pollution controls may be sized for smaller volumetric flow rates than when a stoker grate design is used. However, the common use of flue gas recirculation (FGR) systems in fluidized bed applications means that FGR and booster fans may be required in addition to a larger ID fan. These increase both capital and parasitic operating costs for the combustion air system. If a CFB is used, cyclones may also need to be greatly increased in size in order to capture and recirculate a larger quantity of bed material, which will also increase the capital cost.

Fluidized beds generally have lower CO, VOC, and particulate emissions than stoker boilers. This is attributed to better mixing of the air and fuel, which leads to an improved carbon conversion and higher efficiencies. CO and VOCs from biomass combustion can be maintained below 100 PPM and 10 PPM (7% dry oxygen), respectively, by good bed fluidization and fuel distribution (EPRI, 2010b). Based on operational experience from existing biomass-fired fluidized bed boilers, CO emissions are expected to be around 0.10 lb/MMBtu, and can range from about 0.05 to 0.15 lb/MMBtu.

⁹ Temperature control capability, heat transfer area, and flame impingement will still limit the dimensions, and the heat rate may not be as high if the boiler configuration is particularly exotic.

NO_x emissions are also expected to be somewhat lower for fluidized beds compared to stoker grate boilers. NO_x can be controlled by maintaining even bed temperatures and staged overfire air (down to 300 to 400 PPM). SNCR can provide up to an additional 60% reduction.

Uncontrolled NO_x emissions could range from about 0.15 to 0.3 lb/MMBtu, which could be reduced to around 0.07 to 0.15 lb/MMBtu with the use of an SNCR system. A simple, example process diagram of a biomass-fired power plant using a new fluidized-bed boiler is presented in Figure 2-5. Major equipment items requiring replacement are highlighted in the diagram to indicate the scope of the plant's modifications. Material flows indicated on the diagram are taken from boiler modeling in a recent feasibility study performed by EPRI for a modified coal power plant with a capacity of about 48.8 MW gross power generation when operating on biomass.

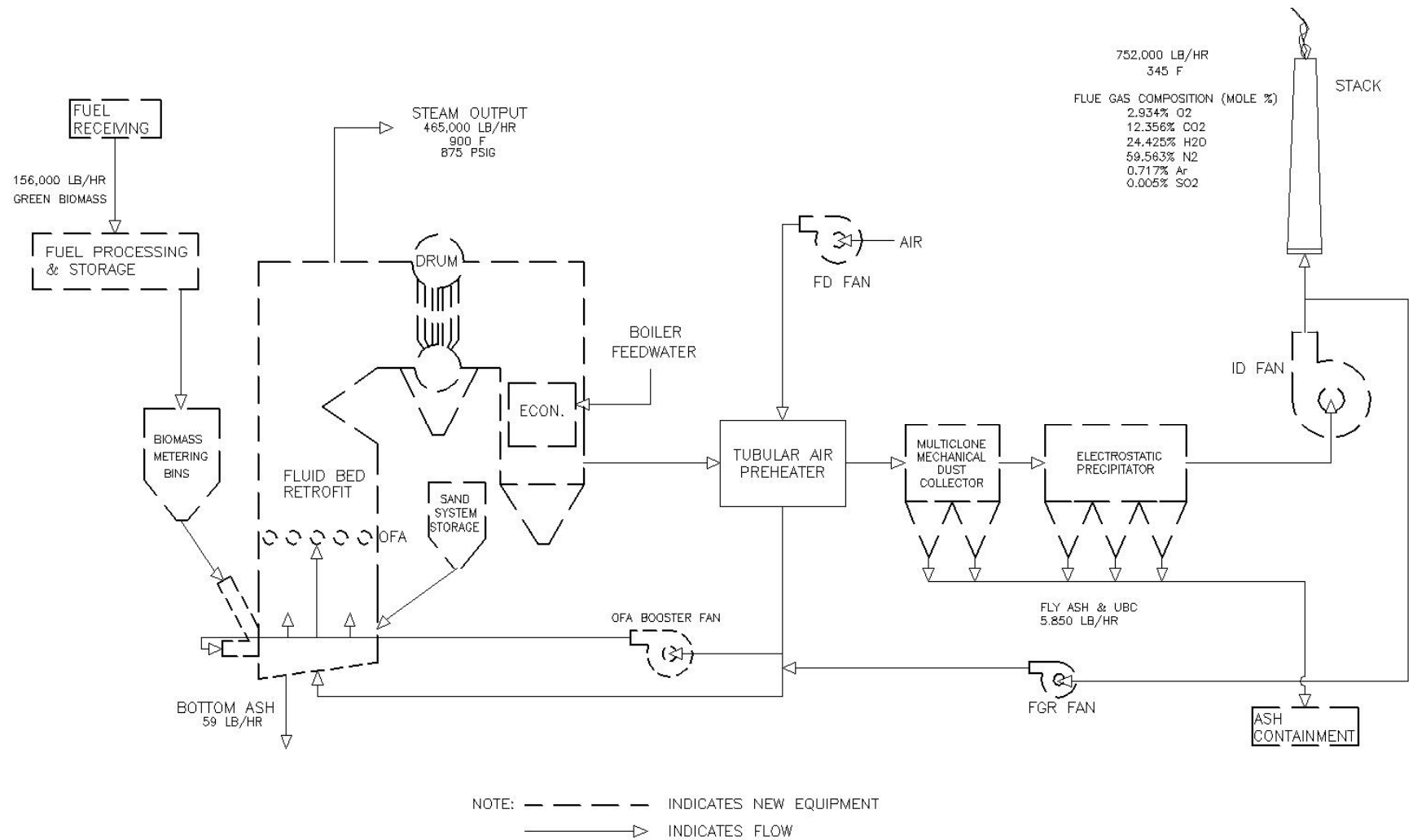


Figure 2-5
Example Process Diagram for Option 2: Turbine-Sized Repowering using Fluid Bed Boiler (48.8 MW_{gross})

Appropriate Fuel Qualities

A fluidized bed boiler, whether a replacement or a retrofit, is generally more flexible in fuel type than a stoker grate boiler. The presence of the bed material as a heat sink means that rapid changes in fuel composition, such as from ash or moisture content, are stabilized by the bed's thermal inertia. More long-term changes in fuel composition can be compensated for by changing the bed operating conditions. Fuel particle sizing is also flexible, provided that the fuel handling system does not get clogged or damaged. The high level of surface area and the staged nature of fluidized bed combustion allow both over- and undersized particles to be completely combusted.

One fuel constraint on fluidized beds involves the use of high-alkaline fuels. Van den Broek (1995) reported that CFBs in particular, when burning high-alkaline fuels, can form large particles of alkaline deposits, which can grow in size until the bed is no longer fluid. This can be prevented by holding fuel alkali content below 0.79 lb/MMBtu (0.34 kg/GJ) (*Ibid.*).

Construction Schedule and Permitting

Because a turbine-sized boiler replacement project will likely require consideration of significant increases in one or more criteria pollutants, or installation of new controls to mitigate potential increases, the associated permitting process will require a significant time investment.

The timeline for completing the 50 MW biomass repowering project at Schiller Station in Portsmouth, New Hampshire is an illustrative example. At this facility, a pulverized coal boiler was replaced with a CFB boiler of similar steam capacity. Biomass handling equipment and associated pollution controls were installed over the course of the project. A fuel supply study and a techno-economic feasibility study were performed in January, 2003. Applications for state approval were subsequently filed by the project developer, state-owned utility Public Service of New Hampshire, in August 2003. Construction began in October of the next year, and the plant began commercial operation in December 2006. This three to four year project timeline would be typical of a utility-scale project of this scope.

Costs

Based on the discussion above, a sample list of required equipment for replacement of an existing utility boiler with a fluidized bed biomass boiler (sized to maintain the plant's original generation capacity) would require the following major equipment investments:

- Boiler house modifications/equipment rearrangement, or new boiler house construction,
- Replacement fluid bed boiler and auxiliaries,
- FD, FGR, booster and ID fans,
- Stacker-reclaimers (wood yard),
- Truck dumpers and walking floor unloading pits,

- Conveyors, chip hogs, and scalping screens,
- Baghouse or electrostatic precipitator, and
- NO_x control system (SNCR).

The total non-capital, non-fuel operating cost for a 100 MW_e-scale plant would be about 1.9¢/kWh. The fuel cost component would be highly dependent upon the fuel type and location. Any pollution reduction benefits, such as saleable renewable energy certificates or avoided pollution control costs, may reduce this operating cost.

The Schiller Station project can be used to illustrate expected investment costs. This station underwent a roughly \$75 million repowering project to replace one of its existing coal-fired boilers with a fluidized bed boiler of similar steam output. The capacity of the new unit is about 50 MW. Major project costs included a new fluidized bed boiler, emission controls equipment, covered wood storage, a wood chip unloading station (with multiple tippers and the capability of receiving fuel from walking floor trailers), and a covered conveyor system. The unit cost of the project was \$1,439 per kW (in 2010 dollars). One noteworthy aspect of this project is that the boiler and fuel handling equipment were designed for dual-fuel capability, allowing the facility to switch between biomass and coal firing. This flexibility may imply a higher project cost than for a similar biomass-only installation.

In general, fluid bed boilers may have slightly higher O&M costs than stoker boilers, due to required refractory maintenance and repairs to the boiler equipment, as well as regular bed material replenishment. In addition, the requirement for a significant volume of higher pressure fluidizing air (compared to the under-grate air required for stoker grates) will increase the parasitic load.

Technology Status and Development Risks

Fluidized bed combustion is a less thoroughly deployed technology than stoker grate combustion, in part because of the care with which fluidized bed combustion must be managed. Bed height, density, and temperature must be controlled in order to avoid bed agglomeration or damage to any convection tubing suspended in the bed (if applicable). Emergency shutdowns must be avoided, as they cause a rapid bed collapse. The boiler must also be monitored carefully for damage to the refractory due to the abrasive effect of the bed particulates.

Despite more limited deployment, both circulating and bubbling fluidized bed boilers have been built and are in operation at a utility scale. Some examples of these facilities in which the boiler was installed new rather than as a boiler retrofit include:¹⁰

- Schiller Station in New Hampshire (CFB)
- Lahti CHP facility in Finland (CFB)
- Colmac Energy CHP facility in California (CFB)

¹⁰ Sources: (van den Broek, 1995; NREL, 2000)

- Tacoma Steam Plant in Washington (BFB)
- Delano Power in California (BFB)
- Grenaa CHP Plant in Denmark (CFB)
- Händelöverket CHP Plant in Sweden (CFB)

These established plants, though small in number, are of a large scale and have been commercially operated for, in some cases, over a decade. As with the stoker replacement option, fluidized bed boiler replacement projects probably fall in the category of low to moderate technical risk, depending on the level of plant integration and target steam conditions.

A summary of key factors for this option is provided below.

Table 2-8
Summary for Option 2: Replace existing boiler with turbine sized new fluid bed boiler

Example Capital Cost Estimate	\$1,439/kW for 50 MW
Non-fuel O&M Cost Estimate	\$0.02/kWh
Feedstock Requirements	Particle size and moisture content can vary somewhat during operations. Alkali content ≤ 0.79 lb/MMBtu (≤ 0.34 kg/GJ)
Project Development Timeline	Need revised air permits. Estimate 3-4 yrs from feasibility to commercial operation. One example as low as 34 months.
Emissions Performance Summary	Lower CO and VOC emissions than stoker grate.

Option 3: Modify existing coal boiler for grate firing

Technology Description

In this scenario, an existing fossil fuel-fired utility boiler is modified, rather than replaced, in order to burn biomass instead of pulverized coal (PC). Modifying an existing coal boiler for grate firing of biomass would involve demolition and/or retirement of the existing coal receiving, crushing, and conveying equipment, and replacement with systems for handling and processing wood chips. Truck receiving and unloading equipment will need to be installed for biomass deliveries, and storage areas may need to be modified or expanded. Within the boiler house, modifications will be required for the combustion air supply systems, fuel feed systems, and ash reclaim systems, as well as the complete removal and replacement of the bottom portion of the furnace (to permit installation of a grate and accompanying bottom ash removal systems). However, much of the existing boiler house and downstream equipment could be reusable, including the existing induced draft fans and all of the downstream steam and power generating

equipment. Depending on the specifics of existing equipment and their design capacities, it is possible to retain major heat exchange surfaces (including the water walls, superheaters, reheater, economizer, and air heater) as-is or with relatively minor modifications.

It is anticipated that the plant will be forced to derate due to the lower heat release rate of a stoker grate compared to a PC boiler with a similar boiler footprint. In terms of total emissions, the derating will significantly reduce the aggregate emissions potential at full load; however, if one is repowering a plant, an increase in the anticipated dispatch rate for the unit would offset a portion of that expected reduction. It is anticipated that a new SNCR system may be required for NO_x control, and a new multiclone will be required for removing large particles from the flue gas prior to reaching the air heater and ESP (to minimize fire risks and achieve effective and reliable particulate removal). A simple process diagram for an example 95 MW facility is shown in Figure 2-6.

Based on recent feasibility studies performed for similar retrofit scenarios, it is expected that the full load capacity for biomass firing could be about 35% to 50% lower than the original pulverized coal boiler design capacity, partly depending on whether the boiler bottom is expanded to allow for a higher throughput (EPRI, 2010b; EPRI, 2010c). The modified stoker boiler would also have a decreased efficiency, from about 89% with coal to about 70% operating on wood. Based on recent experience, the estimated net heat rate for a plant with about 100 MW gross capacity after modification would be about 12,600 Btu/kWh (13,280 kJ/kWh) at full-load biomass operation (the historical net heat rate operating on coal was about 10,500 Btu/kWh, 11,067 kJ/kWh). A similar project with an 80 MW gross capacity at full-load biomass operation was estimated to have a net heat rate around 12,250 Btu/kWh (12,912 kJ/kWh).

Additional space will be required for handling and conveying biomass fuel; the fuel storage area will likely need to be expanded in order to maintain an acceptable period of fuel reserve. As with previous scenarios, because biomass fuel is generally delivered by truck from distributed sources (rather than by rail from a few major points), equipment for truck receiving, weighing, and unloading will need to be installed in this scenario.

The prevalence of unburned carbon in ash must also be considered; as in previous scenarios, reburn systems might be necessary to reduce the amount of unburned carbon in the fly ash before collection. In addition, this unburned carbon may limit the economic viability of SCR systems being used to reduce NO_x emissions, as high levels of unburned carbon may reduce the SCR's catalyst life.

Emissions considerations for the biomass-fired stoker boiler configuration discussed for Option 1 also apply to this option. The significant reductions in sulfur, nitrogen oxides, mercury, and greenhouse gas emissions, as well as the addition of a large, new renewable power installation, will improve the environmental profile of the plant. At the same time, emissions of carbon monoxide and volatile organic compounds are expected to increase. Good combustion control is currently expected to be sufficient for CO and VOCs for a biomass conversion, but a complete BACT analysis will be required during the permitting process.

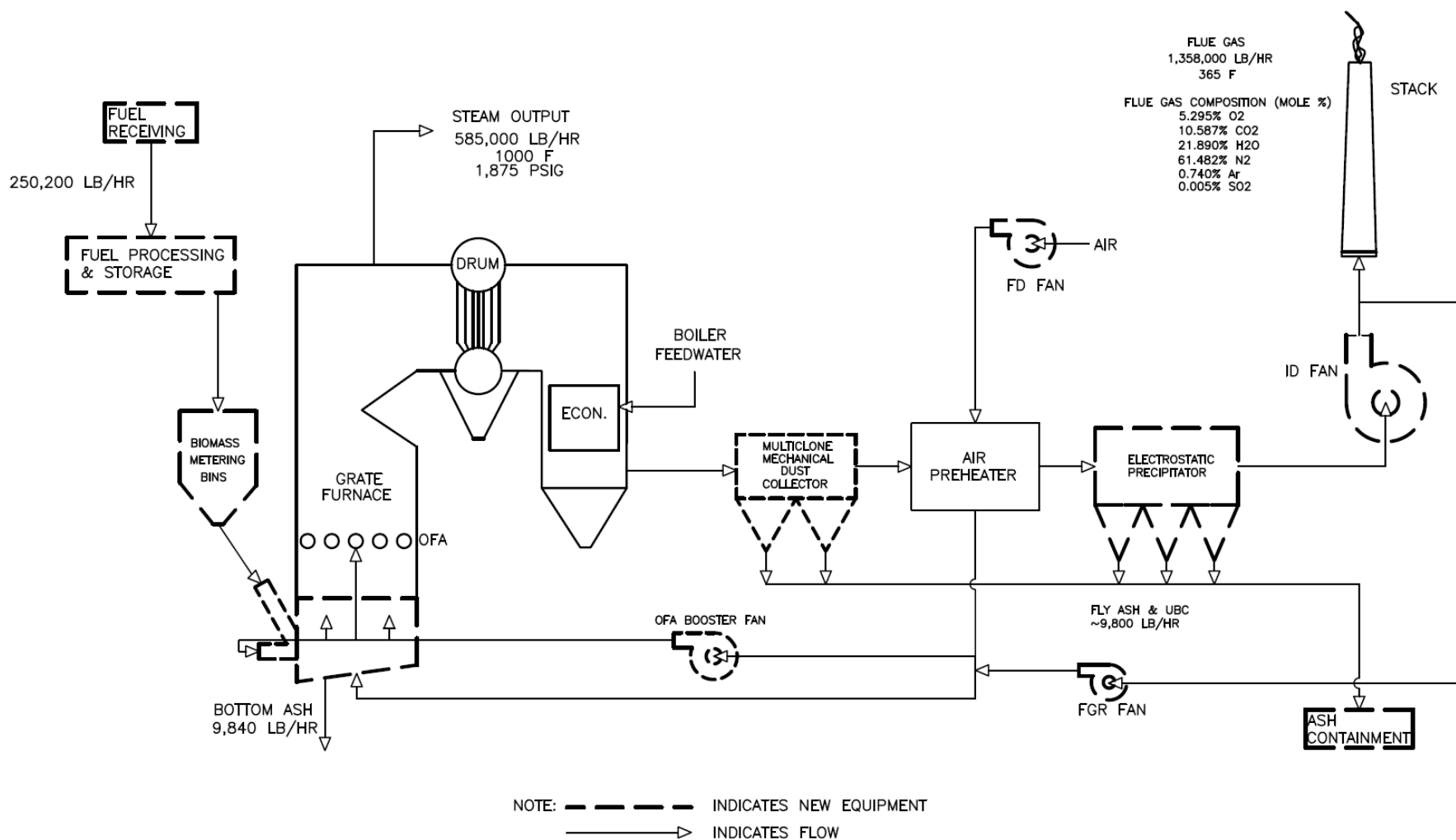


Figure 2-6
General Process Flow Diagram for Option 3 – Modified Grate Boiler (95 MW_{gross})

Appropriate Fuel Qualities

The discussion of fuel requirements for grate firing technologies was discussed previously for Option 1 (pg 2-22). Stoker grates can be designed for a wide range of fuel types, but they require consistent fuel during operation, which limits the types of fuels that can be used.

Construction Schedule and Permitting

Because a boiler modification project will likely consider the potential for significant increases in total annual emissions of one or more criteria pollutants (most likely CO, and possibly PM), the associated permitting process will be a significant time investment.

Based on recent studies, an estimated idealized construction schedule for a stoker retrofit project could be as low as 25 months. This is a very aggressive timeline that includes about 5 months for the boiler modifications. For comparison, the Plant Schiller boiler replacement project (described in Option 2 above) took more than 36 months from feasibility study planning through construction and commissioning.

Costs

Based on the discussion above, the major equipment investments that would be required for modifying an existing utility boiler with a stoker grate for biomass firing are expected to include:

- Demolition and removal of coal processing and handling systems, including conveyors, pulverizers and feeders, and pulverized coal supply pipes,
- Removal of combustion air supply ductwork, windboxes, and coal burners,
- Asbestos abatement associated with demolition work,
- Addition of a new biomass fuel yard and fuel delivery system to the boiler,
- Removal of the bottom portion of the boiler and replacement with a stoker grate and associated bottom ash removal equipment,
- Possible modification of convection pass heat exchangers,
- New combustion air supply ductwork and overfire air nozzles and piping,
- Addition of air supply booster fans for overfire air and fuel distributors,
- Addition of mechanical dust collectors (and associated ash removal storage) to remove unburned carbon and large ash particles from the flue gas prior to the existing air heaters and electrostatic precipitator,
- Possible installation of new tubular air heaters to replace or supplement existing regenerative air heaters,

- Installation of an ammonia-based SNCR system for NO_x reduction, and
- Other ancillary requirements in support of the above items, including controls, wiring, foundation support for the stoker, etc.

Budget estimates for the major components are dependent upon site-specific conditions. The estimated cost for this type of retrofit project is about \$90 to \$135 million, including engineering, permitting, and operator training, twenty percent contingency, and contractor fees (EPRI, 2010b; EPRI, 2010c). These estimates come from recent studies for plants with a gross capacity of 80 to 95 MW after modification, which equates to around \$1,100 to \$1,650 per kW capacity. These cost estimates depend on site-specific factors such as wood yard specifications and upgrade requirements. Variations in estimates for indirect costs, such as engineering and contingency, also contribute to the spread. The least certain aspects of the budget estimate were the cost of performing the retrofit of the furnace bottom, the required costs for modifications to the convection pass heat exchangers, the added costs for obtaining a turn-key package with performance guarantees, and the mark-ups on equipment from a turn-key contractor.

The O&M costs for this option will be similar to those presented in Option 1. The non-fuel O&M for a recent stoker retrofit repowering study was estimated to be \$0.011/kWh for an 85 MW (net) plant (EPRI, 2010b).

Technology Status and Development Risks

Utility-scale grate biomass boilers constructed as retrofit projects include:

- Bay Front Station in Ashland, Wisconsin. Two spreader stoker boilers were converted in 1979 from coal-only to allow for multiple fuel operations (including coal, wood, and/or shredded rubber). This retrofit resulted in a 30 MW capacity operating on wood and tire-derived refuse (44 MW operating on coal). Additional NO_x controls were added to the boilers in 2008 to allow for continued wood-fired operation in line with the stricter emissions limits.
- Elk River Station in Minnesota (now called Elk River Energy Recovery Station). This facility was converted in 1989 from pulverized coal and oil firing to operate using refuse-derived fuel (RDF). The 35 MW facility currently uses up to 1,000 tons of RDF per day.

Although this configuration is not new or unique, the research for this report did not suggest that it was a common approach. While grate technology is well understood, boiler retrofits require a much greater integration with existing plant systems than the replacement options discussed above. The heavier reliance on older heat transfer systems and equipment designed for a materially different fuel implies a greater degree of application and integration risk, and very careful consideration of the performance and lifetime of such systems must be included in the retrofit analysis.

Based on prior projects, there are several challenges and constraints to the stoker boiler retrofit:

- 1) Reheater (RH) Outlet Steam Temperature and Superheater (SH) Outlet to RH Outlet Steam Temperature Differential: Changes in reheater surface area may be required, and optimizing those areas for the individual project will be a challenge.

- 2) **Attaining Design Grate Heat Release Rates:** The typical range of grate heat release rate is 800,000 to 1,200,000 kBtu/hr-ft². For most repowering projects, it is desirable to attain the top end of that range.
- 3) **Low Temperature SH (LTSH) Outlet Steam Temperature:** With the significant increase in flue gas flow that results from firing biomass, the LTSH outlet steam temperature will increase significantly. The LTSH surface may need to be removed.
- 4) **Subcooling Delta Temperature (Drum Saturation Temperature minus Economizer Outlet Water Temperature):** The significant increase in flue gas flow will also cause the Economizer Outlet water temperature to increase significantly and will reduce the subcooling delta temperature compared to the existing operation. Inadequate subcooling for a natural circulation unit may result in non-uniform drum levels, insufficient thermal head in the waterwall circuits, and potential waterwall circuit overheating.
- 5) **Air Heater (AH) Flue Gas Outlet Temperature:** A significant increase in Air Heater Gas Outlet (AHGO) temperature is possible when firing biomass fuel. An increased economizer surface may be necessary.
- 6) **Economizer Gas Outlet Flow and Total Gas to ID Fans:** Installation of a hot air booster fan and/or larger capacity FD fans are likely issues when firing biomass.
- 7) **Flue Gas Velocities:** typical maximum flue gas velocities for boiler designs firing wood biomass fuels are in a range of 50-60 ft/s (15.2 – 18.3 m/s). Many sections of the boiler are likely to see an increase over the recommended velocities, with increased erosion being a possible outcome.

A summary of key factors for this option is provided below.

Table 2-9
Summary for Option 3: Modify existing coal boiler for grate firing

Example Capital Cost Estimate	\$1,100-\$1,650/kW for 85 MW net
Non-fuel O&M Cost Estimate	\$0.02/kWh
Feedstock Requirements	Fuel moisture content must be w/in 10% of design fuel specs. No fuels with low ash melting temps.
Project Development Timeline	2-4 years. Need revised air permits. Estimate 1-2 yrs financing/permits, 1-3 yrs construction & commissioning.
Emissions Performance Summary	Reduce SO _x , NO _x , Hg, and GHG relative to coal; increase CO and VOCs

Option 4: Modify existing coal boiler with fluid bed firing

Technology Description

This scenario considers modifying an existing fossil fuel-fired utility boiler to burn biomass instead of coal. As with the grate firing modification for biomass firing (Option 3), this option would require demolition or retirement of the existing coal receiving, crushing, and conveying equipment, and replacement with systems for storing, handling, and processing biomass. Truck receiving and unloading equipment will need to be installed for biomass deliveries, and existing storage areas may need to be modified or expanded accordingly.

The BFB conversion option entails converting the lower furnace to a BFB while keeping the top end of the furnace intact (with potentially only minor modifications, if any, to the convection heat transfer surfaces above the freeboard combustion zone). Based upon previous modeling efforts and the performance of similar installations, the estimated net heat rate for a BFB retrofit would be around 12,330 BTU/kWh (12,996 kJ/kWh) at full-load biomass operation for a unit with about 100 MW capacity (gross). This represents a modest improvement over the stoker. The steam generation capacity may be higher for the BFB option for the same boiler footprint area. An example process flow diagram for a 94 MW facility is shown in Figure 2-7.

Another advantage for the BFB is potentially better carbon conversion, which will also lead to lower CO and VOC emission rates compared to stoker boilers, without adding flue gas controls. Emissions from a biomass-fired fluid bed boiler (discussed previously for Option 2) also apply for this case. As mentioned in the “Overview of Biomass Repowering Technologies” section, stoker technology does offer an improved turndown ratio of 4:1, as compared to 3:1 for the BFB. Both BFB and stoker options are proven combustion systems for firing biomass.

A review of experiences firing biomass and other fuels in a B&W-designed BFB found that there had been no reported BFB maintenance beyond some refractory repair on the lower furnace walls, in contrast to experiences with a stoker boiler, which required a rebuild of the stoker equipment.¹¹ This reduction in maintenance in a BFB compared to a stoker-fired boiler can have a significant impact on project economics.

¹¹ http://findarticles.com/p/articles/mi_qa3636/is_200501/ai_n9477176/pg_2/?tag=content:coll Greg Pifer. Bubbling Fluidized-Bed Technology Serves Combustion Need for Biomass, Pulp & Paper, January 2005.

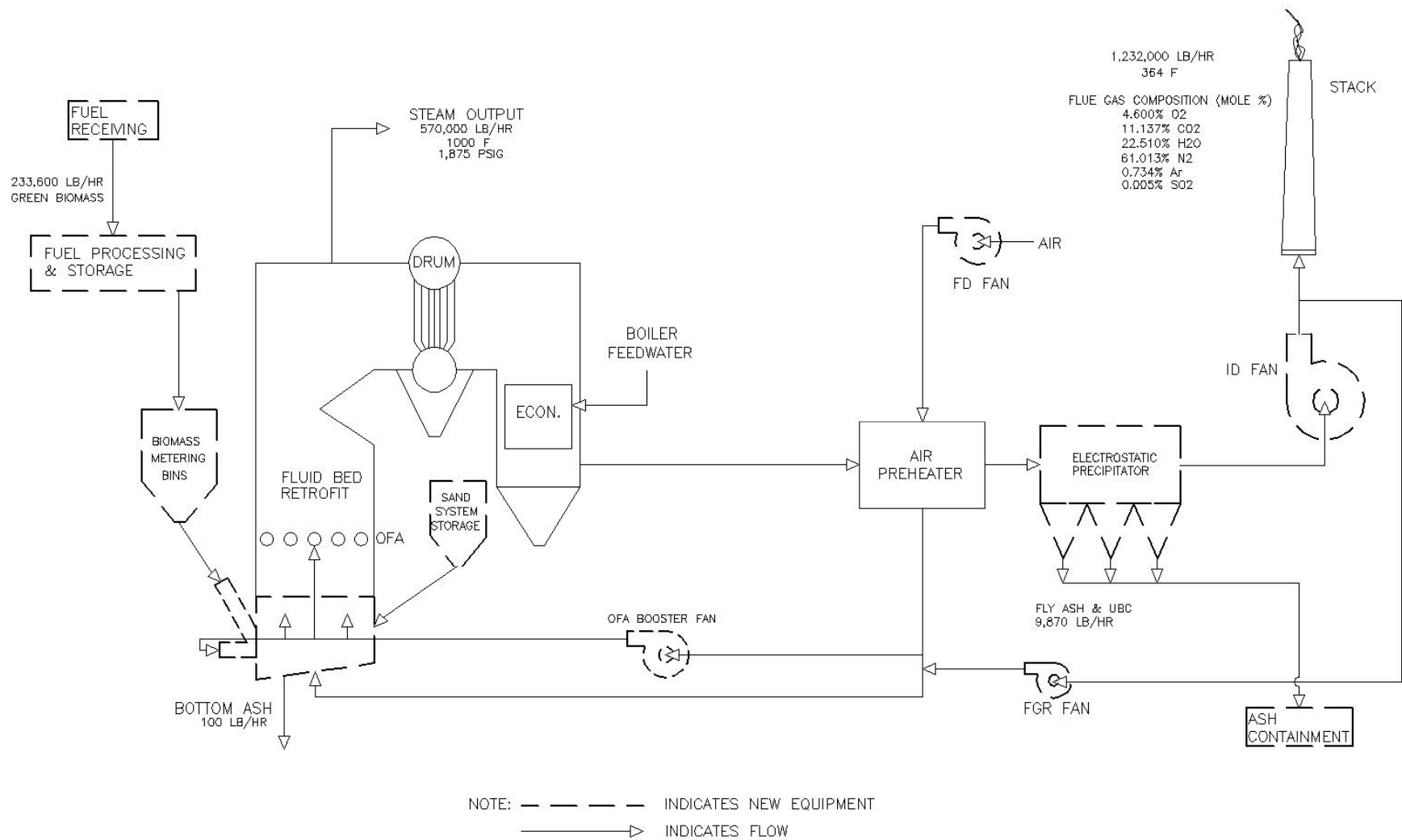


Figure 2-7
General Process Flow Diagram for Option 4 – Modified BFB Boiler (94 MW_{gross})

Appropriate Fuel Qualities

The discussion of fuel requirements for fluidized bed technologies was discussed previously for Option 2 (pg 2-29). In general, BFB boilers are more tolerant of variations in biomass fuel characteristics than stokers. The biomass fuel can be sized up to 3-inch (7.6 cm) minus (at most 3 inches in any dimension), and moisture content can be up to 60%.

Construction Schedule & Permitting

Limited information was available regarding the expected construction schedule for coal boiler modifications. However, the timeline for a boiler replacement project with a turbine-sized fluid bed boiler, as presented in Option 2, can be used as a point of reference. The schedule is also expected to be very similar to the stoker retrofit configuration in Option 3. Based on a recent study prepared for a similar type of project, it is expected that it would take around 3 years for a repowering of this sort to be fully operational, including about 11 months for construction.

Costs

The total investment and installation costs for the major equipment items and modification costs for BFB applications are expected to be about the same as the stoker boiler retrofit (excluding consideration of the additional pollution controls that may be required for compliance with the proposed industrial-boiler MACT guidelines). Based on previous studies and projects, the boiler retrofit portion of the investment can be somewhat higher, in some cases about 25% more than the stoker grate option.

Technology Status and Development Risks

The key areas of operational risk for a BFB retrofit include: 1) increased combustion control complexity (which requires carefully managing bed inventory and temperatures), and therefore increased operating complexity and possible risk of bed agglomeration; 2) avoiding emergency shutdowns with attendant rapid bed collapse; and 3) maintaining boiler refractory linings.

Conversion from coal firing to BFB has been evaluated for a wide array of utility-scale power plants, and a limited number of applications have been successfully carried out. Several examples of existing projects with utility-scale BFB biomass boilers constructed as retrofits are listed below:

- Snowflake White Mountain Power (Snowflake, AZ). 70 MW_{th} output. Start-up in 2007. Operates on wood and sludge biomass materials.
- Pan Pac Forest Industries, Ltd. (Napier, New Zealand). 36 MW_{th} output. Start-up in 2002. Operates on woody residues and sludge.
- Trigen BioPower with Gilman Paper Company (St. Mary, GA). 50 MW_{th} output. Start-up in 2000. Operates on woody biomass residues and paper sludge.

- Bowater (Calhoun, TN). 144 MW_{th} output. Start-up in 1998. Operates mainly on wood and paper mill sludge.
- PannonPower Power Plant (50 MW_e & 65 MW_{th}) (Pécs, Hungary).
- Borsod Power Plant (100 tph steam capacity, 72 MW) (Hungary).
- Ajka Power Plant (30 MW_e) (Ajka, Hungary).
- Rauhalahhti CHP Plant (87MW_e) (Jyväskylä, Finland). Retrofit in 1993.
- French Island (28 MW_e) (La Crosse, Wisconsin).

Nearly all of the challenges described above for stokers with respect to the effects of higher gas velocities and heat transfer surface changes apply to the BFB retrofit option as well. The major exception is the possible compatibility of the BFB with certain types of air heaters. This is a risk that needs to be evaluated during project engineering; OEMs familiar with these types of projects suggest that this risk can be adequately addressed.

A summary of key factors for this option is provided below.

Table 2-10
Summary for Option 4: Modify existing coal boiler for fluid bed firing

Example Capital Cost Estimate	Approx. same as Option 3, \$1,100-\$1,650/kW for 85 MW net
Non-fuel O&M Cost Estimate	\$0.02/kWh
Feedstock Requirements	Particle size and moisture content can vary somewhat during operations. Alkali content ≤ 0.79 lb/MMBtu (≤ 0.34 kg/GJ).
Project Development Timeline	Need revised air permits. Estimate 3-4 yrs from feasibility to commercial operation.
Emissions Performance Summary	Lower CO and VOC emissions than stoker grate.

Option 5: Modify existing gas/oil boiler for grate firing

Technology Description

This scenario considers modifying an existing fossil-fuel-fired utility boiler to burn biomass instead of gas or oil. As with all of the options described above, biomass fuel handling, receiving, and storage equipment will need to be installed. However, unlike the pulverized coal plant, which would have some conveyors and a large fuel yard space already available, a natural gas station may not even have land available to install a storage area, much less have runoff controls already in place. The fuel handling and storage component of this particular retrofit will thus be more extensive, and more expensive, than the coal case.

In general, it is more difficult to modify gas- and oil-fired boilers than PC-fired boilers, as they normally require more modification to the convection pass to reduce air velocity to a desired level. There seems to be little experience converting utility-scale gas or oil boilers for biomass grate firing, and very little information was publicly available.

When designing stoker boiler retrofits, the bed size or the grate size are the primary limiting factors in steam production. Due to the lower heat content of the biomass fuel, modification of the existing furnace will result in a derating of the boiler (assuming the same furnace dimensions are applied with no height increase or modifications to the building structure). Based on a recent feasibility study of a gas boiler retrofit, the net generation capacity may be reduced by about 30% as a result of conversion. The net heat rate for the converted plant was estimated to be about 16,300 Btu/kWh (17,180 kJ/kWh).

New lower furnace wall panels will be needed to accommodate stoker seals and overfire air ports. It is likely that the convection pass of the existing boiler will need to be modified so that the air velocities can be brought within standards for wood firing. If there is insufficient room to allow for these modifications to achieve the desired exit gas temperatures, the steam flow may need to be lowered. An example process flow diagram for a 41 MW (net) biomass-fired converted stoker boiler plant is provided in Figure 2-8.

Emissions considerations for a biomass-fired stoker boiler, as discussed previously for Option 1, will also apply to this option. Mechanical dust collectors or another similar device will need to be installed ahead of the air preheater to control the size of particulate carryover.

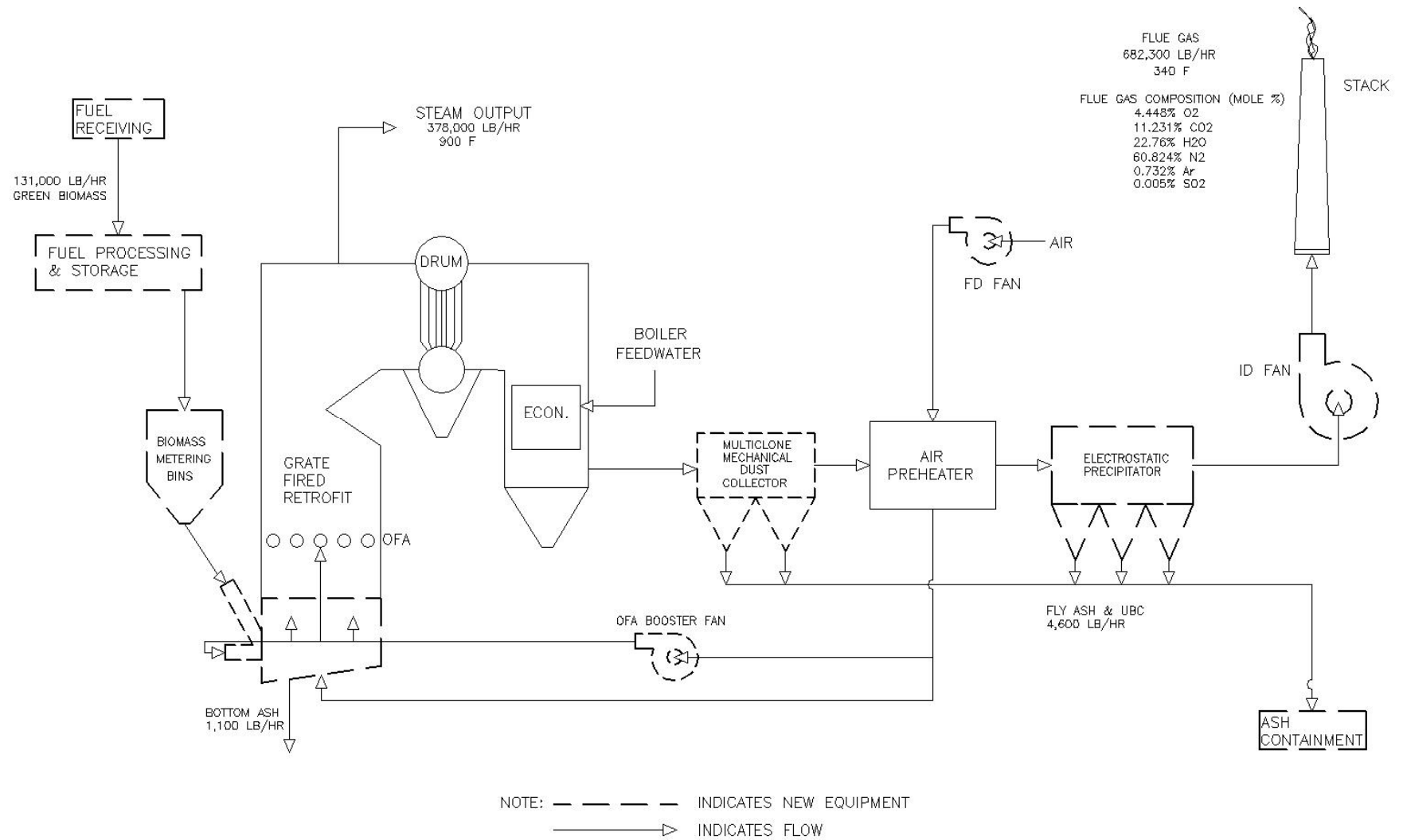


Figure 2-8
Example Process Diagram for Option 5 – Modified Grate Boiler (41 MW_{gross})

Appropriate Fuel Qualities

The fuel requirements for grate firing technologies discussed for Option 1 (pg 2-22) also apply to this case. In general, stoker grate boilers can be designed for a wide range of fuel types, but they require consistent fuel during operation, which limits the types of fuels that can be used.

Construction Schedule and Permitting

Although limited information is available regarding this specific configuration, the construction schedule is expected to be similar to the stoker grate boiler retrofit project described in Option 3 (i.e., approximately 3 years for design, construction, and commissioning).

Costs

The following system modifications would likely be required:

- wood fuel yard and fuel handling equipment,
- removal of existing furnace bottom,
- addition of stoker grate to existing boilers,
- modification of existing combustion air ductwork,
- replacement of existing forced draft (FD) and induced draft (ID) fans,
- addition of fuel delivery and storage equipment within boiler house,
- addition of multiclones for removal of ash and unburned carbon from the flue gas prior to the inlet of the air heater,
- addition of a baghouse to screen out fine particles from the flue gas stream prior to the stack entrance,
- addition of ash removal conveyors and storage silo,
- addition of an ammonia-based SNCR NO_x reduction system, and
- ancillary other requirements in support of the above items, including controls, wiring, foundation support for the stokers, etc.

The total estimated cost for the plant modification is about \$125 million for a 70 MW (net) biomass-fired stoker boiler plant, which corresponds to about \$1,800/kW. As with the other plant modification cases, the least certain aspects of the budget estimate are the cost to perform the retrofit of the furnace bottom, the added costs of obtaining a turn-key package with performance guarantees, and the mark-ups on equipment from a turn-key contractor. The expected non-fuel O&M costs are around 2.14 ¢/kWh, based on the limited available data.

Technology Status and Development Risks

The projects that have completed this process and appeared in the literature researched for this report involved industrial-scale boilers, particularly in the pulp and paper industry, rather than utility-scale retrofits. While the authors have no reason to question the potential technical viability of this approach, the lack of experience at utility scale is problematic for early adopters.

A summary of key factors for this option is provided below.

Table 2-11
Summary for Option 5: Modify existing gas/oil boiler for grate firing

Example Capital Cost Estimate	\$1,800/kW for 70 MW net
Non-fuel O&M Cost Estimate	\$0.02/kWh
Feedstock Requirements	Fuel moisture content must be w/in 10% of design fuel specs. No fuels with low ash melting temps.
Project Development Timeline	2-4 years. Need revised air permits. Estimate 1-2 yrs financing/permits, 1-3 yrs construction & commissioning.
Emissions Performance Summary	Increase in NO _x and CO relative to gas and oil; decrease in GHG. Negligible sulfur emissions.

Option 6: Modify existing gas/oil boiler with fluid bed firing

Technology Description

As with the option above, biomass fuel handling, receiving, and storage equipment will need to be installed to facilitate this type of conversion, and space is expected to be an issue at a significant fraction of the sites where this option is considered. As with stoker retrofits, the bed size is the primary limiting factor for steam production by BFB boilers. Modification of the existing furnace dimensions will result in a derating of the boiler due to the lower heating values of biomass fuel, assuming there are no size increases or modifications to the existing building structure. The capacity deratings for BFB retrofits are lower than for stoker boilers. Based on a recent feasibility study, the net generation capacity is reduced by about 15% during conversion of a natural gas boiler to a BFB operating completely on biomass fuel. The net heat rate for the converted plant was estimated to be about 16,000 Btu/kWh (16,864 kJ/kWh).

As in the previous scenario (Option 5), new lower furnace wall panels will be required in order to accommodate bed seals and overfire air ports. It is likely that the convection pass of the existing boiler will need to be modified, such that the air velocities can be brought to the standards for wood firing. If there is insufficient room to allow for these modifications to achieve the desired exit gas temperatures, the steam flow may need to be reduced. An example process flow diagram for a 39 MW (net) biomass-fired converted BFB boiler plant is provided in Figure 2-9.

Emissions considerations for a biomass-fired fluid bed boiler, as discussed previously for Option 2, will also apply to this option. Unlike with stoker grate firing, a mechanical dust collector will not be required, as particulate carryover is generally not a problem in BFB boilers.

The existing FD and ID fans will need to be evaluated to ensure they are suitable for the new configuration and can maintain the minimum static pressure. The ID fan will need to be evaluated relative to the specified back-end equipment and convention pass; if the equipment needs to be resized, this may lead to an increased draft loss.

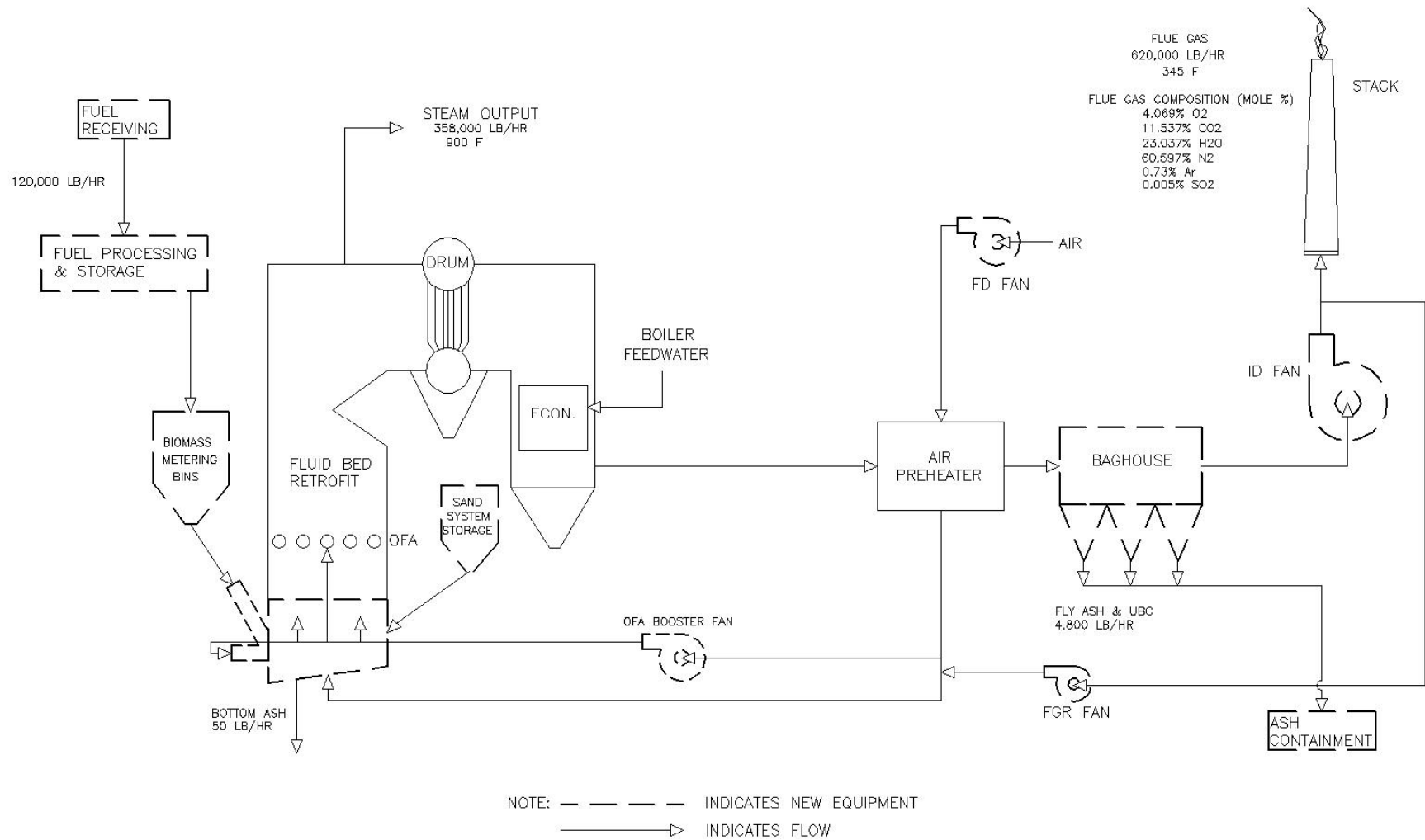


Figure 2-9
Example Process Diagram for Option 6 – Modified Fluid Bed Boiler (39 MW_{gross})

Appropriate Fuel Qualities

The fuel requirements for fluid bed technologies discussed for Option 2 (pg 2-29) also apply to this case. In general, BFB boilers are more tolerant of variations in biomass fuel characteristics than stokers. Although the biomass fuel has to be small (less than 0.25", 0.64 cm), fluidized beds can handle fuels with a moisture content up to 60%.

Construction Schedule and Permitting

Although limited information was available regarding expected construction schedules for this configuration, the timelines noted for Case 5 are probably appropriate.

Costs

The major equipment items and modifications that would likely be required in this scenario are detailed below. This list is largely similar to the stoker modification in Option 5, although the fuel firing systems and ash systems are different for this technology. These items include:

- wood fuel yard and fuel handling equipment,
- removal of existing furnace bottom,
- addition of bubbling bed to existing boiler(s),
- modification of existing combustion air ductwork,
- addition of new tubular air preheater,
- additional equipment for bed material recycling and replacement,
- replacement of existing FD fans, and either new or modified ID fans,
- addition of fuel delivery and storage equipment within boiler house,
- addition of a baghouse to screen out fine particles from the flue gas stream prior to the stack entrance,
- addition of ash removal conveyors and storage silo,
- addition of an ammonia-based SNCR NO_x reduction system, and
- ancillary other requirements in support of the above items, including controls, wiring, foundation support for the stokers, etc.

Based on prior work, the total estimated cost for the plant modification is about \$120 million for a 65 MW (net) biomass fired stoker boiler plant, which corresponds to about \$1,820/kW. As with the other plant modification cases, the least certain aspects of the budget estimate are the cost to perform the retrofit of the furnace bottom, the added costs for obtaining a turn-key package with performance guarantees, and the mark-ups on equipment from a turn-key contractor. The expected non-fuel O&M costs are around 2.30 ¢/kWh.

Technology Status and Development Risks

Again, most projects reviewed in the literature were industrial boilers fired by waste from the pulp and paper industry. While it is possible that much of this experience can be translated to larger boilers, the authors believe that the relative lack of integration and engineering experience will be a factor in the costs and (potentially) the performance of such systems.

A summary of key factors for this option is provided below.

Table 2-12
Summary for Option 6: Modify existing gas/oil boiler for fluid bed firing

Example Capital Cost Estimate	\$1,820/kW for 65 MW net
Non-fuel O&M Cost Estimate	\$0.02/kWh
Feedstock Requirements	Particle size and moisture content can vary somewhat during operations. Alkali content ≤ 0.79 lb/MMBtu (≤ 0.34 kg/GJ)
Project Development Timeline	Need revised air permits. Estimate 3-4 yrs from feasibility to commercial operation.
Emissions Performance Summary	Lower CO and VOC emissions than stoker grate.

Option 7: High percentage cofiring

Option 7, in contrast to the previous options, actually represents a range of technologies, each with very different equipment and implementation requirements. However, the key commonality for these cases is that they do not seek to replace 100 percent of the existing fossil-fuel energy at the target plants. Instead, the goal is to achieve a high percentage ($> 50\%$ thermal energy) of biomass cofiring, while minimizing modifications to the boiler and the balance of the plant.

Cofiring applications are generally divided into two main categories: ***direct cofiring***, in which the biomass is fired together with other fuels in the same combustion system; and ***indirect cofiring***, where the biomass is combusted or gasified separately from the fossil fuel, and the resulting product gas, heat, or steam from the individual streams is then combined. These technologies are introduced below, and described in more detail in the following subsections.

For direct cofiring configurations, biomass can be introduced into a coal-fired unit using one of three different methods,¹² which are summarized in Table 2-13 below. In the first method, the biomass and coal are handled and milled together in existing equipment, and then injected

¹² It is possible to consider direct biomass cofiring in boilers that are currently firing gas or oil. However, a number of technical issues would need to be addressed, especially if the firing occurred at high rates. These include ash handling and many of the issues discussed for repowering Options 5 and 6. Because of these issues and the lack of apparent experience at the utility scale, these options are not discussed further.

directly into the boiler. However, this firing method is generally not practical for achieving high cofiring levels, as the differences in fuel hardness and moisture content (particularly with wood chips) will negatively impact the performance of the coal mill when co-milling biomass fuels with coal. This limits the percentage of cofiring that can be achieved with wood chips to approximately 5% of the thermal load (Laux, Grusha, & Tillman, 2000). Higher percentages of cofiring via co-milling are possible using wood pellets. Further, if the enabling technology is commercialized, higher percentages should also be possible using torrefied wood pellets (TWP).

In fact, both of these fuel types (wood chips and pellets) offer the potential for 100% boiler firing (with some derate) and, because of this opportunity, case studies for these options are presented later in this report (Chapter 4). Co-milling of wood pellets, however, is not considered further, simply because it is not consistent with the concept of repowering presented here.

The other two direct coal-cofiring methods both involve milling the biomass separately from the coal and then either mixing it in with the coal upstream of the boiler, or feeding it directly into the boiler via dedicated burners. The latter is the preferred option, but there are examples of the former as well. Injecting premixed biomass and coal into a common burner (Method 2) increases the risk of blocking the ingoing fuel injection lines and negatively affecting boiler operations. Firing each fuel separately in their own dedicated burners (Method 3) reduces this risk and also isolates biomass fuel feeding problems from the coal-firing system.

Although a wide range of biomass fuel types can be cofired, the amount of biomass that can be fired is limited for some cases. In general, a higher percentage of biomass can be cofired if pretreated biomass materials (such as wood pellets or torrefied wood) are mixed with the coal. An example process diagram for direct cofiring is shown in Figure 2-10.

Table 2-13
Methods of Direct Co-firing

Method	Advantages/Disadvantages
1. Co-handling and co-milling of biomass and coal together in existing equipment. The mixture of biomass and coal is then injected right into the existing coal combustion system.	• Low cost – much of the existing equipment is re-used • Can only accommodate low percentages of biomass co-firing as a result of negative impacts on milling performance
2. Separate handling and milling of biomass and coal. The biomass and coal can then be combined upstream of the combustion system, or combined at the combustion burners.	• Medium cost – would need to install separate handling equipment for biomass • Can accommodate higher levels of biomass co-firing
3. Separate handling and milling of biomass and coal. The biomass and coal are then injected into their own separate burners within the combustion system.	• High cost – existing boiler would need significant modification • Reduced chance of blocked injection lines due to the use of dedicated boiler burners

Data source: Handbook of Biomass Combustion and Co-firing

Indirect cofiring methods (summarized in Table 2-14) include gasifying or combusting the biomass separately from other fuels, and then combining the resulting products at some point in the generation process. The primary indirect cofiring technique considered in this assessment involves gasifying biomass and then combusting the biogas in the existing combustion system (IEA Bioenergy, 2009). Although this method has high capital costs, it also has the benefit of keeping biomass ashes separate from the coal ashes, and can accommodate very high cofiring percentages (Maciejewska, 2006). It can also eliminate many of the problems typically associated with biomass emissions, if the biogas is cleaned of its impurities prior to combustion (European Bioenergy Networks (EUBIONET), 2003). Since gasification can provide greater flexibility for biomass fuels, many types of biomass resources can potentially be utilized. Figure 2-11 shows an example schematic diagram for this configuration.

Table 2-14
Methods of Indirect Cofiring

Method	Advantages/Disadvantages
1. Gasification of biomass to create a low calorific fuel that is then combusted in the existing combustion system	• Greater fuel flexibility (compared to direct cofiring) • The biogas may require extensive fuel gas cleaning before it can be combusted
2. A separate combustor and boiler are installed for biomass combustion. The resulting steam generated from biomass is then combined with the steam that is produced from combustion of coal or other fuels (parallel cofiring)	• Greater fuel flexibility (compared to direct cofiring) • High costs - two separate process trains are required • Space requirements

The other indirect cofiring method is parallel cofiring, in which the biomass is handled and pretreated separately from the fossil fuel and then combusted in its own combustion system, while the steam generated from the process is combined downstream with steam generated by the fossil-fired assets (Figure 2-12). This would require the installation of an additional fuel handling system and boiler specifically for the biomass fuel. This option is generally expensive; however, it would make the combustion of fuels with high alkali and chlorine contents easier and more efficient than the direct cofiring options discussed above. Biomass and coal ashes would be kept separate, allowing for the resale of the coal ashes as concrete additives, and, because the steam from the coal and biomass boilers would be combined downstream, the power output of the facility could potentially be increased (assuming that the existing turbine is sufficiently large enough to handle the extra steam demand). This option is similar to Options 1 and 2 discussed previously, and may be appropriate in situations where a full repowering is not possible due to the size of the coal-fired boiler. (In fact, the authors consider this option to be somewhat of a misnomer and suggest that it is actually better described and handled as a repowering technology, not a cofiring technology, as there is not any co-combustion of any sort actually taking place).

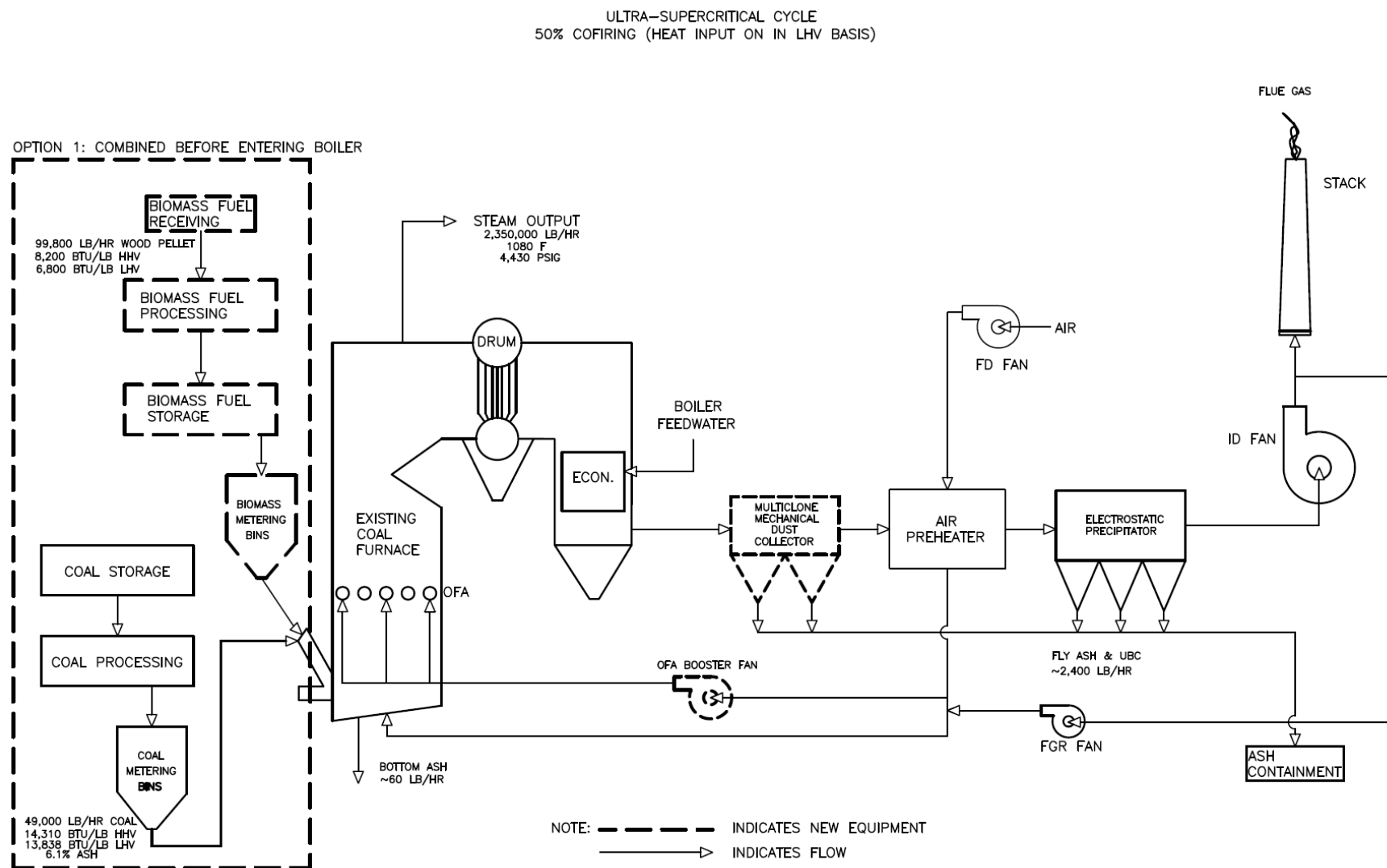


Figure 2-10
Example Process Diagram for Direct Cofiring

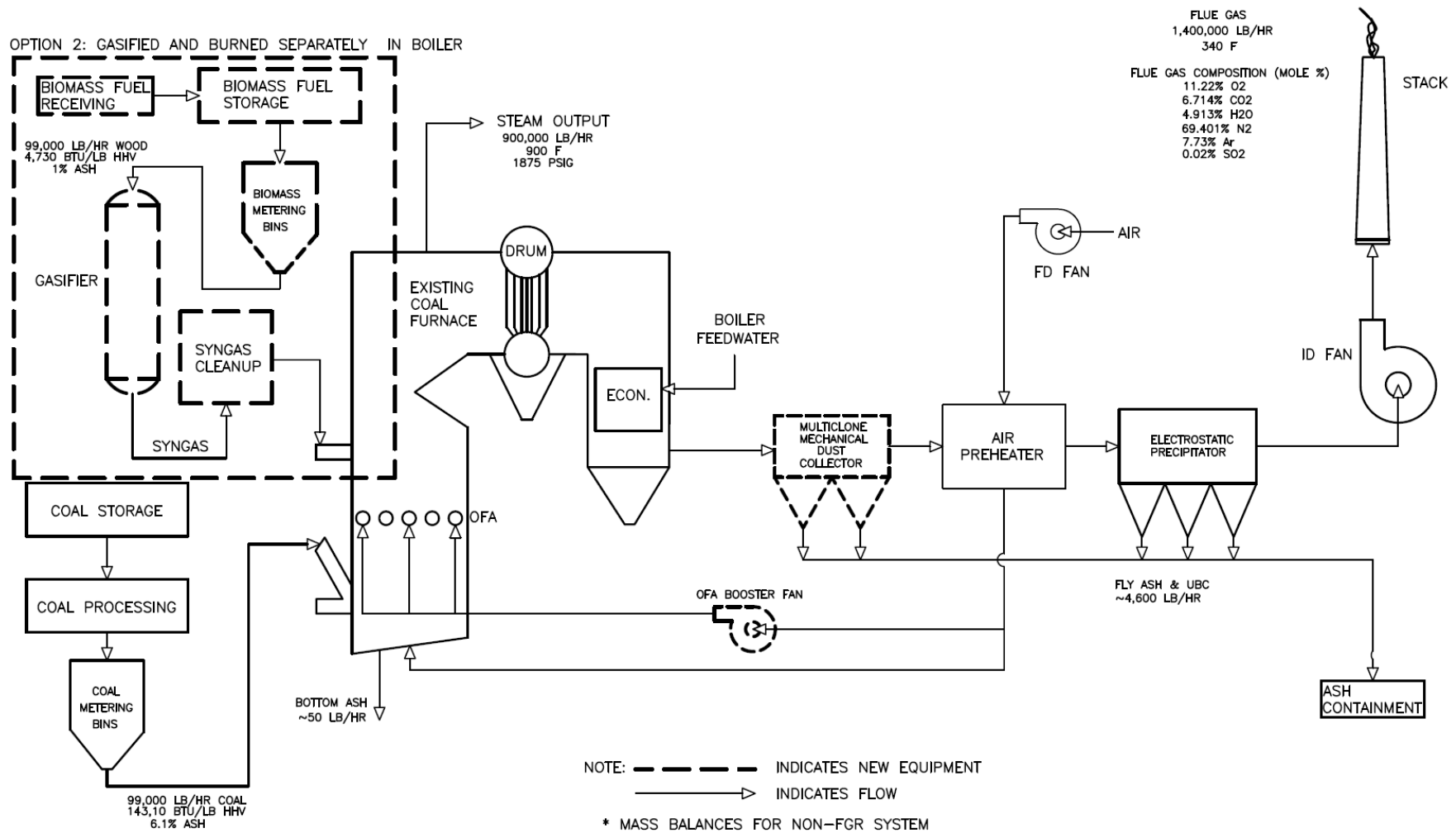


Figure 2-11
Example Process Diagram for Indirect Cofiring

OPTION 3: SEPARATE BIOMASS BOILER AND EQUIPMENT

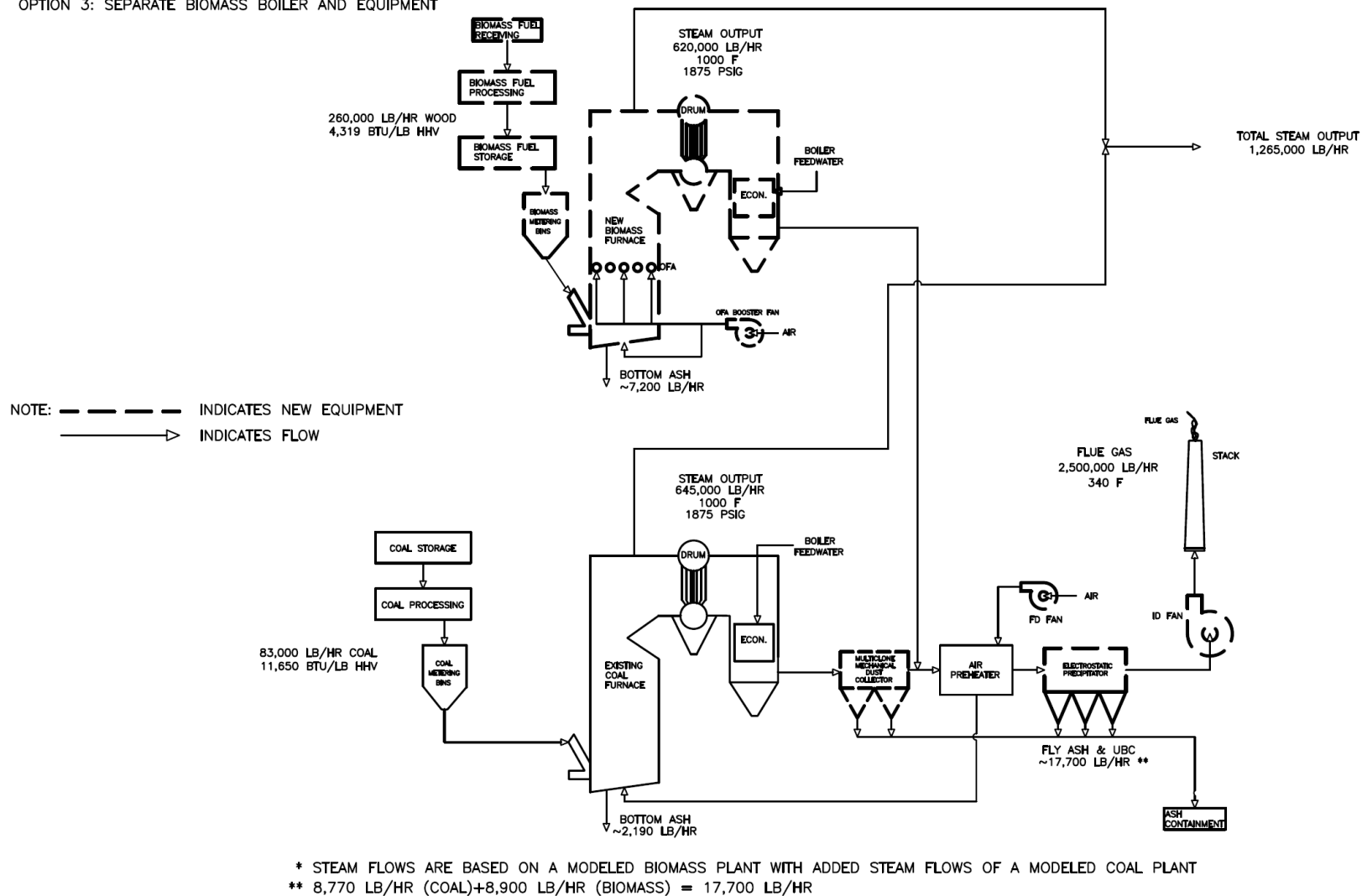


Figure 2-12
Example Process Diagram for Parallel Cofiring

Of the high percentage cofiring options reviewed, the following technologies are discussed in greater detail below:

- Option 7a: Apply suspension firing of biomass to existing coal boiler
- Option 7b: Externally gasify biomass and fire in existing coal boiler
- Option 7c: Externally gasify biomass and fire in existing gas/oil boiler

7a) Direct Cofiring – Suspension Firing of Biomass in Existing Coal Boiler

Technology Description

Coal combustion technologies that are typically considered for direct cofiring applications include fixed bed combustion (stoker or grate), fluidized bed combustion (bubbling or circulating), and pulverized fuel combustion. Of these three types, the fluidized bed combustion has the highest flexibility in terms of fuel type and moisture content, which makes it the most suitable for cofiring applications. Fixed bed boilers are limited to using wood fuels, as they do not accommodate mixtures of fuel that have different combustion behaviors (such as wood and straw together). Pulverized boilers are typically limited to cofired fuel sources that have fairly consistent fuel size and moisture contents, such as sawdust, finely ground wood chips, shavings, or pulverized wood pellets. Both fixed bed and fluidized bed boilers may achieve lower investment costs for conversion to cofiring by avoiding extensive fuel processing, while pulverized bed boilers generally have higher investment costs (Maciejewska, 2006).

Wood pellets and possibly torrefied wood can be directly cofired at a high percentage in an existing suspension or pulverized coal burner with limited modifications. Both products have low moisture contents and are made of compacted particles that can be readily broken down either by dedicated mills and possibly coal pulverizers. The fuel can then be combusted in existing burners (Marshall, 2010). If processed separately, it is possible to also use woodchips at high percentages, though extensive milling will be required. Some general wood pellet properties are compared with coal and other biomass fuels in Table 2-15.

Table 2-15
Comparison of Properties for Different Fuels

Material	U.S. Units		SI Units	
	HHV (Btu/lb)	Density (lb/ft ³)	HHV [MJ/kg]	Density [kg/m ³]
Coal	12,038	54.9	28	880
Wood Chips	4,514	34.3	10.5	550
Wood Pellets	6,879	37.5	16	600
Torrefied Pellets	9,028	49.9	21	800

Data sources: (Mitchell, 2007; Brown, 2003)

Overall, the lower energy content of biomass means that a greater fuel volume would have to be processed in order to maintain the same approximate overall power output when using high percentage cofiring. The size and capacity of the existing primary air source will limit the percentage of biomass cofiring that can be completed successfully. As such, modifications to the primary air system will likely be needed for high percentage cofiring applications to increase either overall volumetric flow or air pressure (IEA Bioenergy, 2009). If wood pellets will be used in an existing coal pulverizer, the primary air source will also have to be modified to use colder air, as biomass releases volatile gases at much lower temperatures than coal (Marshall, 2010). If using other sources of biomass, such as waste derived fuel or biomass residues, it may be necessary to sort out any non-desirable material (such as metal or plastic) that happens to be mixed in with the biomass before it can be cofired (European Bioenergy Networks, 2003).

The ash content of wood is very different from that of coal. Although biomass generally produces a smaller quantity of ash, it fuses to boiler surfaces at much lower temperatures (Baxter, 2003). Biomass ash deposition rates can vary depending on the type of material used; higher-quality woods exhibit ash deposition rates that are approximately an order of magnitude lower than those of coal. When cofiring a combination of biomass and coal, total ash deposition rates typically fall between the deposition rates of each material individually. However, sometimes ash deposition rates are lower than the expected value due to interactions between alkalis from the biomass and sulfur from the coal (Baxter, 2003).

Cofiring biomass with coal can help to mitigate the corrosive effects from chlorine compounds that damage superheater tubes. Although biomass gases are usually very high in chlorine content and will sometimes form corrosive alkali chlorides, the chlorine-rich gases will form much less corrosive alkali sulfates in the presence of the SO_2 generated from coal combustion (Robinson, A. et al, 1998). The facility may also choose to inject ammonium sulfate into flue gas after combustion, which has the same mitigating effect (Maciejewska, 2006). At the same time, the alkali and alkaline earth metals that can be found in biomass ash can cause significant deactivation of SCR catalysts (Baxter, 2003). This catalyst deactivation can be mitigated by washing the catalysts with water to remove the alkali buildup. The Avedøre Power Station in Denmark employs a similar water washing system to prolong the lifetime of its SCR catalysts, which receive buildup as a result of the combustion of wood pellets (Van Loo, 2008).

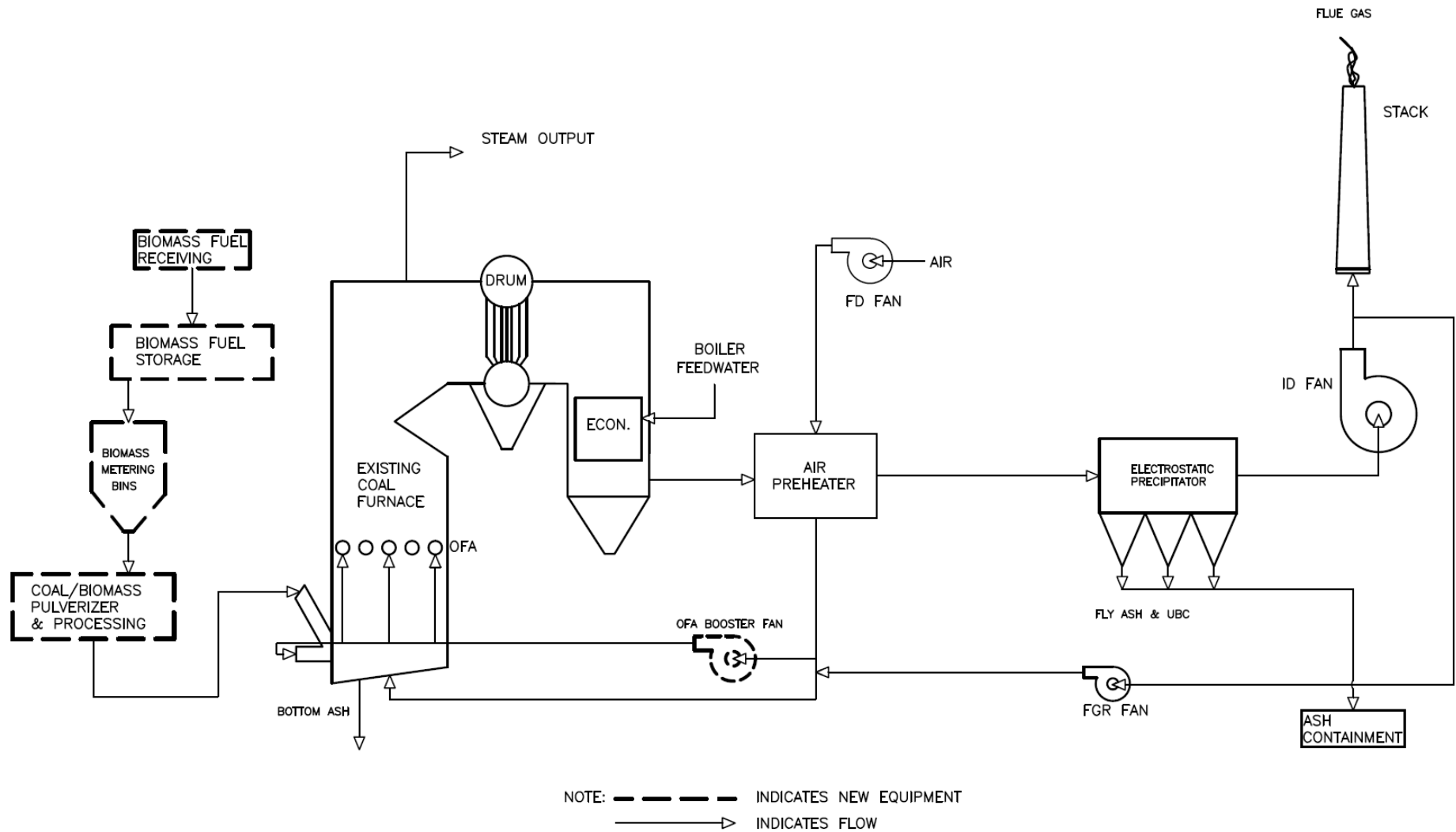


Figure 2-13
Example Process Diagram for Option 7a – Direct Cofiring in Existing Coal Boiler

Appropriate Fuel Qualities

A large variety of fuel types can be used for cofiring, although the applications vary somewhat depending upon the specific technology utilized. Table 2-16 shows the range of fuel sizes and moisture contents that can be used in different types of coal boilers. Sawdust, shavings, or wood pellets are all ideal fuel sources for a suspension boiler because of their potential to be reduced to the appropriate size (as well as, possibly, their typical as-received moisture content).

Table 2-16
Biomass Fuel Qualities for Cofiring in a Coal Boiler

	Stoker Grate Boiler	Fluidized Bed Boiler	Suspension Boiler
Biomass Size Requirement	0.25" - 2" (0.6 – 5.1 cm)	1.5" - 3" (3.8 – 7.6 cm)	< 0.25" (<0.64 cm)
Biomass Max. Moisture Content Requirement	10-50%, depending on manufacturer	up to 60%, depending on manufacturer	15-20%
Example Biomass Fuels	Wood chips, wood waste materials, straw	Wood chips, agricultural residues	Wood pellets, torrefied wood, sawdust

Costs

High percentage cofiring will require less total capital investment in the facilities than full repowering. However, on an incremental basis, the costs to operate and maintain both biomass and coal systems (including receiving, handling, and milling equipment) at high throughput levels may increase relative to the costs of operating a single fuel plant. The potential exception would be the use of torrefied biomass, which will in theory blend in with coal operations seamlessly. Based on the discussion above, the following is a sample list of required equipment that would need either replacement or modification for the incorporation of higher percentage biomass cofiring into an existing utility-sized coal boiler:

- Biomass fuel storage system to accommodate truck delivery and to shelter material from the weather,
- Updates to the fuel handling system, including additional biomass handling lines, fire suppression, and air quality control,
- Modifications to the primary air system to increase pressure and/or flow,
- New burners in the existing boiler, and
- Pollution control in the stacks.

Since there is not a lot of experience with high percentage cofiring applications, specific cost estimate information is limited. However, it is expected that the unit costs will lie within the range of costs for more typical low percentage cofiring (10-15%) and full repowering (excluding

the boiler bottom retrofit costs). One reference point is the retrofit of the Les Awirs Unit 4 boiler in Belgium to convert it from operating on pulverized coal to 100% biomass pellets. It is estimated that the total capital cost for the retrofit was about \$10 million (\$125/kW), since some of the existing material handling equipment was able to be reused (Ryckmans, 2006). The total capacity of the repowered unit is about 80 MW.

Similarly, it is possible to bracket the capital costs of high percentage cofiring by using the estimated costs of cofiring at lower percentages and the costs to completely repower. According to the U.S. Department of Energy, costs for a 15 MW fixed bed stoker boiler plant that cofires biomass at 20% of its total heat input can range from \$50-350/kW for the biomass capacity portion (U.S. DOE, 2004). A recent report suggested that capital costs for low percentage cofiring of biomass with separate injection systems in PC units range from about \$300-\$600/kW. In contrast, the data for full repowering suggests costs that range from \$1,100 to 2,300/kW. The middle of these ranges suggests that high percentage cofiring might fall in the range of \$1000/kW. Although this value is considerably higher than the Les Awirs data point, it is the understanding of the authors that considerable modifications would have been necessary, and the costs referenced above may be understated.

In the United States, ash generated from biomass combustion cannot be used as a concrete additive. According to ASTM specifications, only ash derived entirely from coal combustion may be used in concrete (Baxter, 2003). If revenue was previously generated through the sale of coal ash, the facility may not be able to count on this source of income after the retrofit. Biomass ash does have some beneficial uses (fertilizer, aggregate products, etc.) and, depending on local markets, disposal costs may be mitigated. The ability to find a market for the ash will be dependent upon market access and state/local regulations. For agricultural markets, biomass ash may require pre-treatment before use (Maciejewska, 2006).

Construction Schedule and Permitting

Cofiring will require modifications to a facility's Title V permit to add the relevant biomass to the list of permitted fuels. In most cases, emissions testing is also carried out to demonstrate that the fuel switch does not deteriorate the plant's environmental performance. The process of testing and applying for the necessary modifications often takes more time than would generally be expected, in some cases stretching over a period of years. However, the long period for making changes usually also has to do with the complicating issues that can surround cofiring retrofits, such as the potential to trigger New Source Review action by state environmental regulators. For low percentage cofiring, utility companies have shown reluctance to make relatively modest changes to their plants to accommodate biomass (which may only demonstrate marginal benefit, while simultaneously putting the permitting status of their entire asset at risk). Given the more substantial impact and potential benefit of high percentage cofiring, perhaps this issue will be less of a concern and may speed development time.

With respect to design and construction, biomass cofiring retrofits can be accomplished relatively quickly. The conversion from pulverized coal to 100% biomass pellet firing at Les Awirs was completed in only 7 months, which includes the associated studies (Ryckmans, Allard, Liegeois, & Mewissen, 2006). This is an extremely fast turn-around, which may not be

possible in all cases. The permitting and regulatory processes in Belgium at that time may have been significantly faster than those currently experienced in the U.S.

Technology Status and Development Risk

Despite limited deployment overall, there have been several commercial-scale projects that have involved high percentage cofiring of biomass. Some examples are provided in Table 2-17. This list includes a number of pulverized coal plants experienced with using wood pellets to supply a portion of their energy requirements (Marshall, 2010). Other technologies are also employed for direct cofiring, such as circulating fluid bed combustion at the Alhomens Kraft and Malarenergi facilities.

Table 2-17
Commercial Scale Direct Cofiring Project Examples

Facility	Country	Operational Since	Net Output	Efficiency	Fuels	Biomass Percent Contribution (by heat, unless otherwise noted)
Alholmens Kraft	Finland	2002	265 MW _e 310 MW _{th}	40%	Peat, wood waste, bark, recovered fuel, coal	90% (by mass)
Frantschach	Austria	1984	29 MW _e 61 MW _{th}		Bark, heavy fuel oil, coal, sewage sludge, gas	95%
Mälarenergi, Västerås	Sweden	2000	72 MW _e 185 MW _{th}	39%	Peat, wood waste, coal	up to 80% (by mass)
Amager – Unit 1	Denmark	2009	71 MW _e net 250 MW _{th}		Coal, wood pellets, straw pellets, oil	35-90% straw pellets, 35-100% wood pellets
Hässelbyverket	Sweden	1994	70 MW _e 205 MW _{th}		Wood pellets, fuel oil, olive waste	up to 80%
Avedøre – Unit 2	Denmark	2002	585 MW _e 565 MW _{th}	45%	Natural gas, fuel oil, wood pellets, straw (separate biomass boiler)	up to 70%*
Amer – Unit 9	Netherlands	2002	600 MW _e 350 MW _{th}	40%	Natural gas, fuel oil, wood pellets, demolition wood (gasifier)	up to 27%**
Les Awirs – Unit 4	Belgium	2005	80+ MW	34%	Wood pellets	100%

* Up to 70% by heat using wood pellets in the ultra supercritical steam boiler, and an additional 16% by heat using straw pellets in the biomass boiler.

** Pellet contribution up to 27% by heat if used in main boiler, and up to 5% by heat using indirect gasification.

Many facilities have started to cofire biomass in some capacity as a way to reduce energy costs and emissions. However, the number of facilities cofiring 50% or more of their heat capacity with biomass is limited. Many of the facilities that do cofire 50% or more of their thermal output from biomass were designed to do so and originally built to handle a wide variety of fuel types. There are a few exceptions to this, however. The Vattenfall Amager Unit 1 in Denmark was part of a large redesign project of an existing coal boiler. The only components that were reused in the new facility were the boiler house, boiler frame, fuel silos, and electrostatic filter. A new boiler, fuel handling system, and back pressure turbine were installed so that the facility could achieve greater fuel flexibility (Vattenfall AB, 2009). The Hässelby CHP plant (located in Sweden) was also a rebuild of an existing coal boiler that was modified to handle biomass dust from wood pellets. At the Les Awirs facility, Electrabel retrofit a pulverized coal boiler (Unit 4) to operate solely using biomass pellet fuels to generate electricity. The original boiler was built for gas firing, and later modified as a 125 MW coal-fired unit. In the latest modification from coal to biomass pellets, there was no change to the boiler, although there were some burner modifications (Ryckmans, 2006).

Facilities that use pulverized wood pellets typically only cofire about 5-20% of their thermal load. At those low levels, the effects of the biomass emissions profile are greatly reduced. And although much has been learned from these experiences, high percentage cofiring does present a new level of technical challenges. Most of the technology risk associated with high percentage cofiring relates to the changes in ash and emissions. There continues to be significant “art” in the design of appropriate storage and handling systems, but there is commercial experience to draw upon and many of the critical design issues are well known at this point. However, the effects of the biomass ash and emissions on the existing coal-based boilers, emission controls systems, and environmental performance of these high percentage systems are still under intense review.

7b) and 7c) Indirect Cofiring - Externally gasify biomass and fire in existing fossil fuel boiler

Technology Description

In these scenarios, a biomass gasifier is installed at an existing fossil-fuel-fired power station and the existing boiler is retrofitted to fire producer gas. The specific scenarios considered are externally gasifying biomass and firing in an existing pulverized coal boiler (Option 7b) or in an existing natural gas or fuel oil boiler (Option 7c).

In this configuration, the existing boiler is modified, rather than replaced. Biomass producer gas is a low-Btu fuel, with a heating value of between 100 and 325 Btu/scf. On a mass basis, this is equivalent to 1,550 to 5,100 Btu/lb, depending upon the temperature of the syngas before combustion. Coal and natural gas are much more energy dense fuels. Natural gas has a higher heating value, around 22,000 Btu/lb, which equates to 900 to 1,000 Btu/scf on a volumetric basis.

Efficiently combusting this low-Btu fuel requires higher amounts of excess air, and thus more heat transfer area, to accomplish the same heat exchange from a larger, lower-temperature volume of flue gas. The boiler’s existing heat transfer area will limit boiler steam production, as will the boiler’s dimensions. The flame characteristics of burning biomass producer gas are also

different than they are for natural gas (and certainly coal). Flame lengths can be very long, and it may be necessary to change burner orientation to ensure that flames do not impinge on the furnace walls and cause boiler damage. Existing burners will need to be replaced, and additional penetrations will need to be put into the boiler walls for new burners and/or secondary air supply. The placement of these ports will be specific to the individual geometry of the existing boiler and the results from fluid dynamics modeling of its combustion.

Modifications and the potential derate will be more dramatic for a gas or oil boiler than for a pulverized coal boiler due to the different geometries of solid- and gas/oil-fueled boilers. Though the particle size reduction achieved with coal pulverizers leads to very effective combustion, coal still requires a longer residence time to combust than fuel oil or natural gas. In contrast, gas particles are free to diffuse immediately into the combustion air and combust; they have, in effect, the largest possible surface area to volume ratio. The issues with respect to boiler volume and geometry described above will thus be exacerbated for gas-fueled boilers.

The potential issues with the retrofit are further aggravated by the fact that natural gas or fuel oil firing generally requires a lower percentage of excess air (10-15%) than does pulverized coal (15-20%). Thus, the increase in required excess air to 18-25% when operating on syngas is more substantial for natural gas boilers than for coal, particularly given the energy-diffuse nature of syngas. As a result, the heat transfer areas and combustion volumes are reduced even further in comparison to coal, as air and flue gas volumes will be smaller. The amount of excess air required may also mean that new ID and FD fans will be required to handle much larger volumes of air. Unless these fans are currently well oversized, they will likely have to be replaced.

A final factor in determining the derate to the plant's overall electrical output is the change in parasitic load as a result of the conversion to producer gas firing. Natural gas power stations do not operate pulverizers or ESPs, and generally have smaller fan power requirements than similar pulverized coal facilities, particularly given the lack of pollution control equipment (and their large pressure drops) in the flue gas system. They also do not have extensive fuel conveyor systems or fuel unloading facilities. Their overall parasitic loads, as a result, are far smaller than those of coal-based systems. This means that the incremental change in parasitic load after repowering with a biomass gasifier will be far greater than for a pulverized coal plant. This again leads to a larger derating, as more of the already reduced gross power output will be used to run the plant itself than in the original configuration.

The amount of support equipment for a coal boiler may be reduced or eliminated in this type of repowering. For example, depending on the level of cofiring, fewer pulverizers may be needed. Furthermore, ash carryover from the gasifier is generally captured in gasifier vendor-provided cyclones and filters before the syngas fuel reaches the boiler. This may reduce sootblowing requirements and lessen demands on particulate control systems.

On the other hand, there will be an expansion in fuel handling and conveying equipment. The lower energy density of biomass will result in larger mass flows than was needed previously for coal. Depending on the specifications of the particular fuel, this may result in increased parasitic loads for the conveyors and process equipment.

The placement of the new gasifier and cleanup system on site will determine the amount of ducting and piping necessary to both convey the cooled producer gas from the syngas cooler to the boiler burners and move the hot water generated by the syngas cooler to wherever it will be integrated into the plant (likely in the feedwater system). The temperature drop on the syngas side of the syngas cooler can be as large as 600°F (316°C), leading to a significant feedwater preheating capability.

The emissions implications of using a gasified biomass fuel rather than pulverized coal are not clearly defined for utility-scale firing, as experience is limited. A 42 MW_e gasification cofiring system was commissioned in Lahti, Finland in 1998. The circulating fluidized bed operated at atmospheric pressure, supplying syngas to a once-through boiler originally designed for oil fuel and since retrofitted to pulverized coal firing. This project did not publish extensive emissions data for pre-and post-cofiring operation, but did provide the following reductions data in a white paper written by the gasifier vendor, Palonen (2005):

Table 2-18
Emissions Data for Lahti Gasification Cofiring

Pollutant	Change Caused by Gasifier
CO ₂	110,200 ton/year decrease
NO _x	0.023 lb/MMBtu (5-10%) decrease
SO _x	0.047-0.058 lb/MMBtu decrease
HCl	0.012 lb/MMBtu increase
CO	Unchanged
Particulates	Slight decrease
Heavy Metals	Slight increase in some elements; base level low
Dioxins, Furans, Phenols, Polyaromatic Hydrocarbons, Benzene	Unchanged

Data source: (Palonen, Anttikoski, and Eriksson, 2005)

These data are for gasifier operation on a mixture of wood wastes, shredded tires, classified/sorted refuse-derived fuels, plastics, and paper. The mixed nature of this fuel may limit the relevance of these data to the biomass-only operation of a gasifier (as discussed in this section).

Other utility-scale cofiring projects have been constructed. The Amer 9 gasification cofiring arrangement has operated since 2002 with an atmospheric circulating fluidized bed gasifier, producing approximately 34 MW_e (Thek, 2010). Foster Wheeler Oy constructed a third atmospheric circulating fluidized bed gasifier in 2002 in Ruien, Belgium. Limited operation of this gasifier with demolition wood and wood chip fuel produced 17 MW_e in a cofiring arrangement within an existing pulverized coal boiler (Hiltunen, 2004).

Emissions data for these two projects are limited. No emissions data are publicly available for the Amer 9 facility. For the Ruien facility, some data were (316°C) presented by the gasifier vendor after the end of the commissioning period. The plant saw reduced NO_x and SO_x emissions, while particulate and CO emissions remained relatively constant. Dioxin and trace metal emissions also remained unchanged (Hiltunen, 2004).

One additional but less relevant data point that is available is a cogeneration project in Güssing, Austria that fires wood-based, medium-Btu producer gas in reciprocating engines to generate 2 MW of electrical power.¹³ This facility has reported 0.42-0.49 lb NO_x per MMBtu, compared to 10 lb NO_x per MMBtu for a pulverized coal plant using low-NO_x boilers (EPRI, 2010f). This significant reduction is due partly to the steam- rather than air-injected nature of the Güssing gasifier, which admits no molecular nitrogen until the syngas is actually combusted, thereby performing much of the oxidation of the original biomass fuel in the absence of non-fuel nitrogen. Depending on whether an air-, oxygen-, or steam-blown gasifier is used (as well as on the facility's permit limits), a retrofitted power station may be able to avoid using SNCR or the more expensive SCR equipment that would be required if it had continued to solely fire coal.

A natural gas power station will not have the same degree of pollution control already installed as a comparable coal station, largely due to the low-sulfur, no-ash nature of a gaseous or liquid fuel. Being without baghouses, ESPs, sootblowers, or pulverizers, less equipment will have to be decommissioned in this situation, though an SNCR system may have to be added for NO_x control. Other plant changes include the addition of ducting and piping to convey the cooled producer gas from the syngas cooler to the boiler burners and to move the hot water generated by the syngas cooler to wherever it will be integrated into the plant (likely in the feedwater system). The temperature drop on the syngas side of the syngas cooler can be as large as 600°F, leading to a significant feedwater preheating capability.

Simple example process diagrams of a biomass-fired power plant using a gasifier to supply producer gas to fuel a coal and gas/oil boiler are presented in Figure 2-14 and Figure 2-15, respectively. These diagrams represent 100% biomass cofiring scenarios. Major equipment items requiring replacement are highlighted in the diagrams to indicate the scope of the plant's modifications. Material flows indicated on the diagram are taken from a recent feasibility study for a 138 MW_e coal-fired power plant (EPRI, 2010f).

¹³ This project differs from the repowering scenario under discussion in a number of key ways. The Güssing project is much smaller in scale – 2 MWe, vs. 35-60 MWe for a pulverized coal boiler – and uses a different type of prime mover to generate electricity. The Güssing syngas is not fired in a boiler, but rather in a reciprocating engine generator set to produce electricity. The engine exhaust transfers heat in a heat recovery steam generator to produce steam for distribution through a district heating loop. A power station, in contrast, would use a condensing extraction steam turbine in a Rankine cycle optimized for power generation only.

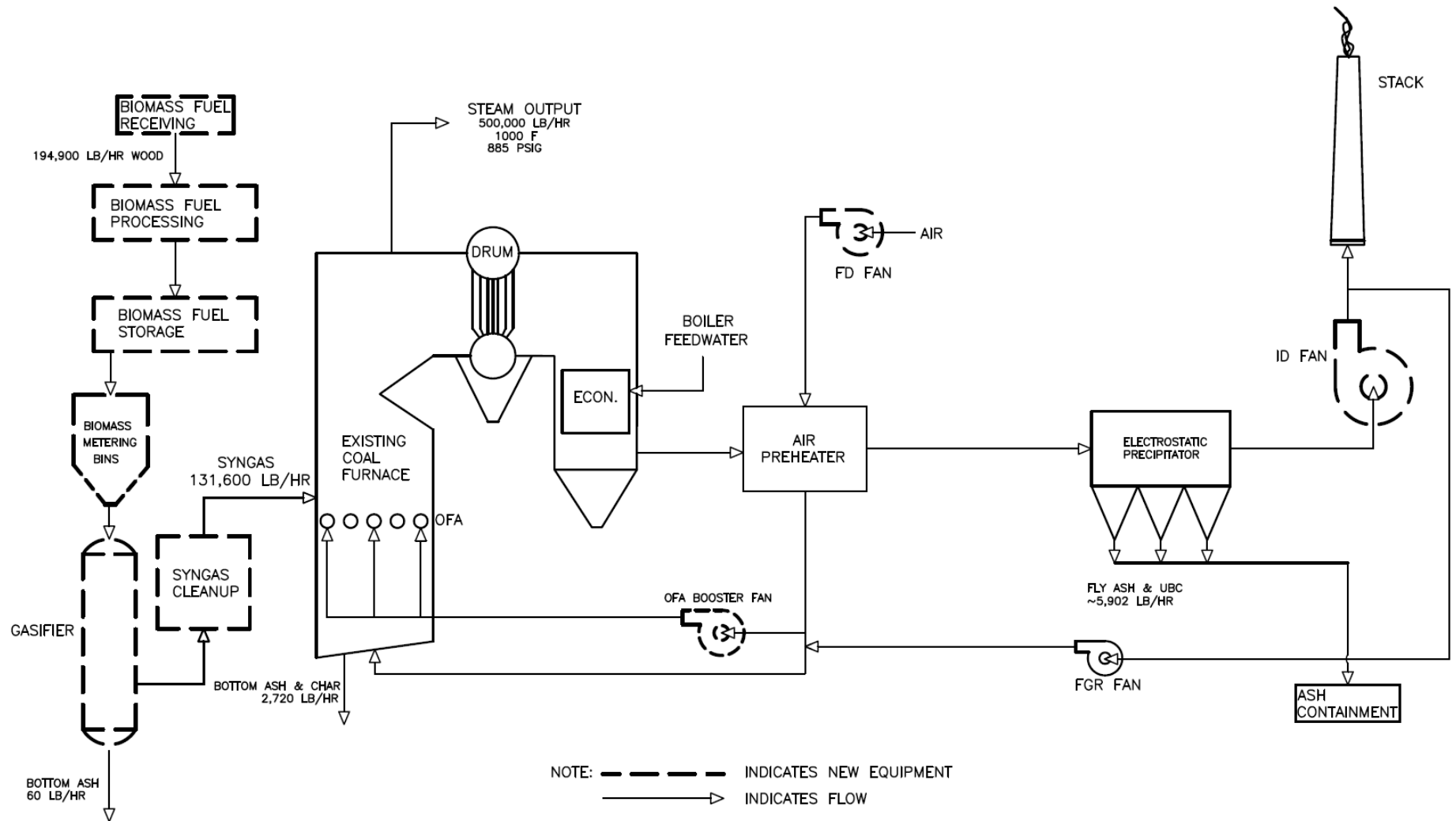


Figure 2-14
Example Process Diagram for Option 7b – Indirect Cofiring in Existing Coal Boiler

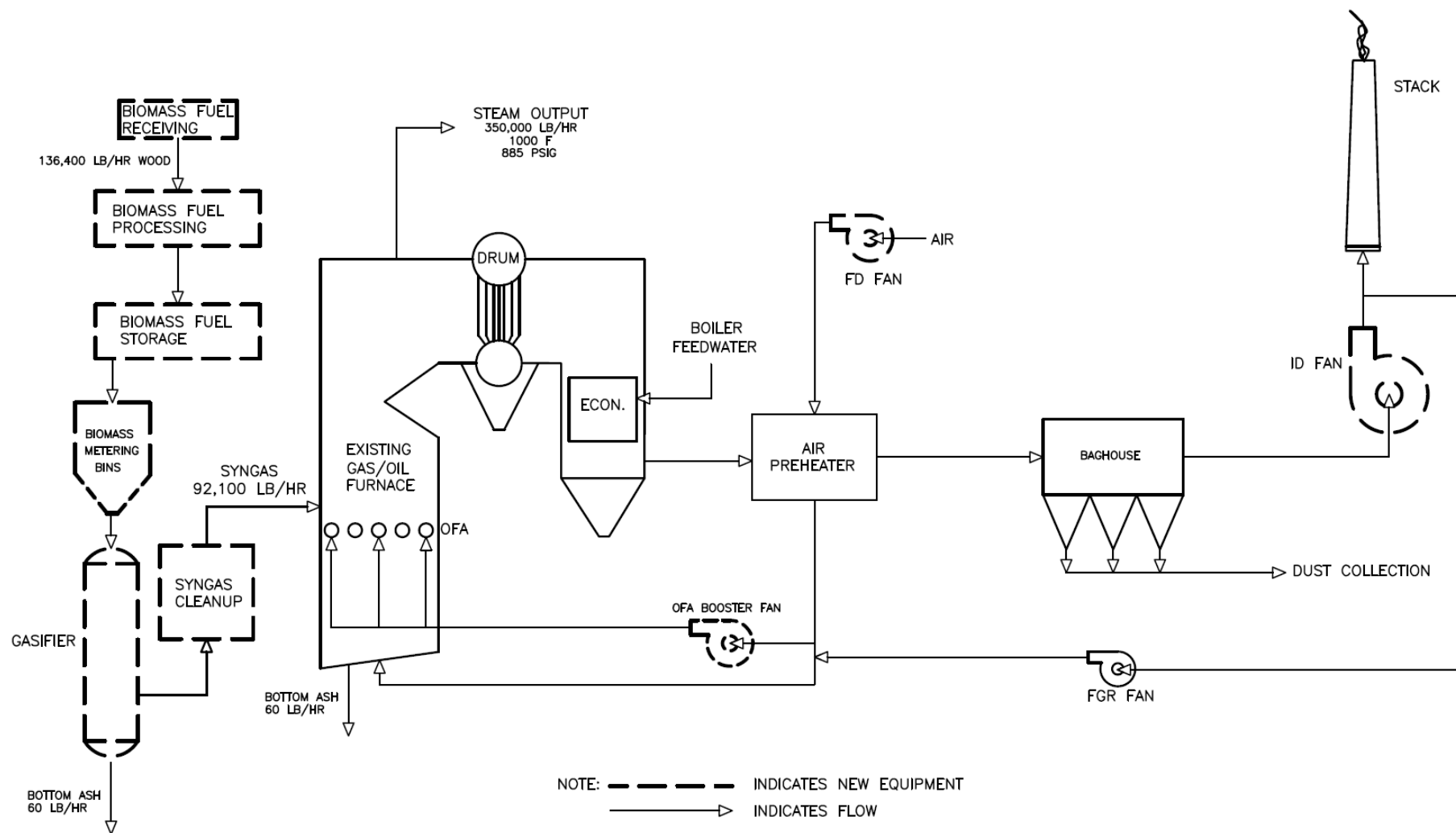


Figure 2-15
Example Process Diagram for Option 7c – Indirect Cofiring in Existing Gas/Oil Boiler

Appropriate Fuel Qualities

The requirements for fuels vary widely by gasifier type and vendor. Two key fuel requirements are particle size and moisture content. As noted in the beginning of the chapter, fixed bed gasifiers often require ¼" (0.64 cm) or smaller biomass particles at 20% or less moisture. Fluidized bed gasifiers allow both higher moisture levels and larger particle sizes, but are still limited to 30% moisture. As biomass commonly contains 40-50% moisture when green or stored outdoors, this makes it necessary to install fuel dryers or selectively purchase dry fuels.

Because temperatures in gasifiers are generally lower than in combustors, many of the slagging problems encountered in conventional boilers do not occur in gasifiers of similar type. Fuels need not be screened as carefully for high ash contents as with conventional boilers. However, as with boilers, fixed bed gasifiers are far more likely than fluid bed gasifiers to have slagging problems with high-ash fuels. A UNFAO report on small gasifiers (FAO, 1986) recommends limiting ash content to 5-6% in up- and downdraft fixed-bed gasifiers.

A final consideration is the amount of volatiles present in the fuel, since high-volatile fuels lead to excessive tar contents in the producer gas. While various types of cleanup technologies (ranging from stripper-absorbers to ceramic filters) can be used to remove tars before firing in the boiler, high tar levels may lead to deposition and clogging in these cleanup devices and within ductwork. If allowed to reach the boiler and its downstream pollution control technologies, the tars can deposit and reduce heat transfer coefficients of heat exchangers and reduce baghouse or ESP performance. This is a less acute problem than for gas turbine or reciprocating engine centered systems, but is still of concern to boiler firing of syngas.

Construction Schedule and Permitting

No precise timeline data are available for exactly this type of retrofit. The data that are available refers to the construction of greenfield cogeneration facilities rather than retrofits. However, since the gasifier is central to the retrofit and is likely to control the procurement, construction, and commissioning time requirements, this provides a useful reference point for this scenario. A recent gasifier vendor quote received by the authors estimated a total of 28 months from placement of a gasifier order to the beginning of commercial operation. Six months of this time would be basic engineering, another 18 months would be used for overlapping detailed engineering and construction, and a final two months would be needed for commissioning.

For comparison, timelines for some similar projects are outlined below:

University of South Carolina (USC) Biomass Gasification Cogeneration Facility (Columbia, South Carolina)

- Nexterra gasifier with a system peak capacity of 60 klb/h (27,000 kg/h) steam and 1.38 MW_e.
- 1-1.5 years development
- 8 months procurement before construction; 14 month procurement time for gasifier

- 1.5 years construction
- 1 year start-up and commissioning

Biomass Gasifier at CVEC (Ames, Iowa)

- Frontline gasifier processing 75 tons per day (tpd) (67 tonne/day) of feedstock input
- 1.5 years construction
- 3 months start-up and commissioning

CHP Gasification Facilities: Güssing and Heiligenkreuz (Austria)

- Güssing gasification facility with an output of 8 MW_e gross, 4.5 MW_{th} useful heat
 - Two-phase construction:
 - Gasifier system: 15 months
 - Electrical generation system: 6 months
 - 1.5 years commissioning
- Heiligenkreuz gasification facility with an output of 10 MW_e net, 6-12 MW_{th} useful heat
 - 2 years from equipment ordering to completion of construction
 - 6 months start-up and commissioning

Costs

Based on the discussion above, a sample list of required equipment for the repowering of an existing utility boiler with producer gas from a fluidized bed gasifier would require the following major equipment investments:

- Fuel dryer (depending on gasifier vendor's specifications and purchased fuel characteristics),
- Gasifier and associated ductwork,
- Gas cleanup system, multi-cyclones, and syngas cooler,
- Boiler house modifications/equipment rearrangement,
- Boiler burner and penetration modifications,
- FD and ID fans (if needed to provide additional excess air),
- Stacker-reclaimers,
- Truck dumpers and walking floor unloading pits,
- Conveyors, chip hog, and scalping screens, and
- NO_x control system (SNCR).

A feasibility study was recently performed in which a biomass gasifier was to be retrofitted to a 139 MW pulverized coal power plant. The project considered cofiring syngas with pulverized coal in the existing boiler, with some modification to it (including new burners and additional boiler penetrations). The capital costs were estimated to be between \$1,226 and \$2,657 per kW for scales ranging from 13 to 68 MW_e biomass electrical production. Total non-capital operating costs for such a plant ranged from about 5.4¢/kWh (composed of roughly 3.6¢/kWh in non-fuel costs and 1.8¢/kWh in fuel costs) to 12.8¢/kWh (10.5¢/kWh in non-fuel costs and 2.3¢/kWh in fuel costs) (EPRI 2010f). Any pollution reduction benefits, such as saleable renewable energy certificates or avoided pollution control costs, may reduce the total operating cost.

In fall of 2008, Xcel Energy announced a repowering project based on biomass at the Bay Front Power Plant in Ashland, Wisconsin. This would have been the first of its kind in the U.S., but the planned project was recently cancelled due to an increase in estimated costs and regulatory uncertainty at the federal level.¹⁴ This facility already has two wood-fired stoker boilers (discussed in the Option 3 subsection above), and the planned repowering project would have converted the final coal-fired unit on-site to operate on 100% biomass (primarily from forest residues). The repowered unit was expected to maintain the current capacity at around 40 MW, and would have utilized approximately 250,000 tons (226,800 tonnes) per year of biomass material.

The total cost of the Bay Front gasification project was estimated to be about \$79.5 million, including expansion of the biomass receiving and handling equipment and the gasifier, modifications to the existing coal boiler, and upgraded air quality controls (Xcel Energy, 2010). This more recent cost estimate was significantly larger than the original estimate of \$58-\$70 million, which was based on the first phase of engineering studies. The increased cost is a result of studies which showed that additional boiler upgrades would be needed to maintain stable combustion using syngas without requiring natural gas cofiring.

No specific cost data for the indirect cofiring at an existing gas/oil facility has been identified, since natural gas boilers make up a relatively small portion of the boiler fleet and biomass gasification projects themselves are relatively rare. However, the overall cost for the retrofit is expected to be similar to the pulverized coal boiler repowering project described above. Absolute costs in this case may be slightly lower, due to the fact that a smaller gasifier and smaller fuel yard are needed due to the limited fuel capacity of the existing boiler, and less major equipment (such as pulverizers and ESPs/baghouses) will need to be removed or decommissioned. However, the addition of more extensive additional fuel yard infrastructure will in part cancel out these reductions. When evaluated on a per-kW basis, the larger derate of the gas/oil boiler case may lead to a larger unit cost overall for a gasifier retrofit.

Technology Status and Development Risks

The main component of risk in such a repowering project centers on the gasification island rather than the modified boiler. Although there are a variety of vendors offering stand-alone biomass gasification systems on a very limited basis, most are still best characterized as demonstration or

¹⁴ This information is still included here as a reference point.

semi-commercial systems. Some gasification-centered plants have been built, though generally in combined heat and power applications rather than for electrical generation. Examples of relatively large plants using gasification technology include (EPRI, 2010f):

- Kymijärvi cogeneration plant in Lahti, Finland (Foster Wheeler Oy air-blown circulating fluidized bed). This plant cofires syngas and natural gas in a pulverized coal boiler. The fuel energy input to the boiler from producer gas is estimated to be 40MW_{th} (for a 50% fuel moisture content entering the gasifier) to 70MW_{th} (for a 20% moisture content).
- Unit 9 of the Amer generating station in Geertruidenberg, the Netherlands (atmospheric circulating fluidized bed gasifier). The unit's boiler co-fires biomass-derived syngas with pulverized coal and wood pellets. The 83MW_{th} gasifier can contribute as much as 34 MW of the unit's electricity production (Van Loo and Koppejan, 2008).
- Generating Station in Ruien, Belgium (Foster Wheeler Oy air-blown circulating fluidized bed). The gasifier is fueled with demolition wood and wood chip fuel, producing 17 MW of electricity in a cofiring arrangement within an existing pulverized coal boiler (Hiltunen, 2004).
- Piedmont Green Power in Barnsville, Georgia (Energy Products of Idaho fluidized bed staged gasifier). Plans to construct this 53MW_e facility were published in November 2010. The gasifier is to use chipped biomass for power production with 1,500 psig (10,342 Pa) steam.
- CHP facility in Heiligenkreuz, Austria (Repotec steam-blown fluidized bed). This facility, also using biomass, began operating in 2006 and supplies 10 MW (net) electricity from a steam turbine, as well as 6-12 MW of thermal energy for district heating.
- Chippewa Valley Ethanol Company in Minnesota (Frontline pressurized fluidized bed). This plant has been operating since March 2008, logging at least 2,000 hours of run-time. The biomass-fueled gasifier has an operating capacity of 75 tpd (67 tonne/day) of feedstock input, and the output gas is used in a steam boiler for ethanol production.
- McNeil Station in Burlington, Vermont (Air-blown fluidized bed gasifier). This 200 t/d (178 tonne/day) gasifier operated from 1996 to 2001 as a demonstration project, producing fuel for 8 MW of electrical generation. The syngas was fired directly in the boiler for steam production.

Given the low degree of deployment of these biomass-centered projects, repowering of large-scale stand-alone gasifiers presents a significant development risk.

A summary of key metrics for this option's three scenarios is provided below.

Table 2-19

Summary for Option 7a: Suspension firing of biomass to existing coal boiler

Example Capital Cost Estimate	\$125/kW for 80 MW (100% pellet firing); \$640/kW 312 MW net (wood chips, pellets, and briquettes with up to 20% coal)
Non-fuel O&M Cost Estimate	Low
Feedstock Requirements	Very Inflexible. Requires dry (15-20% MC), uniform small particles <0.25" (<0.64 cm)
Project Development Timeline	Estimate 1-4 years. Need revised permits, construct fuel handling equipment, etc. Conversion for Les Awirs only took 7 months.
Emissions Performance Summary	Reduce SO _x , NO _x , Hg, and GHGs relative to coal; increase CO and VOCs.

Table 2-20

Summary for Option 7b: Externally gasify biomass and fire in existing coal boiler

Example Capital Cost Estimate	\$2,657/kW for 13 MW net; \$1,988/kW for 40 MW; \$1,226/kW for 68 MW net. (All capacities refer to biomass electrical generation).
Non-fuel O&M Cost Estimate	\$0.035-\$0.10/kWh
Feedstock Requirements	Fixed bed: Dry (20% MC), small particles 0.25" (<0.64 cm) Fluidized bed: Wetter feedstocks (20-30% MC), particle size 3" (7.6 cm)
Project Development Timeline	Estimate 3-5 years for permitting, engineering, construction, commissioning.
Emissions Performance Summary	Lower NO _x per MMBtu than coal. Increase in CO. Negligible sulfur emissions.

Table 2-21**Summary for Option 7c: Externally gasify biomass and fire in existing gas/oil boiler**

Example Capital Cost Estimate	Somewhat higher than Option 7b.
Non-fuel O&M Cost Estimate	\$0.035-\$0.10/kWh
Feedstock Requirements	Fixed bed: Dry (20% MC), small particles 0.25" (<0.64 cm) Fluidized bed: Wetter feedstocks (20-30% MC), particle size 3" (7.6 cm)
Project Development Timeline	Estimate 3-5 years for permitting, engineering, construction, commissioning.
Emissions Performance Summary	Higher NO _x per MMBtu than gas. Increase in CO. Negligible sulfur emissions.

Discussion and Comparison of Repowering Technologies

This section provides qualitative and quantitative comparisons of the technologies considered in the above subsections. This assessment compares several characteristics that are important for project development and that are likely to have a significant impact on technology selection and implementation. The key characteristics selected for comparison include:

- Capital cost
- O&M cost
- Technical challenges
- Deployment status
- Deployment opportunity
- Feedstock flexibility
- Project timeframe
- Emissions
- Carbon burnout
- Incentives

Many of these factors impact technical and/or economic feasibility on a project level. For example, capital and O&M costs, incentives, and the timeframe for project development all contribute to the overall project economic feasibility and need to be considered in detail prior to undertaking a repowering project. Technology-specific challenges and expectations will be considered to select preferred configuration options and to determine expected system performance. Although these factors will be highly location and project specific, each technology follows a general trend that can be used for relative comparison.

Meanwhile, other factors considered in this comparative analysis are important for determining the overall market for implementation. For example, deployment opportunity provides a qualitative evaluation of the number of facilities where the considered technologies could potentially be implemented.

Review of Factors

Many of the selected categories were discussed directly in the option descriptions in the subsections above. For those categories, this analysis is useful to summarize those results and provide a comparative look across all of the considered technologies. There are also a few categories that are being introduced here for the first time, such as deployment status, deployment opportunity, and availability of incentives. These factors are defined and discussed in the subsections below.

Deployment Status

The level of deployment for each option was evaluated based upon operational status, commercialization of the considered technology, and experience with operating on biomass fuels or repowering projects. The deployment status categories are assigned as follows:

- High – commercial technologies that have been deployed in similar situations at utility scale many times.
- Moderate – limited commercial applications, and/or significant experience and deployment mostly at smaller scales.
- Low – technologies that are characterized as semi-commercial and that have generally only been deployed at small scale (in demonstration or one-off projects) with biomass fuels.

Deployment Opportunity

The opportunity for deployment is based on the number of existing fossil fuel facilities that could potentially be utilized for a repowering project for each selected technology option. The existing U.S. power generation fleet was evaluated based on 2005 data from the U.S. EPA's *eGRID* and Platts' *World Electric Power Plants Database* (2005 release). Table 2-22 summarizes the number and capacity of existing coal boiler facilities, as well as the total annual electricity generation (based on 2005 data). Gas and oil boiler information is provided in Table 2-23. Although these data does not show the age distribution of the existing facilities, they do show that there is a significant potential for biomass repowering projects overall. Additional details about the existing U.S. coal fleet were provided in the beginning of this chapter.

Table 2-22
U.S. Coal Plant Data Summary

# Coal Plants	# Boilers	Total Nameplate Capacity (MW)	Electricity Generated (GWh/yr)	Net Capacity Factor
605	1,733	341,580	2,004,491	0.67

Based on 2005 data, from eGRID v.1.1

Table 2-23
U.S. Utility Scale Natural Gas and Oil Boilers

	Natural Gas	Oil
Number of utility scale power plant boilers*	432	192
Total Capacity (MW)	73,184	38,553
Number of plants with ESP	26	30
Number of plants with SCR	18	0
Subset based on plant status		
Number of <i>Operational</i> boilers	306	121
Total capacity (MW)	64,137	33,437
Number of <i>Retired / deactivated</i> boilers	81	61
Total capacity (MW)	6,196	4,599
Number of <i>Standby</i> boilers	45	10
Total capacity (MW)	2,851	518

**Only includes steam turbine plants with capacities • 25MW and known/listed boiler types.*

Repowering technology options at coal facilities have the highest deployment opportunity overall, as these facilities generate by far the most power of the considered sources. Options based on natural gas and oil, in turn, have a medium deployment opportunity (because their potential is lower than coal, but there is still a significant existing capacity at these types of facilities). Although the fleet for these units is smaller, the number of boilers is significant and many of these units have low capacity factors. On the other hand, if these units are currently being used for peaking, there may be a strategic disadvantage to moving them to solid fuel (which would require baseload operation to be cost effective). Option 7a is unique in that it requires a particular type of coal boiler for suspension firing of biomass. Based upon the coal fleet assessment in the beginning of the chapter, pulverized coal boilers make up about 80% of the total existing boiler fleet units.

Incentives

The characterization of incentive applicability for the selected repowering options is determined primarily from the existing federal incentives potentially available to such projects, including the Production Tax Credit (PTC) and the Investment Tax Credit (ITC). The application of these incentives will depend on both the technology and the fuel resource decisions best suited for each asset/unit. In addition, some facilities may be eligible for state and local incentives. Since there is a significant amount of variability in these incentives across different states (and even different localities), the applicability to a particular project must be evaluated on a case-by-case basis. For the purposes of this assessment, a survey of available incentives in four states was performed to provide a sense of the applicability of state incentives to the various technology options considered. The selected states consist of California, Iowa, New York, and Maryland (which were chosen with the intent of capturing some sense of regional variability).

In general, the applicability of federal incentives is characterized as follows:

- Cofiring projects are applicable for federal incentives only if using closed-loop biomass materials cofired with coal, but are not eligible if using open-loop biomass materials.
- Biomass standalone projects placed in service before January 1, 2014 are eligible for any biomass fuel (i.e. closed-loop or open-loop). These facilities will receive the PTC for 10 years. Minimal cofiring with fossil fuels is allowed for start-up and flame stabilization.
- Expansion at existing facilities can be eligible for the PTC (for 10 years credit) if placed in service before January 1, 2011. However, the credit only applies to the increased amount of electricity produced at the facility due to a new unit for closed-loop fuels. For open-loop biomass fuels, the credit only applies if the value of the new property is greater than 80% of the plant's fair market value, or if a new increment of power is added to the facility.

A more detailed discussion of the potentially applicable incentives is provided below. It is worth noting that the state-level incentives are both significant and less restrictive with respect to cofiring than the Federal credits.

Federal Production Tax Credit – The renewable energy PTC supports the development of the renewable energy industry by giving power producers a tax credit for producing energy from renewable sources, thus lessening the burden of constructing these capital-intensive facilities. The main goal of the PTC is to make renewable and alternative forms of energy cost-competitive with traditional, fossil-fuel technologies.

For biomass facilities, the value of the PTC depends on the type of feedstock used at the facility; projects using closed-loop biomass may be eligible to receive 2.2 ¢/kWh of electricity generated, while open-loop biomass projects receive a lower value of 1.1 ¢/kWh. Closed-loop biomass includes any organic matter from plants that are planted for the sole purpose of being harvested to produce energy, such as willow and switchgrass energy crops. Open-loop feedstocks include more traditional biomass materials, such as wood chips, cellulosic waste materials from manufacturing processes, agricultural by-products and residues, agricultural livestock waste nutrients, and eligible solid waste materials.

Qualified biomass facility technology configurations eligible for the PTC include: standalone biomass, co-firing biomass with fossil fuel, and cogeneration applications. Stand-alone biomass projects may still qualify if they use fossil fuel for start up and flame stabilization as needed, but only the electricity generated by the biomass will qualify to receive the credit. Co-firing projects have different requirements depending on the type of biomass they utilize. For closed-loop, the biomass feedstock may be co-fired with coal, other biomass, or both, but first the closed-loop modification must be approved under the Biomass Power Rural Development program or demonstrate that it is part of a pilot project of the Commodity Credit Corporation. The IRS guidance documents note that, “in general,” electricity produced from open-loop biomass and co-fired with fuels other than fossil fuels may qualify for the PTC.

New units at existing plants placed in service after the enactment of HR 1424 (The Emergency Economic Stabilization Act of 2008) are eligible for the PTC. New units at existing facilities (both open- and closed-loop) are only eligible up to the amount of increased electricity produced at the facility due to the addition of the new unit. The value of the new unit must exceed 80% of the plant’s overall fair market value, or a new increment of power must be added.

The PTC credit period is 10 years, and begins on the date the facility was placed in service. Biomass facilities must be placed in service by December 31, 2013 in order to receive the incentive.

Federal Investment Tax Credit – The American Recovery & Reinvestment Act of 2009 added an election in Section 48 to take a total capital cost ITC in the first year of operation (against federal income tax liability) instead of the production tax credit. Projects that are eligible for the PTC are also eligible for the ITC, which is valued at 30% for projects using eligible renewable energy technologies/resources (including biomass).

California Renewables Portfolio Standard – The California RPS was originally established in 2002, and currently requires all utilities to meet a target of 33% of retail electricity sales from renewable energy resources by 2020. Technologies that qualify as renewable for the RPS target include solar PV, solar thermal electric, wind, certain biomass resources, geothermal electric, certain hydroelectric facilities, ocean wave, thermal and tidal energy, fuel cells using renewable fuels, landfill gas, and municipal solid waste conversion (but not direct combustion).¹⁵ Eligible biomass materials include: “any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, biosolids, sludge derived from organic matter, and wood and wood waste from timbering operations” (California Energy Commission, 2008).

¹⁵ Requirements for eligibility of a solid waste conversion include: (1) it uses a two-step gasification conversion process to create energy; (2) it is located in-state or satisfies the out-of-state requirements; and (3) it meets all of the following criteria: (i) process does not use air or oxygen in the conversion process, except to maintain temperature; (ii) process produces no discharges of air contaminants or emissions, including GHGs; (iii) The technology produces no discharges to surface or groundwater of the state; (iv) the technology produces no hazardous wastes; and (v) MSW stream is sorted to remove recyclable and compostable materials.

Facilities that use multiple fuels are eligible to count towards the RPS. If fossil fuels make up less than 2% of the fuel usage (i.e. if the project meets the *de minimus* requirement), then 100% of the electricity generated is eligible. For co-firing facilities that do not meet this criterion, only the renewable portion of their generation will count as RPS eligible.

Repowered facilities are eligible under the condition that all prime generating equipment at the facility is replaced with new equipment. For biomass facilities, the entire boiler is considered the prime generating equipment. Stoker boilers may be replaced with boilers using improved stoker technology or fluidized bed technology. The applicant must document that the value of the capital investment made to repower the facility equals at least 80 percent of the total value of the repowered facility.

Iowa RPS / Alternative Energy Law (AEL) – Iowa requires its investor-owned utilities to own or contract for a total of 105 MW of renewable energy generating capacity. Each utility's share of this capacity is based on the utility's estimated percentage share of Iowa peak demand, based on the utility's highest monthly peak. Eligible alternative energy resources include solar, wind, refuse-derived fuel, agricultural crops or residues, and wood materials.

Iowa Alternate Energy Revolving Loan Program – AERLP is a competitive program which provides low-interest loan funds to selected entities (including non-state regulated utilities) that build renewable energy production facilities in Iowa. Eligible facilities generate energy from solar, biomass, wind, and small hydro resources. Portions of the total funds may be set aside for technologies using specific resources, including 20% for biomass.

New York Renewable Portfolio Standard – New York's RPS regulation was initially adopted in 2004. The regulation was recently expanded to a renewable energy target of 30% by 2015. Resources eligible for the Main Tier include methane digesters and other forms of biomass, liquid biofuels, fuel cells, hydroelectric power, solar PV, ocean power, tidal power, and wind power. Accepted energy conversion technologies are steam generators, reciprocating engines, micro turbines, gas turbines, fuel cells, and co-firing. Adulterated biomass resources must undergo a primary fuel conversion step such as thermal gasification, landfill decomposition, anaerobic digestion, esterification, fermentation, or hydrothermal gasification. Only the renewable portion of power generated from co-firing technologies counts towards meeting the RPS goals. New renewable energy generation from repowering or retrofit of existing facilities can also be applied to the RPS.

Maryland Clean Energy Production Tax Credit – Production tax credit for electricity generated by certain renewable resources. Eligible resources are generally the same as those included in the federal PTC, and include forest- and agricultural-derived biomass materials and some municipal solid waste. Sawdust and wood shavings from mill residues are not eligible. The credit is to be claimed against state income taxes over a five-year period. Currently the credit stands at \$0.0085/kWh for eligible renewable resources and \$.0005/kWh for co-fired electricity generation. Projects must be placed in service (or begin cofiring) before January 1, 2016. The maximum incentive value for each project is calculated based on the estimated annual energy production over a 5-year period and is capped at \$2.5 million.

Maryland Renewable Portfolio Standard – Maryland enacted a state RPS in 2004. The legislation requires that all utilities and competitive retail electric suppliers meet an annually increasing percentage of their electricity sales from renewable sources, culminating at 20% in 2022. Eligible resources are divided into two classes, each with its own escalating percentage requirements. Tier 1 resources include solar, wind, qualified biomass (a definition which excludes sawdust and wood shavings, but allows for whole-tree wood chips), methane, geothermal, and ocean kinetic energy. Tier 2 facilities include hydropower other than pump-storage and waste-to-energy facilities. These Tier 2 resources must comprise a minimum of 2.5% of the electricity sold through 2018, when the percentage drops to zero. Compliance with the RPS program is based on the accumulation of Renewable Energy Credits. Alternately, electricity suppliers can choose to make a compliance payment into the Maryland Strategic Energy Investment Fund, equivalent to 2 ¢/kWh of shortfall from required Tier 1 renewable sources until 2011, and 4 ¢/kWh of shortfall from required Tier 1 renewable sources starting in 2011.

Other Considerations

Maintaining existing capacity is a challenge in almost all biomass repowering project options due to the lower energy density of biomass fuels compared to fossil fuels, and some options are particularly limited. Specifically, the options which involve modification of an existing boiler (Options 3 through 6) will be very constrained in terms of physical size and will almost certainly lead to a facility derate unless additional capacity is added separately. How significant this constraint is will depend in part on the power generator's objectives. If the intent is to maximize carbon- or renewable-compliant generation at a single site, then this shortcoming may be important. However, fuel constraints and other issues may be such that the limitation does not pose a significant problem.

Another issue to consider when evaluating biomass repowering project options is the expected cost of biomass fuel. Fuel costs are typically the largest single recurring annual operational cost at a power plant. Some technologies are limited in terms of which type of fuels are applicable and some require very specialized fuel sources. In general, technologies that are the most flexible in terms of fuel characteristics will benefit from having the lowest cost of fuel, as they will be able to utilize whichever material has the most competitive price. This is not to suggest that even the most fuel-flexible designs can allow wide variations in fuel specifications without repercussions, but opportunity fuels may simply be more tolerable in general.

Additionally, the actual cost of biomass fuels will vary depending on materials used and location. However, average estimated costs for fuel types that can be utilized in the various considered repowering options can be used to provide a relative weighting of fuel costs. Many of the technologies can fire a range of fuel types, while there are some that require very specific fuel specifications. The fuel selected will also impact system performance and operations. High percentage suspension cofiring in a pulverized coal boiler (Option 7a) is particularly specialized, as it requires torrefied wood or pellet fuels, both of which are relatively expensive. Torrefied wood pellets in Europe have been reported to cost about \$94/ton to \$155/ton (\$84 – 138/tonne), which is equivalent to \$5.17/MMBtu to \$8.70/MMBtu (Mittchell, Kiel, Livingston, & Dupont-Roc, 2007).¹⁶ According to a recent presentation at the Agricultural Engineering Technology

¹⁶ Costs converted from Euros to USD using the July 22, 2010 exchange rate: \$1.2893 = 1 €.

Conference, current production costs for generating pellets from woody biomass materials is around \$24-\$27/ton (\$21-24/tonne) without drying, and \$40/ton (\$36/tonne) including feedstock drying (Mani, 2009).¹⁷ This does not include the cost of the raw biomass materials, fuel delivery, capital recovery, or profit. The same presentation estimates the production cost for torrefaction followed by pelletization to be about \$30/ton without drying. The torrefaction process itself is stated to cost \$6.45/ton (5.75/tonne). For comparison, Bergman (2005) estimates the cost of pellet production to be about \$62/ton from sawdust feedstocks, and \$82/ton from green wood chips (costs converted from Euros and escalated to 2010 USD).¹⁸ The production cost of torrefied wood pellets is estimated to be \$68/ton (\$61/tonne) from sawdust and \$76/ton (\$68/tonne) from green wood chips. These considerably higher estimates do include the cost of feedstock drying, which adds significant expense. Bergman (2005) further estimates market price for conventional wood pellets at \$182-\$227/ton (\$162-\$203/tonne), and torrefied wood pellets at \$224-\$280/ton (\$200-\$250/tonne) (again converted from Euros to 2010 USD).

For comparison, based on recent biomass survey work for clients across the country, the price for securing woody biomass materials from forest residues currently ranges from about \$20-\$40/ton (\$18-\$36/tonne) (as received), depending on the region. This corresponds to delivered prices between \$2.11/MMBtu and \$4.23/MMBtu. Although there are a variety of opportunity fuels available on a site-specific basis, many new projects are now looking to forest removals as the basis for project development. This material may include residues generated in the course of harvesting merchantable wood or dedicated harvesting of low-value species to promote timber stand improvement.

Summary of Results

The relative performance of each option in these categories is illustrated in Table 2-24. This graphic shows a distilled technology comparison matrix, which rates each of the considered characteristics on a simple three-point scale (good, moderate, and challenging) in order to provide an easy reference point for comparison across all considered technology choices. This distilled matrix was developed from a more detailed matrix that summarizes the relative costs and description inputs for each technology based on the characterization of each option provided in the subsections above. This detailed summary matrix is provided in Appendix A.

Some general trends can be seen in the result. Overall, the fluid bed boiler configurations have the best rating. In general, boiler modifications are more economical than boiler replacements, and are likely to be completed in a shorter timeframe. Furthermore, biomass repowering projects at an existing coal plant are expected to have fewer challenges than at a gas or oil plant, and there is considerably more experience with these types of repowering projects than most of the other options, which should help to minimize implementation risk. Fluid bed boilers should also be more feedstock flexible and have better emissions performance than stoker boilers. The largest drawback to this option is that the lower energy density of biomass materials will lead to a significant derate in plant capacity.

¹⁷ Actual prices will vary based on site-specific factors and the throughput capacity of the pellet mill.

¹⁸ Wood chips require more energy for drying and sizing than sawdust, which leads to higher pellet production costs.

Table 2-24
Simplified Technology Comparison Matrix

OPTION	Technology Type/ Description	Capital Cost	Non-Fuel O&M	Technical Challenges	Deployment Status	Deployment Opportunity	Feedstock Flexibility	Project Time Horizon	Emissions Performance	Carbon Burnout	Availability of Incentives
1	Grate boiler replacement	×	✓	✓	✓	✓	•	×	•	×	✓
2	Fluid bed boiler replacement	×	✓	•	✓	✓	✓	×	✓	✓	✓
3	Coal boiler grate modification	•	✓	✓	✓	✓	•	•	•	×	✓
4	Coal boiler fluid bed modification	•	✓	•	✓	✓	✓	•	✓	✓	✓
5	Gas/oil boiler grate modification	×	✓	×	•	•	•	×	×	×	✓
6	Gas/oil boiler fluid bed modification	×	✓	×	•	•	✓	×	✓	✓	✓
7	High percentage cofiring (> 50% by heat)										
7a	Suspension firing of biomass in PC boiler	✓	✓	•	•	•	×	✓	•	✓	•
7b	Gasify biomass and fire in coal boiler	•	×	•	×	✓	•	×	✓	✓	•
7c	Gasify biomass and fire in gas/oil boiler	•	×	•	×	•	•	×	×	✓	×

Description of Criteria

- 1) Relative capital cost is based on expected values for an average 100 MW plant from available data. Site specific factors can have a substantial influence on these values.
- 2) O&M requirements are listed qualitatively and relative to the other options listed.
- 3) Technical challenges considers key technical issues that need to be addressed for technology implementation.
- 4) Deployment status provides a relative indication of commercial status and experience at existing facilities.
- 5) Deployment opportunity is a qualitative indication of each technology relative to its potential market penetration.
- 6) Feedstock flexibility indicates the flexibility each technology has in terms of design and handling off-design/off-specification fuels once commissioned.
- 7) Project Time Horizon is an estimate of the time needed to complete a project employing the technology.
- 8) Emissions performance is a relative measure (compared to the original fuel and technology utilized for each option), based on a typical installation employing each strategy.
- 9) Carbon burnout is a relative, qualitative measure describing the amount of unburned carbon in the fly ash.
- 10) Availability of incentives is assessed in terms of current federal incentives. State and local incentives can vary considerably and are site specific.

Table Key:	
✓	Good
•	Moderate
×	Challenging

Suspension firing is the best rated high percentage cofiring option, with good to moderate ratings in all categories except for feedstock flexibility. Indirect cofiring at a coal plant may likely be more feasible than at a gas or oil plant.

While it is important to recognize that an individual facility considering repowering will likely be limited in technology choices based on existing configuration and plant design, these trends suggest that the industry is already moving in the right direction. As more experience is gained with advanced technologies and large-scale biomass processing and handling systems, more exotic configurations are likely and the industry will be in an even better position to embrace them.

3

FUEL HANDLING CONSIDERATIONS

Given the importance of material processing, handling, and storage for solid fuel plants, this chapter discusses many of the issues and design considerations for large scale biomass-fired facilities. In many ways, these systems are similar to coal-fired power plant operations, but the low energy density, physical properties, and chemical composition of biomass fuels are sufficiently different to lead to fuel handling system design differences that are important to understand and address. These differences are especially important to appreciate in the context of the case studies, as they have a material impact on the design and cost of the systems considered.

Fuel Handling, Storage, and Processing Considerations

The following criteria should be taken into consideration when selecting infrastructure to accommodate a biomass fuel source during plant repowering:

- physical characteristics of the biomass fuel (size, density, grindability)
- chemical characteristics of the biomass fuel (off-gassing, oxidation, hygroscopicity)
- moisture content
- energy density of the fuel
- on-site fuel storage capacity
- managing risks of explosions/fires
- highway (especially high-capacity interstate-type roads), rail, and barge access
- level of automation desired (fully automated vs. personnel-operated)

Physical Characteristics

The physical characteristics of the biomass resources will determine the type of fuel storage and handling system that is installed at the repowering facility. Size is one important consideration, and the consistency in the size of incoming biomass will determine the number of choices that a facility has when selecting its fuel handling equipment. Other factors include handling durability and the potential for creating dust. Pelletized biomass fuels are composed of fine biomass particles compressed together, and precautions will need to be taken to prevent premature breakage of these pellets (which may lead to excessive dust generation and associated safety and health issues). The fuel's bulk density, particle size, and water absorption properties should also be considered (Koppejan, 2008).

Chemical Characteristics

The chemical characteristics of the biomass will have a significant effect on the installed safety measures required at the facility. Biomass fuels with higher moisture contents will have higher levels of microbiological growth and oxidation, which lead to off-gassing, self-heating, and dry matter loss (summarized in Table 3-1). This will require adequate ventilation and temperature monitoring in enclosed storage areas to prevent the accumulation of harmful gases and to prevent temperature increases from going unnoticed and unchecked (Thek, 2010).

Table 3-1
Chemical Reactions in Biomass

Chemical Reaction	Consequence
Microbiological growth	• Off-gassing (VOCs) • Oxygen depletion • Spontaneous combustion • Dry matter loss
Chemical oxidation	• Off-gassing (VOCs) • Oxygen depletion • Spontaneous combustion

Data Source: Wood Pellet Association of Canada

Energy Density

The energy density of the biomass will influence fuel delivery management (lower energy density translates to more deliveries) as well as the cost/size of fuel storage areas. To the extent that existing processing and handling equipment is used, lower energy density fuels will also effectively lower the throughput of conveyors, hoppers, and milling equipment.

Amount of Fuel to be Stored on Site

Facilities can choose the amount of biomass storage on site based upon plant configuration, available land area, and fuel storage constraints. Some facilities choose to have as little as 12 hours worth of biomass stored on site, while others prefer to have a minimum of two weeks' worth. Storage requirements will depend heavily on the seasonal supply of biomass that is available and how steady the supply is expected to remain. Facilities that have an abundant supply of biomass available to them year-round may choose to operate "just-in-time" with small on-site reserves for brief fuel supply interruptions. This would reduce the need for costly large-scale storage and reclaiming system investments, but will present problems during extended periods of supply disruption. However, it may also put considerable pressure on suppliers, who may not financially be able to bear the risk of supply shortages that are out of their control.

Risk of Explosions or Fire

Certain types of biomass will pose higher risks of fire or explosions. Fuels that decompose quickly (high moisture, typically) tend to generate heat when stored in piles for an extended period of time. This can lead to self-ignition. Other fuels (usually dryer fuels) that emit significant amounts of dust during fuel handling and processing will be prone to dust explosions. They will require dust mitigation techniques, such as specialized conveying equipment (to minimize dust formation), dust collection equipment (such as baghouses and other filters), and most likely spark detection and fire suppression systems (to respond to hazardous conditions).

Proximity to Existing Transportation Infrastructure/Ease of Transportation

Trucks, trains, and ocean vessels or barges can all be used to deliver biomass to a power plant. Unlike coal, truck transport is the prevailing mode for transporting local biomass fuel supplies. The cost and convenience of using one form of transportation over another will depend on the distance that the biomass has to travel as well as the existing power plant infrastructure. If a repowered facility is not already configured to accommodate truck deliveries, it will need to install additional infrastructure on site, such as truck scales, truck dumpers, dust suppression equipment, or conveyor systems.

Level of Automation Desired

Some plants employ low capital cost-intensive biomass handling systems, which generally require more manpower to operate. Since large utility plants operate 24 hours a day, there is a clear cost trade-off between manual and automated fuel management systems.

Biomass Fuels to be Considered

Wood chips, wood pellets, and torrefied wood pellets are the primary focus of this report, and some additional discussion with respect to these particular fuels is warranted. Although the discussion below is not exhaustive, it does highlight areas of concern that will impact fuel receiving, processing, and handling differences. This will facilitate making different system design choices for the case studies presented in later chapters.

Key Properties: Wood Chips

Physical Characteristics

Wood chip size can vary depending on the supplier and the type of raw material that is used to make the chips. Depending on the consistency that is required by fuel specifications, the facility will almost certainly require a screening system to sort out wood chip pieces that are oversized (usually greater than 2 inches (5.1 cm) in any dimension) for additional reprocessing. Some facilities also screen for undersized material and dust (fines), which can negatively impact the handling system.

Mechanical wood chip handling and processing is well understood, as it is central to many different operations in the wood products industry. Pneumatic transport systems are less frequently used outside of the power industry, and there is still considerable “art” employed in individual system design. However, the toughest operational issues with systems designed for fuel handling of biomass often result from the non-homogenous nature of potential fuel sources. Pneumatic systems work best when the incoming particles are of uniform size and density and are more sensitive to changes in these parameters than bulk mechanical conveyance.

Milling is used to further reduce the wood chips’ size if required by the power plant. However, the fibrous nature of wood chips can make reducing them to a fine, consistent particle size challenging and energy intensive. Pulverizers that rely on grinding (which is effective for the diminution of minerals) are much less effective with biomass in chip form, for which hammermills and tub grinders (which shred materials) are more effective.

Chemical Characteristics

Wood chips can vary considerably with respect to their chemical properties, including their ratios of key chemical constituents such as cellulose, hemicelluloses, and lignin. However, the moisture content of biomass fuels is a critical factor that often dictates many of the design choices associated with processing, handling, and firing biomass in general (and wood chips in particular). High moisture fuels increase challenges in storage and transport, and also change combustion dynamics. Although moisture contents can be homogenized by processing and drying, moisture content for wood chips will vary naturally based on species, geography, and environment. In short, managing wood fuel moisture content is challenging, and compromises are always made in striking a balance between the cost of managing moisture content and the desire to maintain a consistent fuel product.

Relative to dry wood chips, green wood chips have an elevated potential for microbiological growth and oxidation, which can lead to off-gassing, self-ignition, and dry matter loss in storage. Biomass that has been chipped to a smaller size often has higher levels of biological degradation, dry matter loss, and off-gassing than large wood chips because of its increased surface area to volume ratio.

Microbiological growth and oxidation within a wood chip pile will also cause heat production, and improper pile management can lead to pile fires. Pile temperature monitoring, first-in-first-out inventory management, and management of different fuel types in different fuel piles can be used to prevent these problems.

Biomass off-gassing¹⁹ can be particularly hazardous to employees in confined areas, making adequate ventilation or outdoor storage a requirement when considering long-term fuel storage.

¹⁹ Biomass off-gassing is the emission of volatile organic compounds (VOCs) that result from decomposition. Carbon monoxide (CO), carbon dioxide (CO₂), and methane (CH₄) are only three of the gases that can be emitted (Thek, 2010).

Dry matter loss²⁰ is also another result of microbiological growth. Under certain conditions, up to 5% of a wood chip pile's energy content can be lost during one month of storage, which is important to consider in determining a facility's fuel storage requirements. Lastly, microbiological activity can cause odor issues. Depending on the plant's proximity to other establishments, this could be viewed as an annoyance by local residents.

The table below shows a summary of the common wood chip handling concerns discussed above, as well as some preventive measures that can be taken to avoid or mitigate their effects.

Table 3-2
Wood Chips – Chemical Reaction Effects & Preventive Measures

Handling Concerns	Preventive Measures
Self-heating	• High fuel turn-over rate • Emergency discharge for high-temperature fuel • Temperature monitoring of storage areas • Restrict oxygen access to storage piles • Reject fuels with high moisture contents
Off-gassing	• Adequate ventilation • Gas concentration monitoring • Avoid unnecessary personnel access
Dry-matter loss	• Decrease fuel moisture content • Store biomass in larger pieces • Chemical applications to reduce micro-biological activity

Data Source: Wood Pellet Association of Canada

A high initial moisture content does not make it necessary to place the chips in a covered storage area, as covered storage alone will not do much to reduce the moisture content of the biomass without the addition of a ventilation system, which can be costly. Uncovered storage or unloading areas can be improved to minimize contamination from the ground. Depending on local environmental laws, waste water treatment may also be needed to control pile leachate.

In general, long-term storage of wood chips should be minimized, if possible. Smaller storage facilities implies greater fuel turnover, which is desirable but not always practical. For larger biomass plants, 3-4 weeks of on-site fuel storage is unusual. If longer term storage cannot be avoided, then there are at least some potential ways to mitigate these problems:

²⁰ Dry matter loss is defined as energy losses that result from microbiological growth and oxidation in biomass fuel piles (Koppejan, 2008).

- Material may be harvested and stored un-chipped with the bark on, and then chipped as needed. This has the additional benefit of allowing the wood to dry naturally and substantially reduce moisture content.
- If the material is to be stored in an enclosed environment, it can be dried upon receipt. However, the wood will gradually rehumidify over time, such that this can be a counter-productive measure depending upon the rate of fuel throughput at the facility.

Energy Density

Wood chips (green wood chips in particular) have a much lower energy density than bituminous and sub-bituminous coal. The energy density difference is considerably less dramatic for lower-rank coals such as Powder River Basin coal.

This has a number of important implications:

- Any storage or holding equipment that is reused at an existing coal-fired facility will effectively have its “energy” storage capacity reduced. Between the bulk density differences and the energy density differences of high-Btu coals and green wood chips, the storage capacity of some systems may be reduced by a factor of four.
- Similarly, bulk transport and processing systems designed for coal may become volume limited and will see significant derate in moving “energy” to the boiler.
- For a given energy output, a greater volume of fuel will have to be stored on site than previously required. The availability of adequate storage space must be considered carefully.

Depending on the magnitude of these differences, it may be possible to modify existing equipment to minimize operational impacts, but in most cases new systems must be installed to ensure proper plant functioning and reliability.

Risk of Explosions or Fire

In addition to pile fires, dust from wood chip handling (especially dry chips) can be a concern, but there is considerable experience in the other wood handling industries, and the technology and systems for dust suppression and control are well understood.

As a precaution, however, mechanical and heat-generating equipment that is exposed to dust should be enclosed and grounded to prevent heat sources or sparks from igniting the biomass, and this is especially important in confined spaces. Table 3-3 shows different precautions that are commonly taken to prevent fires in wood chip handling facilities.

Table 3-3
Wood Chips – Fire Preventative Measures

Handling Concerns	Preventative Measures
Fires	• Monitoring of all hot equipment • Spark detection and suppression systems • Avoid electrical heating devices

Data Source: Wood Pellet Association of Canada

Key Properties: Wood Pellets

As the supply of wood pellets has increased, they have garnered interest from utility plant operators as a potential alternative to using wood chips. Wood pellets do address many of the shortcomings of traditional wood chip fuels, including homogeneity in moisture content, size, and shape.

Physical Characteristics

Wood pellets are cylinders of compressed wood particles that typically have a 1.6” to 3.9” (4 to 10 mm diameter) and a 7.9” to 15.7” (20 to 50 mm) length, depending upon the shape of the machine that is used to produce them. They can also be shaped into cubes and can be designed for particular firing characteristics. Their uniform shape gives them predictable flow characteristics, which together with their low moisture content (<10%) makes them ideal for automatically operated fuel systems.

Pellets can easily be reduced to their constituent particle size distribution through the use of hammer or attrition mills, or even vertical air-swept coal pulverizers. This can make them easier to fire, especially in cases where the pellets are being used to replace coal in suspension firing systems.

The ease with which pellets can be broken apart can be a disadvantage for fuel handling if they are broken down prematurely. The number of times the fuel is transferred, the number of drops, and the type of collision (elastic vs. inelastic) associated with each drop affect the rate at which dust is generated. Pellets that are handled more frequently generally have a higher rate of breakage. Direct collisions with hard metal surfaces, as opposed to softer collisions such as those that occur at low angles with conveyor belts, also generate more dust. The height from which pellets are dropped should always be minimized to reduce breakage (Thek, 2010).

There are significant health hazards associated with dust generation from wood pellets during fuel handling and processing. Staff working near the storage or processing facilities for wood pellets should take adequate precautions to prevent prolonged exposure to pellet dust, which can cause irritations to the respiratory system and epidermis (*Ibid.*).

Chemical Characteristics

The relatively low moisture content of wood pellets (< 10%), means that there is a lower potential for microbiological growth and oxidation than there is from wood chips. However, there are still some negative effects associated with the storage of pellets.

A pilot study conducted at the Swedish University of Agricultural Science in Uppsala, Sweden drew some important conclusions about the effects of long-term (5 month) storage on pellets. The study concluded that although pellets typically have low initial moisture content, their moisture-absorptive properties (hygroscopicity) give them the tendency to achieve moisture equilibrium with their surrounding environment. Pellets that are stored in a moist environment would likely increase in moisture content to match that of their surroundings, while pellets that are stored in very dry environments would likely reduce in moisture content. This has the potential to create an ideal environment for microbiological growth and oxidation (Lehtikangas, 2000). Similarly, wood pellets that come to the facility with high initial moisture contents should be rejected, as they have the potential to influence the moisture content of existing fuel stores and could lead to self-heating and dry matter loss.

The aforementioned study also concluded that long-term storage reduces the strength of the pellets, especially in cases where the pellets are made of freshly harvested materials. In most cases, the average pellet length was decreased from the beginning to the end of the study due to breakage while in storage, and there were greater levels of fines in the material. Pellets with especially high moisture contents (>20%) experienced biological growth, as did pellets that had high levels of breakage, which increased the surface area available for growth (*Ibid.*).

A separate study, funded by the Natural Sciences and Engineering Research Council of Canada and the Wood Pellet Association of Canada, observed the effects of temperature on off-gassing of stored wood pellets, and concluded that pelletized materials have more off-gassing than solid biomass fuels. This is likely attributed to the low-grade heat treatment that is used during pellet production, which may partially degrade some of the wood's constituent compounds while also exposing more of the surface of the biomass material, giving a larger area for chemical reactions (Xingya Kuang, 2008).

The low initial moisture content of the wood pellets makes it necessary to place them in a covered storage area. Adequate ventilation should be designed into the storage system, as there have been numerous problems with off-gassing of wood pellets being stored in silos or shipped overseas in container vessels. Off-gassing can be extremely hazardous to humans, potentially resulting in serious injury or death if it continues undetected. Temperature or gas sensors can be used to ensure that off-gassing does not pose a serious threat to personnel working around the biomass. High turnover rates for biomass storage supplies can also help to mitigate the health concerns resulting from off-gassing (Melin, 2010).

Table 3-4 summarizes the problems associated with the chemical reactions that can result from wood pellet handling.

Table 3-4
Wood Pellets – Chemical Reaction Effects & Preventative Measures

Handling Concerns	Preventative Measures
Self-heating	• High fuel turn-over rate • Emergency discharge for high temperature fuel • Temperature monitoring of storage areas • Restrict oxygen access to storage piles • Reject fuels with high moisture contents • Keep pellets in a dry environment
Off-gassing	• Adequate ventilation • Gas concentration monitoring • Avoid unnecessary personnel access
Dry-matter loss	• Decrease fuel moisture content • Store biomass in larger pieces • Chemical applications to reduce microbiological activity

Data Source: Wood Pellet Association of Canada

It is worth noting that some pellet manufacturers may use a binding agent to aid in the manufacturing process of the pellets, which can add to their overall sulfur content. For this reason, the addition of these types of chemicals to pellets during manufacturing is illegal in several European countries (where pellets are heavily utilized).

Energy Density

Because of their lower moisture content and densification, the energy density differences between wood pellets and coal are not as pronounced as they are for wood chips. The issues described above for woodchips are still relevant, but abated by use of this fuel. Use of a facility's existing handling, processing, storage, and material sizing equipment is considerably more feasible for a repowering project utilizing wood pellets.

Risk of Explosions or Fire

Due to the relatively low moisture content of wood pellets in general, fires from internal heating are expected to be less of an issue here than for wood chips. Based on the available research, it also appears that the few facilities that are using large volumes of wood pellets tend not to have very long term storage anyway. In some cases, less than a day's worth of fuel is stored on-site.

However, wood pellets in particular are prone to generating dusty conditions, as they are comprised of compressed, dry, wood dust particles that break down as they are handled and processed. Dust suppression and spark detection systems can be installed in the storage and processing areas to help prevent the problems associated with dust generation from wood pellets. As a precaution, mechanical and heat-generating equipment should be enclosed and grounded to prevent heat sources or sparks from igniting the biomass. Table 3-5 summarizes different precautions that are commonly taken to prevent fires in wood pellet processing facilities.

Table 3-5
Wood Pellets – Fire and Explosion Preventative Measures

Handling Concerns	Preventative Measures
Dust generation	• Frequent cleaning of dust • Dust collection equipment, especially when the pellets are being transported • Minimize drop heights • Minimize direct collisions, particularly on hard surfaces
Fires	• Monitoring of all hot equipment • Spark detection and suppression systems • Avoid electrical heating devices
Explosions	• Explosion venting in storage areas • Explosion suppression systems • Explosion panels for enclosed storage vessels

Data Source: Wood Pellet Association of Canada

Key Properties: Torrefied Wood Pellets

Torrefied wood pellets (TWPs) potentially offer significant benefits over traditional wood pellets, especially as a substitute for coal. The chemical and physical properties of these pellets are such that they may reduce or eliminate the need for key coal plant modifications in repowering projects. However, unlike wood chips and pelletized wood, experience with this fuel is very limited, and there are considerable unknowns about TWPs as a commercial product. The data in the following section and the balance of this report is based on limited research data and published information from companies developing TWP products

Physical Characteristics

Torrefied pellets are cylinders of compressed particles generated from torrefied wood chips that are subsequently milled. They are similar in size and flow characteristics to wood pellets, and they are also low in moisture content levels.

Initial test results suggest that torrefied pellets can easily be reduced to their constituent particle size distribution through the use of a variety of milling techniques. The torrefaction process degrades the wood fibers, making the material more brittle. As a result, it is relatively easy to grind torrefied pellets to a smaller average particle size than that of the particles that composed the pellet. This makes torrefied pellets easy to prepare for firing, especially in cases where the pellets are being used to replace pulverized coal (Thek, 2010).

Even though the individual particles are easier to grind, torrefied pellets themselves are much better than conventional wood pellets at resisting breakage during fuel handling. Regardless, the same fuel handling rules should apply to torrefied pellets in terms of designing the system to avoid excessive handling and hard collisions (*Ibid.*).

As with conventional wood pellets, there are significant health hazards associated with dust generation of torrefied pellets during fuel processing. Staff working near the storage or processing facilities for torrefied pellets should take adequate precautions to prevent prolonged exposure to dust, which can cause irritations to the respiratory system and epidermis (*Ibid.*).

Chemical Characteristics

During torrefaction, biomass feedstocks experience a chemical change. The heat treatment reduces the moisture content, but volatiles are also driven off. One important result of the process is that the pellets are hydrophobic (repels water), much like coal. This particular characteristic has garnered considerable interest since wood chips and wood pellets have a tendency to attract moisture, which is problematic for the reasons discussed above.

However, it is possible that the torrefied pellets will still off-gas. A study funded by the Natural Sciences and Engineering Research Council of Canada and the Wood Pellet Association of Canada compared the effects of temperature on the off-gassing between wood pellets and torrefied wood while in storage. The study did suggest, however, that the off-gassing potential of TWPs may be lower than for standard wood pellets, and also that the amount of off gassing may not be as heavily influenced by temperature (Xingya Kuang, 2008).

Energy Density

The energy density of TWPs is also improved relative to wood chips and wood pellets, and in some cases will compare favorably with low-Btu coal. This further increases the potential to avoid extensive modifications (and the associated upfront capital costs) at existing plants, and this is widely viewed as a key potential strength relative to other forms of biomass.

Risk of Explosions or Fire

Self-ignition from internal heat production within torrefied pellet piles is not a concern, primarily because the biomass is hydrophobic, and most volatile organic compounds have already been driven off during the torrefaction process. However, the high grindability of torrefied wood is a function of its decreased fibrousness and increased brittleness. Although more resistant to breakage, it is possible that these properties can increase fine dust production and have a

negative impact on the overall explosion risk. However, until such time that large volumes of TWPs become available for testing, it will be difficult to evaluate these risks. For later chapters in this report, it is assumed that plants using this material will need to install explosion and fire suppression systems similar to the ones that are required for pelletized wood.

4

CASE STUDY ANALYSES: TECHNICAL DATA

This chapter presents detailed models of selected options for repowering a pulverized coal plant. The coal facility that will be used as the basis for each of these four case studies is described first, as this starting point dictates the changes required for each option and is used as a reference point for the performance model. An overview of the selected repowering option case studies is presented next, followed by a description of the four individual case study analyses and the results from each including capital costs. Finally, a comparison of the selection options is provided to evaluate the relative costs and benefits of each system.

In reviewing the case studies, the reader should be aware of the following overarching assumptions and caveats employed throughout this discussion:

- **Delivery Transportation Mode:** A detailed analysis of some of the key considerations regarding delivery transport modes for wood chips, wood pellets, and TWPs is provided in Appendix B, but in all cases fuel is assumed to be delivered by truck to the plant. This is by no means the only method for delivering fuel to large wood-fired plants, but if sufficient fuel can be sourced in the area immediately surrounding the plant, this will be the lowest-cost option. A detailed discussion of this topic, including transport mode implications and justifications for other delivery methods for specific circumstances, is provided in Chapter 6.
- **Regulatory Changes and Uncertainty:** At the time of this report, significant regulatory uncertainty exists regarding the implementation and final form of a number of EPA regulations that could have a material impact on biomass power plants. These include the Industrial Boiler MACT and Tailoring Rule. If promulgated as currently proposed, these rules could have a sweeping impact on the design and implementation of the potential project configurations discussed below. The capital cost estimates presented in Chapter 5 are based on status quo conditions, but substantial increases may be realized if extensive new emissions control equipment is required.
- **Comparative Intent:** The purpose of the case studies is primarily to provide a controlled comparison between the options reviewed. Technical, operational, and economic factors are considered. Some simplifying assumptions (such as ignoring property taxes in all cases) were made to minimize modeling complexity that the authors did not feel would have a material “net” impact on the final comparison metric: namely, levelized cost of electricity rates.

Baseline Pulverized Coal Plant Facility Description

The baseline coal plant selected for modification is representative of the size and type of plants that are broadly available in the U.S. fleet. In an effort to minimize speculation, actual data collected during the course of a recent repowering analysis for a unit in the Southeast was used as the foundation for the analysis. Clearly each plant has unique features, but the baseline unit for this analysis has common characteristics that include the following:

- It is an Alstom Power Inc. natural-circulation, radiant, reheat, balanced-draft, single-furnace-cell, tilting tangential-fired steam generator.
- The original maximum continuous rated (MCR) steam flow for the boiler is 900 kpph (408,000 kg/h) at the superheat outlet at 1000°F (538°C) and 1875 psig (129 bar)
- The MCR at the reheater outlet is about 800 kpph at 975°F (524°C) and 424 psig (29.2 bar) with an inlet economizer feed water temperature of 450°F (232°C).
- The superheater is designed to maintain a constant steam temperature of 1000°F (538°C) from 650 to 900 kpph (294,000 – 408,000 kg/h).
- The total furnace bottom footprint is approximately 1,144 ft² (106 m²)
- The boiler was designed to fire pulverized coal through four elevations of coal nozzles positioned in tangentially arranged windboxes.
- Combustion air to each boiler unit is supplied by two FD fans. Each unit also uses a primary air fan to pull preheated air from a header connected to the boiler windbox. These fans provide preheated air to the pulverizers.
- The unit uses two ID fans.
- Coal is processed in four RB Bowl Mills (type 633) and pneumatically transported to four elevations of tilting tangential fuel nozzles located in each of the four windbox corners of the furnace.
- Pulverizer throughput is 32,800 tons per hour (28,600 tonne/hour) for coal ground to 70% through 200 mesh and 15 % moisture.
- The unit was recently retrofitted with Alstom's P2 LNCFS™ (Low NO_x Concentric Firing System).
- The unit is equipped with a selective non-catalytic NO_x reduction system (SNCR).
- Particulate control is provided by a high-efficiency electrostatic precipitator with 97.7% control efficiency for PM10.
- The unit fires bituminous coal.

From this baseline, four basic repowering/fuel switching modifications are proposed. These cases are described below.

Conceptual Plant Modification Diagrams and Overview of Case Studies

Four repowering scenarios (with several subcases) were evaluated in detail. These cases were selected for a variety of reasons, including the potential for broad deployment, current industry interest, and the potential to offer low/no-cost investment options for deployment. The selected options are summarized below:

- Case 1 – Boiler-sized BFB repowering project using green wood chip fuel. No coal is cofired.
- Case 2 – Wood pellets are fired in suspension in the un-modified boiler at high levels. No coal is cofired.
- Case 3 – Pulverized torrefied wood pellets are fired in suspension in the un-modified boiler at high levels. No coal is cofired.
- Case 4 – A 400 MMBtu/hr gasifier is installed to produce syngas for high percentage co-firing in the existing boiler with pulverized coal.

The general principles of each type of retrofit are explained in some detail in the preceding chapters. All cases require significant changes to the fuel receiving and handling systems. Cases 1 and 4 also require large investments in or additions to the boiler island. Cases 2 and 3 require modest boiler upgrades and investment. The following subsections present the changes required to each major equipment cluster in the plant for each proposed scenario.

Case 1 – BFB Retrofit to Fire Wood Chips

Figure 4-1 presents a basic block flow diagram showing each of the major equipment islands for a BFB facility upgrade. It is important to note that these are the general requirements for this type of retrofit, some of which are optional or only apply for particular coal plant designs.

In the specific case evaluated, the following changes would apply: only truck unloading is considered; the FD fans and possibly the ID fans will need to be replaced (replacement of ID fans has been assumed); the rotary air heater will not be replaced with a tubular model; and, since the base coal plant does not have an FGD installed, it will not need to be decommissioned. Furthermore, SCR will not be required in addition to the existing SNCR for NO_x reduction (the location of the SNCR nozzle placement would likely have to be changed from the location that fits current coal operation to one more suited to utilizing the optimal NO_x reduction temperature window during biomass operation).

Based on past efforts, it is assumed that the existing FD fans cannot be kept and reused in this case, and combustion gas volumes and velocities across heat exchangers and pollution control equipment will be an important factor that limits plant steam rates. Although it is possible to push these velocities up with modifications, based on vendor data, stack gas volumes are held to rates similar to those of coal operation at maximum load. This will allow the ID fans to operate near their original design points even at maximum biomass capacity. The rotary air heater can also be kept due to the fineness and low carbon carryover of the fly ash from the BFB boiler.

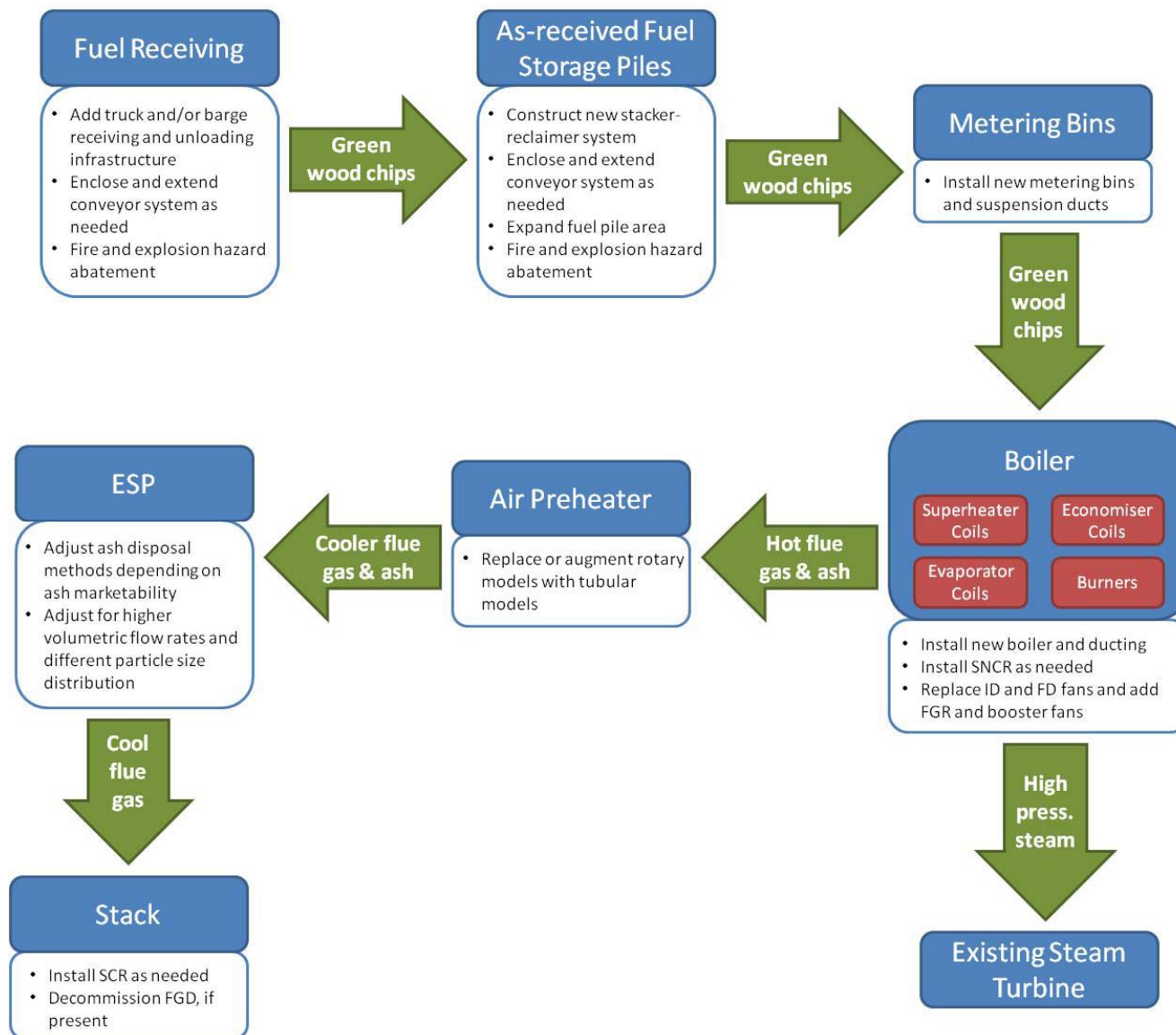


Figure 4-1
Block Flow Diagram for Case 1

Case 2 – Suspension Firing of Pulverized Wood Pellets

Figure 4-2 presents a basic block flow diagram for a pulverized coal facility firing pulverized wood pellets. As with the previous scenario, not all of the changes listed will be applied to the specific configuration evaluated in this chapter.

Specifically, it is assumed that no SCR will be required in addition to the existing SNCR, and since the baseline coal plant does not currently have an FGD installed, it does not need to be decommissioned. The fuel yard will require extensive changes to accommodate a hygroscopic fuel with a high dust explosion hazard, while the boiler island and flue gas train will remain largely untouched. One key change will be a reduction in steam outlet temperature and pressure from the boiler, intended to reduce the likelihood of halide corrosion in the boiler by reducing the furnace exit temperature (van Loo, 2008). This will be discussed in more detail in the performance modeling subsection below. Another important modification will be reducing the suspension air temperature to prevent premature evolution of volatiles from the wood fuel (Ryckmans, 2006). Fuel delivery for this case is assumed to occur by truck.

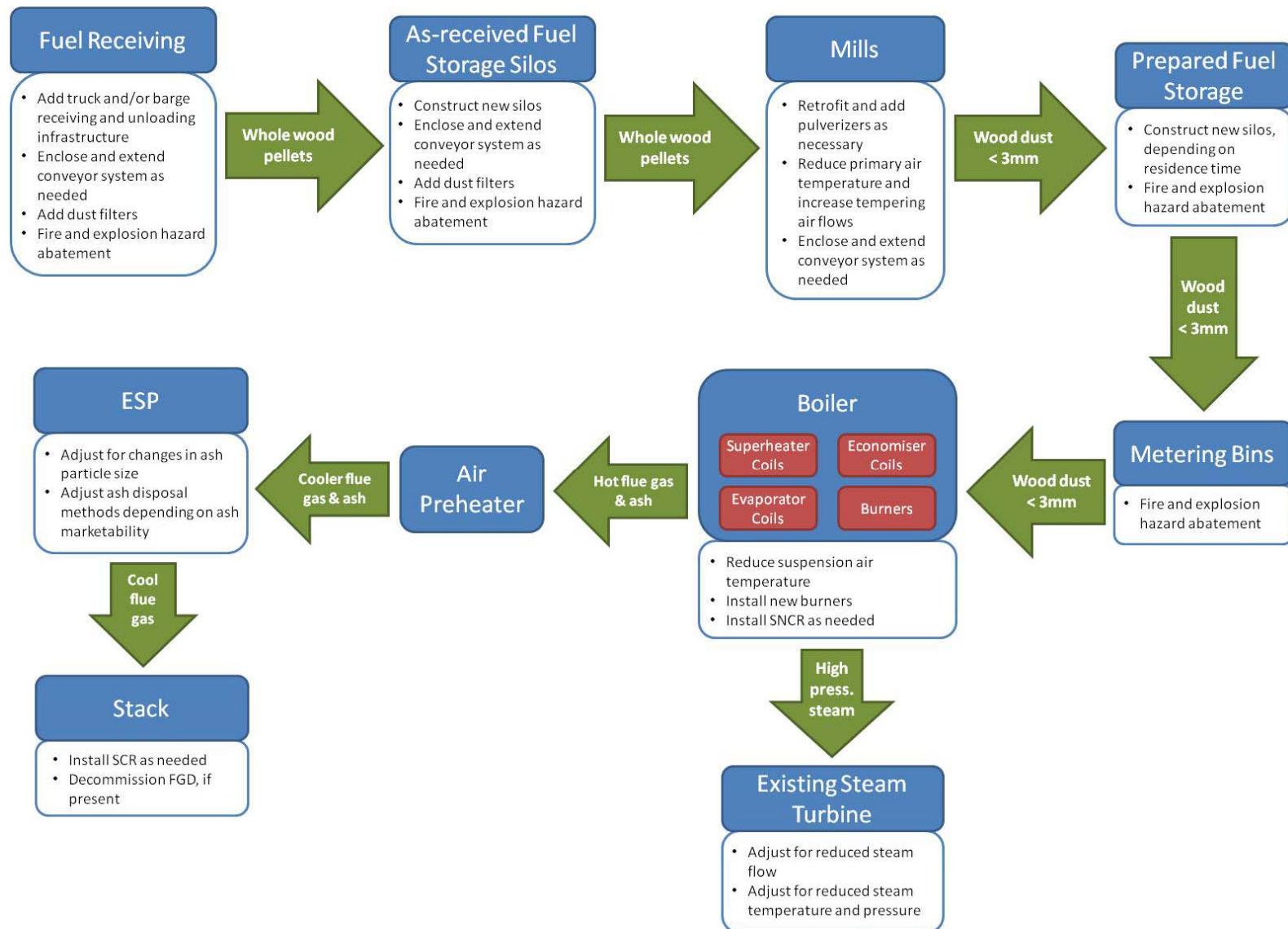


Figure 4-2
Block Flow Diagram for Case 2

Case 3 – Suspension Firing of Pulverized Torrefied Wood Pellets

A block flow diagram of a facility firing pulverized torrefied wood pellets is presented in Figure 4-3. No SCR will be required in addition to the existing SNCR, and since no FGD is currently installed, it does not need to be decommissioned. The fuel yard will require significant modifications, though not as significant as in Case 2 due to the greatly reduced hygroscopicity of torrefied wood and the decreased volatiles content.

Because of the potential for torrefied wood pellets to be stored outside, multiple fuel yard scenarios were developed for this case. The boiler island and flue gas train will remain largely unchanged. Delivery is again assumed to occur by truck.

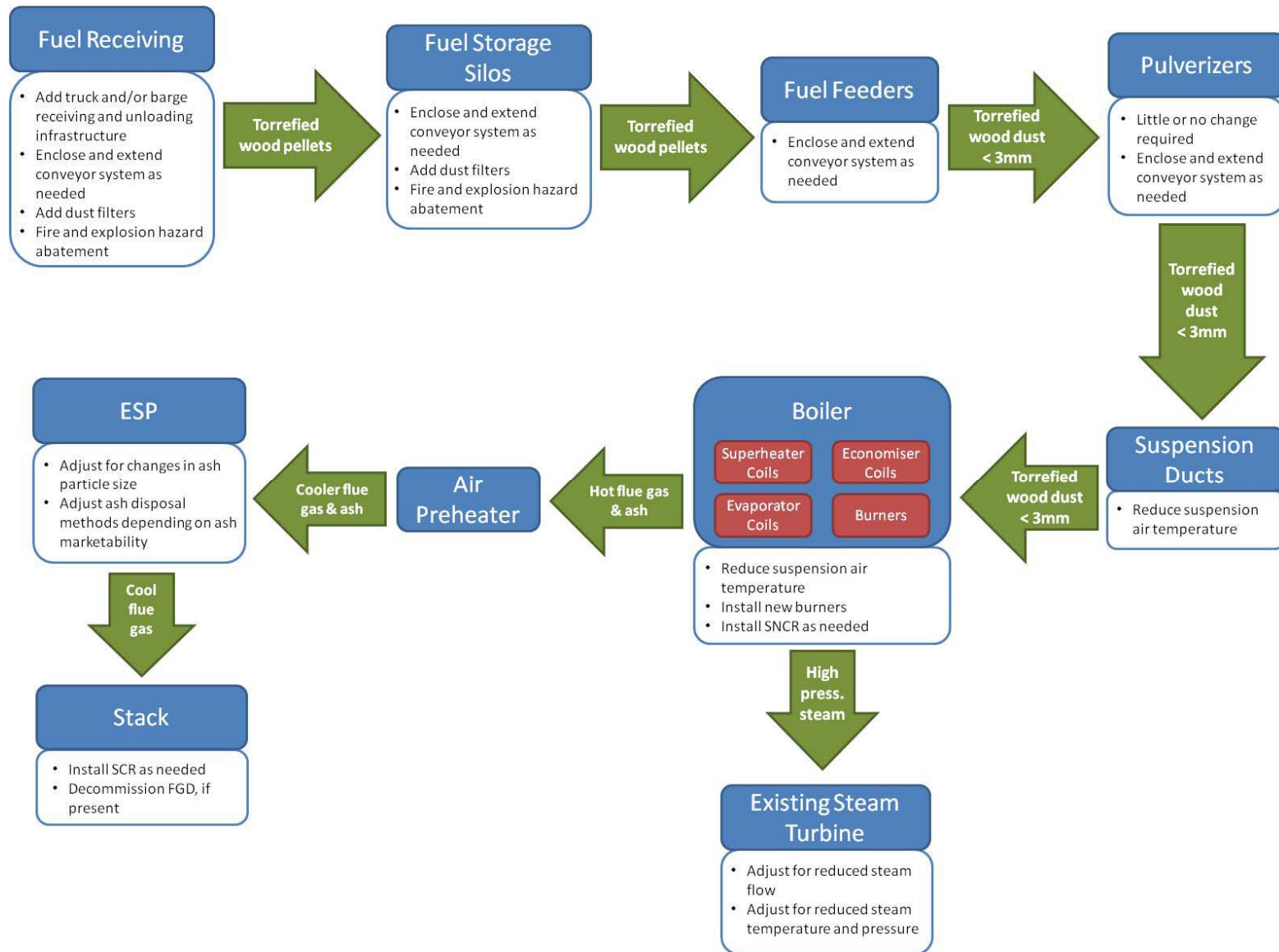


Figure 4-3
Block Flow Diagram for Case 3

Case 4 – Cofiring of Biomass-derived Syngas with Pulverized Coal

Figure 4-4 shows the proposed block flow diagram for a facility retrofitted to produce and cofire biomass-derived syngas. The exceptions stated for the prior cases with respect to FGD and SCR apply. This case adopts a fuel yard similar to that in Case 1, receiving green wood chips (via truck) that are unloaded and stored in an open pile with a circular stacker-reclaimer system. This scenario requires the addition of a gasification island.

This case is the only cofiring option evaluated. A relatively large biomass gasifier (Frontline's 400 MMBtu/hr model) is used in this evaluation, providing approximately 75% of the boiler's total heat input requirement.

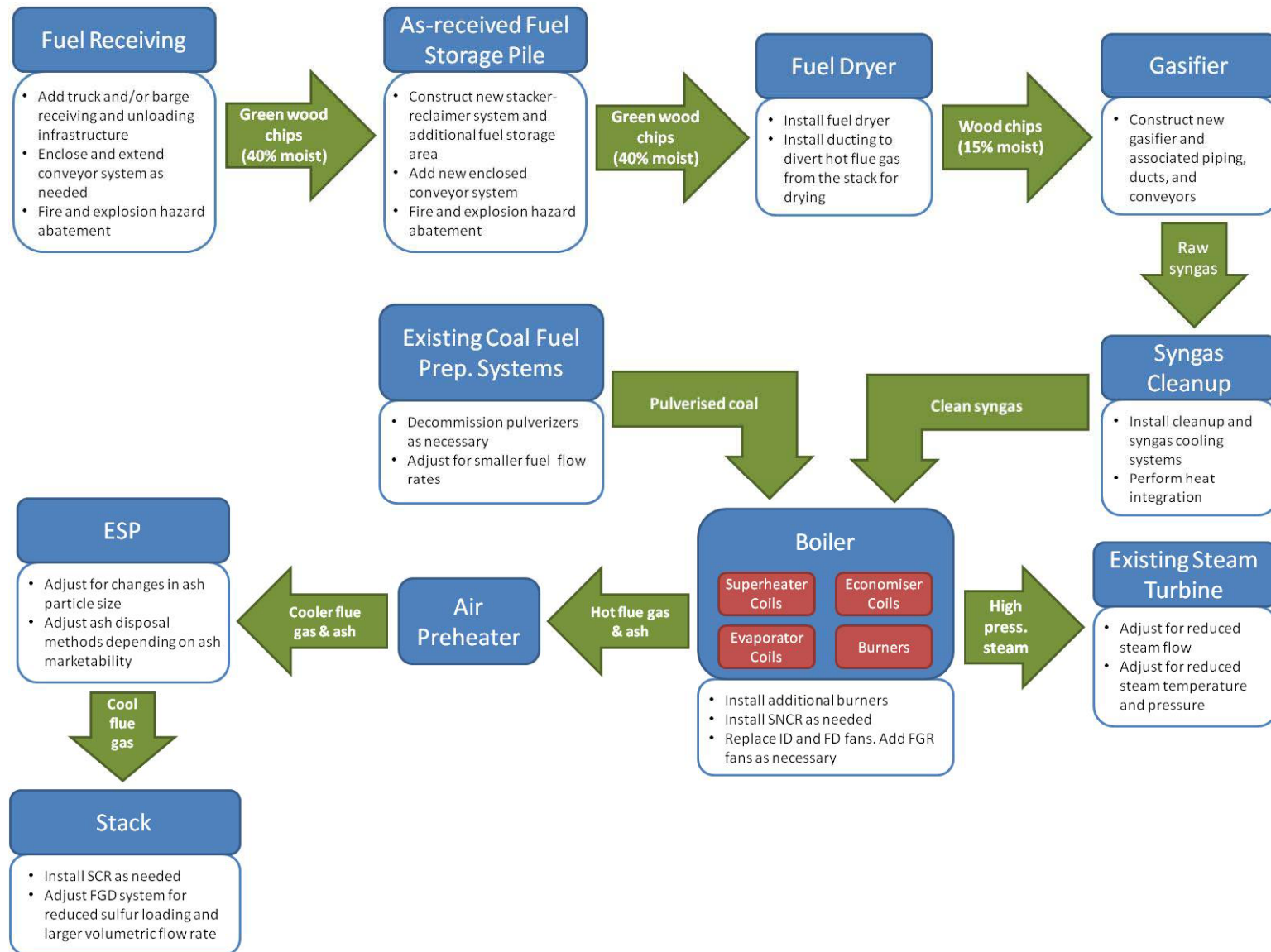


Figure 4-4
Block Flow Diagram for Case 4

Performance Modeling

Performance modeling for the selected cases was performed using a wide range of data resources, commercial heat and balance software, and supporting spreadsheet analyses. Each case is rooted in a heat and mass balance developed for the baseline coal-fired facility. The baseline modeling was performed using original contract specifications for an existing coal-fired plant; vendor-provided data, including equipment performance maps and relevant pressure and temperature limits, were also used. The calculations were performed using Thermoflex/PEACE, an industry-accepted heat and mass balance software package developed by Thermoflow.

The baseline modeling effort was used to establish a reliable model for the pulverized coal operations. Once the base case was thoroughly specified and examined for agreement with available data, the various changes required for each repowering scenario could be extrapolated by calculating the performance of key equipment under the different flow, temperature, and pressure conditions imposed by the repowering or fuel switch.

It should be noted that the modeling is intended primarily for heat and mass balance/transfer applications, such as sizing heat exchange surfaces, predicting fuel consumption, and determining system state points. Its application of kinetics, such as those associated with particle burnout times and breakthrough times, and its application of complex fluid dynamics, such as the calculation of effective particle residence time in the furnace, are limited. For this reason, some specifications presented in the following sections were derived from literature rather than the Thermoflex calculation engine. The analysis provides a reasonable basis for comparison using first-principles, but it is also clear that more data and more detailed computational modeling would be required to further refine these results.

The following section discusses the methodology and assumptions used in the base case coal modeling exercise, as well as the key inputs and assumptions used in each scenario. Detailed results for each individual repowering scenario will be presented within separate technology sections later in the chapter.

Key Inputs and Assumptions

Feedstock Assumptions

Table 4-1 presents a variety of relevant feedstock specifications on a wet, dry, and dry/ash-free basis. The specifications in the green-highlighted columns are those used in the performance modeling. The other specifications are presented for comparison.

The coal characterization is based on the original contract design specifications for the pulverized coal plant; the wood pellet specifications are from Toniato et al. (2007); the torrefied pellet specifications are from Arias et al. (2005); and the wood chip specifications are from the authors' previous repowering studies (EPRI, 2010b). The comparison specifications (not highlighted) are taken from the Thermoflex fuel composition library.

Table 4-1
Fuel Properties Used in Analysis

	Mass %	Bituminous (Coal Design)	PRB Coal, Wyoming	Wood Pellets	Torrefied Pellets	Green Wood Chips	Forest Residuals	Wood Chips for Gasification
Wet Basis	Moisture	8.50	31.63	8.00	2.10	50.00	48.91	45.00
	Ash	13.20	4.57	0.37	0.69	3.76	2.03	0.83
	C	64.00	46.59	46.37	51.62	25.81	25.69	28.60
	H	4.77	3.38	5.61	5.93	2.70	2.35	2.99
	N	1.40	0.63	0.09	0.00	0.17	0.53	0.19
	Cl	0.00	0.00	0.00	0.00	0.00	0.02	0.01
	S	1.00	0.37	0.09	0.00	0.03	0.06	0.02
	O	7.14	12.84	39.47	39.66	17.53	20.41	22.37
	<i>Total</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>
	HHV, Btu/lb	11,650	8,149	8,453	9,953	4,319	4,429	4,730
Dry Basis	LHV, Btu/lb	11,114	7,500	7,842	8,974	3,541	3,695	3,977
	Moisture	0	0	0	0	0	0	0
	Ash	14.43	6.68	0.40	0.70	7.52	3.97	1.50
	C	69.95	68.14	50.40	52.73	51.62	50.28	52.00
	H	5.21	4.94	6.10	6.06	5.40	4.60	5.44
	N	1.53	0.92	0.10	0.00	0.34	1.04	0.34
	Cl	0.00	0.00	0.00	0.00	0.00	0.04	0.01
	S	1.09	0.54	0.10	0.00	0.06	0.12	0.03
	O	7.80	18.78	42.90	40.51	35.06	39.95	40.68
	<i>Total</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>
Dry, Ash-Free Basis	Moisture	0	0	0	0	0	0	0
	Ash	0	0	0	0	0	0	0
	C	81.74	73.02	50.60	53.10	55.82	52.36	52.80
	H	6.09	5.29	6.12	6.10	5.84	4.79	5.52
	N	1.79	0.99	0.10	0.00	0.37	1.08	0.35
	Cl	0.00	0.00	0.00	0.00	0.00	0.04	0.01
	S	1.28	0.58	0.10	0.00	0.06	0.12	0.03
	O	9.11	20.12	43.07	40.80	37.91	41.60	41.30
	<i>Total</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>	<i>100.0</i>

Other feedstock assumptions used in the assessment are as follows:

- Wood pellets are composed of $\leq 0.23''$ (6 mm) diameter particles, compressed to 0.23 in by .78 in (6 mm by 20 mm) pellets. These pellets are milled to their constituent particle sizes, meaning that the particles are broken back apart from each other, but not reduced any further in size. This assumption is consistent with the literature and follows from discussions with individuals familiar with pellet wood milling common practices. The required grinding energy will be discussed in detail in the following subsection.
- Torrefied wood pellets are assumed to be received as 0.16 in by 0.6 in (4 mm by 15 mm) pellets and are milled with an attrition mill to an average diameter of 190 μm (0.19 mm). The required grinding energy is 39 kWh per ton, based on data presented in Bergman (2005).
- Wood chips are green, received at $\leq 2''$ (5 cm) in all dimensions.

One key fuel characteristic implied by the fuels' compositions is the amount of air each fuel requires per unit of energy released. The following table (Table 4-2) was constructed in order to gain some insight into potential impacts on boiler performance, and it provides theoretical calculations relating to combustion air and flue gas volumes according to fuel type.

These results only tell half the story about air use and derate mechanisms in the retrofitted boilers, but it is interesting to note that, per unit heat input, combustion of green woodchips results in nearly 20% more flue gas per unit energy than coal. This is not the case for wood pellets and torrefied wood, suggesting that these fuels may have an advantage with respect to gas-side equipment performance.

Table 4-2
Air Requirements by Fuel Type

Fuel	HHV	Stoichiometric Air Flow (0% Excess Air)	Fuel Flow	Mass Air per Unit Heat Input, 0% Excess Air	Typical Excess Air	Mass Air per Unit Heat Input, Typical Excess Air	Mass Flue Gas per Unit Heat Input, Typical Excess Air
	<i>Btu/lb</i>	<i>kpph</i>	<i>kpph</i>	<i>lb/kBtu</i>	<i>%</i>	<i>lb/kBtu</i>	<i>lb/kBtu</i>
Eastern Bituminous Coals	11,650	19.17	2.18	0.755	15	0.868	0.954
PRB Coal	8,149	19.52	3.243	0.739	20	0.887	1.01
Green Wood Chips	4,319	22.09	6.989	0.732	25	0.915	1.15
Wood Pellets	8,452	17.27	3.086	0.662	25	0.828	0.946
Torrefied Wood Pellets	9,553	16.98	2.695	0.660	20	0.792	0.896
Syngas (Frontline)	2,334	17.13	12.54	0.585	20	0.702	1.13

Base Case: Coal-fired Operations

As noted above, the original contract data sheets were available for the pulverized coal-fired power station that will be used as the base case for all subsequent modeling. This plant was constructed in the 1950s in the southern U.S. and was originally designed for bituminous coal operation. Data available from the plant included turbine mass flow / state point diagrams; heat exchange surface areas and anticipated temperatures; pressure drops and draft losses; and estimated design fuel usage and composition. Diagrams of the boiler were also available.

A Thermoflex model was constructed for the major plant components, and a conceptual diagram can be found in Appendix C. The major components consist of:

1. a furnace with integral pulverizer,
2. an SNCR unit,
3. deaerator tank and four closed feedwater heaters,
4. ID and FD fans,
5. electrostatic precipitator (ESP),
6. rotary air heater,
7. condenser and cooling tower,
8. economizer and additional superheaters,²¹
9. feedwater pumps,
10. fuel source,
11. air sources, and
12. flue gas sinks.

The sources listed above were used to provide inputs for these components to allow Thermoflex to perform a detailed heat and mass balance. The following key specifications were used:

- 900,000 pph (408,000 kg/h) of primary steam and 800,000 pph (363,000 kg/h) of reheat steam flow, both at 1000°F (538°C) Superheater steam outlet pressure is 1875 psig.
- 15% excess air at full load.
- Stack temperature of 294°F (146°C).
- ESP particulate exit concentration of 0.02 lb/MMBtu fuel input.
- 80% of total ash to the boiler exits as fly ash, 20% as bottom ash.
- 1% of the carbon entering the boiler does not combust and exits as fly ash.

²¹ The furnace component includes both a superheater section and a reheat section, so additional superheater sections are not generally necessary. However, the existing boiler's design included three superheater sections that are not exposed to the flue gas in a strictly counterflow order. For this reason, it was necessary to break the convective pass heat exchange into three separate component operations.

- Pulverizer electrical consumption of 15 kWh/ton coal, based on a Hardgrove Grindability Index (HGI) of approximately 55.
- Fuel yard and conveyor parasitic load of 20 kWh/ton.
- 0.25% blowdown.
- Furnace exit temperature of 2,200°F (1204°C).
- The SNCR component operates at 50% efficiency and a 1.2 stoichiometric ratio.
- Rotary air heater exit temperature, air-side, of 575°F (302°C). Leakage of 5.3% on both hot and cold ends, or a leakage flow of about 103,000 pph (46,800 kg/h).
- Turbine generator reheat pressure of 385 psig. Condensing section pressure of 2" Hg. Extraction steam enthalpies in accordance with the contract data specifications for the turbine at a similar load:
 - Stage 1 outlet: 1308 Btu/lb
 - Stage 2 outlet: 1434 Btu/lb
 - Stage 3 outlet: 1335 Btu/lb
 - Stage 4 outlet: 1250 Btu/lb
 - Stage 5 outlet: 1155 Btu/lb
 - Stage 6 outlet: 1042 Btu/lb (condensing pressure)
- Feedwater temperature to the boiler of 447°F. The feedwater systems were specified as follows:
 - Heater 1 (closed): 8.23 psia; 184.2°F; TD of 5°F
 - Heater 2 (closed): 27.76 psia; 245.9°F; TD of 5°F; DC of 10°F
 - Heater 3 (open): 75.53 psia; 308.1°F
 - Heater 4 (closed): 182.9 psia; 374.4°F; TD of 0°F; DC of 10°F
 - Heater 5 (closed): 411.7 psia; 447.4°F; TD of 0°F; DC of 10°F

With these specifications, the model converged to an operating point with approximately the expected heat rate, fuel consumption, and electricity production. The model was then set to off-design operation such that its equipment sizes and specifications would be fixed regardless of fuel, steam, or air flow rates.

Case 1 – BFB Retrofit with Wood Chip Firing

Boiler Plant Performance

The off-design coal model was significantly modified to represent a retrofitted BFB repowering scenario. Guiding these modifications were engineering reports and published data for boilers (such as those available for the baseline unit). Available data included operating parameters after

the removal and replacement of the bottom of the boiler and the addition of a small amount of heat transfer area to the superheater section, both done to accommodate BFB firing of green wood chips. These modifications included:

- Replacement of the furnace component with a radiant boiler and removal of the pulverizers. External superheater and economizer sections remained intact.
- Reduction in primary steam flow to 570,000 pph.
- Reheater and superheater steam outlet temperatures will be controlled to near-design specifications using desuperheating flows.
- Increase in excess air rate to 29%.
- Change in fuel from the design coal to the 40% moist wood chip discussed in the previous section.
- Increase in unburned combustibles from 1% to 2% due to the high moisture content and large particle size of the fuel.
- Change in fly ash to bottom ash ratio from 80:20 to 99:1.
- Significant changes to the combustion air and flue gas configuration, as shown in the process diagram in Figure 4-1. Booster and flue gas recirculation fans were added to accommodate the increased pressure drops and changed primary to secondary air ratio. Duct components were used to make slight corrections to the fans' outlet pressures.
- Flue gas recirculation was added.
- Fuel yard parasitic load of 1086 kW. This was based on information received from the fuel yard vendor and data received from a similar operating wood yard.

Table 4-3 below presents some of the key performance parameters for this case study in comparison with the parameters calculated or measured for the design coal case. The system diagram for this scenario can be found in Appendix C.

Table 4-3
Estimated Performance of Case 1

Parameter	Unit	<i>Design Coal</i>	<i>Case 1: BFB</i>
Boiler efficiency, HHV	%	88.2%	72.3%
Electrical efficiency, net, HHV	%	36.4%	27.4%
Primary steam flow	kpph	900	570
Reheat steam flow	kpph	794	508
Coal flow	kpph	109	n/a
Coal flow, HHV	MMBtu/hr	1,271	n/a
Biomass fuel flow	kpph	n/a	234
Biomass fuel flow	MMBtu/hr	n/a	1,024
Flue gas flow	kpph	1,293	1,232
Flue gas flow	cfs	6,660	7,125
Fly ash collected	kpph	12	8.7
Preheated air flow	kpph	1,199	1,008
Air rate	lb-air/kBtu	0.943	0.985
Excess air	%	15	29
Air heater exit temp., air-side	degrees F	568	400
Stack temperature	degrees F	292	334
Primary outlet steam temperature	degrees F	1,000	1,000
Reheat outlet steam temperature	degrees F	1,000	1,000
Adiabatic flame temperature	degrees F	3,630	2,361
Gross electrical generation	kW	143,948	93,415
Non-pulverizer parasitics	kW	7,646	9,964
Estimated pulverizer parasitic load	kW	1,177	0
Conveyors and fuel yard parasitics	kW	1,091	1,086
Net electrical generation	kW	134,034	82,365
Particle size	mm	0.0500	12.7
Particle size	in	0.00197	0.500
Unburned carbon	% entering	1	2
Unburned carbon	ash LOI, %	5.46	12.2

Fuel Delivery and Storage

For the purposes of this initial evaluation, it has been assumed that the primary method for wood chip delivery to the power plant would be via tractor-trailers. The trucks will enter the inbound truck scale at the scale house and then continue on to the unloading area, where they will unload the chips using one of four truck tippers installed on site. After the biomass has been unloaded from the trucks, it will be screened for scrap metal and pieces of biomass that are over 2'' (5 cm) in size in the hog and screen tower. Any oversize pieces will be re-processed for size reduction and then added back into the fuel supply stream. They will then be conveyed up an incline with the rest of the fuel supply to one of two open circular storage areas. The fuel storage facility will then stack and reclaim biomass for further processing as it is needed.

A reclaim system similar to the one seen in Figure 4-5 was selected for this analysis. This system uses an overhead conveyor to reclaim the biomass. Based on the density of the wood chips, it was determined that two 324-ft (99m) diameter storage/reclaimer areas would be required for two weeks of fuel supply storage (39,400 tons, 35,200 tonnes). Figure 4-6 shows the plant layout for the biomass fuel delivery and storage area. Outbound trucks will pass over the outbound scale at the scale house and be given a weigh receipt for fuel delivery. Note that two scales are specified in the site design. This will facilitate traffic flow at the site under heavy delivery schedule scenarios.

Biomass deliveries were assumed to occur between the hours of 6 a.m. and 6 p.m. from Monday through Saturday; no deliveries were assumed to occur on Sunday. The facility will need 10.9 truck deliveries every hour to meet fuel supply requirements.

The wood chips that are used for this analysis are green woodchips with an average moisture content of 50% on a wet weight basis. The high initial moisture content does not make it necessary to place the chips in a covered storage area, as covered storage alone will not do much to reduce the moisture content of the biomass. To do this, the covered storage would need to be coupled with fuel dryers, which add greatly to the overall cost of the plant and are not in general use for plants of this type. The storage area selected for this case uses a circular outdoor storage area with overhead reclaimers.



Photo courtesy of BRUKS Rockwood. (<http://www.bruks.com>)

Figure 4-5
Biomass Storage and Reclaim System

Fuel Processing

The wood chips will not need processing in mills. As a result, after the chips are reclaimed they will be fed directly into one of five silos, which are designed to hold up to 12 hours of biomass (1,400 tons, 1250 tonnes) prior to combustion in the boiler.

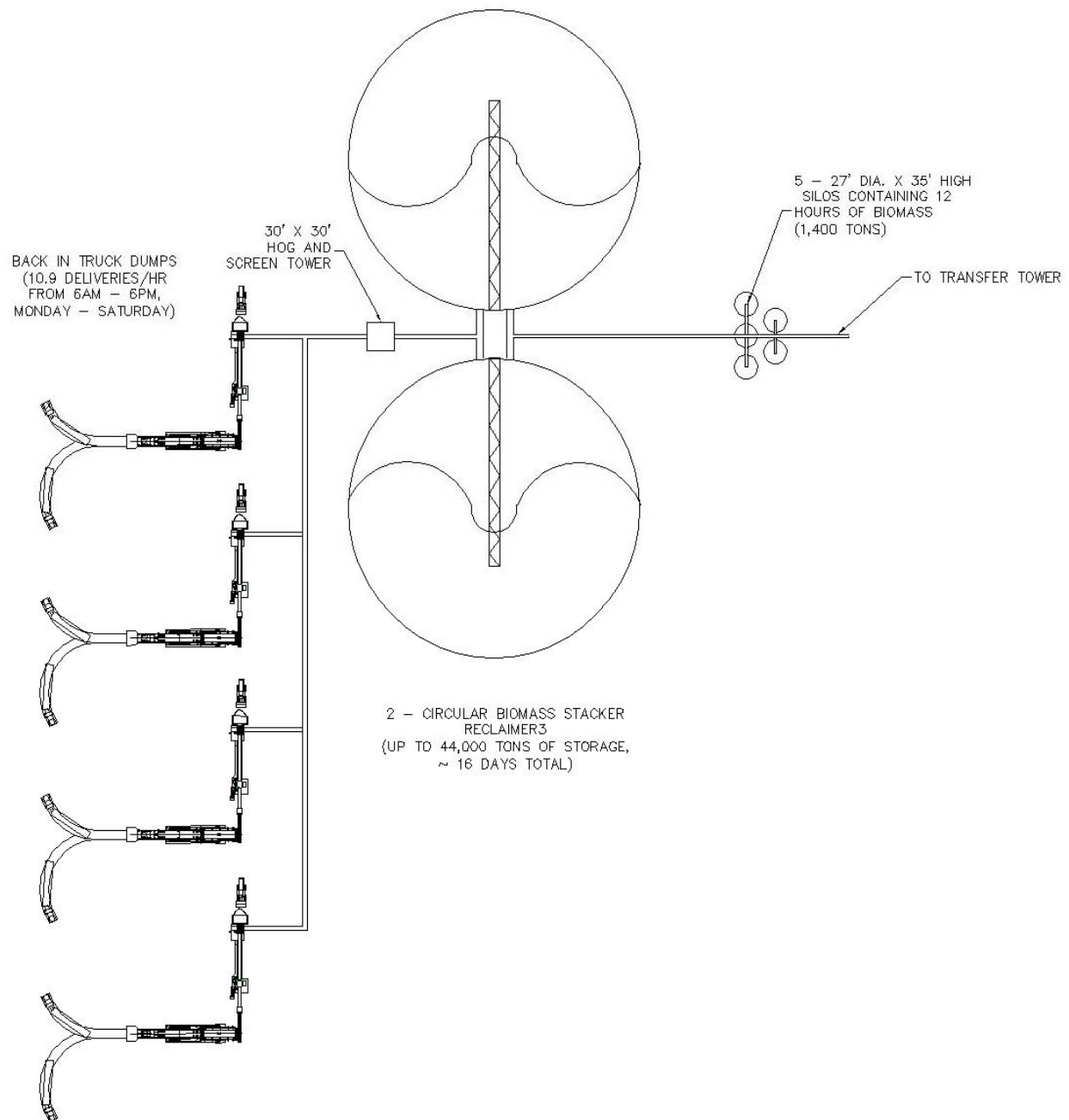


Figure 4-6
Power Plant Layout (Case 1)

Additional Data

A project timeline was estimated for the proposed changes and is shown in Figure 4-7. The Plant Schiller repowering project (see Chapter 2) offered key insights into project duration, given its similar size and scope.

The reader will note that a range for the project development times has been provided. Starting with the Preliminary Feasibility Study through Commissioning phase, projects such as the one detailed in this case might reasonably take 3-4 years to complete. One key driver is equipment procurement. Lead times for fuel yard and boiler equipment were stated as potentially taking as long as 18 months to deliver. Depending on the jurisdiction and owner risk tolerance, most or all of the permitting may need to be completed before placing equipment orders, such that timelines can become extended.

Case 1 - BFB Retrofit for Wood Chip Firing Project Timeline Estimate Assumes January 1, 2011 Start				
TASKS	Duration (Weeks)		Estimated Completion Date	
	Aggressive Timeline	Conservative Timeline	Aggressive Timeline	Conservative Timeline
1.0 Engineering			9/22/2011	2/23/2012
1.1 Preliminary Engineering	24	36	6/17/2011	9/9/2011
1.2 Final Engineering: Process	12	16	9/9/2011	12/30/2011
1.3 Final Engineering: Structural	6	12	9/22/2011	2/23/2012
2.0 Permitting/Procurement			2/28/2013	3/6/2014
2.1 Air Re-permitting	24	52	12/2/2011	9/7/2012
2.2 Discharge Permits	16	20	10/7/2011	1/27/2012
2.3 Procure Long-Lead Items (Fuel Yard, Boiler Parts)	65	78	2/28/2013	3/6/2014
3.0 Construction and Installation			6/13/2013	10/9/2014
3.1 Civil Site Work/Construction Preparation	16	20	3/20/2013	3/26/2014
3.2 Equipment/Buildings/Structures	24	36	5/16/2013	8/14/2014
3.3 Mechanical, Electrical, Balance of Plant, and Finish Work	12	16	6/13/2013	10/9/2014
4.0 Testing and Commissioning			10/17/2013	3/12/2015
4.1 Initial Start-up Testing	12	16	9/5/2013	1/29/2015
4.2 Emissions Testing	4	4	10/3/2013	2/26/2015
4.3 Training	4	4	10/3/2013	2/26/2015
4.4 Substantial Completion and Acceptance	2	2	10/17/2013	3/12/2015
		Total Months	33	50

Figure 4-7
Case 1 BFB Retrofit Project Timeline

Case 2 – Suspension firing of pulverized wood pellets

Boiler Plant Performance

For this case, the baseline coal model was modified to represent the suspension firing of pulverized wood pellets. A key objective of this case was to minimize the capital investment and plant modifications necessary to convert to using 100% biomass fuel. As noted in the previous chapter, this approach remains a rare (but possibly emerging) technology with only a few examples currently in operation.

This case relied on a significant amount of technical input from published literature about Les Awirs and Hässelby, and scientific literature about the various issues related to suspension firing of biomass. These issues included particle sizing and residence time, as well as their implications for carbon burnout, milling requirements, and fire/explosion hazards.

Particle sizing and residence time

The kinetics of combustion of fuel particles is a fairly complex topic best suited to CFD modeling of the particular boiler in question. However, it is generally true that particle burnout time increases as the square of the particle diameter and increases proportionally with the particle's density. Given that coal is generally milled to 50 to 200 μm (5×10^{-5} to 2×10^{-4} m), and that the wood particles that generally compose a wood pellet are 1 to 4 mm (1×10^{-3} to 4×10^{-3} m) in diameter, wood pellet particles will typically exhibit burnout times longer than those of coal particles. As particle burnout time begins to approach the furnace residence time, excessive amounts of unburned carbon can be expected in the resultant ash, leading to efficiency reductions.

Saastamoinen et al. (2010) studied the burnout times associated with biomass and coal particles as a function of size. Due to the lower density and higher volatiles content of biomass, a larger biomass particle can be used to achieve the same burnout rate as a coal particle of a given size. However, burnout times increase exponentially as a function of particle size, meaning that while a 200 μm wood particle burns out in 0.15 s, a 400 μm wood particle would burn out in 0.8 s and a 1 mm particle would require more than two seconds. While this study did not deal with particle sizes greater than 1 mm, it is clear that the particle sizes found in a wood pellet will approach or exceed the 1-3 second residence time found in the furnace section of a typical utility boiler.

Saastamoinen also investigated the effect of particle size on a particle's flow dynamics in the boiler as a function of the height at which it is injected into the boiler. Larger particles are difficult to suspend and often fall to the bottom of the boiler after only partial combustion. In turn, the smallest particles are often propelled into the convective pass of the boiler too soon, leaving them only partially combusted or, dangerously, still burning during the convective passes of the boiler. The researchers point to a particle size of 1 to 1.5 mm as an effective compromise between these two outcomes, allowing optimal residence time in the furnace section through a U-shaped vertical motion. Carbon burnout approaches 100% for these particles in the researchers' model of a pulverized coal furnace.

CFD modeling of the furnace was outside the scope of this work, so the 1.5 mm optimum particle size was chosen as a first approximation to that required for wood pellet firing in the chosen boilers. This would still be likely to result in an increase in the percent of particles falling to the bottom of the boiler and being removed as bottom ash, and the overall level of unburned carbon would be likely to increase in both ash types.²² This choice of particle size agrees well with the milling standards published for the Les Awirs facility: namely, 100% <3 mm and 75% <1 mm (Ryckmans, 2006). The expectation of increased unburned carbon levels is consistent with the operation of the Hässelby CHP facility, which transports its bottom ash to another facility for combustion due to its high degree of unburned combustibles. Hässelby and Les Awirs both landfill rather than sell their fly ashes, an indication that these may contain high levels of carbon (Thek, 2010).

²² As will be discussed later, the high-LOI nature of the fly ash produced would make it unlikely that the fly ash could be sold for concrete production under ASTM C618, which requires an LOI of less than 6%. The economic implications of this will be considered in the following section.

Milling and associated parasitic loads

Several approaches can be taken to reaching this particle size requirement. The Les Awirs facility replaced its existing pulverizers with two 30 ton/hour (27 tonne/h) hammer mills. This same approach was taken during the pellet cofiring retrofit at Essent's Amer 8 power unit, where two 18 ton/hour hammer mills were installed to process the pellets. An alternative approach to mill replacement has been taken at Essent's Amer 9 unit and the Hässelby CHP facility. The Amer 9 unit uses two of its pre-existing coal pulverizers to grind pellets, while Hässelby uses a total of six pre-existing coal mills and two new 20 ton/hour hammer mills. Both of these facilities retrofitted the existing coal pulverizers to process wood pellets with an undisclosed degree of resultant capacity reduction.

As discussed in the fuel specification section, milling can reduce the pellets to their constituent particle size distribution without further particle size reductions. For the two Amer units, it has been published that this is the case (Thek, 2010). Given the 0.5 to 3 mm particle size distribution cited for the Hässelby plant, it is likely also the case for that facility as well. At Les Awirs, however, the pellets appear to be ground beyond a return to the baseline size distribution. Thek states that "The wood pellets are not only broken down coarsely but further milled." How far this distribution is from the baseline particle distribution is unclear, but this may indicate an increased parasitic load per unit of fuel for Les Awirs in comparison to the other facilities.

For example, information provided by West Salem Machinery, a supplier of wood particle size reduction and handling equipment, indicated that milling a wood pellet to an average size of 1.5 mm would result in a significant capacity derate for hammer mills. In the case of this study's example plant, fourteen hammer mills with a nominal capacity of 25,000 pph (effective capacity 9,000 pph) would be required at full load, rather than the five that would be required to reach merely the pellets' original size distribution. This baseline distribution varies by manufacturer and starting material, but Thek (2010) indicates a 4 mm target particle size for a 6 mm diameter pellet. This would mean that a repowering project developer would need to work closely with feedstock suppliers to develop feedstock specifications that ensure that the baseline particle size distribution is not exorbitantly too large for efficient combustion.

Apart from the particle size distribution reached, the replacement and retrofit options for milling have different economic and operational implications, such as reliability. Thek (2010) compared the experiences of the two Amer units and found that the converted coal mills had "very high" availability, while the hammer mills had reduced availability due to wear. Another issue is capacity. The coal pulverizers will experience a capacity derate due to the fibrous, lower-density nature of pellets compared to coal. Marshall et al. (2010) performed milling and firing tests of wood pellets in the pulverized coal boilers at Ontario Power Generation's Nanticoke and Atikokan generating stations. The Nanticoke plant's ball-race mills, designed for bituminous coal, performed at about 70% of their original capacity on an energy basis. Primary air requirements were greatly increased in order to effectively fluidize and transport the milled particles, leading to an increased air to fuel ratio and an increased pressure differential across the mill. In addition, the mill inlet air temperatures had to be reduced to 65°C (149°F) in order to avoid premature evolution of volatiles.

The Atikokan roller-race mills, originally designed for lower-energy-density lignite, performed almost at original capacity on an energy throughput basis. Primary air supply was found to be a limiting factor, as a 3:1 air to fuel ratio was required for fluidization and transport, producing an almost 7 kPa (30 in. H₂O) pressure differential through the mill. This differential could be reduced with mill modifications (such as the installation of a rotating versus a static throat), but remained significant.

Beyond derate, there is the operational concern of possibly decreased heat transfer in the air preheater. A key complication of the Atikokan mill retrofits was an increase in stack gas temperature, because a significant amount of the primary air had to be bypassed around the air preheater in order to reduce the temperature at the mill inlet. This reduced the amount of heat transferred from the hot flue gas in the air preheater, increasing stack heat losses and increasing overall plant heat rate. Though this alternative will not be considered in the present modeling, it may be feasible to install additional flue gas heat transfer equipment, such as a feedwater preheating heat exchanger, to limit stack heat loss.

Two subcases are considered in this analysis: one representing a low-capital approach to the question of milling and heat exchange surface area, the other representing a capacity-maximization approach. In subcase 2a, only as much pellet fuel as can be processed with the existing coal mills will be fired in the boiler. This avoids the capital investment of additional or replacement mills, but leads to a smaller maximum capacity rating while firing the pellets (since the pulverizers reach their capacity limit before the flue gas train and heat exchangers reach their operating limits). As the plant examined in this study was originally designed for bituminous coal, its mills will likely resemble the Nanticoke rather than the Atikokan pulverizers in their derate. The plant's vertical air-swept mills are therefore modeled with a 70% energy derate on an energy basis, a 7 kPa (30 in. H₂O) pressure differential, a 3:1 primary air to fuel ratio (mass basis), a 20°C (36°F) temperature differential, and a 65°C (149°F) inlet air temperature.

Subcase 2b maximizes the plant's capacity to approach the limits of the plant's ID fans. Four additional hammer mills are installed to increase milling capacity, and capital-intensive pressure part modifications are performed to allow more efficient heat exchange at 115% of the original volumetric flue gas flows, without excessive stack temperatures. This represents a scenario in which it is particularly important to the developer to meet a target MW capacity of renewable generation without resorting to additional repowering projects or more capital-intensive greenfield renewable energy projects.

Additional concerns

While it was not necessary to consider fire suppression systems in the heat and mass balance modeling, the fine particle size resulting from the milling has a high explosive and combustible potential. Fire and explosion abatement strategies and costs will be described in more detail in the following sections.

It was also not necessary to take into account additional furnace cleaning for a steady state boiler model. However, it is important to note that the high-carbon nature of the fly ash and the differences in ash composition between coal and wood may make it more resistant to traditional sootblowing techniques and frequencies, and more prone to fouling. (Hässelby, for example, has

experienced deposition in its air preheater.) For this reason, additional cleaning mechanisms, such as waterlances or additional sootblowing capacity, may improve furnace heat transfer and reliability. These will be discussed in the following sections.

Specifications

In order to adapt the coal heat and mass balance model to the firing of pulverized wood pellets, the following changes were made:

- Re-specification of the pulverizer component in accordance with the Nanticoke and Atikokan performance data. Outlet temperature was set to 113°F (45°C), overall air to fuel ratio to 3:1 on a mass basis, and pressure drop to 30 in. H₂O. In the absence of published data on energy consumption of existing mills processing wood pellets, the non-fan existing pulverizer energy consumption was specified to be 20 kWh/ton, as was estimated for the coal case. In subcase 2b, the hammer mills were specified to consume 34 kWh/ton, based on the size of the motor in each mill.
- In subcase 2a, reduction in primary steam flow to 559,000 pph (254,000 kg/h), at which flow rate the mills reach their mass flow limit.
- In subcase 2b, reduction in primary steam flow to 812,000 pph (368,000 kg/h), at which steam flow rate the flue gas train volumetric flow rates reach 115% of the flows in the full-load coal case.
- Reduction in steam outlet temperature from 1000°F to 950°F (538° to 510°C) in an effort to prevent boiler corrosion or fouling due to halides and ash slagging, respectively. The relatively low moisture content of the pellets and the suspension rather than BFB arrangement of the boiler means that the furnace exit temperatures will be higher than in the wood chips case, leading to a higher likelihood of halide corrosion.
- Reheater and superheater steam outlet temperatures controlled using desuperheating flows.
- Increase in excess air rate to 25%.
- Change in fuel from the design coal to the wood pellets discussed in the previous section.
- Change in fly ash to bottom ash ratio from 80:20 to 60:40. This is an estimated value, as no reference was available for the magnitude of the change in ash distribution due to the change in inlet particle size distribution. CFD modeling would be required to determine the true value.
- Fuel yard parasitic load of 10 kWh/ton. This was based on a previous project in which a largely automated fuel yard was specified for wood chip handling (EPRI 2010b). It was assumed that despite the differences in storage type (silos versus piles), fuel yard parasitic loads would be similar for wood pellets.

The off-design systems were converged with the changes above in order to estimate net electrical generation and fuel consumption at this part-load turbine condition.

Table 4-4 presents some of the key performance parameters in comparison to the same parameters calculated or measured for the design coal case. The Thermoflex system diagram for these scenarios can be found in Appendix C.

Table 4-4
Estimated Performance for Case 2

Parameter	Unit	Design Coal	Case 2a: Existing Boiler with Wood Pellets, Mill-Limited	Case 2b: Existing Boiler with Wood Pellets, 115% of Flue Capacity
Boiler efficiency, HHV	%	88.2%	83.2%	82.9%
Electrical efficiency, net, HHV	%	36.4%	31.4%	31.5%
Primary steam flow	kpph	900	565	853
Reheat steam flow	kpph	794	506	756
Coal flow	kpph	109	n/a	n/a
Coal flow, HHV	MMBtu/hr	1,271	n/a	n/a
Biomass fuel flow	kpph	n/a	105	151
Biomass fuel flow	MMBtu/hr	n/a	888	1,273
Flue gas flow	kpph	1,293	875	1,271
Flue gas flow	cfs	6,660	5,274	7,725
Fly ash collected	kpph	12	0.3	0.4
Preheated air flow	kpph	1,199	393	728
Air rate	lb-air/kBtu	0.943	0.442	0.572
Excess air	%	15	25	25
Air heater exit temp., air-side	degrees F	568	527	400
Stack temperature	degrees F	292	404	408
Primary outlet steam temperature	degrees F	1,000	950	950
Reheat outlet steam temperature	degrees F	1,000	1,024	937
Adiabatic flame temperature	degrees F	3,630	3,390	3,433
Gross electrical generation	kW	143,948	91,350	129,984
Non-pulverizer parasitics	kW	7,646	7,620	8,818
Estimated pulverizer parasitic load	kW	1,177	1,398	2,421
Conveyors and fuel yard parasitics	kW	1,091	488	699
Net electrical generation	kW	134,034	81,845	117,653
Particle size	mm	0.0500	1.5	1.5
Particle size	in	0.00197	0.059	0.059
Unburned carbon	% entering	1	1	1
Unburned carbon	ash LOI, %	5.46	55.77	55.77

Fuel Delivery and Storage

For this analysis, it is assumed that trucks will enter the inbound truck scale at the scale house and then continue on to the unloading area, where they will unload the pellets using one of two truck tippers installed on site. After the biomass has been unloaded from the trucks, it will be conveyed up an incline to a concrete dome storage area. The fuel storage facility will then stack and reclaim biomass for further processing as it is needed. A reclaim system similar to the one shown in Figure 4-8 was selected for this analysis. This system uses an overhead conveyor to stack the biomass and an under-pile reclaimer to ensure first-in/first-out flow. Based on the bulk density of the wood pellets, it was determined that a dome approximately 100 ft in diameter (30m) and 95 ft (29m) in height would be required for seven days of fuel supply storage (10,900 tons, 9700 tonnes). Outbound trucks will pass over the outbound scale at the scale house and be given a weigh receipt for fuel delivery. Note that two scales are specified in the site design. This will facilitate traffic flow at the site under heavy delivery schedule scenarios.

Biomass deliveries were assumed to occur between the hours of 6 a.m. and 6 p.m. from Monday through Saturday; no deliveries were assumed to occur on Sunday. The power plant will need approximately 6.1 truck deliveries every hour to meet fuel supply requirements.

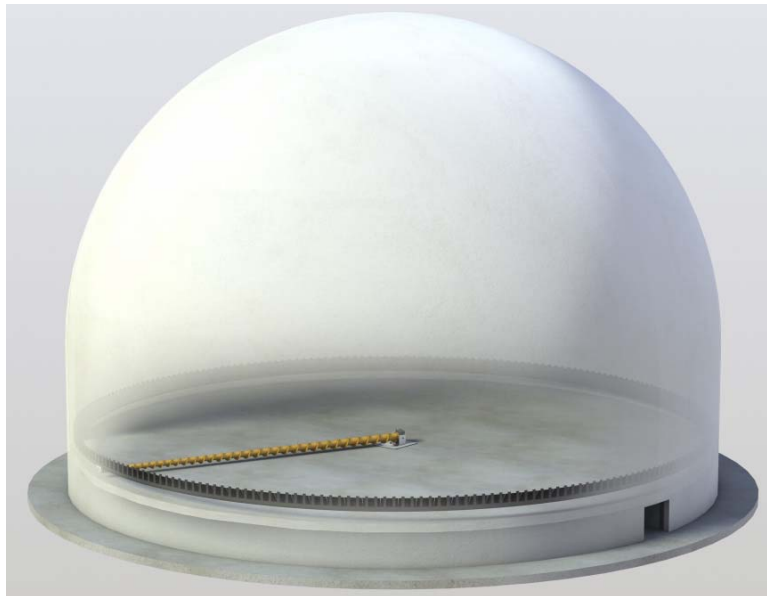


Photo courtesy of Laidig Systems Inc.
(<http://www.laidig.com/index.php?reclaim-systems/concrete-domes.html>)

Figure 4-8
Biomass Storage and Reclaim System

The enclosed storage system that is discussed above was selected based on the fuel properties of the wood pellets. Pellets are very hydrophilic in nature, meaning that they readily absorb moisture. Increased moisture content of the biomass lowers the energy content of the fuel (due to the increased energy required to burn off the moisture), and can result in dry matter loss and fungal formation.

One fuel storage concern with wood pellets was that the collective weight of the biomass pile could potentially crush the wood pellets located at the pile's bottom, creating dust and resulting in greater explosion hazards. A study conducted by Seabra da Rocha at Aachen University in Germany determined that the maximum pressure that could be applied to wood pellets before they begin to crush was approximately 4.0 MPa to 5.6 MPa. The equation used to determine the maximum pressure at the bottom of the pellet pile in the concrete dome storage building is shown below:

$$\text{Pressure} = \text{Height}_{\text{pile}} \times \text{Density}_{\text{pellets}} \times \text{Gravity}$$

$$\text{Pressure} = 29\text{m} \times 750 \frac{\text{kg}}{\text{m}^3} \times 9.81 \frac{\text{m}}{\text{s}^2}$$

$$\text{Pressure} = 0.21 \text{ MPa}$$

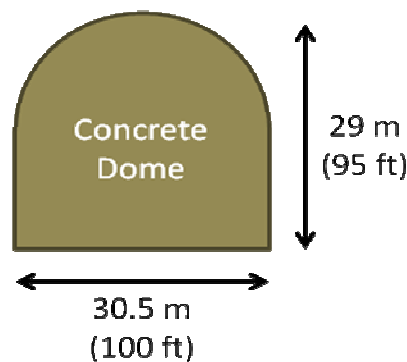


Figure 4-9
Cross Section of Biomass Pile in Storage

Since the pressure at the bottom of the pile is much less than the crushing pressure of the pellets, the facility should not be concerned about dust creation due to collective pressure.

There was also concern regarding the storage and handling of wood pellets. Wood pellets in particular are prone to dust explosions and spontaneous combustion. Information obtained from the Wood Pellet Association of Canada identified the following measures in Table 4-5 that are recommended for safe storage and handling of wood pellets. These measures were incorporated into the site and system design.

Table 4-5
Storage and Handling Safety Measures for Wood Pellets

Storage	Handling
• Silos preferable (instead of A-frame) • Concrete or insulated steel • Reflective or white external surface • Hopper bottom with first-in/first-out flow • Reject material with a high moisture content • Cascade chute/ladder to soften impact • Continuous monitoring for carbon monoxide and temperatures • Prohibit unnecessary access	• Dust collection at transfer points • Spark detection and fire suppression in contained spaces • Explosion venting • Grounding of all equipment in contact with dust material (idlers, vacuum piping) • Eliminate exposure to hot surfaces ($> 225^{\circ}\text{C}$) • Minimize drop heights • Monitor rotating equipment (motors, etc.) and enclose all electrical motors • Conductive belting and liners • Heating of galleries with glycol loops, not electrical radiators

Fuel Processing

The existing boiler house will house the three additional processing lines required by subcase 2b. Each line will be sized with a capacity of 15 tons per hour (for 24 hour per day operation). One of those three lines will not be needed to meet the facility's maximum power production, and as a result will provide redundancy within the system. Each process line will have a mill dedicated to size reduction of pellets to less than 1.5 mm in any dimension. For each processing line, biomass will be drawn through the mill pneumatically, and a baghouse and fan will be used to move the material from the bottom of each mill while ensuring dust control. Processed biomass will drop through a rotary airlock into a blow-line feeding the boiler. The existing coal bunkers will be reused.

Fuel firing

Reclaim from the concrete dome will include two weigh bin feeders. The feeders will provide real-time mass flow measurement of the biomass and will be integrated into the boiler control system. The two feeders will supply biomass to the existing mills and, in subcase 2b, to the new hammer mills.

The layout of the fuel delivery and storage areas is shown in Figure 4-10.

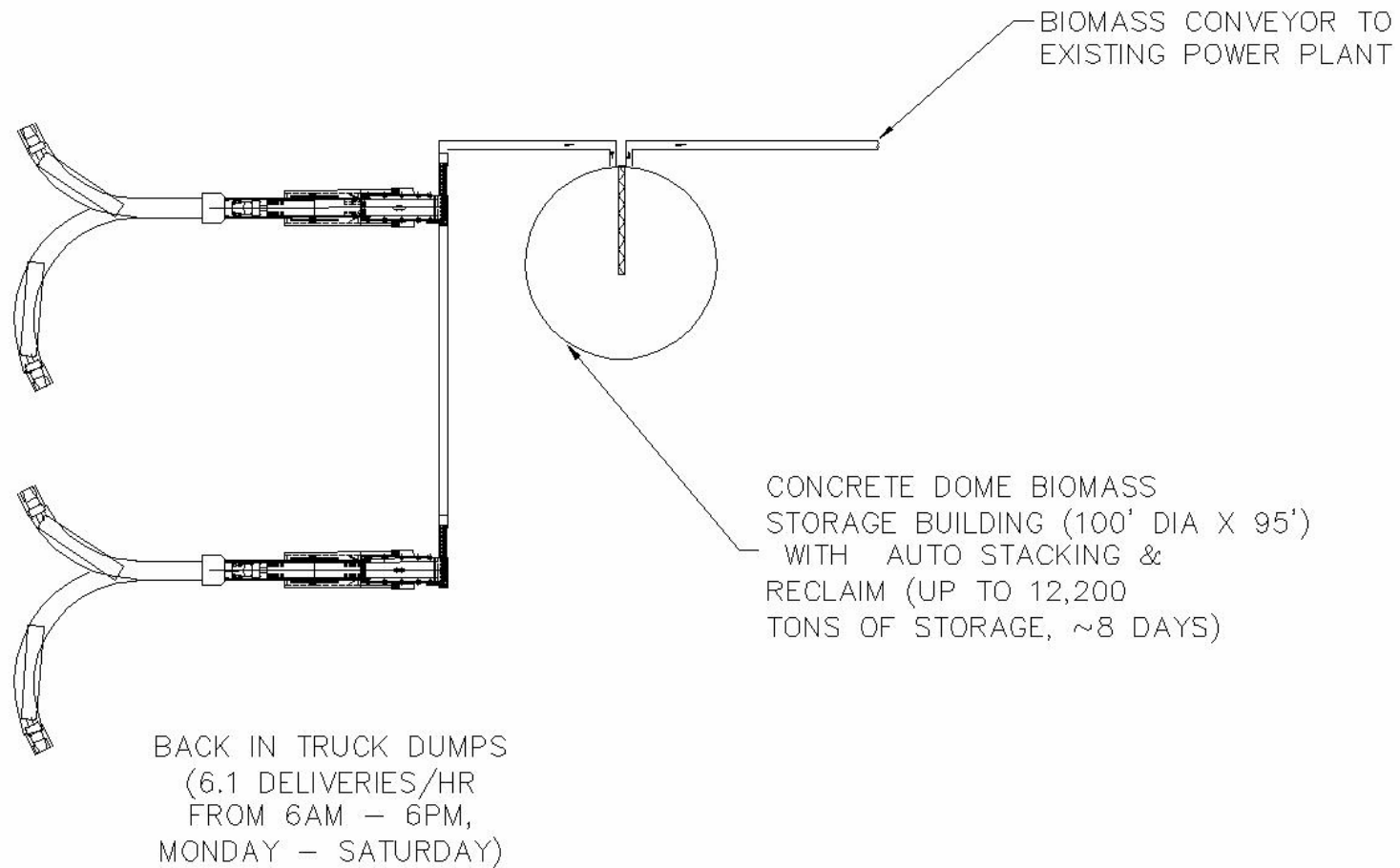


Figure 4-10
Power Plant Layout (Case 2)

Additional Data

A project timeline was estimated for the proposed changes and is shown in Figure 4-11. There is no expectation that the differences between the two subcases examined above will result in materially different timelines, so only one project development range is provided. The Les Awirs repowering project offered some insight into project duration, but the extremely compressed timeframe associated with the project (seven months, including engineering) made it likely an atypical example of such a project, particularly in the United States. Despite the very different scope of the two projects, the BFB retrofit case and this case share many common elements. Additionally, delivery times for the wood handling and processing systems are not expected to vary much from those used in the wood chip cases. Lastly, the authors expect that feasibility and engineering timelines might be extended, at least for the first few projects developed in the United States.

Case 2 - Suspension Firing of Wood Pellets				
Project Timeline Estimate				
Assumes January 1, 2011 Start				
TASKS	Duration (Weeks)		Estimated Completion Date	
	Aggressive Timeline	Conservative Timeline	Aggressive Timeline	Conservative Timeline
1.0 Engineering			11/3/2011	12/29/2011
1.1 Preliminary Engineering	24	32	6/17/2011	8/12/2011
1.2 Final Engineering: Process	12	12	9/9/2011	11/4/2011
1.3 Final Engineering: Structural	12	12	11/3/2011	12/29/2011
2.0 Permitting/Procurement			1/24/2013	11/28/2013
2.1 Air Re-permitting	24	52	12/2/2011	8/10/2012
2.2 Discharge Permits	16	24	10/7/2011	1/27/2012
2.3 Procure Long-Lead Items (Fuel Yard)	60	68	1/24/2013	11/28/2013
3.0 Construction and Installation			1/17/2013	12/19/2013
3.1 Civil Site Work/Construction Preparation	16	16	2/13/2013	12/18/2013
3.2 Equipment/Buildings/Structures	12	12	1/17/2013	11/21/2013
3.3 Mechanical, Electrical, Balance of Plant, and Finish Work	8	12	1/17/2013	12/19/2013
4.0 Testing and Commissioning			5/23/2013	5/22/2014
4.1 Initial Start-up Testing	12	16	4/11/2013	4/10/2014
4.2 Emissions Testing	4	4	5/9/2013	5/8/2014
4.3 Training	4	4	5/9/2013	5/8/2014
4.4 Substantial Completion and Acceptance	2	2	5/23/2013	5/22/2014
Total Months			28	40

Figure 4-11
Estimated Project Schedule for Case 2

Case 3 – Suspension firing of torrefied wood pellets

Boiler Plant Performance

This case represents a natural evolution of the wood pellet scenario. In many ways, torrefied wood pellets hold the hope of being the ultimate designer fuel for switching from coal to biomass. This fuel offers the promise of minimizing (or even eliminating) the capital investment required to make the switch, and the fuel has recently attracted considerable attention. However, there are as yet no commercial examples of projects utilizing this fuel, and currently there is not even sufficient capacity to produce this fuel for significant testing.

As TWPs are similar in heating value, ash content, and ash composition to Powder River Basin (PRB) coal, some corollaries may be drawn between coal plants that have converted from bituminous to PRB fuels and the potential use of TWPs. Fortunately, a significant quantity of literature is available regarding PRB conversions, including the following key findings (Exothermic Engineering, 2009; Hunt, 2006):

- Modifications to existing pulverizers and additional pulverizing capacity were often required due to the decreased heating density of the fuel.
- Convective passes of the boiler were sometimes re-spaced in order to prevent excessive ash deposition.
- Frequent and thorough furnace cleaning was generally necessary due to a high slagging potential and changes in fly ash composition (and thus reflectivity). Waterlances were often necessary, depending on the ash loading and composition.
- Dust collection was usually enhanced and anti-explosion measures taken due to the high-dust nature of the fuel. Mill outlet temperatures were reduced.

Although torrefied wood will not behave exactly as a low-heating value coal (due to the likely high-carbon nature of its ash and the high-volatiles nature of the fuel), all of the strategies listed above are conservatively adopted for this scenario except for the convective pass re-spacing.

Also available were a number of studies on the grindability of torrefied wood. Torrefied wood appears to require significantly less grinding energy than untreated pellets (Arias et al. 2006), but most testing has been done in knife mills, rotary mills, or attrition mills rather than in the ball or roller mills traditionally used in coal applications. When such tests were performed, the HGI was determined to be only 30 for TWPs, compared to a coal value of approximately 50 (*Ibid.*).²³ However, the relative success of ball-race and roller-race mills with untreated wood pellets, which have an HGI of only 17 (*Ibid.*), casts doubt on the usefulness of the HGI as an indication of the compatibility of a pulverizer with pellet fuels. The increased brittleness, decreased fibrousness, and increased energy density of torrefied wood in comparison with untreated wood make it likely that torrefied wood would at least be more compatible with the existing pulverizers.

There is a marked absence of published data regarding torrefied pellets in coal pulverizers. The only data available appears to be from a 2009 test burn at the James River generating station, which co-milled and cofired a 20% (mass basis) fraction of torrefied biomass chips with sub-bituminous coal. The James test indicated a build-up of fibrous material (particles that did not appear to have been torrefied and that were larger than most of the particles in the as-received mixture) in the facility's bowl mills, leading them to decrease the cofiring percentage to 20% from 25%. The researchers noted that the fuel appeared "good, but not perfect" in consistency, and suggested that a more fully torrefied, consistent fuel would be key to steady operation of the mills and boiler (City of Springfield Utilities, 2009).

²³ The grindability value is taken at what researchers deemed to be the optimum torrefaction time, a compromise between torrefaction energy losses and enhanced grindability.

Calls to two major milling and particle size reduction companies revealed interest in torrefied wood, but a lack of practical experience with torrefied wood pellets, due in large part to the difficulty of obtaining large enough quantities of torrefied pellets to perform pilot-scale milling studies. In the absence of any data on the performance of existing mills with torrefied pellets, it will be assumed here that the grinding energy exhibited by knife mills will be similar to that exhibited by the existing coal pulverizers processing torrefied wood. The pulverizer capacity will be assumed to be equal on a mass flow basis to operation with the bituminous design coal.

Particle size again had to be considered in relation to particle burnout time. According to the particle size-burnout time correlation in Saastamoinen (2010), assuming that torrefied wood behaves similarly to coal adjusted linearly for density, a 190 μ m particle size would be required to achieve the same burnout time as the original 50 μ m coal particles. It is unclear what constituent particle size distribution could be expected of torrefied wood pellets, as they are not a commonly available or standardized material. For this reason, the pellets have been approximated as having the same particle size distribution as un-torrefied wood pellets, and are assumed to be ground to a 190 μ m average particle size in the existing coal pulverizers.

As in the wood pellets scenario, two subcases are considered for torrefied wood pellet repowering. In minimum-capital subcase 3.1, torrefied pellets will be fired only as the capacity of the existing mills permits, leaving the flue gas train at less than maximum capacity. In maximum-capacity subcase 3.2, capital will be invested in additional hammer mills to increase that milling capacity to reach the flue gas train flow rates of the existing coal operation.

Specifications

In order to adapt the coal heat and mass balance model to firing of pulverized torrefied wood pellets, the following changes were made:

- Re-specification of the pulverizer component to consume 39 kWh per ton, based on a grindability index published by Bergman (2005). Outlet temperature is reduced to 135°F.
- In subcase 3.1, reduction in primary steam flow to 704,000 pph, at which steam flow rate the existing mills reach maximum capacity on a mass flow rate basis.
- In subcase 3.2, reduction in primary steam flow to 885,000 pph, at which steam flow rate the flue gas train volumetric flow rates remain approximately equal to those in the full load coal case. This ensures that no fan replacements, air heater modifications, or pollution control modifications will be necessary due to higher flue gas velocities.
- Reduction in steam outlet temperature from 1000°F to 950°F in an effort to prevent boiler corrosion or fouling due to halides and ash slagging, respectively. The relatively low moisture content of the pellets and the suspension rather than BFB arrangement of the boiler mean that the furnace exit temperatures will be higher than in the wood chips case, leading to a higher likelihood of halide corrosion.
- Reheater and superheater steam outlet temperatures will be controlled using desuperheating flows.
- Increase in excess air rate to 20%, based on that required for PRB coal.

- Change in fuel from the design coal to the torrefied wood pellets discussed in the previous section.
- Fuel yard parasitic load of 10 kWh/ton. This was based on a previous repowering study performed for EPRI, in which a largely automated fuel yard was specified for wood chip handling (EPRI 2010b).

The heat and mass balances for these cases are summarized in Table 4-6 below and compared to the base coal case. The details of the modeling of these cases can be found in Appendix C.

Table 4-6
Estimated Performance of Case 3

Parameter	Unit	Design Coal	Case 3.1: Torrefied Pellets, Mill Limited	Case 3.2: Torrefied Pellets, Flue Limited
Boiler efficiency, HHV	%	88.2%	87.4%	86.4%
Electrical efficiency, net, HHV	%	36.4%	33.9%	34.1%
Primary steam flow	kpph	900	704	893
Reheat steam flow	kpph	794	626	788
Coal flow	kpph	109	n/a	n/a
Coal flow, HHV	MMBtu/hr	1,271	n/a	n/a
Biomass fuel flow	kpph	n/a	109	135
Biomass fuel flow	MMBtu/hr	n/a	1,037	1,290
Flue gas flow	kpph	1,293	989	1,232
Flue gas flow	cfs	6,660	5,195	6,717
Fly ash collected	kpph	12	0.6	0.7
Preheated air flow	kpph	1,199	643	814
Air rate	lb-air/kBtu	0.943	0.62	0.631
Excess air	%	15	20	20
Air heater exit temp., air-side	degrees F	568	545	590
Stack temperature	degrees F	292	298	325
Primary outlet steam temperature	degrees F	1,000	977	1,000
Reheat outlet steam temperature	degrees F	1,000	1,016	987
Adiabatic flame temperature	degrees F	3,630	3,637	3,659
Gross electrical generation	kW	143,948	113,373	140,773
Non-pulverizer parasitics	kW	7,646	7,906	8,595
Estimated pulverizer parasitic load	kW	1,177	2,126	2,645
Conveyors and fuel yard parasitics	kW	1,091	504	627
Net electrical generation	kW	134,034	102,837	128,907
Particle size	mm	0.0500	0.190	0.19
Particle size	in	0.00197	0.00748	0.01
Unburned carbon	% entering	1	1	1
Unburned carbon	ash LOI, %	5.46	42.97	42.97

Fuel Delivery and Storage

The torrefaction process that is applied to the biomass prior to manufacturing the torrefied pellets makes the pellets hydrophobic in nature, meaning that they repel moisture. For this reason, either a covered or an uncovered storage area could be selected for storing torrefied pellets. The site layouts presented in the following cases (3a – 3c) show three different storage options: a concrete dome storage area, an open circular storage area, and a covered rectangular storage area. Fuel is also assumed to arrive by truck. Upon entering the plant, the fuel will be weighed and unloaded, but the details of the handling will vary somewhat depending upon the storage employed for each case.

Case 3a

After the biomass has been unloaded from the trucks, it will be conveyed up an incline to a concrete dome storage area. The fuel storage facility will then stack and reclaim biomass for further processing as it is needed. A reclaim system similar to the one seen in Figure 4-8 and described for Case 2 was selected for this subcase. It is the most capital intensive, but also the most protective. Based on expectations for torrefied wood pellets, it should represent the most conservative case with respect to capital invested in handling and storage.

Biomass deliveries were assumed to occur between the hours of 6 a.m. and 6 p.m. from Monday through Saturday; no deliveries were assumed to occur on Sunday. The power plant will need 6.3 truck deliveries every hour to meet fuel supply requirements.

Case 3b

This case assumes a reclaim system similar to the one shown in Figure 4-5. This system uses an overhead conveyor to reclaim the biomass. Based on the bulk density of the torrefied wood pellets, it was determined that a 260 ft diameter storage/reclaimer area would be required for seven days of fuel supply storage (11,400 tons). This is a more optimistic fuel handling and storage case for the torrefied wood pellets, as it assumes that this material can be stored safely outside in piles. Although short of the ideal objective (i.e., complete re-use of the original coal handling yard), it does represent a lower cost, higher capacity option than case 3a. To account for this being the most optimistic case, an economic sensitivity analysis is performed that assumes that the torrefied wood can be used without any capital investment at the plant. The fuel delivery schedule described above is assumed to remain the same.

Case 3c

This case represents a compromise between the two cases above. After the biomass has been unloaded from the trucks, it will be conveyed up an incline to a covered storage area similar to the one shown in Figure 4-12. This system uses an overhead conveyor to reclaim the biomass. Based on the bulk density of the wood chips, it was determined that three 320 ft. by 100 ft. rectangular buildings would be required for seven days of fuel supply storage (11,400 tons). The delivery schedule would again remain the same.



Photo courtesy of Basic Machinery Co.
(<http://www.basicmachinery.com/reclaimers.html>)

Figure 4-12
Biomass Storage and Reclaim System

Fuel Processing (all cases)

Two different fuel processing subcases were developed for the 3a scenarios to support different firing configurations (see Fuel Firing below). The existing boiler house will house the two additional processing lines specifically required by subcase 3a.2 (flue gas limited). Each line will be sized with a capacity of 15 tons per hour (for 24 hour per day operation). One of those two lines will not be needed to meet the facility's maximum power production, and as a result will provide redundancy within the system. Each process line will have a mill dedicated to size reduction of pellets to less than 1.5 mm in any dimension.

For each processing line, biomass will be drawn through the mill pneumatically, and a baghouse and fan will be used to move the material from the bottom of each mill while ensuring dust control. Processed biomass will drop through a rotary airlock into a blow-line feeding the boiler. The existing coal bunkers will be reused.

Fuel Firing

Fuel is fired at one of two rates depending upon the subcase. For subcases 3a.1, 3b, and 3c (the letter designations correspond to the fuel yard configurations noted above), firing is limited to the mass flow that can be accommodated by the existing pulverizers. However, to ensure maximum usage of the boiler capacity, subcase 3a.2 also implements additional milling capacity and separate injection of additional fuel. The limit on this case is flue gas volume flow rates. Layouts for the fuel receiving, processing and handling systems for all subcases are provided in Figure 4-13, Figure 4-14, and Figure 4-15 below.

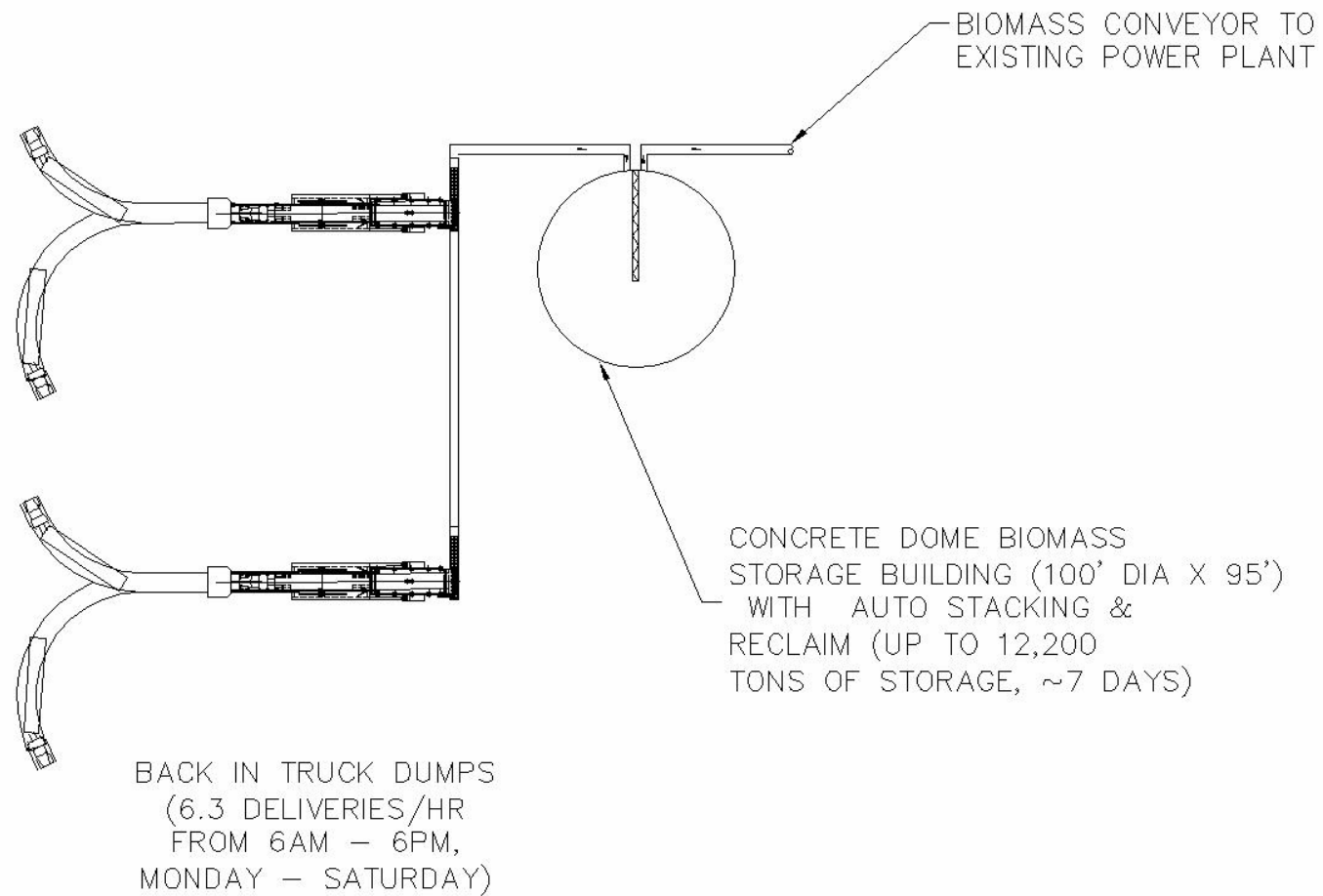


Figure 4-13
Power Plant Layout (Case 3a)

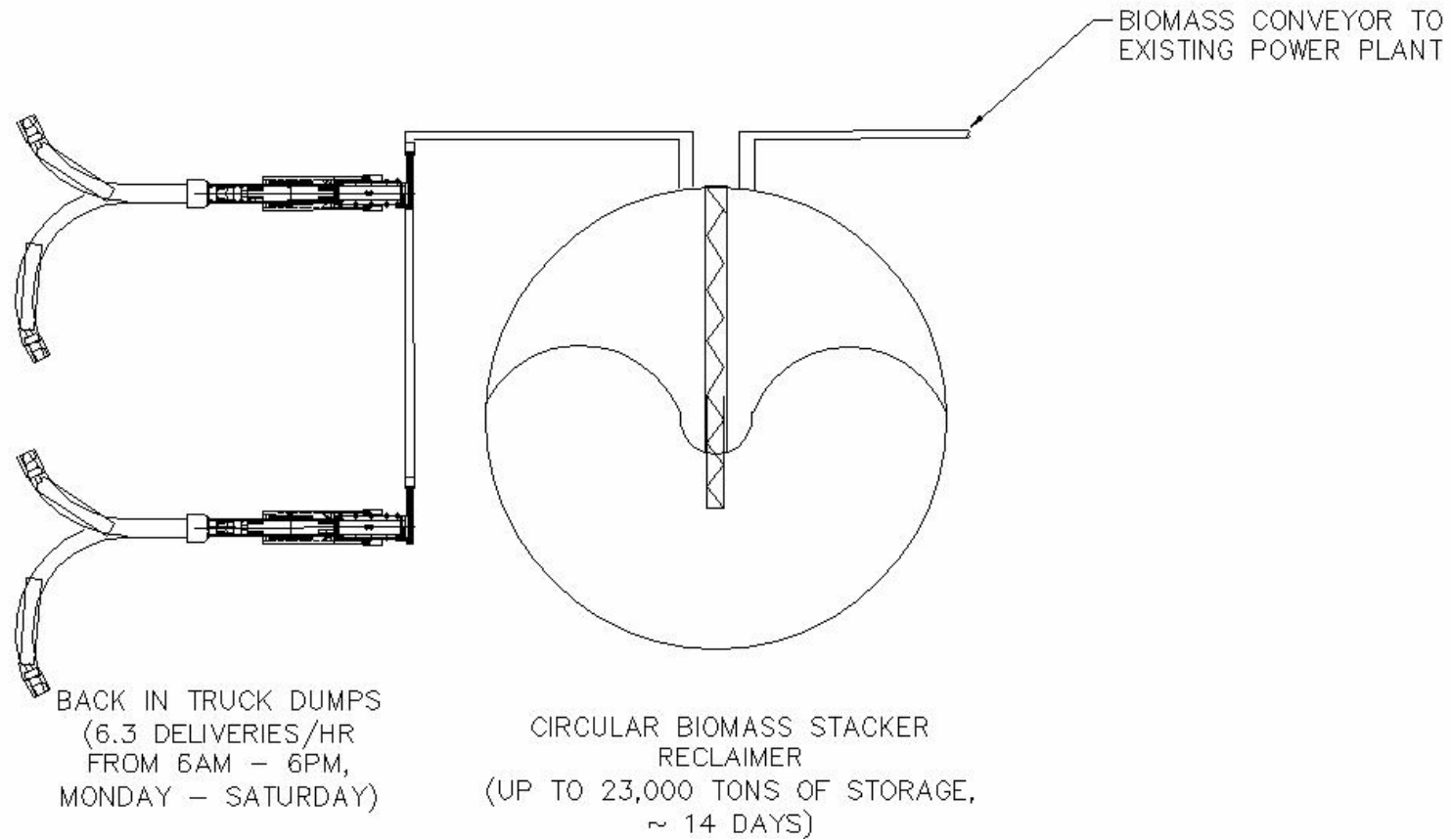


Figure 4-14
Power Plant Layout (Case 3b)

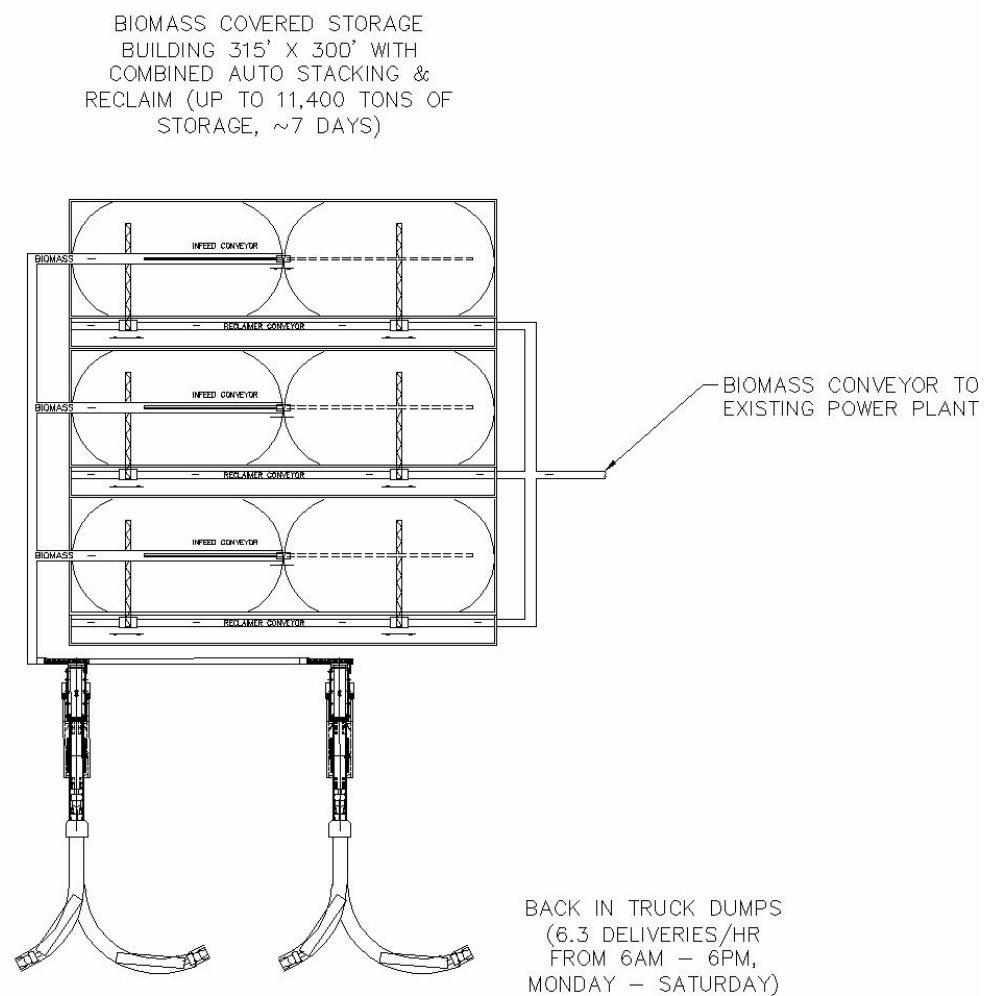


Figure 4-15
Power Plant Layout (Case 3c)

Additional Data

A project timeline was estimated for the proposed changes and is shown in Figure 4-16. As no utility-scale torrefied wood repowering project has yet been undertaken, the project's duration had to be estimated based on the timeline data used to develop the wood pellet cases previously, and the reader should note the similarity.

However, it is the most optimistic case (i.e., having no plant investment required to use torrefied wood pellets) that is the most interesting. This circumstance is not reflected in the project timeline table below. As noted in the prior cases, equipment procurement is a critical process and includes long-lead items in the project timelines presented. By avoiding such procurements and at least some engineering, however, it is conceivable that the timelines shown could be halved or even further lessened. This has a variety of benefits, not the least of which are cost and the flexibility to bring a large-scale biomass project online quickly to react more effectively in an uncertain regulatory environment.

Case 3 - Suspension Firing of Torrefied Wood Pellets Project Timeline Estimate Assumes January 1, 2011 Start				
TASKS	Duration (Weeks)		Estimated Completion Date	
	Aggressive Timeline	Conservative Timeline	Aggressive Timeline	Conservative Timeline
1.0 Engineering			11/3/2011	12/29/2011
1.1 Preliminary Engineering	24	32	6/17/2011	8/12/2011
1.2 Final Engineering: Process	12	12	9/9/2011	11/4/2011
1.3 Final Engineering: Structural	12	12	11/3/2011	12/29/2011
2.0 Permitting/Procurement			1/24/2013	11/28/2013
2.1 Air Re-permitting	24	52	12/2/2011	8/10/2012
2.2 Discharge Permits	16	24	10/7/2011	1/27/2012
2.3 Procure Long-Lead Items (Fuel Yard)	60	68	1/24/2013	11/28/2013
3.0 Construction and Installation			1/17/2013	12/19/2013
3.1 Civil Site Work/Construction Preparation	16	16	2/13/2013	12/18/2013
3.2 Equipment/Buildings/Structures	12	12	1/17/2013	11/21/2013
3.3 Mechanical, Electrical, Balance of Plant, and Finish Work	8	12	1/17/2013	12/19/2013
4.0 Testing and Commissioning			5/23/2013	5/22/2014
4.1 Initial Start-up Testing	12	16	4/11/2013	4/10/2014
4.2 Emissions Testing	4	4	5/9/2013	5/8/2014
4.3 Training	4	4	5/9/2013	5/8/2014
4.4 Substantial Completion and Acceptance	2	2	5/23/2013	5/22/2014
Total Months			28	40

Figure 4-16
Estimated Project Schedule for Case 3

Case 4 – Cofiring of biomass-derived syngas with pulverized coal

Boiler Plant Performance

As with case 1, this option requires a substantial capital investment, but it facilitates the use of minimal-cost biomass fuel. As noted in the previous chapter, there are a few commercial examples of cofiring biomass syngas in boilers. Therefore, although it represents a technologically advanced application, it does have the virtue of having already been tried at

utility-scale, and significant, relevant experience has been gained in smaller industrial applications, where similar (though slightly different) concepts have been employed.

For this case, a 400 MMBtu/hr Frontline air-blown gasifier with a fuel dryer is coupled to the existing boiler. The gasifier operates at full load, with the remainder of the required heat input supplied with coal. In a prior study, Frontline provided basic performance data that has been used to specify the gasification island components.

Specifications

In order to adapt the coal heat and mass balance model to co-firing of syngas, the following changes were made:²⁴

- Addition of the following gasification island components:
 - secondary fuel source,
 - fuel dryer,
 - gasifier,
 - syngas cooler, and
 - pressure-reducing valve (PRV).
- Excess air of 15% for coal firing and 20% for syngas firing. Again, this is not intended to imply that the materials are combusted separately, but rather to simulate an overall excess air rate of about 17-18%.
- The biomass fuel specification is based on green wood chips with a moisture content of 45%. This material has an as-received HHV of 4,730 Btu/lb (LHV of 3,974 Btu/lb) and an ash content of 0.83%. The heating value for oven-dry wood chips is 8,600 Btu/lb.
- The fuel exiting the fuel dryer is assumed to contain 15% moisture.
- Gasifier produces 400 MMBtu/hr of syngas at full load. The gasifier operates at 70 psia and 1500°F and requires air in a 25% of stoichiometric ratio with dried biomass fuel, by mass.
- Syngas composition exiting the gasifier is approximately 18.8% CO, 12.3% H₂, 4.1% CH₄, 1.0% C₂H₄, 11.2% CO₂, 14.6% H₂O, 0.45% Ar, and 37.0% N₂ on a wet volumetric basis.
- The syngas cooler transfers heat from the syngas to the air flow to the gasifier and the fuel dryer, cooling the syngas to 700°F. (This is equivalent to the two gas/air heat exchangers specified by Frontline.)
- A second syngas cooler is used to reduce the temperature of the syngas feed to the boiler to 275°F. This heat is used to preheat feedwater to the boiler. (This secondary heat exchanger is not specified by Frontline, but was added in order to prevent excessive boiler temperatures and poor heat exchange in the existing boiler.)

²⁴ A combustor was added into the model to better simulate system performance.

- Multiclone particulate removal from the syngas is simulated by a pressure drop (assumed to be 0.105 psi).
- Gasifier injection air is assumed to be preheated using the syngas exit stream from the gasifier.
- The feedwater temperature leaving the economizer is 450°F, based on the expected temperature rise during full load coal operation. After the economizer, additional heat transfer from the flue gas stream occurs in the rotary air heater and the electrostatic precipitator.
- Reduction in primary steam flow to 606,000 pph, at which steam flow rate the flue gas train volumetric flow rates remain approximately equal to those in the full-load coal case. This ensures that no fan replacements, air heater modifications, or pollution control modifications will be necessary due to higher flue gas velocities.
- Reheater and superheater steam outlet temperatures will be controlled using desuperheating flows.
- Fuel yard parasitic loads of 20 kWh/ton coal and 10 kWh/ton wood chips.

The off-design system was converged with the changes above in order to estimate net electrical generation and fuel consumption at this part-load turbine condition.

Table 4-7 below presents some of the key performance parameters in comparison to the same parameters calculated or measured for the design coal case. Details of the heat and mass balance modeling for this scenario are presented in Appendix C.

Table 4-7
Estimated Performance of Case 4

Parameter	Unit	Design Coal	Case 4: Existing Boiler with Syngas Cofiring
Boiler efficiency, HHV	%	88.2%	83.9%
Electrical efficiency, net, HHV	%	36.4%	29.4%
Primary steam flow	kpph	900	613
Reheat steam flow	kpph	794	543
Coal flow	kpph	109	47
Coal flow, HHV	MMBtu/hr	1,271	549
Biomass fuel flow	kpph	n/a	99
Biomass fuel flow	MMBtu/hr	n/a	440
Flue gas flow	kpph	1,293	1,190
Flue gas flow	cfs	6,660	6,722
Fly ash collected	kpph	12	5.6
Preheated air flow	kpph	1,199	883
Air rate	lb-air/kBtu	0.943	0.89
Excess air	%	15	15-20
Air heater exit temp., air-side	degrees F	568	569
Stack temperature	degrees F	292	347
Primary outlet steam temperature	degrees F	1,000	1,000
Reheat outlet steam temperature	degrees F	1,000	1,045
Adiabatic flame temperature	degrees F	3,630	3,082
Gross electrical generation	kW	143,948	99,481
Non-pulverizer parasitics	kW	7,646	12,980
Estimated pulverizer parasitic load	kW	1,177	471
Conveyors and fuel yard parasitics	kW	1,091	932
Net electrical generation	kW	134,034	85,097
Particle size	mm	0.0500	0.0500
Particle size	in	0.00197	0.00197
Unburned carbon	% entering	1	1
Unburned carbon	ash LOI, %	5.46	5.46

Fuel Delivery and Storage

The delivery and storage systems for this case are similar to those specified for case 1, as the fuel feeding requirements for both cases are very similar. The only difference is that only eight truck deliveries would be required per hour from 6 a.m. to 6 p.m. Monday through Saturday. The reader is referred to the prior discussion for more specific details.

Fuel Processing

The wood chips will not need processing in mills. As a result, after they are reclaimed they will be fed directly into one of four silos, which are designed to hold up to 12 hours of biomass (1,000 tons) prior to gasification. As they are needed, the wood chips will be conveyed to the gasifier where they will be converted into a low-Btu gas, which is then piped to the existing boiler for combustion. Figure 4-17 shows the proposed layout for this case.

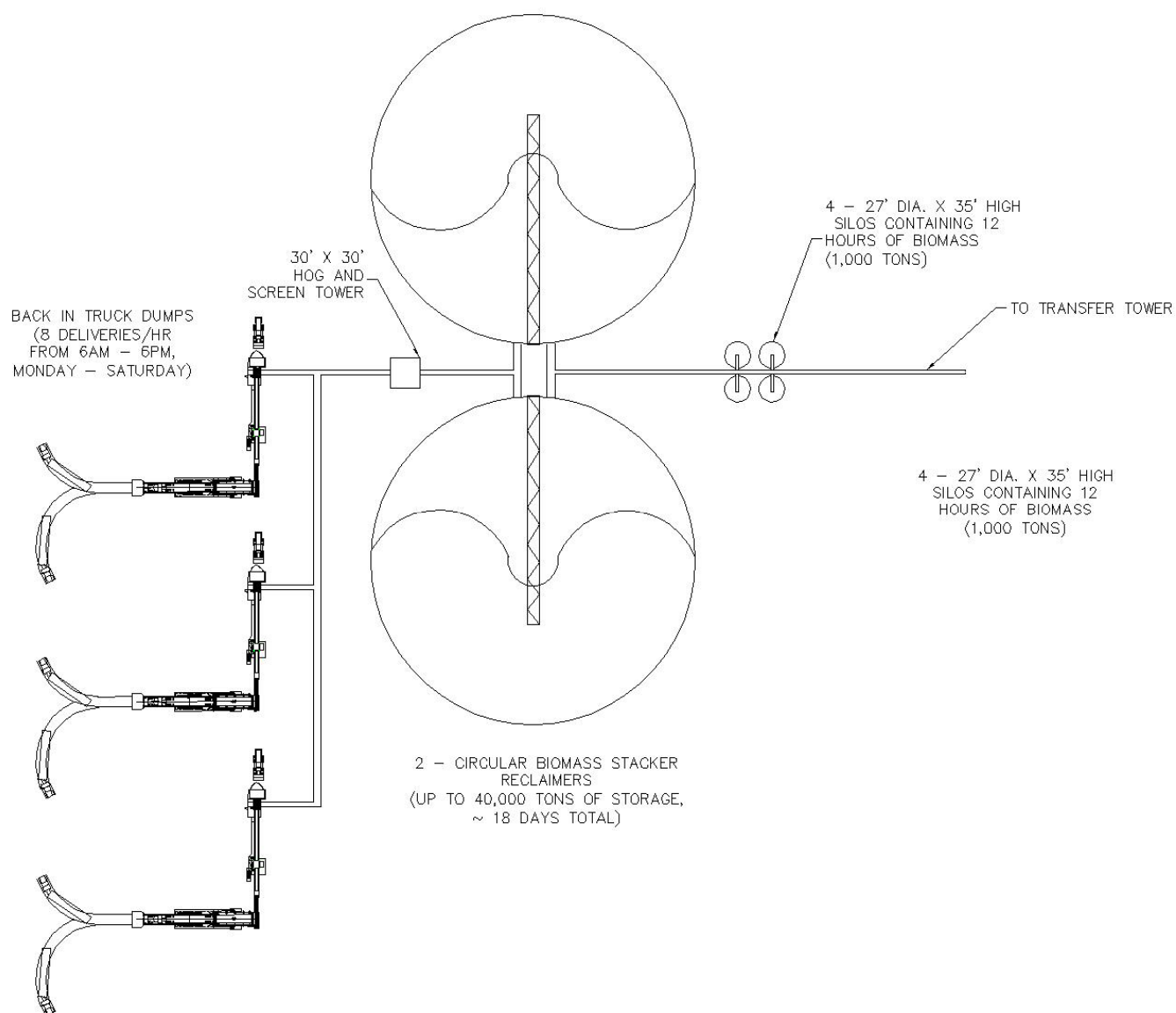


Figure 4-17
Power Plant Layout (Case 4)

Additional Data

A project timeline was estimated for the proposed changes and is shown in Figure 4-18. The project's duration was estimated based on the timeline data available for the Amer 9 and Lahti projects, as well as for Repotec's Güssing gasification cogeneration plant and CVEC's stand-alone gasifier (discussed previously in Chapter 2). Amer 9's construction began in October 1998, and the plant finished its commissioning and began operation in December 2002. Construction was completed during the first half of 2000, but system modifications to remedy severe syngas cooler fouling required almost two additional years (Willeboer, 2000). This 50+ month project compares well to the 51 month conservative timeline presented below. The Lahti project was constructed in 1997 and began commercial operation in 1998, in a timeline more similar to the aggressive schedule shown below (Palonen, 2005). Plant Schiller's retrofit to CFB firing of biomass was also used as a reference point, due to its similar size and the fact that it was a retrofit rather than greenfield construction.

Case 4 - Co-firing of Biomass-derived Syngas Project Timeline Estimate Assumes January 1, 2011 Start				
TASKS	Duration (Weeks)		Estimated Completion Date	
	Aggressive Timeline	Conservative Timeline	Aggressive Timeline	Conservative Timeline
1.0 Engineering			11/17/2011	3/22/2012
1.1 Preliminary Engineering	32	40	8/12/2011	10/7/2011
1.2 Final Engineering: Process	12	16	11/4/2011	1/27/2012
1.3 Final Engineering: Structural	6	12	11/17/2011	3/22/2012
2.0 Permitting/Procurement			4/25/2013	4/3/2014
2.1 Air Re-permitting	24	52	1/27/2012	10/5/2012
2.2 Discharge Permits	16	20	12/2/2011	2/24/2012
2.3 Procure Long-Lead Items (Fuel Yard, Gasifier)	65	78	4/25/2013	4/3/2014
3.0 Construction and Installation			8/8/2013	11/6/2014
3.1 Civil Site Work/Construction Preparation	16	20	5/15/2013	4/23/2014
3.2 Equipment/Buildings/Structures	24	36	7/11/2013	9/11/2014
3.3 Mechanical, Electrical, Balance of Plant, and Finish Work	12	16	8/8/2013	11/6/2014
4.0 Testing and Commissioning			12/12/2013	4/9/2015
4.1 Initial Start-up Testing	12	16	10/31/2013	2/26/2015
4.2 Emissions Testing	4	4	11/28/2013	3/26/2015
4.3 Training	4	4	11/28/2013	3/26/2015
4.4 Substantial Completion and Acceptance	2	2	12/12/2013	4/9/2015
Total Months			35	51

Figure 4-18
Estimated Project Schedule for Case 4

Comparative Analysis: Key Economic Decision Factors and Industry Viewpoint

This section of the report offers some comparative analysis of the technologies reviewed. Although an economic analysis is provided in Chapter 5, it is useful to examine the data presented thus far in a more strategic light. The performance of the four cases with the base case, key state points, mass flows, and efficiencies resulting from the performance modeling are tabulated in Table 4-8 below.

Table 4-8
Performance Comparison for Repowering Technologies

Parameter	Unit	Design Coal	1 BFB: Wood Chips	2a Existing Boiler: Wood Pellets, Mill Limited	2b Existing Boiler: Wood Pellets, 115% of Flue Capacity	3a.1 Existing Boiler: Torrefied Pellets, Mill Limited	3b.1 Existing Boiler: Torrefied Pellets, Flue Limited	4 Existing Boiler: Syngas Cofiring
Electrical efficiency, net, HHV	%	36.4%	27.4%	31.4%	31.5%	33.9%	34.1%	29.4%
Coal flow	kpph	109	n/a	n/a	n/a	n/a	n/a	47
Biomass flow	kpph	n/a	234	105	151	109	135	99
Gross electrical generation*	kW	143,948	93,415	91,320	129,984	113,373	140,773	99,481
Net electrical generation*	kW	134,034	82,365	81,845	117,653	102,837	128,907	85,097
Fly ash LOI	%	5.46	12.2	55.77	55.77	42.97	42.97	5.46

*Case 4 includes firing coal and biomass, and electrical generation values include power produced from both fuels.

The results indicated that the most severe boiler derate was experienced in the case of the BFB retrofit, primarily because of high excess air rates and large flue gas volumes. This case also had the most severe efficiency loss, which was impacted by the use of fuel with a high moisture content and a high unburned combustibles rate. Torrefied wood pellet repowering, in contrast, demonstrated a relatively minor derate due to the high energy density and low moisture content of the fuel. Wood pellets and syngas co-firing exhibited similar derates, again due to flue gas volume limitations.

Emissions Performance

The switch from coal to biomass firing has both positive and negative consequences for the plant's emissions profile. Some, like SO₂ emissions, are easily predicted. Others are more variable. NO_x emissions in particular are influenced by a whole host of furnace combustion variables, and can only be predicted by detailed combustion modeling, which will narrow (but not eliminate) the potential range of expected emission rates for a specific boiler configuration.

During combustion, nitrogen oxides form within the immediate vicinity of the flame zone by oxidation of both atmospheric nitrogen and any nitrogen contained in the fuel, generating "thermal NO_x" and "fuel NO_x". Limiting the amount of oxygen available to the fuel can control both thermal NO_x and fuel NO_x. This is typically achieved in the furnace by two techniques: (1) staging the combustion air, and (2) balancing the amount of excess air available to the fuel to achieve efficient burnout of the biomass particles (while limiting the CO emissions to reasonable levels). Further, post-combustion NO_x emissions reduction can be achieved by the use of SNCR and SCR technologies. Since catalyst life has been an issue for biomass combustion, SNCR would be the more favorable post-combustion control technique.

The BFB boiler provides good mixing in the fluidized bed, which acts as a mixing device. BFBs will typically achieve slightly lower CO and VOC emissions than equivalently sized stokers.

Particulate emission control in combustion is dependent upon good mixing of air and fuel to achieve complete combustion, and, like CO and VOCs, can be moderated by overfire air. A properly designed overfire air system will further oxidize the charred biomass particles to improve burnout. In some BFB retrofit cases (however, not for the case studied in this report), a mechanical (cyclone or tubular) dust collector may be required downstream of the economizer outlet to minimize the particulate flow of larger particles to the air heater, since the combustible particles in the flue gas stream may ignite if they accumulate in the air heater. Typical performance for a tubular dust collector for the application discussed in this report may be on the order of 90-95% of the particulate (fly ash) flow from the boiler. An electrostatic precipitator downstream of the air heater would achieve further particulate emission reduction if required.

One of the direct benefits of switching to biomass fuels is the low sulfur content of these fuels (less than 0.1 % on a dry weight basis for most species). SO₂ emissions are directly related to the fuel's sulfur content. Typically 90 to 95% of the fuel's sulfur will be converted to sulfur dioxide during combustion. For the BFB conversion, in-bed sorbents can be used for SO₂ control. For the 100% biomass conversion cases, in-bed and post-combustion controls are not required to meet current federal emission limits. High percentage cofiring will reduce but not eliminate the SO₂ emissions from the cofired coal and, depending upon the plant's air permit (for the converted

facility), the plant may need additional controls. Reference air emissions for biomass BFB boilers and for biomass stoker boilers are shown in Table 4-9 and Table 4-10, respectively, based on both permit limits and actual operating data.

Table 4-9
Reference Emissions for Biomass Fluid Bed Operation

Criteria	Plant Schiller New Boiler (SR5)		Greenville Steam Station, Greenville, ME	
	Permit Limit	Actual	Permit Limit	Actual (Projected)
NO _x	0.075 lb/MMBtu (24 hour avg) 236.5 tons per year	0.07 lb/MMBtu 151.2 tons per year	0.3 lb/MMBtu (30 day avg) 218.6 tons/yr	0.10 lb/MMBtu (pending verification)
SO ₂	0.12 lb/MMBtu while firing Coal 0.02 lb/MMBtu while firing Wood	0.0005 lb/MMBtu 1.2 tons per year	71.2 lb/hr 45.4 tons/yr	0.035 lb/MMBtu
PM	0.025 lb/MMBtu 0.01 lb/MMBtu (24 hour average)	Not available	.03 lb/MMBtu 8.1 lb/hr	0.03 lb/MMBtu
PM10	0.025 lb/MMBtu 0.01 lb/MMBtu (24 hour average)	Not available	8.1 lb/hr	Not Available
Opacity	10% (1 hour avg) 20% (continuous 6 minute period)	Not available	<20% (6 minute average) <27% (1 - 6 min block per hr)	Not Available
CO	0.10 lb/MMBtu (24 hour avg) 315.4 tons (12 month period)	Not available	0.65 lb/MMBtu (6/1 to 11/30) 949.1 tons/yr	0.16 lb/MMBtu
VOCs	0.005 lb/MMBtu (24 hour avg) 15.8 tons (12 month period)	Not available	23.6 lb/hr	0.035 lb/MMBtu
Permit Date	October 2004; Reissued March 2007		August 7, 2003 (Expires August 7, 2008)	
Boiler Type	Wood Fired Fluidized Bed (Unit #5)		Bubbling Fluidized Bed (Converted from wood-fired vibrating grate stoker in 2006)	
Plant / Boiler Size	50 MW (Unit #5 only)		19 MW (revised from 16 MW on 4/24/06 after conversion to BFB)	
Fuel Input	720 MMBTU/hr gross heat input (76.5 tons/hr) while firing wood; or 635 MMBTU/hr gross heat input (23.3 tons/hr) while firing bituminous coal	4,638,316 MMBtu/year	300 MMBtu/hr heat input to Boiler; max of 98.7 MMBtu/hr of #2 oil (and 30,000 gallons/yr)	Increased capacity from 271 MMBtu/hr to 300 MMBtu/hr by converting to BFB.
Emission Control Devices	SNCR, limestone injection system for use during coal operation, fabric filter for particulate matter		Multicyclone, ESP, Overfire Air and "Good Combustion Control" for CO & VOCs, SNCR for NOx	

Table 4-10
Reference Emissions for Biomass Stoker Operation

Criteria	McNeil Station		Pittsylvania Station (Hurt, VA)	
	Permit Limit	Actual	Permit Limit	Actual
NO _x	0.23 lb/MMBtu 145 lb/hr	.1535 lb/MMBtu 99.9 lb/hr	0.1 lb/MMBtu 37.4 lb/hr	.0890 lb / MMBtu
SO ₂	0.0083 lb/MMBtu	.0014 lb/MMBtu .9 lb/hr	0.016 lb/MMBtu 6.0 lb/hr	.0235 lb / MMBtu
PM	0.02 lb/MMBtu	.0055 lb/MMBtu	0.02 lb/MMBtu 7.47 lb/hr	0.0048 lb / MMBtu
PM10	0.02 lb/MMBtu		0.02 lb/MMBtu 7.32 lb/hr	.00356 lb / MMBtu
Opacity	20% (6 minute average)		10%	
CO	1500 ppm	.42 lb/MMBtu	0.35 lb/MMBtu 130.8 lb/hr	.333 lb / MMBtu
VOCs	< 50 tons per year	.012 lb/MMBtu	0.07 lb/MMBtu 26.2 lb/hr	.00872 lb / MMBtu
Permit Date	October 28, 2003		July 28, 2004	
Boiler Type	Wood Fired Stoker		3 Wood Fired Stoker units	
Boiler Size	50 MW		90 MW	
Fuel Input	750 MMBtu/hr Wood		373.3 MMBtu/hr, limited to 1,048,512 tons of wood per year (on a 40% MC basis)	9,349,870 MMBtu/yr
Emission Control Devices	ESP, Cyclones, Flue Gas Recirculation, Low NO _x burners for NG combustion		Multicyclone, ESP, SNCR/urea injection	

Industry Perspectives and Risk Analysis

As might be expected, boiler performance increased when using more highly processed and higher quality fuels. The use of the highly processed fuel also afforded a significant decrease (and potentially elimination, in the case of TWPs) of capital investment required at the plant. In the end, this single result sets the stage for the economic analysis in Chapter 5. Much of the decision regarding the use of these fuels comes down to whether paying more for the highly processed fuels and avoiding a big capital investment is a better economic choice than using a less ideal, but less expensive, fuel that requires a sizable on-site investment.

While the capital versus operating cost debate is important to answer, it does not necessarily tell the whole story. There are potentially several key strategic advantages that the pelletized fuel cases (especially the torrefied wood case) seem to offer that would be considerably more problematic with traditional repowering technologies:

- First, since the boiler requires relatively minor modifications to switch to the pelletized fuels, reverting to prior firing modes or even cofiring may be relatively simple to accomplish. This is especially true for the torrefied wood case.
- For similar reasons, and under the best circumstances (no capital investment required at the plant at all), torrefied wood may also offer a pathway to rapid regulatory compliance. A key issue plaguing the portion of the power generation industry that is considering biomass repowering is regulatory uncertainty regarding CO₂ and the treatment of biomass under the proposed rules. As noted in the prior sections, project development times for the more intense retrofits can stretch across four years. It is very hard for any company to see four years into the future and decide if embarking on a \$100M project is justified in such an environment. Designer fuels (such as torrefied wood) offer a way to mitigate this uncertainty by at least shortening (and possibly eliminating) the lead time in complying with rapidly evolving regulation. This topic is further explored in Chapter 5 in the context of the economic evaluation.

There is also the matter of plant outage time versus project development time. While these items are related and share a temporal element, the difference may be significant to project developers. For example, case 1 and 4 have similar project development timelines and both are estimated to be relatively long. However, case 4 does not require the intense boiler modifications needed in case 1. This means that implementation of case 4 will likely require a shorter boiler outage period than case 1. One estimate provided by a vendor during the preparation of this report suggested that a 10-week planned outage would be required to complete the boiler modifications listed for case 4.

The implementation of a repowering project does involve its share of technical and non-technical risks. Many of these risks are difficult to quantify, but a review of potential risks is provided below. The authors have also attempted to expand the discussion on these topics and provide insight based on perceptions of the current market and likely future directions.

Fuel supply issues

Having an adequate fuel supply is crucial for any energy project. Detailed fuel supply studies are performed prior to undertaking biomass projects and the current U.S. industry norm is to focus on projects where locally available supply is assured. If potential or perceived threats to a supply are identified or if the cost of procuring the material is too high, projects are tabled to await changes in market conditions.

This logic, which is generally sound for current U.S. market conditions, has led to relatively conservative biomass project development in recent years and conservative assumptions regarding fuel sourcing. Seeking fuel from sources beyond 100 miles is generally not preferred, and concerns about the potential lack of control or encroachment by competition dominate fuel supply discussions, especially for larger projects. This approach is also justified given past

experiences with rapid expansion of biomass power capacity. The biomass power boom on the west coast in the late 1980's eventually collapsed in on itself, in part because of the industry's failure to ensure it had access to fuel at the prices it had projected and a failure to appreciate the impact of overlapping fuel supply sheds.

However, the view that local availability of biomass is the key is not entirely accurate, and the European paradigm hints at a greater truth. For the most part, there is not a general sense of a worldwide biomass fiber supply shortage. Even in context of high demand scenarios, it is widely agreed that energy crops and other sources of biomass can be brought into almost any market – for the right price.

Driven by government mandates, some foreign electric generators are moving biomass fuels across the ocean to meet their fuel demands and paying, in some cases, upwards of \$10/MMBtu to get it. So, from this perspective, price (and not supply) is the issue. In other words, no one is worried that if they build a biomass project they will run out of fuel; they are worried they will run out of fuel they can afford.

Some may suggest that the above point is a difference without a distinction, but that is only true because of current U.S. policy. If policy in the U.S. shifts to parallel the policies implemented in other parts of the world, current thinking with respect to the need for local suppliers will change, just as they have for Europe.

The overall point is further refined by looking at prices being paid for wood fuels. At current wood chip prices, fuel runs from between \$2-4/MMBtu. Prices at the higher end of this range are usually viewed as being at the upper limit for an economically viable project. As noted above, recent prices for pellet fuels in Europe have been on the order of \$10/MMBtu. In this context, the relatively narrow range for which wood chip prices are considered acceptable is small in the U.S. In the long run, public policy (and not local supply shed dynamics) is really the forcing function for the price and supply of biomass.

Technology risk

There are a number of processes in biomass plants that could lead to increased maintenance costs or equipment overhauls. For example, it is fairly common for biomass boilers to experience corrosion from reactions between alkali metals/metal oxides and chlorides. Biomass gases are usually very high in chlorine content and will sometimes form corrosive alkali chlorides. There are options for minimizing this effect, such as injecting ammonium sulfate into flue gas after combustion. However, if left untreated, these gases can result in severe corrosion within the boiler. Generators seeking to leverage existing assets will be forced to manage compromises with respect to original heat transfer equipment design (including metallurgy) and the new demands biomass fuels will place on all systems.

For example, plants that modify their existing pulverizers to handle wood report increased maintenance requirements/costs. These increased costs would likely be moderate relative to maintenance costs for processing coal.

Many dedicated biomass facilities also have trouble with fouling and material buildup in their SCR systems. This can be very costly to handle. Biomass ash can also cause problems for the ash handling system. Although biomass tends to have a smaller quantity of ash than coal combustion, the ash content and composition is very different. Biomass ash particles fuse to boiler surfaces at much lower temperatures than coal ash. Ash deposition rates can vary significantly depending on the material used.

Explosion hazards / fire

Dust generated during transportation and unloading of biomass has the potential to cause an increased risk of explosion, particularly for pellet fuels. These risks can be minimized by utilizing good engineering practices and following safety requirements. For example, explosion panels can be installed in the top of enclosed storage areas. Since explosions are most likely with high volumes of storage for extended periods of time, the fuel storage area can be designed as a first-in/first-out process with a high turnover rate. Spark detection and mist suppression can be used to prevent fires and explosions in the conveyers and dust handling system.

Project cost

The cost of the initial capital investment can be a significant hurdle to project development. It can be difficult to find investors for high-cost projects with long payback periods or minimal returns. In addition, advanced technologies that have limited commercial development tend to have high contingency factors, as the processes required for successful operation are generally not well-known in as much detail as commercial technologies. This cost will be particularly significant for projects with a large capital investment, such as gasification technologies. Although there are not many examples of utility-scale pulverized plants firing with pellets, the risk is somewhat lessened because they do not require such a large investment.

Environmental compliance

The ability to meet existing environmental and regulatory compliance requirements will depend in part on the technology and fuel utilized at the individual facilities. Since states and regions have different regulations, compliance must be evaluated on a case-by-case basis. In order to mitigate the cost of compliance, it will be important for facilities to take emissions into consideration during repowering project development, in order to select the most appropriate technology available to meet existing limits while also considering likely future changes in the requirements. As stated previously, the EPA is currently revising the boiler MACT rules, which will impact the limits set for the repowering technologies considered in this analysis. Other legislation could further reduce or change the limits of criteria pollutants or greenhouse gas emissions in the future.

Future economic benefit cash flow

RECs, carbon credits, or other credits for emission reductions such as SO₂ or NO_x allowances can add value to renewable energy projects. The value of these credits can vary by location and change significantly over time. This unpredictability can be risky for a project whose economic viability is dependent on this added value. In the current voluntary REC market, the added value from RECs is typically more of an added benefit than a key component of the economics. However, additionality is a primary requirement for most carbon offset markets. If these environmental credits are a driver in project economics, then future variations will have a large effect on the project success. Implementation of a federal RPS or other governmental initiatives could considerably reduce these fluctuations, or at least help to ensure a continued market.

Future shifts in government or public perception

Potential future shifts in governmental policies regarding biomass could have a detrimental effect on biomass power plants. Examples of such shifts include:

- Executive / Congressional view unfavorable to biomass
- Biomass viewed as unsustainable for the utility sector
- Biomass not given any preference over coal

However, it is likely that governmental perception of biomass will be positive, at least in the foreseeable future, as part of continued and increased support for clean and renewable energy technologies to increase environmental responsibility and reduce greenhouse gas emissions. Increases in conventional energy prices or reduced availability of fossil fuels will also lead to increased support of alternative energies. The push for increased sustainability may limit the types of biomass fuels that can be utilized, as well as how they are harvested. This is already happening in certain states.

Public support will also play a role in the government's actions, and is an important factor in planning any biomass plant. Awareness of climate change and renewable technologies has been continually increasing and becoming more mainstream, although there is still some conflict and criticism of this support across the country. The "not-in-my-back-yard" factor is also prevalent, and likely to continue in the near term and beyond. Support for renewables also tends to wane somewhat during times of economic hardship, and some perceive monetary and political support for these technologies as wasteful and unnecessary. Limited funding or incentives available for biomass projects could negatively impact financing of future projects.

5

CASE STUDY ANALYSIS: ECONOMICS

In this chapter, the technical data presented above are distilled and used to develop Levelized Cost of Electricity (LCOE) values for each of the plant case studies. The economic analysis for each case varies primarily with respect to their individual capital requirements, operating costs, and fuel prices. Assumptions developed for each of these variables are presented below, and are followed by a summary of the analysis results.

Capital Costs

Detailed capital cost estimates were developed for each scenario.²⁵ These estimates are shown in 2010 USD, unless otherwise specified. Cost estimates were prepared for all major equipment components that would be modified or replaced, including but not limited to the following:²⁶

- 1) Fuel processing equipment, including mills, screens, silos, and bins,
- 2) Gasifier and associated heat exchange equipment,
- 3) Boiler modifications,
- 4) Emission control equipment, and
- 5) Civil works, including site development and building construction.

Where possible, equipment specifications were used to secure budgetary quotes from equipment vendors, including vendor estimates or guidance on the necessary installation efforts and/or costs. To the extent required, individual equipment items were grouped into assemblies, so that total installed cost estimates could be prepared using equipment costs, estimates for installation labor, and estimates for materials. Factored estimates are still used for general mechanical, electrical, and civil site work, but these estimates are made at the assembly level, consistent with expected construction techniques.

In cases where vendor data could not be obtained, cost estimates were developed using recent data from similar projects and industry-standard cost scaling methodologies. Some items were also estimated using RS MeansTM cost estimating software.

The power generation and gasification equipment costs are unique for each scenario, as each configuration required a variety of equipment at different specifications. These items were generally accounted for directly from vendor quotes.

²⁵ Some portions of this section have been excerpted from prior work by the authors (EPRI, 2010b).

²⁶ The costs for spare parts and fuel inventory are included as part of the O&M cost.

The civil works estimates include site development for the wood yard and fuel processing equipment, access roads, and other equipment, as well as the construction of a new building (if required). These development costs varied based on the land area required as well as the extent of development needed. A conceptual layout of each scenario was developed using equipment dimensions provided in vendor estimates. Once the required land area was determined, a range of potential site work costs (from low level development to extensive development) was calculated. All site development costs were calculated using RS Means™ cost estimating software. Each scenario required slightly different fuel processing equipment, which is explained by scenario in greater detail in Chapter 4 and below; however, all scenarios were assumed to require truck unloading infrastructure to accommodate the lowest possible fuel costs. Detailed information about the site work estimate methodology is presented in a recent related EPRI report (2010f).

Scenario Cost Summary

Case 1 – BFB with wood chips

The capital costs for a bubbling fluidized bed boiler retrofitted to fire green wood chips fell into the following categories:

- *Fuel handling.* All fuel handling equipment, including the fuel storage area, boiler house fuel feeding, and conveying equipment would have to be replaced with materials compatible with wood chips. A recent quote for a turnkey wood yard from Bruks Rockwood featuring two circular overpile stacker reclaimers was used as the basis for the analysis. The package included covered conveyors, truck scales, truck dumper platforms, a magnetic separator and platform, and temporary wood chip storage silos. Conveyor lengths were adjusted based on in-house information. In-house information for a project of similar size at a similar plant was also used to estimate the cost of civil and site work, including road widening and repaving, site clearing, and grading.
- *Boiler island modifications.* The bottom of the boiler would have to be removed and replaced with a bubble cap fluidization system. The boiler bottom dimensions are assumed to remain the same. Booster, flue gas recirculation, ID, and FD fans would need to be replaced, and some pressure part modifications would need to be performed. The ESP would need to be upgraded in order to be used with the flue gas volumes shown; this cost is also included in the boiler island value. This line item cost was scaled from two vendor estimates received for a recent EPRI study of biomass repowering at a similar facility (2010b).
- *Balance of plant.* A significant decommissioning cost is required for removing the existing coal pulverizers, the existing boiler bottom, and the existing coal storage infrastructure. Controls and electrical work are also required. This cost was also scaled from a prior EPRI study (*Ibid.*).

Case 2 – Conversion for wood pellet firing

The capital costs for a retrofit for suspension firing of wood pellets in an existing pulverized coal boiler fell into the following categories:

- *Fuel handling.* All fuel handling equipment, including the fuel storage area, boiler house fuel feeding, and conveying equipment would have to be replaced with materials compatible with wood pellets. As wood pellets are hygroscopic, they require covered storage. The following new equipment costs were obtained from in-house resources: covered conveyors, truck scales, and truck dumper platforms. The cost for a new concrete dome storage structure (including reclaiming equipment and controls) was obtained from a vendor familiar with such systems (Laidig).
- *Fuel processing.* The explosive nature of wood dust and air mixtures also requires significant fire suppression and dust control equipment. Costs for fire suppression equipment were estimated based on quotes received for a similar project. In subcase 2b, milling the product to a 1.5 mm diameter particle size would require three hammer mills (with associated blowers, rotary airlocks, and 6" piping) to augment the existing pulverizers. (Two hammer mills would operate at a time, with one used as backup capacity.) A reputable vendor provided a quote for the replacement mills.
- *Boiler island modifications.* Due to the larger particle size, higher excess air requirements, and lower mill exit temperatures, new burners would likely be necessary. The cost for this replacement was obtained from EPA's CUECost software, based on the rated heat input to the boiler. Additional boiler cleaning capacity was also included in the total direct cost, using an estimate of \$100 per square foot of boiler surface area to be cleaned by waterlances. A requirement of sixteen waterlances with cleaning diameters of 20 ft was estimated based on the boiler's total heat exchange area. For subcase 2b, pressure part modification costs were estimated based upon data collected from a recent feasibility study (EPRI, 2010b).
- *Flue gas train modifications.* The changed resistivity and particle size distribution of wood ash compared to coal ash may necessitate changes to the fly ash handling system. For example, the wall angles of the fly ash hoppers may be too shallow for the particle flow characteristics of wood ash. The carbon content of the fly ash may also increase (as discussed in the performance modeling section), leading to fire/explosion hazards that will need to be abated. Data published by the EPA and TVA were used to develop a cost estimate for the entire fly ash handling system, excluding the ESPs themselves.
- *Balance of plant.* In contrast with case 1, no cost was estimated for this item. The much narrower scope of boiler and boiler house modifications imply a much smaller cost of demolition and equipment relocation. Removal of the existing coal yard equipment was included in the fuel processing category.

Case 3 – Conversion for torrefied wood pellet firing

There were numerous options to consider with respect to the equipment choices for this case, and the authors considered the possibility of assuming that no capital investments would be required for this case at all. However, after some deliberation it was decided to assume that an investment in dedicated fuel processing and handling equipment would be required, and the "no investment" option was handled as an economic sensitivity case. The capital costs for a retrofit for suspension firing of torrefied pellets in an existing pulverized coal boiler fell into the following categories:

- *Fuel processing.* In subcase 3.2, two hammer mills would be required to augment the existing pulverizers: one for base load operation, and one for backup operation. Vendor

quotes were used to estimate the cost of the replacement mills, including labor and shipping (as described above).

- *Fuel handling.* All fuel handling equipment, including the fuel storage area, boiler house fuel feeding, and conveying equipment would have to be replaced with materials compatible with torrefied pellets. The following new equipment costs were obtained from in-house resources: covered conveyors, truck scales, and truck dumper platforms. Costs for three different biomass storage structures (complete with reclaiming equipment and controls) were also obtained as follows:
 - Case 3a – concrete dome storage area from Laidig
 - Case 3b – outdoor circular overpile stacker reclaimer from Bruks Rockwood
 - Case 3c – covered steel storage area with overhead reclaim system from in-house resources
- *Boiler island modifications.* Costs for replacement burners and additional sootblowing capacity were estimated in the same manner as for case 2. Given the potential for smaller, readily combustible particles relative to the other cases, no fly ash handling modifications were included for this case (in anticipation of reduced issues with carbon burnout).
- *Balance of plant.* No cost was estimated for this item, for the reasons stated for case 2.

Case 4 – Gasification Cofiring

The capital costs for adding a biomass gasification system firing green wood chips and modifying the existing coal boiler to cofire the resulting syngas fell into the following categories:

- *Fuel handling.* All fuel handling equipment, including the fuel storage area, boiler house fuel feeding, and conveying equipment would have to be replaced with materials compatible with wood chips. A quote for a turnkey circular overpile stacker reclaimer was obtained from Bruks Rockwood. The following new equipment costs were obtained from in-house resources: covered conveyors, truck scales, truck dumper platforms, a magnetic separator and platform, and temporary wood chip storage silos.
- *Boiler island modifications.* A new gasifier, syngas cleanup system, syngas cooler, and syngas ducting would be required. Frontline provided a budgetary quote for these items as part of a recent EPRI study (2010f); this quote was scaled to present-day cost. Burner replacements (as well as additional boiler penetrations for burners and air ports) would likely be required as well. The cost of such modifications was included in the cost estimate provided by the gasifier vendor. The cost of the additional building required to house the gasifier was estimated using RS Means™ cost data on a per-square foot basis.
- *Balance of plant.* No line item is shown, as the modifications to the boiler are modest and the gasifier island already includes balance of plant costs for that portion of the system.

In all cases, a range of costs is presented, roughly estimating the upper and lower limits of the budgetary quotes received. The expected cost is estimated to lie somewhere between these values. The base case shows the value used in the economic analyses.

Table 5-1
Capital Costs for Case 1 (BFB retrofit with wood chips)

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$22,822,000	\$27,386,000	\$18,258,000
Turnkey Wood Yard	\$16,295,000	\$19,554,000	\$13,036,000
Boiler House Wood Chip Handling	\$3,065,000	\$3,678,000	\$2,452,000
Civil Works / Site Development	\$3,462,000	\$4,154,400	\$2,769,600
Direct Cost - Boiler Island	\$39,428,000	\$47,314,000	\$31,542,000
Boiler Bottom Removal, BFB Firing System & Auxiliaries			
Gas & Air Duct Mods., Fan Systems, Ash System Equipment			
Pressure Parts & Convection Pass Upgrades, Aux. Fuel Firing			
Pollution Control Mods. (ESP), Installation			
Direct Cost - Balance of Plant	\$9,487,000	\$6,154,000	\$4,102,000
Demolition and Decommissioning	\$1,173,000	\$1,408,000	\$938,000
Controls, Foundations, Electrical	\$3,955,000	\$4,746,000	\$3,164,000
<u>Subtotal Direct Costs</u>	<u>\$71,737,000</u>	<u>\$80,854,000</u>	<u>\$53,902,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$43,042,000</u>	<u>\$48,512,000</u>	<u>\$32,340,000</u>
Project Contingency (20% of Subtotal)	\$14,347,000	\$16,171,000	\$10,780,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$1,435,000	\$1,617,000	\$1,078,000
Overhead, Contractor's Fees (20% of Subtotal)	\$14,347,000	\$16,171,000	\$10,780,000
Equipment Escalation (8% of Subtotal)	\$5,739,000	\$6,468,000	\$4,312,000
Engineering (10% of Subtotal)	\$7,174,000	\$8,085,000	\$5,390,000
<u>Total Capital Requirement</u>	<u>\$119,370,000</u>	<u>\$134,541,000</u>	<u>\$89,692,000</u>
Total Project Cost (Direct + Indirect)	\$114,779,000	\$129,366,000	\$86,242,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$4,591,000	\$5,175,000	\$3,450,000

Table 5-2
Capital Costs for Case 2a (Wood pellets, mill limit)

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$9,771,000	\$11,725,000	\$7,817,000
Turnkey Fuel Yard	\$6,046,000	\$7,255,000	\$4,837,000
Boiler House Wood Pellet Handling	\$1,749,000	\$2,099,000	\$1,399,000
Civil Works/Site Development	\$1,975,643	\$2,371,000	\$1,581,000
Direct Cost - Explosion Hazard Abatement	\$350,000	\$420,000	\$280,000
Covered Conveyor Adder / Fire Suppression	\$250,000	\$300,000	\$200,000
Fire Suppression in Silos	\$30,000	\$36,000	\$24,000
Baghouse / Cyclone After Milling	\$70,000	\$84,000	\$56,000
Direct Cost - Boiler Modifications	\$4,954,000	\$5,944,000	\$3,964,000
Add Sootblowing Capacity, Water Lances	\$502,000	\$602,000	\$402,000
Add Fly Ash Handling Capacity	\$1,200,000	\$1,440,000	\$960,000
Replace Burners	\$3,252,000	\$3,902,000	\$2,602,000
<u>Subtotal Direct Costs</u>	<u>\$15,075,000</u>	<u>\$18,089,000</u>	<u>\$12,061,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$9,046,000</u>	<u>\$10,854,000</u>	<u>\$7,236,000</u>
Project Contingency (20% of Subtotal)	\$3,015,000	\$3,618,000	\$2,412,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$302,000	\$362,000	\$241,000
Overhead, Contractor's Fees (20% of Subtotal)	\$3,015,000	\$3,618,000	\$2,412,000
Equipment Escalation (8% of Subtotal)	\$1,206,000	\$1,447,000	\$965,000
Engineering (10% of Subtotal)	\$1,508,000	\$1,809,000	\$1,206,000
<u>Total Capital Requirement</u>	<u>\$25,086,000</u>	<u>\$30,101,000</u>	<u>\$20,069,000</u>
Total Project Cost (Direct + Indirect)	\$24,121,000	\$28,943,000	\$19,297,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$965,000	\$1,158,000	\$772,000

Table 5-3
Capital Costs for Case 2b (Wood pellets, flue gas limit)

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$13,443,000	\$16,130,000	\$10,755,000
Turnkey Fuel Yard	\$7,797,000	\$9,356,000	\$6,238,000
Boiler House Wood Pellet Handling	\$2,256,000	\$2,707,000	\$1,805,000
Civil Works/Site Development	\$2,547,768	\$3,057,000	\$2,038,000
Install Additional Hammer Mills	\$506,000	\$607,000	\$405,000
Blowers / Rotary Air Locks / Piping	\$336,000	\$403,000	\$269,000
Direct Cost - Explosion Hazard Abatement	\$359,000	\$431,000	\$287,000
Covered Conveyor Adder / Fire Suppression	\$250,000	\$300,000	\$200,000
Fire Suppression in Silos	\$39,000	\$46,800	\$31,200
Baghouse / Cyclone After Milling	\$70,000	\$84,000	\$56,000
Direct Cost - Boiler Modifications	\$15,778,000	\$18,933,000	\$12,623,000
Add Sootblowing Capacity, Water Lances	\$502,000	\$602,000	\$402,000
Pressure Part Modifications	\$10,824,171	\$12,989,000	\$8,659,000
Add Fly Ash Handling Capacity	\$1,200,000	\$1,440,000	\$960,000
Replace Burners	\$3,252,000	\$3,902,000	\$2,602,000
<i>Subtotal Direct Costs</i>	<i>\$29,580,000</i>	<i>\$35,494,000</i>	<i>\$23,665,000</i>
<i>Subtotal Indirect Costs</i>	<i>\$17,748,000</i>	<i>\$21,297,000</i>	<i>\$14,199,000</i>
Project Contingency (20% of Subtotal)	\$5,916,000	\$7,099,000	\$4,733,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$592,000	\$710,000	\$473,000
Overhead, Contractor's Fees (20% of Subtotal)	\$5,916,000	\$7,099,000	\$4,733,000
Equipment Escalation (8% of Subtotal)	\$2,366,000	\$2,840,000	\$1,893,000
Engineering (10% of Subtotal)	\$2,958,000	\$3,549,000	\$2,367,000
<i>Total Capital Requirement</i>	<i>\$49,221,000</i>	<i>\$59,063,000</i>	<i>\$39,379,000</i>
Total Project Cost (Direct + Indirect)	\$47,328,000	\$56,791,000	\$37,864,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$1,893,000	\$2,272,000	\$1,515,000

Table 5-4
Capital Costs for Case 3a.1 (Torrefied wood pellets with concrete dome storage and mill limit)

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$10,419,000	\$12,503,000	\$8,335,000
Turnkey Fuel Yard	\$6,034,000	\$7,241,000	\$4,827,000
Boiler House Pellet Handling	\$1,795,000	\$2,154,000	\$1,436,000
Civil Works/Site Development	\$2,028,031	\$2,434,000	\$1,622,000
Direct Cost - Explosion Hazard Abatement	\$281,000	\$337,000	\$225,000
Covered Conveyor Adder / Fire Suppression	\$250,000	\$300,000	\$200,000
Fire Suppression in Silos	\$31,000	\$37,000	\$25,000
Direct Cost - Boiler Modifications	\$3,754,000	\$4,504,000	\$3,004,000
Added Sootblowing Capacity	\$502,000	\$602,000	\$402,000
Replace Burners	\$3,252,000	\$3,902,000	\$2,602,000
<u>Subtotal Direct Costs</u>	<u>\$14,454,000</u>	<u>\$17,344,000</u>	<u>\$11,564,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$10,117,000</u>	<u>\$12,141,000</u>	<u>\$8,094,000</u>
Project Contingency (30% of Subtotal)	\$4,336,000	\$5,203,000	\$3,469,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$289,000	\$347,000	\$231,000
Overhead, Contractor's Fees (20% of Subtotal)	\$2,891,000	\$3,469,000	\$2,313,000
Equipment Escalation (8% of Subtotal)	\$1,156,000	\$1,388,000	\$925,000
Engineering (10% of Subtotal)	\$1,445,000	\$1,734,000	\$1,156,000
<u>Total Capital Requirement</u>	<u>\$25,554,000</u>	<u>\$30,664,000</u>	<u>\$20,444,000</u>
Total Project Cost (Direct + Indirect)	\$24,571,000	\$29,485,000	\$19,658,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$983,000	\$1,179,000	\$786,000

Table 5-5**Capital Cost for Case 3a.2 (Torrefied wood pellets with concrete dome storage and flue gas limit)**

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$11,964,000	\$14,357,000	\$9,572,000
Turnkey Fuel Yard	\$6,974,000	\$8,369,000	\$5,579,000
Boiler House Pellet Handling	\$2,086,000	\$2,503,000	\$1,669,000
Civil Works / Site Development	\$2,343,416	\$2,812,000	\$1,875,000
Install Additional Mills	\$337,000	\$404,000	\$270,000
Blowers / Rotary Air Locks / Piping	\$224,000	\$269,000	\$179,000
Direct Cost - Explosion Hazard Abatement	\$286,000	\$343,000	\$229,000
Covered Conveyor Adder / Fire Suppression	\$250,000	\$300,000	\$200,000
Fire Suppression in Silos	\$36,000	\$43,000	\$29,000
Direct Cost - Boiler Modifications	\$3,754,000	\$4,504,000	\$3,004,000
Added Sootblowing Capacity	\$502,000	\$602,000	\$402,000
Replace Burners	\$3,252,000	\$3,902,000	\$2,602,000
<u>Subtotal Direct Costs</u>	<u>\$16,004,000</u>	<u>\$19,204,000</u>	<u>\$12,805,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$11,202,000</u>	<u>\$13,442,000</u>	<u>\$8,964,000</u>
Project Contingency (30% of Subtotal)	\$4,801,000	\$5,761,000	\$3,842,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$320,000	\$384,000	\$256,000
Overhead, Contractor's Fees (20% of Subtotal)	\$3,201,000	\$3,841,000	\$2,561,000
Equipment Escalation (8% of Subtotal)	\$1,280,000	\$1,536,000	\$1,024,000
Engineering (10% of Subtotal)	\$1,600,000	\$1,920,000	\$1,281,000
<u>Total Capital Requirement</u>	<u>\$28,294,000</u>	<u>\$33,952,000</u>	<u>\$22,640,000</u>
Total Project Cost (Direct + Indirect)	\$27,206,000	\$32,646,000	\$21,769,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$1,088,000	\$1,306,000	\$871,000

Table 5-6
Capital Costs for Case 3b.1 (Torrefied wood pellets with open pile storage and mill limit)

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$9,339,000	\$11,207,000	\$7,471,000
Turnkey Fuel Yard	\$5,516,000	\$6,619,000	\$4,413,000
Boiler House Pellet Handling	\$1,795,000	\$2,154,000	\$1,436,000
Civil Works / Site Development	\$2,028,031	\$2,434,000	\$1,622,000
Direct Cost - Explosion Hazard Abatement	\$281,000	\$337,000	\$225,000
Covered Conveyor Adder / Fire Suppression	\$250,000	\$300,000	\$200,000
Fire Suppression in Silos	\$31,000	\$37,000	\$25,000
Direct Cost - Boiler Modifications	\$3,754,000	\$4,504,000	\$3,004,000
Added Sootblowing Capacity	\$502,000	\$602,000	\$402,000
Replace Burners	\$3,252,000	\$3,902,000	\$2,602,000
<u>Subtotal Direct Costs</u>	<u>\$13,374,000</u>	<u>\$16,048,000</u>	<u>\$10,700,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$9,361,000</u>	<u>\$11,234,000</u>	<u>\$7,490,000</u>
Project Contingency (30% of Subtotal)	\$4,012,000	\$4,814,000	\$3,210,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$267,000	\$321,000	\$214,000
Overhead, Contractor's Fees (20% of Subtotal)	\$2,675,000	\$3,210,000	\$2,140,000
Equipment Escalation (8% of Subtotal)	\$1,070,000	\$1,284,000	\$856,000
Engineering (10% of Subtotal)	\$1,337,000	\$1,605,000	\$1,070,000
<u>Total Capital Requirement</u>	<u>\$23,644,000</u>	<u>\$28,373,000</u>	<u>\$18,918,000</u>
Total Project Cost (Direct + Indirect)	\$22,735,000	\$27,282,000	\$18,190,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$909,000	\$1,091,000	\$728,000

Table 5-7**Capital Costs for Case 3c.1 (Torrefied wood pellets with rectangular storage and flue gas limit)**

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Direct Cost - Fuel Processing	\$12,975,000	\$15,570,000	\$10,380,000
Turnkey Fuel Yard	\$8,590,000	\$10,308,000	\$6,872,000
Boiler House Pellet Handling	\$1,795,000	\$2,154,000	\$1,436,000
Civil Works/Site Development	\$2,028,031	\$2,434,000	\$1,622,000
Direct Cost - Explosion Hazard Abatement	\$281,000	\$337,000	\$225,000
Covered Conveyor Adder / Fire Suppression	\$250,000	\$300,000	\$200,000
Fire Suppression in Silos	\$31,000	\$37,000	\$25,000
Direct Cost - Boiler Modifications	\$3,754,000	\$4,504,000	\$3,004,000
Added Sootblowing Capacity	\$502,000	\$602,000	\$402,000
Replace Burners	\$3,252,000	\$3,902,000	\$2,602,000
<u>Subtotal Direct Costs</u>	<u>\$17,010,000</u>	<u>\$20,411,000</u>	<u>\$13,609,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$11,907,000</u>	<u>\$14,287,000</u>	<u>\$9,527,000</u>
Project Contingency (30% of Subtotal)	\$5,103,000	\$6,123,000	\$4,083,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$340,000	\$408,000	\$272,000
Overhead, Contractor's Fees (20% of Subtotal)	\$3,402,000	\$4,082,000	\$2,722,000
Equipment Escalation (8% of Subtotal)	\$1,361,000	\$1,633,000	\$1,089,000
Engineering (10% of Subtotal)	\$1,701,000	\$2,041,000	\$1,361,000
<u>Total Capital Requirement</u>	<u>\$30,074,000</u>	<u>\$36,086,000</u>	<u>\$24,061,000</u>
Total Project Cost (Direct + Indirect)	\$28,917,000	\$34,698,000	\$23,136,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$1,157,000	\$1,388,000	\$925,000

Table 5-8
Capital Costs for Case 4 (Syngas cofiring)

Item Description	Total Direct Cost (Base, 2010)	Total Direct Cost (High)	Total Direct Cost (Low)
Fuel Processing	\$15,731,000	\$18,878,000	\$12,584,000
Turnkey Wood Yard	\$10,963,000	\$13,156,000	\$8,770,000
Civil Works/Site Development	\$4,768,000	\$5,722,000	\$3,814,000
Gasification	\$50,343,000	\$60,412,000	\$40,274,000
Feed Drying & Emissions Control	\$9,615,000	\$11,538,000	\$7,692,000
Gasification Equipment	\$26,558,000	\$31,870,000	\$21,246,000
Auxiliary Equipment	\$11,948,000	\$14,338,000	\$9,558,000
Gasification Building	\$2,222,000	\$2,666,000	\$1,778,000
<u>Subtotal Direct Costs</u>	<u>\$66,074,000</u>	<u>\$79,290,000</u>	<u>\$52,858,000</u>
<u>Subtotal Indirect Costs</u>	<u>\$46,251,600</u>	<u>\$55,503,000</u>	<u>\$37,001,000</u>
Project Contingency (30% of Subtotal)	\$19,822,200	\$23,787,000	\$15,857,000
Legal, Performance Bond Insurance (2% of Subtotal)	\$1,321,000	\$1,586,000	\$1,057,000
Overhead, Contractor's Fees (20% of Subtotal)	\$13,215,000	\$15,858,000	\$10,572,000
Equipment Escalation (8% of Subtotal)	\$5,286,000	\$6,343,000	\$4,229,000
Engineering (10% of Subtotal)	\$6,607,400	\$7,929,000	\$5,286,000
<u>Total Capital Requirement</u>	<u>\$116,819,000</u>	<u>\$140,185,000</u>	<u>\$93,453,000</u>
Total Project Cost (Direct + Indirect)	\$112,326,000	\$134,793,000	\$89,859,000
Estimated Owner Development Costs (4% of Total Project Cost)	\$4,493,000	\$5,392,000	\$3,594,000

Non-Fuel Operations and Maintenance Costs

Annual non-fuel O&M costs were estimated for each of the scenarios considered. O&M costs are used as inputs for the comparative economic analyses. These estimates are not intended to support/justify staffing decisions or to develop detailed operating and maintenance plans. These estimates are considered preliminary, regardless of the apparent detail associated with their development. There was a primary focus on the following: (1) ensuring that key O&M items are included in the economic analysis, and (2) ensuring that the costs are estimated in a consistent manner to allow comparison between the different technology options.

The O&M cost estimates for this study have been built up using detailed consideration of actual facility operations for each scenario. This cost-estimating methodology included the following elements:

- Preparing a plant staffing plan, including all key labor positions required to operate and maintain the plant, as well as overhead positions for management and administration.
- Developing a preliminary operating plan to layout shift arrangements and required staffing necessary to achieve plant production objectives.
- Applying wage and benefit rates to the staffing plan in accordance with industry norms.
- Use of heat and mass balance information and vendor-provided data to develop estimates for general chemical and consumable materials, as well as auxiliary fuel usage.
- Use of vendor data for calculating specialty chemical usage and costs (e.g. fluid bed replacement/make-up material).
- Use of current national average commercial rates to estimate annual utility service costs, such as natural gas, potable water, and diesel.
- Estimated servicing and overhauling budgets based on similar plants and scaled according to the pre-repowering plant capacity for equipment common to all scenarios.

O&M costs are typically classified as either a fixed or variable cost. Fixed costs do not vary, or do not vary significantly with changes in the plant's output, while variable costs are either greatly influenced or directly proportional to plant output.

Scope of Analysis

As previously noted, the results of the O&M analysis are to be interpreted at a high level and taken in comparison to the other scenarios. The results are for repowering a generic coal plant, as discussed in Chapter 4, in a generic location in the Southeast U.S. Included in the analysis are:

- Management and administrative labor
- Operations and maintenance labor
- Consumables including urea, water, lubricants, and bed material (for example)
- Maintenance contracts for turbines and control systems (among others)

- Parts and supplies for overhaul and maintenance of the boiler, turbine, wood yard, structures, and emission control systems
- Costs associated with the disposal of ash from biomass and coal, depending on the scenario
- Property and liability insurance
- Other expenses including legal, environmental compliance, and employee training

Items outside the scope of this analysis include:

- Property taxes
- State and local fees (income taxes are treated in the economic analysis)
- Substation and transmission/distribution maintenance
- Environmental allowances

Power plants are usually major employers in their area of operations. Since property taxes are negotiated on the local level and are subject to political forces and negotiation, and because reasonable arguments can be made for maintaining property taxes at the same levels before and after the retrofit, it is assumed that property taxes will not change regardless of the investment made at the plant. This assumption was also vetted with industry experts. The net impact of this assumption is that, for the comparative analysis, location (and not specific investment at the plant) is the critical element, and no economic advantage is assigned to low-investment technologies.

For this analysis, the plant's parasitic electrical consumption is handled by calculating electrical sales based on the net generation. This is functionally the same as selling all of the electricity to the grid and buying the plant's load back at the sale price. Some plants, because of regulatory or accounting requirements, will buy the in-house load electricity from the grid at a price that can be either higher or lower than what they sell to the grid for. The arrangement is dependent on how the plant is regulated and how the utility prices are structured.

Labor Costs

The labor estimate was developed based on experience with similar projects, discussions with biomass plant operators, and feedback from equipment vendors. Staffing requirements are based on the operating plan, which determines how many shifts per week are required and how many employees are needed to cover each shift. From that operating plan, the number of employees required for each position can then be determined. In general, maintenance positions and administration are only needed during the normal business week, while operations staff must be scheduled for all shifts. The number of staff members required is determined by the size and complexity of the fuel receiving and handling, as well as the complexity of the plant itself. A description of each applicable labor category and position is summarized in Table 5-9.

Table 5-9
Plant Personnel Description

Labor Category	Responsibilities / Skill Set
Management / General & Administrative Staff	
General Plant Manager	Responsible for all personnel and plant decisions, including new employee hiring, operator training, fuel contracts, maintenance contracts, general equipment purchases, external communications, and operating schedules.
Environmental Manager	Responsible for environmental reporting, filings and oversight.
Accounting / Finance	Support the general plant manager, manages personnel records, completes company payroll, manages time accounting records, manages company benefits, employee investment accounts, and insurance enrollments.
Purchasing / Inventory	Day-to-day purchasing and parts searching; managing and maintaining spares inventory. This is likely a part-time position, with remainder of time available to assist with plant operations, maintenance, and/or fuel procurement functions.
HR / Receptionist	Supports the General Plant Manager and Company Controller. Receives visitors, answers phone, and attends to office administrative duties.
Plant, Woodyard & Fuel Procurement Operations Staff	
Plant Operations Supervisor	One per shift, 5 total shifts to allow for coverage during vacations, etc. Supervises and manages day-to-day plant operations.
Plant Operations Staff	Two per shift, 5 total shifts to allow for coverage during vacations, etc. Monitors centralized control system. Operates steam, electrical, and water treatment components.
Plant Engineer	General plant engineering functions, plant performance evaluation, maintenance planning assistance, capital projects planning, reporting, etc.
Plant Maintenance Supervisor	Maintenance staff management and maintenance planning.
Plant Maintenance Staff	One per shift, Monday - Friday, plus after hours and weekend work as needed. Estimated maintenance staffing: 2 mechanics/welders, 2 electricians, 1 instrument technician, 1 water treatment.
Fuel Procurement / Forester	Manages wood purchases, deliveries, payment issues, and ensures the on site wood yard is managed properly. Only applicable to wood chip fuel cases.
Fuel Handling Staff	One per shift, 5 total shifts to allow for coverage during vacations, etc. Logs and coordinates fuel deliveries and truck dumping. Operates front end loader when manual pile management is necessary. Assists general plant operations staff.

As shown in Table 5-10, staffing requirements differ to some extent from one scenario to another, but the baseline staffing is based on a biomass or fossil plant of comparable size. In the scenarios using wood chip fuels (cases 1 and 4), a full-time forester is included to manage the acquisition of fuel for the plant. The wood pellet and torrefied pelletized wood scenarios do not require this position because the refined fuel is assumed to be available from a developed market with established vendors, simplifying fuel acquisition from the plant's perspective. In addition to the forester, additional personnel are assigned to case 4. These positions are required because, by indirectly cofiring the wood fuel with coal, the plant has two fuel yards and effectively two boiler plants. These parallel operations result in one additional fuel handling staff position, one additional maintenance position, and four additional plant operator positions. The plant operator positions are dedicated to the operations of the gasification island, with four positions to cover all shifts.

Table 5-10
Plant Staffing Requirements

	Wood Chips in BFB Replacement Boiler	Existing Boiler with Wood Pellets- Mill Limited	Existing Boiler with Torrefied Wood Pellets-Mill Limited; Concrete Dome Storage	Existing Boiler with Syngas Cofiring
Labor Category	1	2 (a & b)	3 (all subcases)	4
Management / General & Administrative Staff				
General Plant Manager	1	1	1	1
Environmental Manager	1	1	1	1
Accounting / Finance	1	1	1	1
Purchasing / Inventory	1	1	1	1
HR / Receptionist	1	1	1	1
Total G&A Staff	5	5	5	5
Plant, Woodyard & Fuel Procurement Operations Staff				
Plant Operations Supervisor	5	5	5	5
Plant Operations Staff	10	10	10	14
Plant Engineer	1	1	1	1
Plant Maintenance Supervisor	1	1	1	1
Plant Maintenance Staff	6	6	6	7
Fuel Procurement / Forester	1	0	0	1
Fuel Handling Staff	5	5	5	6
Total Operations Staff	29	28	28	35
Total Plant Staff	34	33	33	40

Wages were determined based on state-level hourly salary data reported by the U.S. Bureau of Labor Statistics (US-BLS) for each of the positions above or the equivalent (U. S. Department of Labor, Bureau of Labor Statistics, 2010).²⁷ Management and supervisor positions were conservatively estimated to be in the top 90th percentile of their field, while staff positions were assumed to be in the 50th percentile. A summary of these hourly salaries is provided in Table 5-11.

²⁷ Values used in the analysis are based on averages for the states in Standard Federal Region IV.

Table 5-11
Hourly salaries and assumptions

Management, G&A	Salary (\$/hr)	Assumptions
General Plant Manager	\$ 72.69	Based on US BLS-2009 for 90th % Engineering Managers
Environmental Manager	\$ 51.80	Based on US BLS-2009 for 90th % Environmental Engineers
Accounting / Finance	\$ 41.78	Based on US BLS-2009 for 90th % Human Resource Specialists
Purchasing / Inventory	\$ 41.78	Based on US BLS-2009 for 90th % Human Resource Specialists
HR / Receptionist	\$ 33.21	Based on US BLS-2009 for 50th % Human Resources
Direct Labor	Salary (\$/hr)	
Plant Operations Supervisor	\$ 36.75	Based on US BLS-2009 for 90th % Power Plant Operators
Plant Operations Staff	\$ 27.58	Based on US BLS-2009 for 50th % Power Plant Operators
Plant Engineer	\$ 36.75	Based on US BLS-2009 for 90th % Power Plant Operators
Plant Maintenance Supervisor	\$ 36.75	Based on US BLS-2009 for 90th % Power Plant Operators
Plant Maintenance Staff	\$ 27.58	Based on US BLS-2009 for 50th % Power Plant Operators
Fuel Procurement Mgr / Forester	\$ 34.21	Based on US BLS-2009 for 90th % Foresters
Fuel Handling Staff	\$ 19.32	Based on US BLS-2009 for 50th % Stationary Engineer/Boiler

The labor costs in the O&M analysis also include estimates for employee benefits and time off. Conservative estimates for vacation and medical leave are used, in which each employee receives four weeks paid vacation, one week paid sick leave, and nine paid holidays each year. This benefit is already included in the wages, as the regular wages are calculated based on full-time, year-round working hours (2080 hrs./year).

Non-leave fringe benefits are calculated to be 23.7% of wages. This is based on the second quarter estimates of employer costs for employee compensation as reported by the US-BLS in November, 2010 for non-union utility personnel. This percentage is composed of the following:

- Supplemental Pay (2.4%): overtime and premium (including weekend and holiday pay), shift differentials, and nonproduction bonuses
- Insurance (8.9%): life, health, short-term disability, and long-term disability
- Retirement and savings (4.1%): defined benefit and defined contribution
- Legally required benefits (8.3%): Social Security and Medicare, Federal unemployment insurance, state unemployment insurance, and workers' compensation

Non-Labor Costs

Non-labor costs were determined based on data from similar plants, equipment requirements, and project team expertise, and were allocated into fixed and variable categories. Fixed costs were scaled to the proposed plant based on capital cost or unit size. Variable costs were based on plant output at a baseload capacity factor of 85%. Start-up fuel consumption assumes two cold starts per year.

Non-labor costs include maintenance and overhaul expenses, consumables, water, insurance, and ash disposal costs. Maintenance costs are similar across scenarios, because the vast majority of equipment is identical (buildings, turbines, and potentially even the boiler); these represent most of the maintenance costs. Notable exceptions are the wood yards, which differ in size and complexity, and the gasification plant, which is only applicable to scenario 4. Boiler, turbine, and structural maintenance and overhaul have been scaled from a comparable facility according to the pre-retrofit plant capacity and were applied to all scenarios. This approach was selected because there is some derate in all scenarios, but the duty cycle of the equipment remains unchanged regardless.

Consumables and ash disposal were estimated based on the modeling effort described in Chapter 4 and were priced according to vendor quotes and published price estimates.

O&M Estimation Results

The total O&M costs fell within a range of \$6-8 million per year. Most of the fixed costs, including labor, are similar across scenarios, with the exception of the additional staff requirements and the additional maintenance materials required for the gasification island. The wood fuel and coal cofire cases incurred significant cost for ash disposal compared to the enhanced fuels, because the enhanced fuels selected in this study benefit from having low ash content on an energy basis.

The results of the O&M analysis are presented in Table 5-12, with details provided in Appendix D.

Table 5-12
O&M Results

Scenario Identifier*	Wood Chip BFB	Wood Pellet Suspension Fired		Torrefied wood Suspension fired				Syngas Indirect Cofired
	1	2a	2b	3a.1	3a.2	3b.1	3c.1	4
Gross Capacity (MWe)	93.4	91.4	130.0	113.4	140.8	113.4	113.4	99.5
Net Capacity (MWe)	82.4	81.8	117.7	102.8	128.9	102.8	102.8	85.1
Variable O&M (¢/kWh)	0.20	0.09	0.09	0.09	0.08	0.09	0.09	0.20
Non-Labor Fixed O&M (\$/kw-yr)	33.10	33.27	23.43	26.66	21.45	26.66	26.66	37.82
Labor (\$/kw-yr)	33.44	32.58	22.66	25.93	20.68	25.93	25.93	37.12
Total O&M (¢/kWh)	1.10	0.98	0.71	0.79	0.65	0.79	0.79	1.20

*Sub-scenario explanations: **2a**-Mill limited heat input **2b**-Flue gas limited heat input **3a.1**-Mill limited, Concrete dome storage **3a.2**-Flue gas limited, concrete dome storage **3b.1**-Mill limited, open pile storage, **3c.1**- Mill limited, covered

Fuel Costs

Biomass fuel costs are clearly a critical component to the end results of these economic analyses. Further, as stated previously in the report and noted above in the capital cost estimates provided for each case, there is nearly a \$100M investment gap between the lowest- and highest-cost options explored in this report. The justification for this investment in lieu of the lower-cost options is the presumed benefit of accessing lower-cost wood chip supplies.

In fact, wood chip costs underlie all of the fuel prices used in this analysis. Wood pellets and torrefied wood pellets use high quality wood chips in their production. The cost of the wood chips (dry basis) is reported to be approximately 50% of the total production cost for wood pellets.

Based on past biomass supply survey work, the price for securing green wood chips for energy projects currently ranges from \$20-40/ton delivered, depending on the region. For this analysis, it was assumed that the price for wood chips in the Southeast U.S. (the location of the baseline coal plant) is \$23/ton delivered (RISI 2010), with a delivery distance of approximately 50 miles.

Wood pellet and torrefied wood pellet prices are considerably higher. FOEX Indexes Ltd. listed recent prices for wood pellets at 28.74 Euros/MWh, or approximately \$11/MMBtu. As it is difficult to determine from the limited available data if this price reflects long-term demand or other factors (and given that anecdotal pricing for the U.S. market appears to be 25-30% lower), the authors have estimated wood and torrefied pellet pricing based on a 2005 financial analysis by Bergman et al. The authors estimated the cost of the production of wood pellets and torrefied wood pellets from sawdust and green wood chips, respectively, and estimated the feedstock, production, and transportation costs of both pellet types. The current study uses the production, financing, and depreciation costs per ton of pellets made from green wood chips presented by Bergman et al., scaled for inflation. A 10% profit margin was added, and transportation costs based on a delivery distance of 50 miles by tractor trailer were also included.

Coal prices (used in the cofiring analysis) were based on EIA 2009 average prices for bituminous coal. The resulting total delivered costs for all fuels used in the analysis are shown in Table 5-13.

Table 5-13
Fuel Cost by Type

Fuel	Price \$/ton, Delivered	\$/MMBtu
Coal	\$ 99.84	\$4.28
Green Wood Chips	\$ 23.00	\$2.62
Wood Pellets	\$ 156.51	\$9.26
Torrefied Wood Pellets	\$ 185.42	\$9.70

It is difficult to judge how reasonable the price estimates for torrefied wood are, since production at scales to support utility fuel use is currently non-existent and the published data are limited. However, it seemed reasonable to the authors that the cost of producing wood pellets and torrefied wood pellets would be similar, with an incremental increase for the torrefied pellets.

Other Key Inputs and Assumptions

The economic analyses presented below rely on LCOE as the comparative metric. Inputs and references for the financial inputs common to all of these analyses are provided in Table 5-14.

Table 5-14
Key Financial Inputs

Escalation	
Labor (per year)	3.37%
General (per year)	3.00%
Fuel (per year)	2.74%
Taxes	
Federal Tax Rate	34%
State Tax Rate	6%
Production Tax Credit (\$/ kWh)	n/a
Production Tax Credit Term (years)	n/a
Combined Tax Rate	37.96%
Financing	
Debt Ratio	45%
Equity Ratio	55%
Interest Rate on Debt	5.5%
Cost of Equity	12.0%
Weighted Average Cost of Capital	8.14%
Economic Life (yrs)	20
Operating Assumptions	
Max Hours per Year	8,760
Capacity Factor	85%

Table 5-15 shows key operating inputs for fuel, electricity generation, and O&M costs.

Table 5-15
Operating inputs

Key Inputs and Output	1	2a	2b	3a.1	3a.2	3b.1	3c.1	4
Fuel Cost and Operation Data Summary								
Biomass Fuel Cost (\$/ton as recvd)	\$23	\$157	\$157	\$185	\$185	\$185	\$185	\$23
Biomass Fuel Cost (\$/MMBtu)	\$3	\$9	\$9	\$10	\$10	\$10	\$10	\$3
Coal Fuel Cost (\$/ton)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$100
Coal Fuel Cost (\$/MMBtu)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$4
Annual Fuel Cost	\$20,002,934	\$61,240,346	\$87,752,579	\$74,900,978	\$93,194,765	\$74,900,978	\$74,900,978	\$26,019,964
Electricity								
Net Annual Electricity Generation (kWh)	613,293,513	609,418,825	878,967,525	765,724,944	959,839,132	765,724,944	765,724,944	633,633,934
Net Plant Capacity (kW)	82,365	81,845	118,046	102,837	128,907	102,837	102,837	85,097
Plant Capacity Factor	85%	85%	85%	85%	85%	85%	85%	85%
Annual O&M								
Fixed Cost - Labor (\$/kW-yr)	\$33.44	\$32.58	\$22.66	\$25.93	\$20.68	\$25.93	\$25.93	\$37.12
Fixed Cost - Non Labor (\$/kW-yr)	\$33.10	\$33.27	\$23.43	\$26.66	\$21.45	\$26.66	\$26.66	\$37.82
Variable Cost (\$/kWh)	\$0.0020	\$0.0009	\$0.0009	\$0.0009	\$0.0008	\$0.0009	\$0.0009	\$0.0020

In addition to these standard inputs, a few other items are worth noting:

- AFUDC expenses are assumed to occur over a two-year period, with the majority of expenses occurring in the second year. In most cases, this increased capital expenses by 10-15% above the overnight construction cost.
- Depreciation is taken on a 20-year MACRS schedule, and only new capital expenses are depreciated. The comparison assumes implicitly that the baseline coal plant is fully depreciated.
- LCOEs are expressed on a current and constant dollar basis. Inflation is included in the current dollar calculations and excluded from the constant dollar calculations.
- No incentives, such as tax credits or grants, were included in any of the cases.

Economic Analysis Results

The results of these economic analyses, showing both current and constant LCOE values for each of the proposed scenarios under consideration, are presented in Figure 5-1.

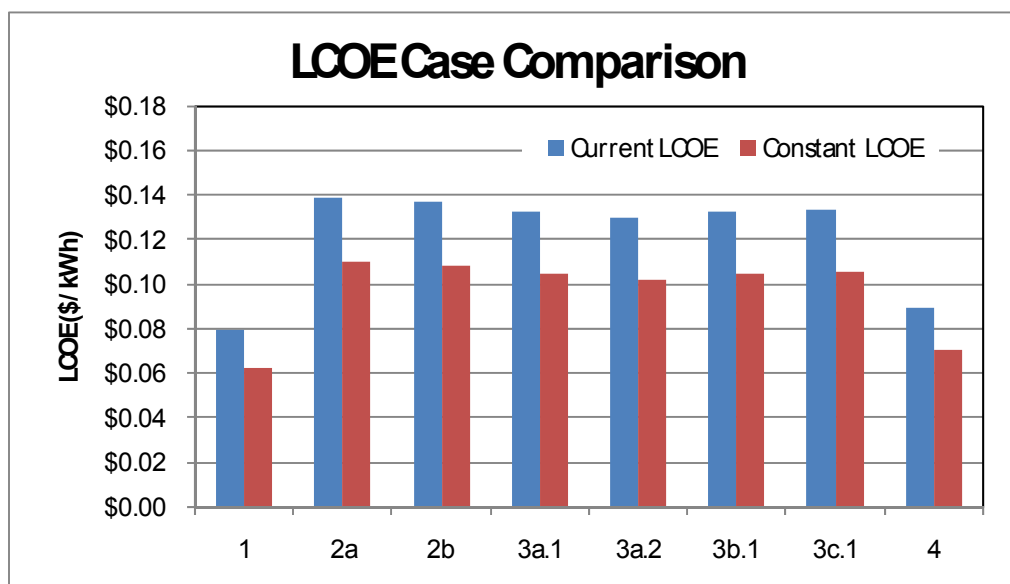


Figure 5-1
LCOE Results

Additionally, the constant LCOE values were broken down into their individual cost components. These breakdowns are presented in Figure 5-2 for each case on a \$/kWh basis. The three components separated out for this analysis were:

1. Fuel costs,
2. Capital recovery and taxes, and
3. Labor and O&M costs.

Cost Components Constant LCOE

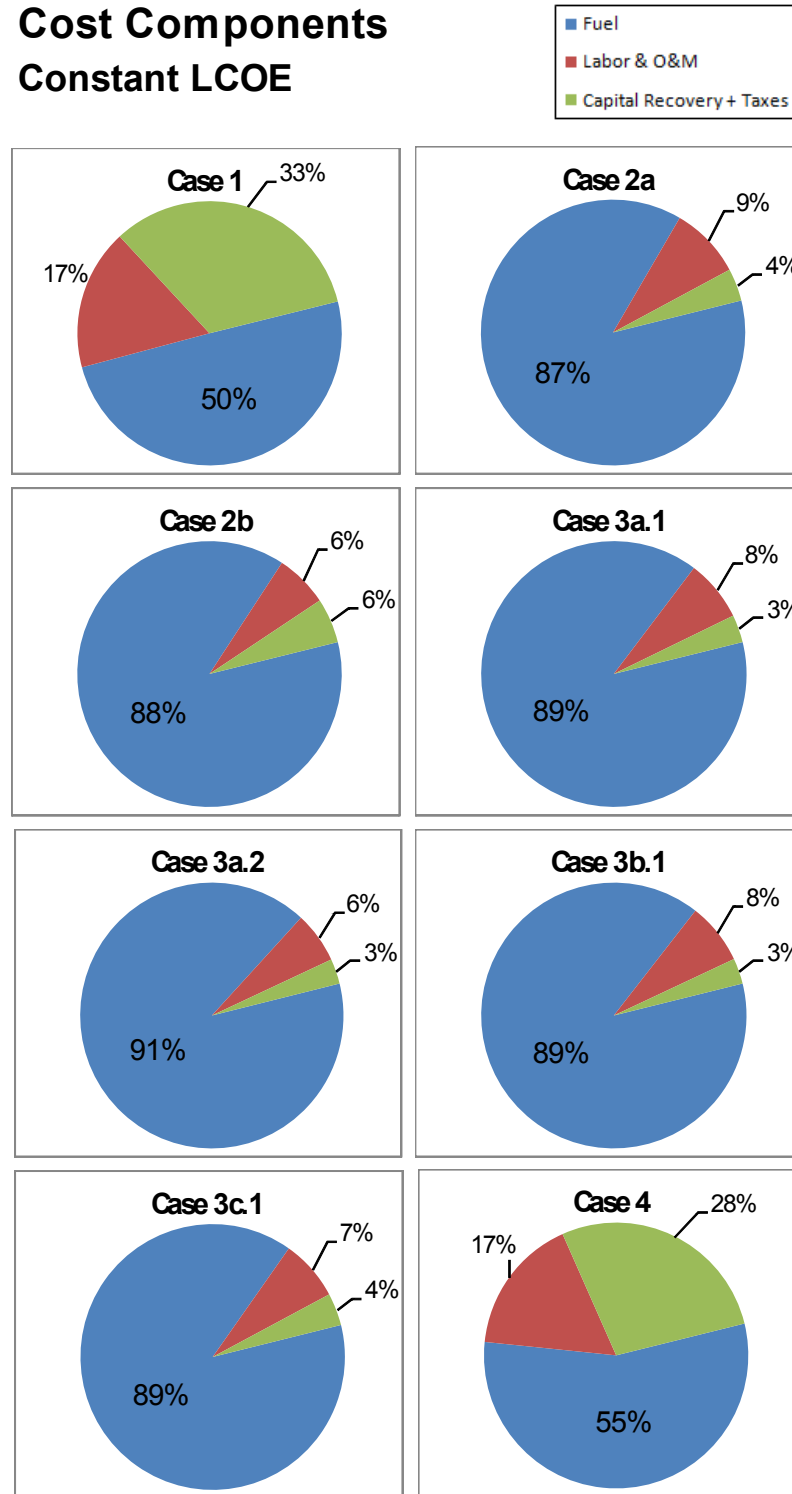


Figure 5-2
Cost Components; Constant LCOE

As one would expect, the production cost of the lower-capital cases were dominated by the cost of fuel. This line item was relatively consistent across the pelletized fuel cases at just under 90% percent of the LCOE.

Sensitivity analyses were also conducted to examine how the cost changes would be impacted by variations in key inputs. The following three inputs (with their respective identified ranges of potential variation) were modified to determine their influence on the final results:

1. Capital cost: -25% to +25%
2. Fuel cost: -50% to +50%
3. Capacity factor: 50% to 90%

Figure 5-3 through Figure 5-8 below display the sensitivity of each case to these three variables. Note that only a single variance is changed at a time, independently of the other two. Sensitivity cases are not presented for Cases 3b.1 or 3c.1 as they showed very similar results to case 3a.1.

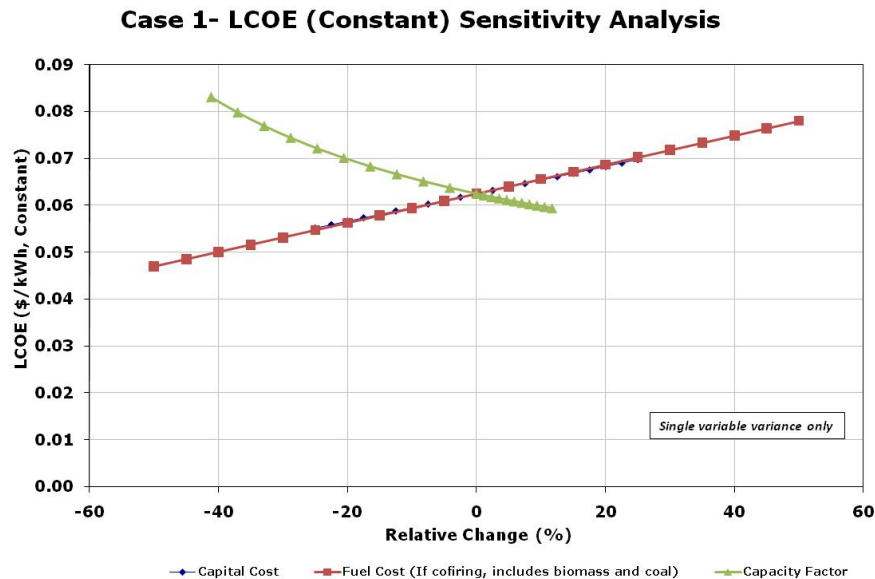


Figure 5-3
Case 1 – LCOE (Constant) Sensitivity Analysis

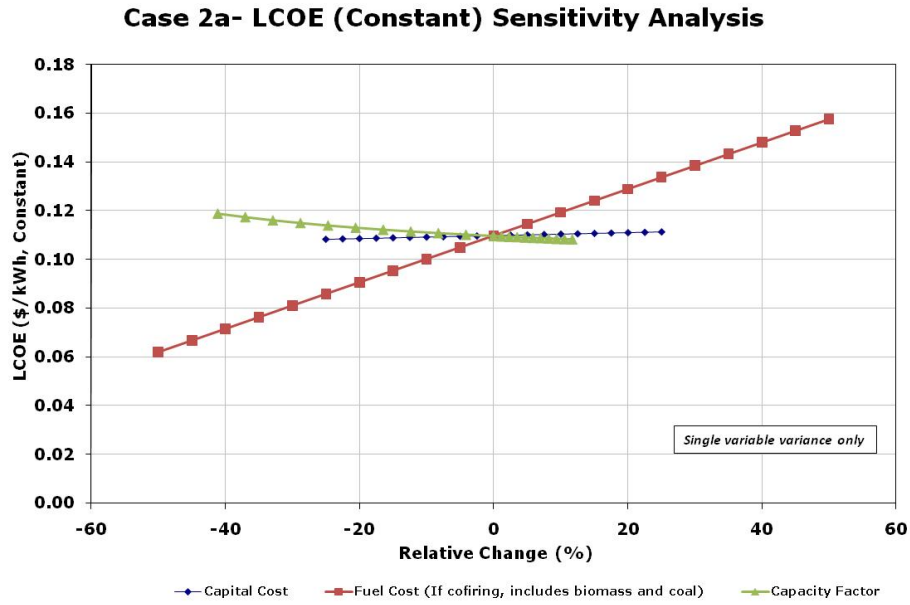


Figure 5-4
Case 2a – LCOE (Constant) Sensitivity Analysis

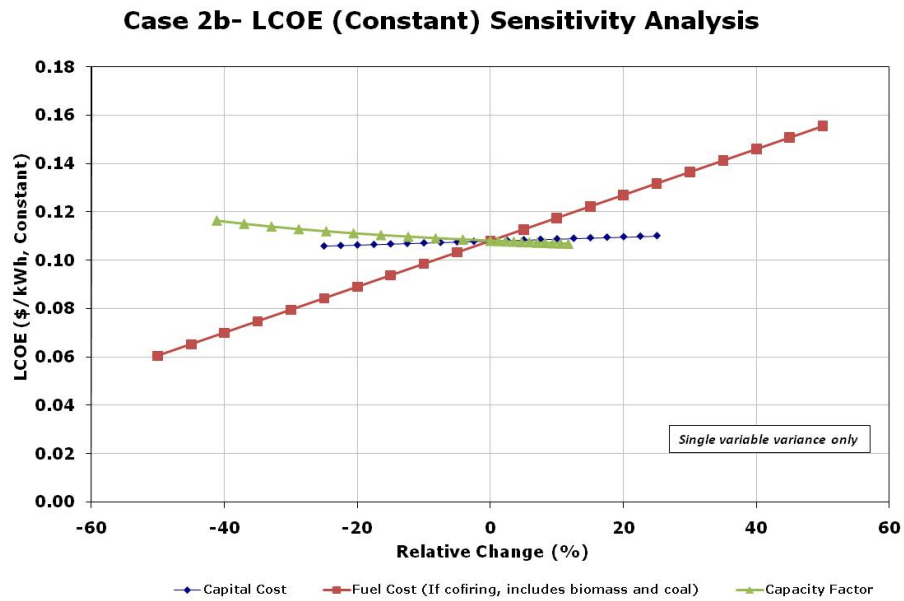


Figure 5-5
Case 2b – LCOE (Constant) Sensitivity Analysis

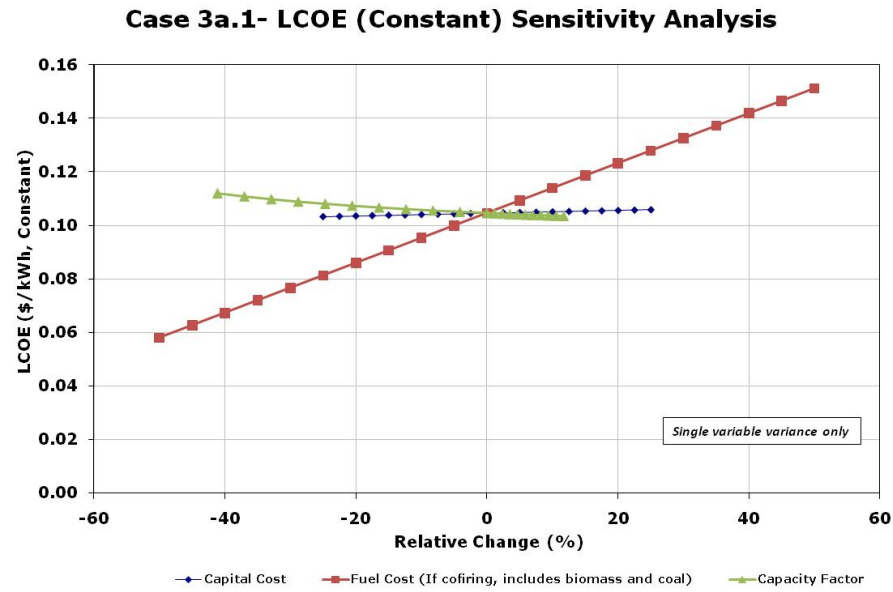


Figure 5-6
Case 3a1 – LCOE (Constant) Sensitivity Analysis

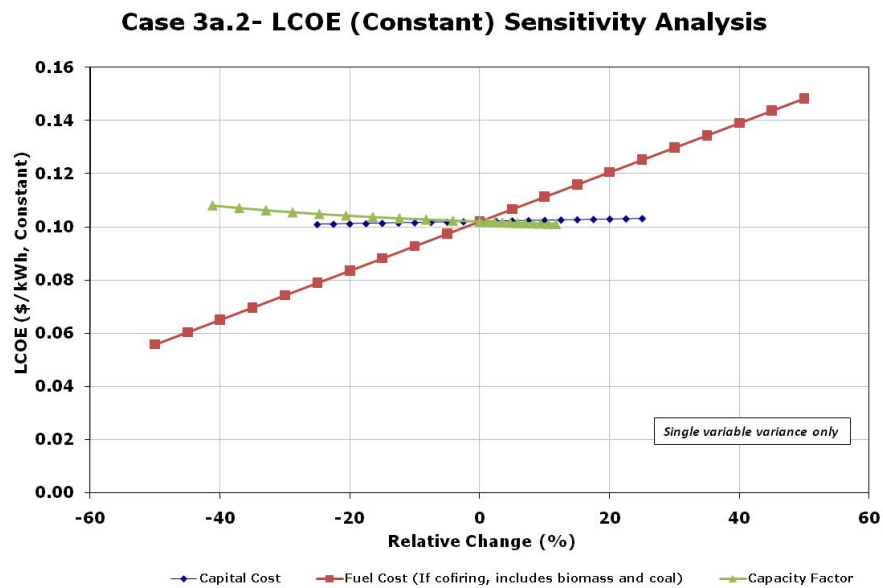


Figure 5-7
Case 3a2 – LCOE (Constant) Sensitivity Analysis

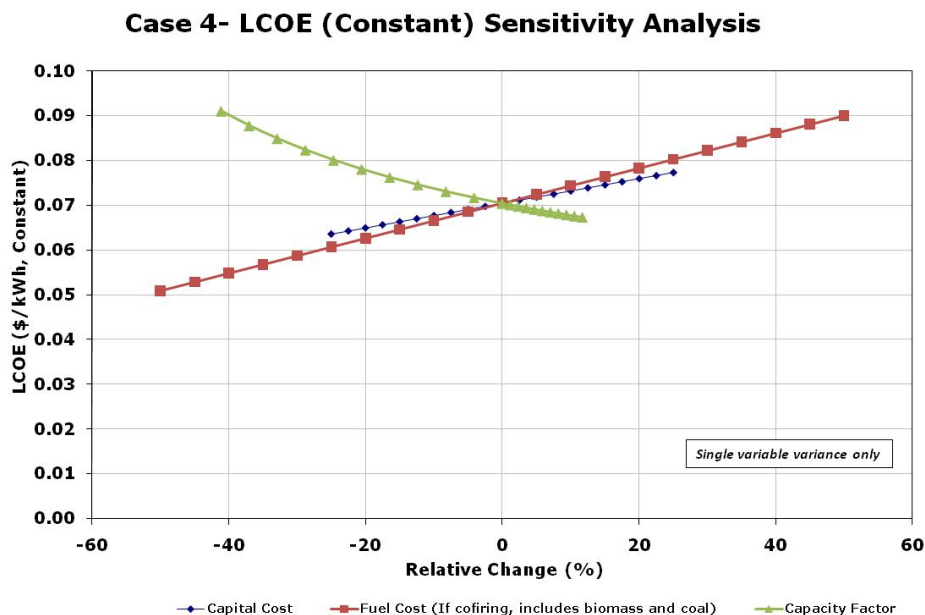


Figure 5-8
Case 4 – LCOE (Constant) Sensitivity Analysis

The results from the sensitivity analyses tell much the same story. While capacity factor had a major influence on cases 1 and 4 (driven by large, fixed capital-recovery costs), the pelletized fuel cases (cases 2 and 3) varied most significantly with changing fuel costs.

Discussion

It is perhaps not surprising that the results of this analysis suggest that, given the prices projected for wood pellets and torrefied pellets in this report, cases utilizing these biomass fuels still do not justify the avoidance of the large upfront capital costs required by the other cases. The difference in fuel cost between the two most comparable cases with respect to output (case 1 and case 2) is nearly \$40M per year. It is also not surprising that the results of the biomass gasification case fell comfortably in the middle. Case 4, which has the highest level of fuel processing (solid to gaseous state), suggests that gasification on-site holds a demonstrable cost advantage over even highly processed solid fuels, presuming that feedstock is plentiful and can be sourced within a reasonable transport range.

Although the disparity between the high- and low-performing cases is wide, the analysis does become more interesting when one considers the potential for the pelletized fuels to experience lower production costs than those assumed above. Given that large-scale torrefied wood pellet production isn't even a reality yet, it is perhaps too early to judge the industry's ability to reduce production costs, and the sensitivity analyses presented above hint at a potentially brighter future for this fuel. Based on the analysis above, the financial viability of cases 2 and 3 could potentially break even with case 1 if torrefied wood pellets can be produced at lower cost. Breakeven fuel costs for cases 2 and 3 were calculated, and these are presented in Table 5-16.

Table 5-16
Breakeven Comparison

Case Name	Fuel Price to Breakeven with Case 1 (\$/ton)
Case 2a: Wood Pellets	\$78.00
Case 3a.1: TWP	\$97.00
Case 3a.1: TWP (no capital investment)	\$105.00

The last row in Table 5-16 is included to offer a glimpse at the ultimate potential for torrefied wood pellets, which is that it could allow for a coal facility to completely switch to biomass with little or no capital investment. Under these circumstances, the delivered price for torrefied wood pellets would need to reach \$105/ton (delivered) to achieve an LCOE similar to case 1. This is significantly lower than the \$185.42/ton assumed for this analysis, but given the comparatively early development stage of this technology, this goal is perhaps achievable. Some technology developers suggest that a production cost of \$100/ton is possible, if sources of existing waste heat (or inexpensive relatively low grade heat) can be integrated into the process to reduce thermal energy costs.

6

INDUSTRY IMPLICATIONS ANALYSIS

In general, facility location will have a considerable impact on the viability of a repowering project, as this will affect technology selection, fuel availability, economic inputs, regulatory/legislative drivers, and environmental considerations. Additionally, the configuration and equipment at the existing facility itself will be crucial for the selection of an appropriate repowering technology. Capital and O&M cost projections will depend on fuel resource costs and availability, permitting requirements and regulations, and labor rates, as well as other local factors. All of these items must be considered when evaluating repowering options.

Although the technical details presented in this report could be applicable anywhere, any location-specific factors (such as labor costs) have assumed that the repowered plant is located in the Southeast U.S. This chapter will provide an overview of the key factors and variables that are likely to change on a regional or local level, in order to provide a more complete picture of repowering opportunities across the country. Where possible, these factors are quantified by region based on publically available data sources to show a range of potential values. The overall impact of these factors on project feasibility and economics is also discussed to better determine which of these variables are the most important to consider. A qualitative summary of how the key factors change by region is also provided.

Data Sources

A variety of public data sources were used to compile information regarding resource availability and state and regional statistics. These sources included:

- Environmental Systems Research Institute Data & Maps Media Kit: Spatial data for transportation networks, national and civic boundaries, and water bodies.
- Emissions & Generation Resource Integrated Database (eGRID): Data pertaining to the national fleet of power plants. The most current published version dates to 2007, and includes operating statistics reflecting the state of the electric industry in the years 2004 and 2005. The database includes plant-specific data for all electricity-generating plants in the U.S. that provide power to the electric grid and report data to the U.S. government.
- NETL 2005 Coal Plant Database was used for specific information on coal plant types and pollution controls.
- Platts *World Electric Power Plants Database* (2005 release) was used for location data on utility-scale power plants with natural gas boilers.
- Standard Federal Regions were used for any regional aggregation of data.

- U.S. Bureau of Labor and Statistics: Labor rates were compiled from the US-BLS using the 2009 50th percentile Power Plant Operator wage, corresponding to the rate used for operations and maintenance staff in the economic calculations of this report.
- Information on Canadian pellet producers was taken from the Canadian Report on Bioenergy 2010.²⁸
- Information on U.S. pellet producers was taken from the USDA's report "North America's Wood Pellet Sector."²⁹
- Wood pellet pricing was taken from <http://www.woodpelletprice.com/>.
- NREL's interactive biopower tool (2008 version) was used for biomass resource assessment.
- The U.S. Energy Information Administration provided state-average prices for electricity for the year 2008.
- RPS and regional carbon initiative data were obtained from the Database of State Incentives for Renewables & Efficiency³⁰ and the Pew Center on Global Climate Change.³¹

Regional variations for selected factors are considered based on the ten standard Federal Regions (as established by the Office of Management and Budget in 1974), illustrated in Figure 6-1.

²⁸ Bradley, D. "Canadian Report on Bioenergy 2010." Canadian Bioenergy Association and Natural Resources Canada - Canadian Wood Fibre Center. September 15, 2010. P31.

²⁹ Spelter, Henry; Toth, Daniel. 2009. "North America's Wood Pellet Sector." Research Paper FPL-RP-656. Madison, WI: U.S. Department of Agriculture, Forest Service, Forest Products Laboratory. P11-17. http://www.fpl.fs.fed.us/documnts/fplrp/fpl_rp656.pdf

³⁰ <http://dsireusa.org/>

³¹ Pew Center for Climate Research

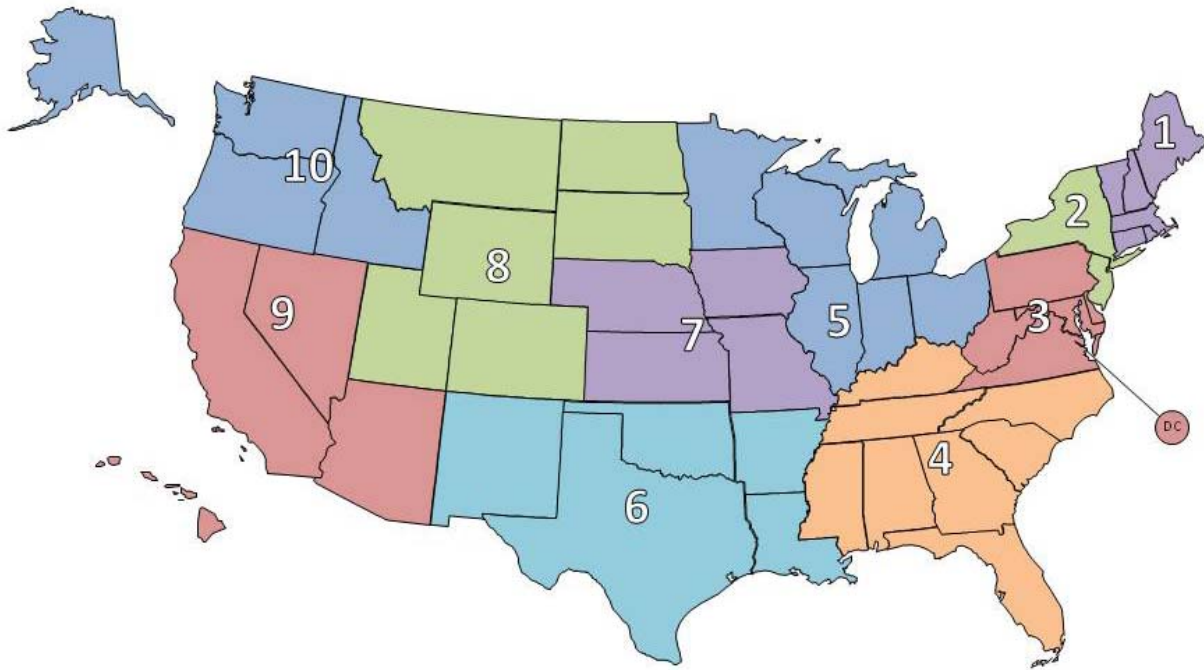


Figure 6-1
Standard Federal Regions

Analysis of Regional Variation of Key Factors

The following analysis provides maps and figures showing variations in some of the key factors that are considered important for biomass repowering projects.

Facility Locations for Repowering Candidates

As mentioned previously, it is useful to understand the distribution of the repowering candidate facilities, as this will affect technology selection. The facility locations will also affect the other factors considered in this discussion. A map showing the locations of the existing coal, gas, and oil-fired boilers in the U.S. is provided in Figure 6-2. Based on these data, it is seen that coal-fired boilers are much more densely distributed in the eastern part of the country. Natural gas fired boilers are more concentrated in the south-central U.S. and California, while oil-fired boilers tend to be located along the northern Atlantic coast and in Florida.

The distribution of coal boilers by type is illustrated in Figure 6-3. Pulverized coal plants make up the majority of the fleet, and are relatively evenly distributed amongst the existing facilities. Cyclone-fired boilers are mostly concentrated in the Great Lakes region, with some plants in the East and Midwest. Stoker boilers are also in the Great Lakes region, as well as the Midwest and some of the Southeast.

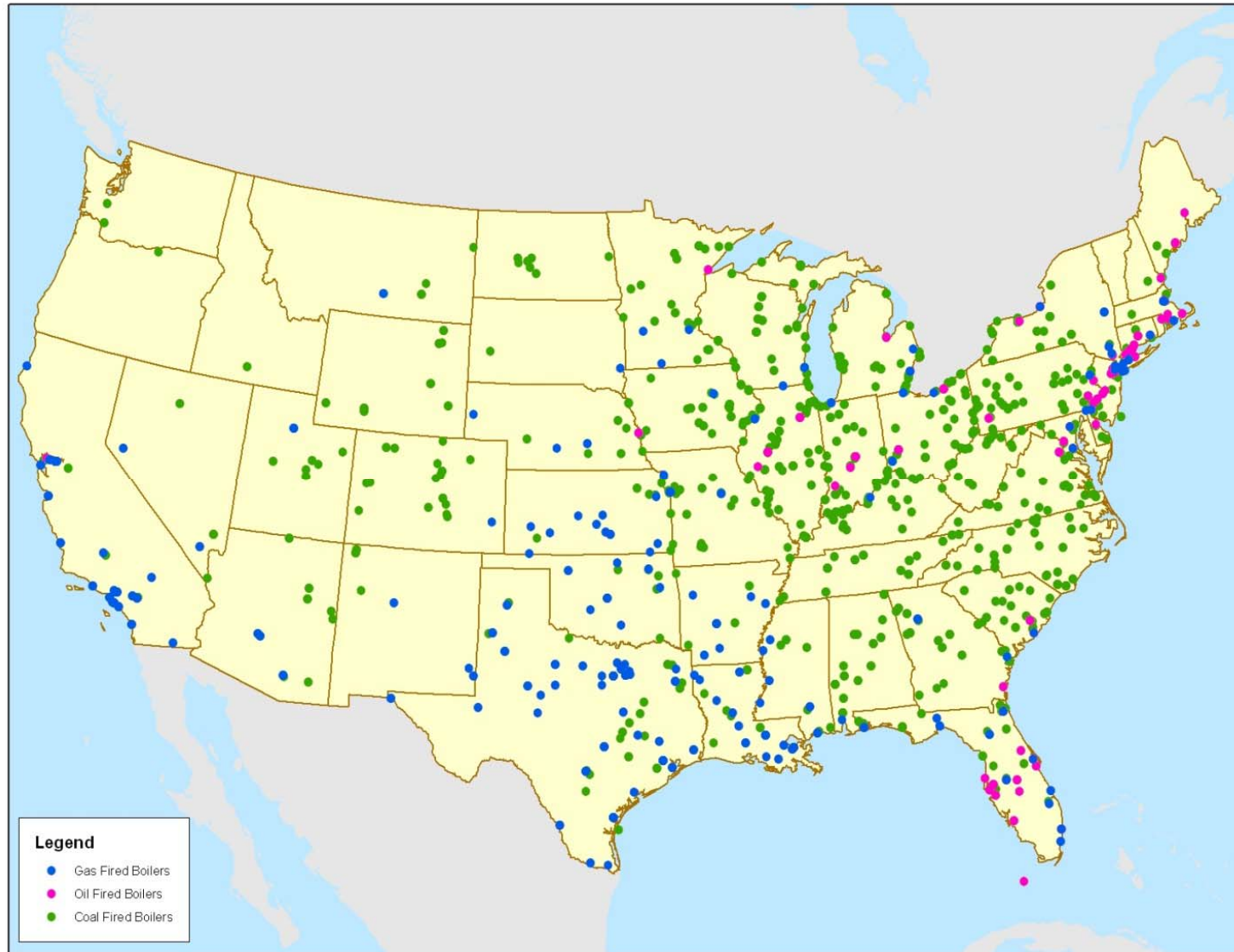


Figure 6-2
Fleet of Coal, Oil, and Natural Gas Fired Boilers

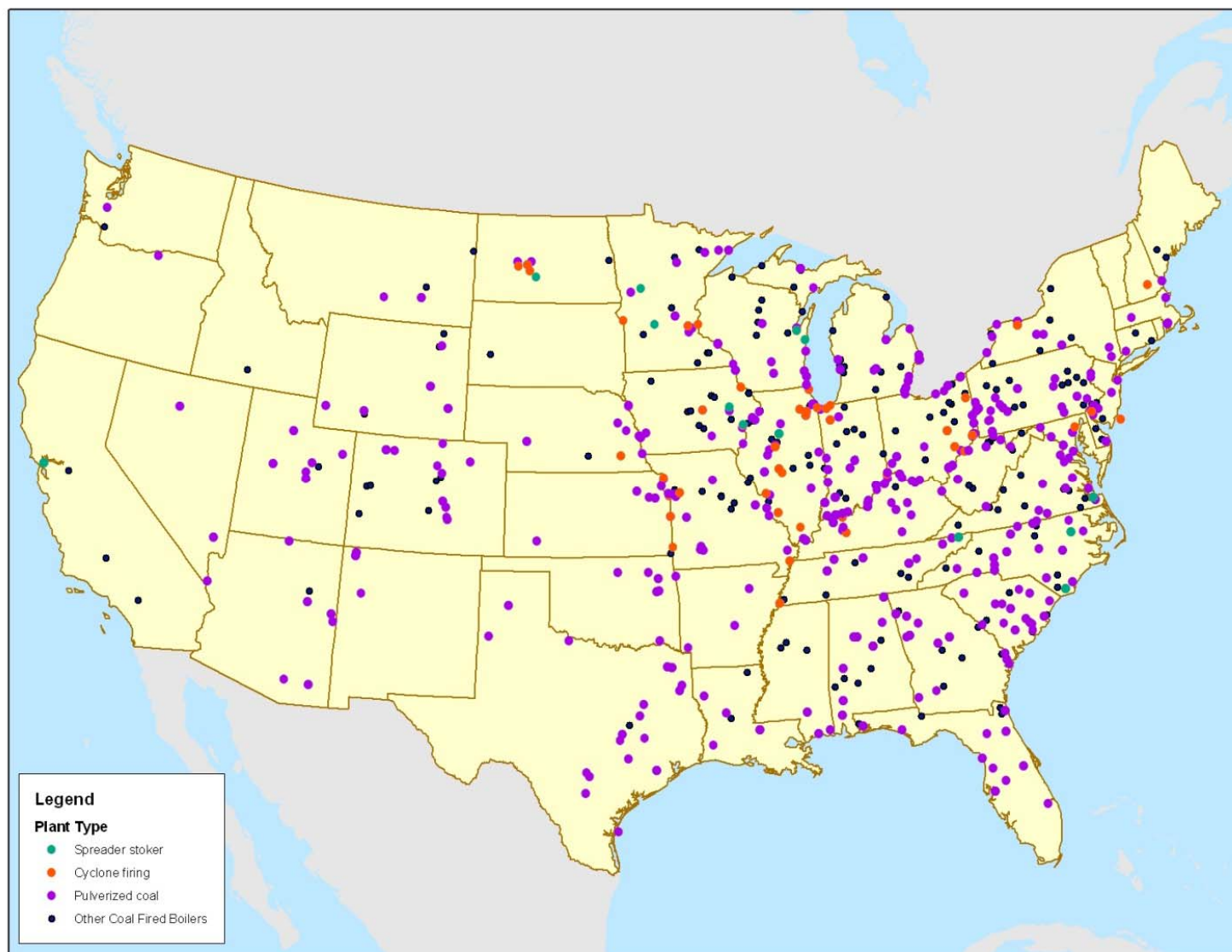


Figure 6-3
Types of Coal-fired Boilers

Biomass Resources and Transportation Modes

Fuel resource availability can be characterized by location and the selected fuel's supply shed. The distance from which the fuel is sourced will have a large impact on the quantity and cost of feedstock materials. The economic distance over which biomass fuels can be transported is a factor of both transportation mode and fuel type, as denser fuels are cheaper to ship on an energy basis. Rail and barge transport is generally cheaper than truck transport over large distances.

Within the detailed case study analyses presented in the previous chapters, it was assumed that all biomass feedstocks could be sourced locally (within 50 miles of the facility), and would be transported and delivered via truck. This is generally consistent with the way that wood chips and other un-processed biomass materials are typically collected and transported. Wood chips and sawdust are likely to come from multiple small, distributed sources such as sawmills, landfills, and transfer stations, as well as timber harvesting operations within a 50- or 100-mile radius of the facility. Truck transportation is well suited to the small shipment sizes, relatively short haul distances, and geographic diversity typical of wood chips. Furthermore, the extensive road network (and the fact that truck transport does not require such specialized equipment) makes it much more appealing for collecting such a distributed resource.

However, the same benefits of truck transportation that make it appropriate for collecting and transporting wood chips are not as important for pelletized fuels. Wood pellets and torrefied wood pellets are likely to be supplied to a power station from fewer suppliers. The aggregation of woody materials is performed by pellet producers prior to densification and processing, which significantly reduces the effort required by the end user. Since pellets can be delivered in fewer shipments and from fewer suppliers than wood chips, barge and rail transport methods are more likely to be economically viable. Field-sourced biomass (like wood chips) would first need to be collected and hauled by truck to an aggregation point, and then loaded into a barge or rail cars. Using two transportation modes tends to significantly increase transportation costs due to the additional handling and processing involved in several rounds of loading and unloading.

The more energy dense wood pellet and torrefied wood pellet fuels considered in these case studies can be economically transported over longer distances than wood chips. Barge and rail transportation methods tend to be more expensive than truck transportation for short deliveries, but cheaper over long hauls. For each transport mode, there is a fixed cost for loading and unloading (in \$/ton), as well as a distance-variable cost for transportation (\$/ton-mile).³² The fixed cost component is larger for rail and barge transportation than for truck transportation, but the variable distance cost is smaller. As a result, there is some distance at which it becomes cheaper per unit of fuel to transport via rail or barge than by truck.

³² The variable distance cost is usually linear, as contributing factors such as wages, fuel, and capital recovery for the transportation equipment are directly proportional to the distance traveled (Mahmudi & Flynn, 2006).

A simplified analysis was performed to estimate these distances for wood pellet and torrefied wood pellet fuels. Overall, it is assumed that for distances under 100 miles, truck transport will be the preferred option. For distances greater than 160 miles, rail transport is estimated to be less costly than truck transport. Barges are less expensive than both truck and rail transportation for any distance over 100 miles up to 1,340 miles, at which point rail transportation becomes less expensive.³³ Additional information about this analysis is available in Appendix B.

It is important to point out that this simplified analysis presumes that no additional transfers will be required to move the fuel across the considered distances (i.e., the fuel will only be loaded and unloaded once). This results in a linear estimation of the variable distance costs for all modes of transportation. However, rail costs in particular can have non-linear costs as a function of distance due to the fact that rail switches are a key cost driver. The number of switches necessary to transport a unit train from one location to another is not always a function of distance, but rather of what rail corridor each location is near. An assessment of these costs is complex for a national-level analysis, but biomass project developers who wish to use rail transportation should consider number of switches as a potential cost indicator when evaluating suppliers at varying locations and distances from the project site.

The barge transport cost calculation also assumes that the fuel can be transported with the same barge for its entire journey, which is not always the case. River-going barges cannot generally be towed on the ocean, ocean barges with deep drafts cannot usually be taken on rivers, and standard river barges may have to be exchanged for smaller barges with shallower drafts in order to pass certain sections of a river. Any transfer of fuel from barge to barge will incur fixed loading and unloading costs, port fees, and other fixed costs that increase transportation costs without any increase in the distance travelled. These additional costs also need to be evaluated on a project-specific level. If truck transport is required to move the material at either side of the transportation channel (from pellet manufacturer/supplier to port or rail station, or from the port or rail station to the power plant), that can also add significant extra cost. In general, distance may not be as important a cost driver as the number of transfers necessary. Each transfer will also degrade the quality of any pellet fuel, as it is exposed to more moisture and can be broken through impacts with hard surfaces. This will increase the content of fines in the delivered fuel, which can create material handling problems that can negatively impact plant operations.

Figure 6-4 overlays the existing coal plants, railroad lines, and ports with the total U.S. biomass resource. This is useful to illustrate where the potential fuel sources are located relative to some of the candidate plants for repowering and the transportation modes available to deliver the fuel. The ability to utilize rail delivery of fuel at a particular site will clearly depend on the proximity of rail stations or spurs to both the pellet or torrefied pellet supplier and the power plant itself, while barge delivery will require a nearby port. As seen in the map, many of the existing coal plants are located near rail lines, and these are likely to already be set up for coal delivery and unloading, as this is a standard transport method for coal. However, if the specialized unloading equipment is not already installed, this could add significant cost to the repowering project (this will likely be most relevant to existing gas- and oil-fired plants).

³³ These calculations are based on the costs for river barges. Ocean vessels were not explicitly included in this analysis.

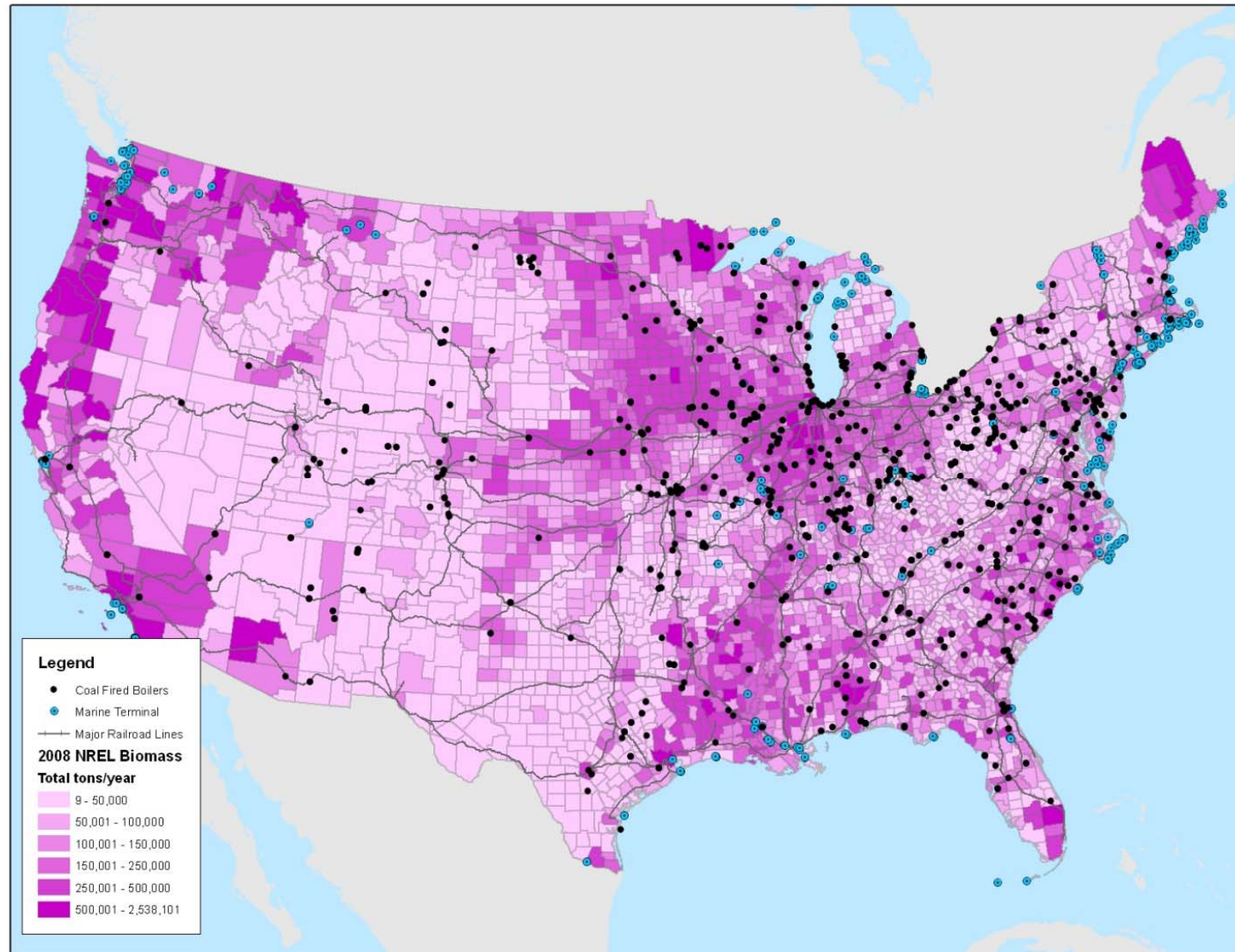


Figure 6-4
Summary of Biomass Resource Availability and Transportation

Using locally-sourced biomass fuels within a 50- or 100-mile radius would severely restrict the number of facilities that can be repowered with biomass, since there needs to be a sufficiently large resource nearby to provide reliable long-term supply. As a result, regions that have limited biomass resources (such as in southwest states like Arizona and Nevada) are not usually considered for utility-scale biomass energy projects. However, being able to economically source biomass fuels from further distances changes the picture considerably. Repowering projects considering pellet fuels would be far less limited if they were able to receive fuel supplies using rail or barge transportation and delivery.

Since they can be economically transported over much larger distances, pellets do not need to be sourced from such a limited supply shed as wood chips. This is an important consideration for these types of repowering projects, particularly considering that there are many fewer suppliers for these materials. Figure 6-5 shows the locations of pellet manufacturers in North America. Overall, the combination of fewer available suppliers and the availability of longer-distance transportation modes makes it more likely that pelletized fuel will be shipped further distances than wood chips. Wood pellets are already shipped in large quantities over long distances, often utilizing barge transportation and international trading. Canada, Finland, and other countries regularly export wood pellets, which are used for energy production projects in countries like Belgium, the Netherlands, and the UK (Junginger, Bolkesjo, Bradley, Dolzan, Faaij, et al., 2008). Exports are also increasing from the U.S. to serve these European markets.

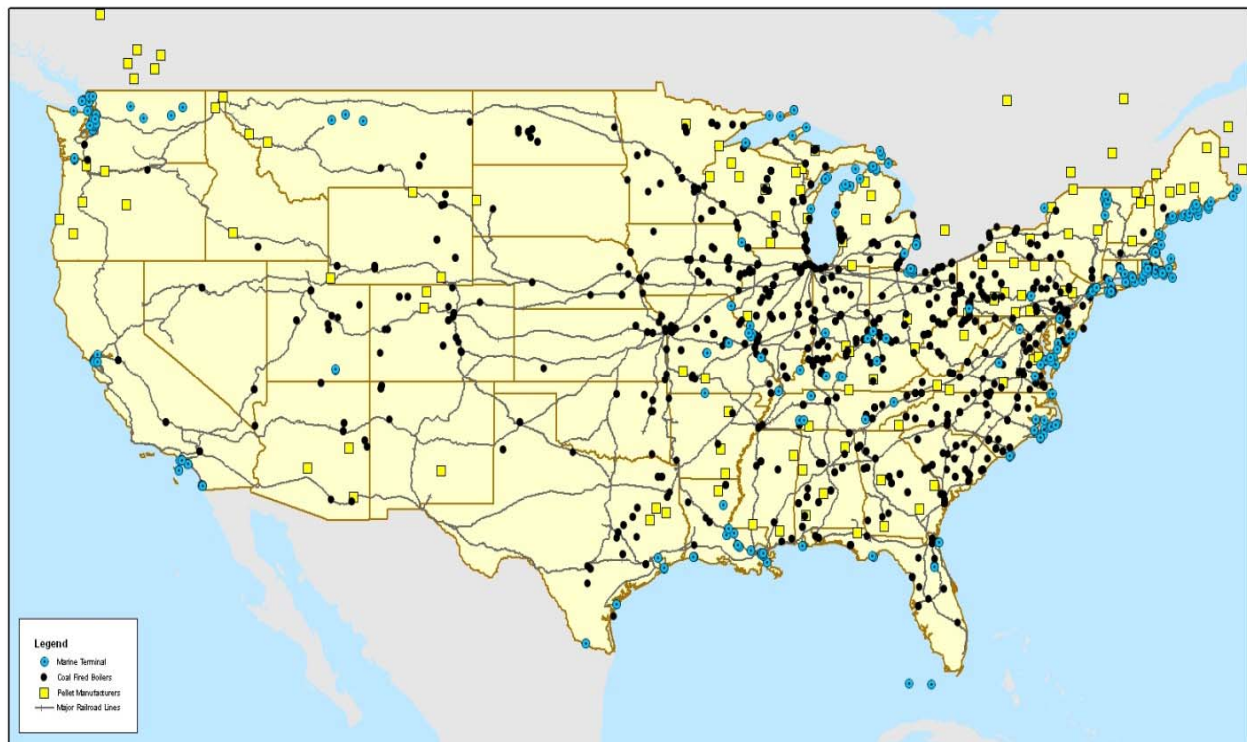


Figure 6-5
Pellet Plant Locations

Economic Factors

In addition to fuel transportation costs, a variety of other regional economic factors can impact the project economics. Some of these factors are illustrated in the following graphics, including pellet fuel costs (Figure 6-6), hourly wage rates (Figure 6-7), and the cost of electricity (Figure 6-78). It is important to note that retail pellet prices are likely to be significantly higher than the prices that a power plant would actually have to pay for bulk pellet purchases. However, these retail price data are intended to serve as a proxy to illustrate current price differences between states, and the results demonstrate a wide variability in market prices.

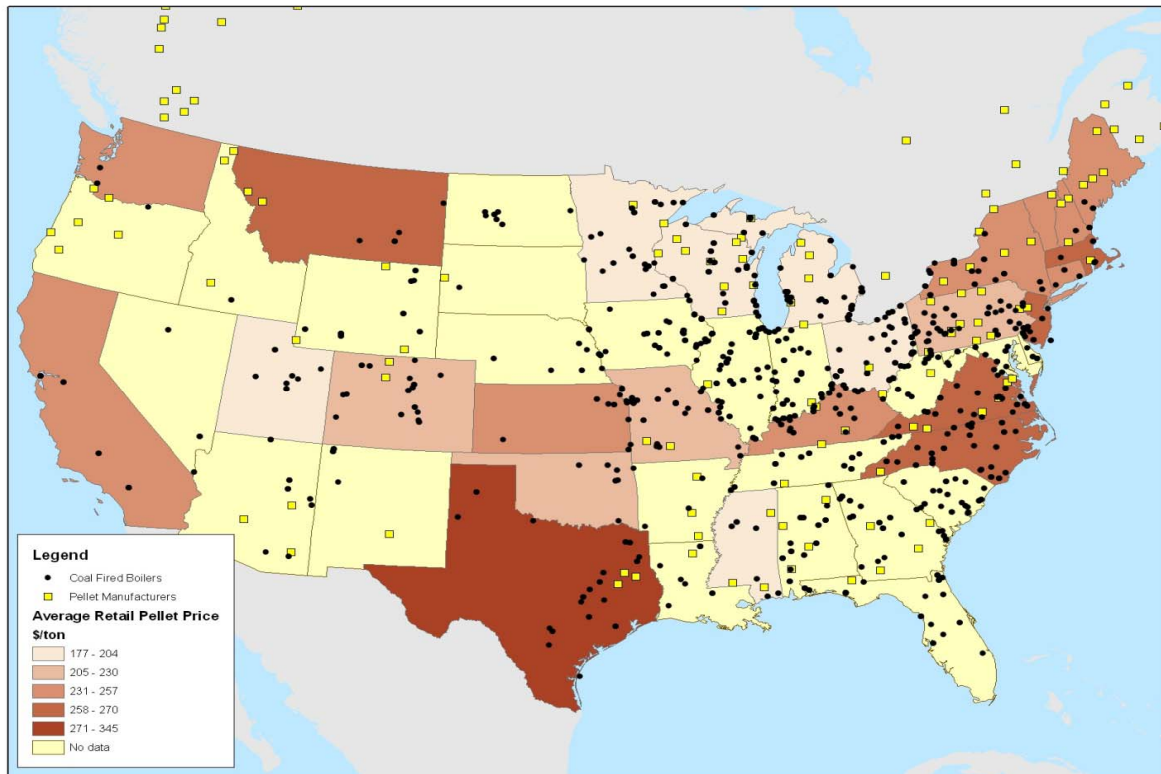


Figure 6-6
Average Retail Pellet Prices

There is also a fair amount of variability in average labor rates from one state to another. Hourly wage rates for power plant operators are used to illustrate the variation for a standard power plant employee. The average rates for other types of laborers also vary by state, but do not necessarily follow the same pattern. Actual expected labor costs for repowering projects will need to be evaluated on a case-by-case basis.

The electric rates presented in Figure 6-8 are state-average rates across all sectors, including commercial, industrial, and residential sectors.³⁴ These average rates vary tremendously, from \$0.056/kWh to \$0.178/kWh. This is clearly a crucial part of any power plant's overarching economics, as their revenue is directly related to the price of their product.

³⁴ This map and represented data only corresponds to the continental U.S., and do not include Hawaii or Alaska.

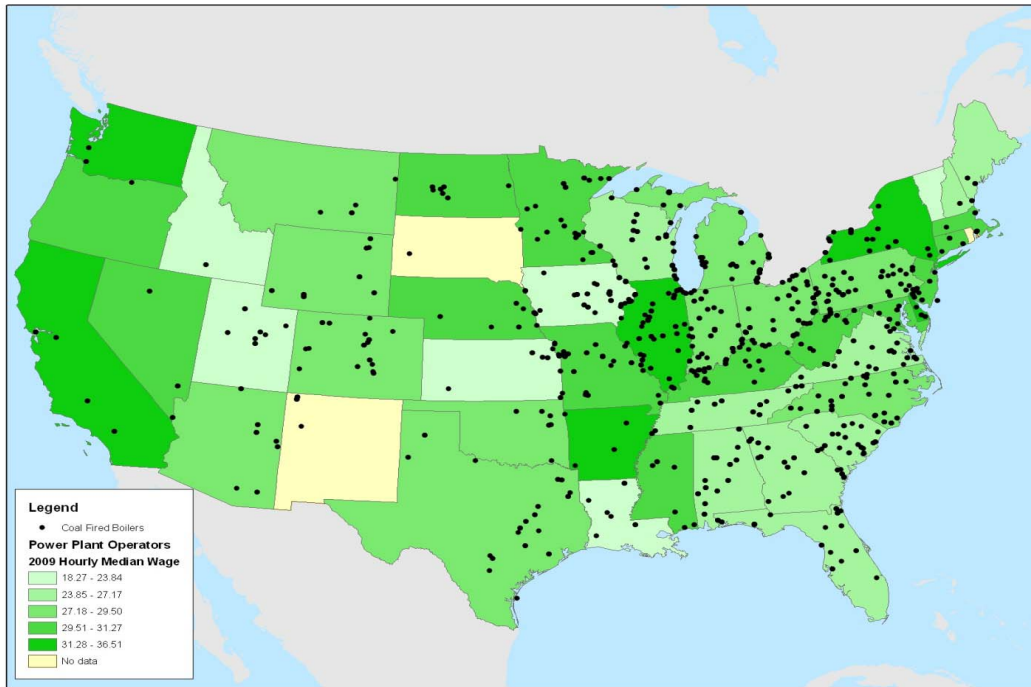


Figure 6-7
Hourly Median Wage for Power Plant Operators

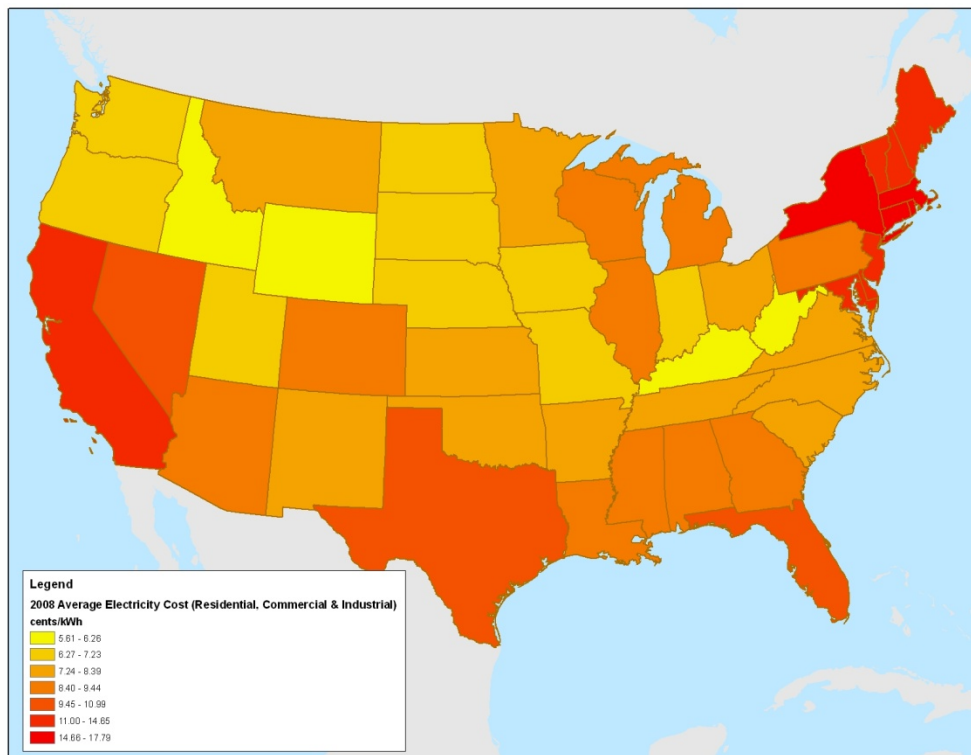


Figure 6-8
State Average Cost of Electricity

Property Taxes

As discussed previously in Chapter 5, property taxes are typically negotiated on a local level and are subject to political forces and negotiation. Publicly available data were not identified that summarize these costs on a statewide or regional level. In general, it is not clear what net impact a repowering project will have on local property taxes, so it is expected that these taxes will need to be considered on a case-by-case basis.

Permitting Lead Times

The time required to complete Title V permitting under the Clean Air Act can be significant and varies widely from state to state. Recently, the EPA began a program to encourage state governments to improve the process and reduce permit review time. A bulletin discussing the results of the program cites significant improvements in the process, and illustrates the range of lead times that can be expected. For example, Indiana reduced the time needed to issue Title V renewals in air permitting from 928 to 270 days, while Michigan decreased the processing time for major air construction permits from 422 to 98 days (U.S. Environmental Protection Agency, 2009).

Incentives and Environmental Standards

There was some discussion of regional variation in incentives in Chapter 2, including mention of the available incentives in several states in particular. In general, state incentive programs vary widely in terms of the available incentive types and amounts and eligibility requirements. Many states use a Renewable Portfolio Standard (RPS) to set their renewable energy goals, but the overall targets, resource applicability, and rules for RPS implementation vary considerably. REC markets and carbon initiatives/markets are regionally dependent, and these added revenue streams can have a significant impact on renewable energy project economics.

Renewable Portfolio Standards

An RPS creates a requirement for retail electric power suppliers, such that a minimum percentage of energy sold must be generated by renewable energy sources. Attempts to pass federal RPS legislation have faced stiff opposition, in part because of the unequal distribution of applicable renewable resources among states, making it easier and more cost-effective for a state located in a high-resource area of the country and possessing a small population to meet any such standard (compared to a populous state with fewer renewable resources). Although the implementation of a federal RPS has been unsuccessful, the majority of states have enacted either an RPS or an official goal for renewable energy. These are shown in Figure 6-9.

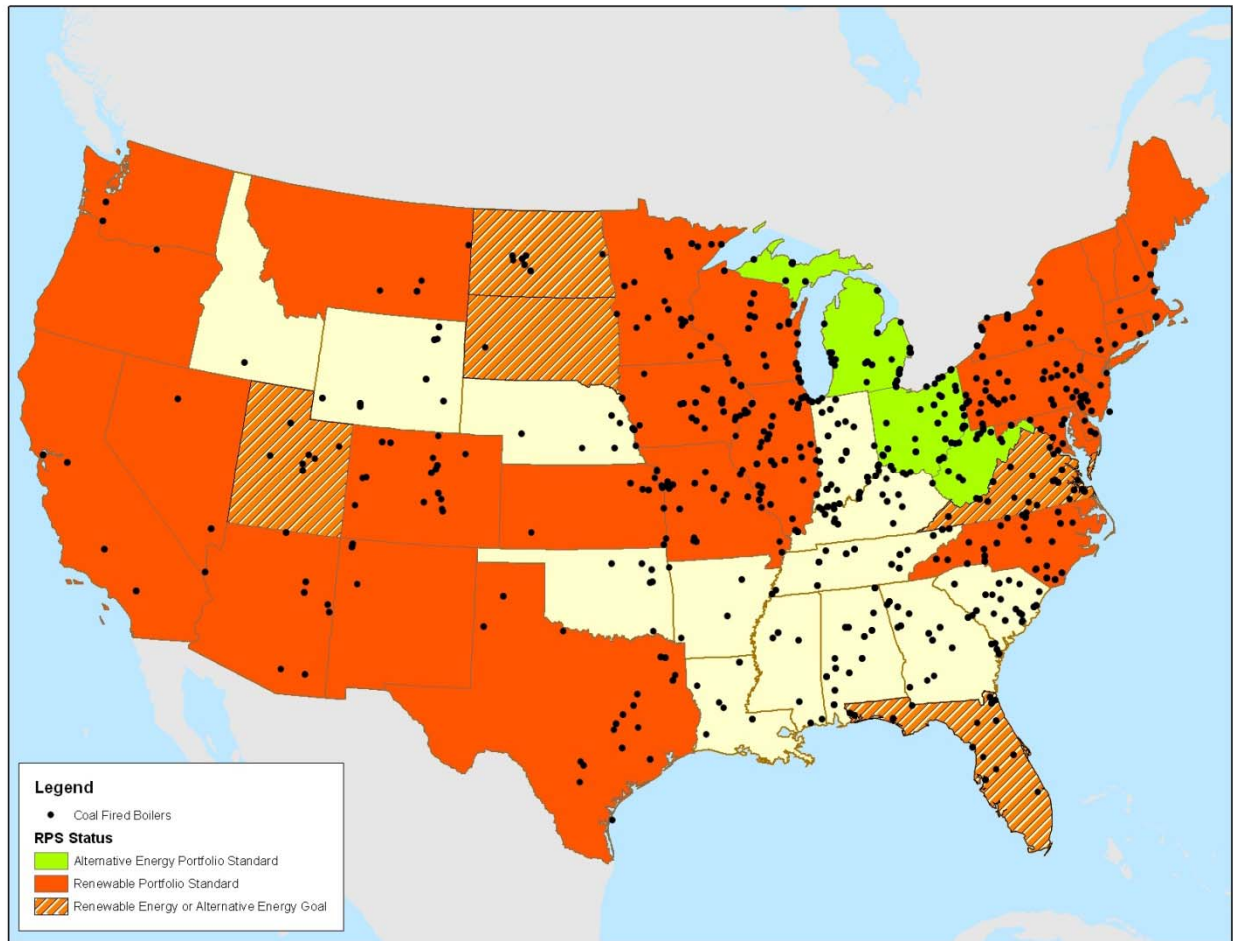


Figure 6-9
Status of State RPS Activity

State RPS incentives, in conjunction with federal production tax credits, are credited by NREL as one of the primary factors that have allowed renewable energy development to increase over the past two decades. RPS incentives are one of the primary explanations why the demand for renewable electricity in some states with fewer indigenous renewable resources exceeds that in states with greater renewable resources.

Regional Carbon Initiatives

The U.S. market for trading carbon credits is still developing. Until federal legislation is passed creating a formal cap-and-trade system, the trading of carbon credits is primarily controlled by one of two approaches. The first is the Northeastern Regional Greenhouse Gas Initiative (RGGI), which consists of a network of ten states that has created a cooperative cap-and-trade carbon market with the goal of collectively reducing their carbon emissions. The second system is the

Chicago Climate Exchange³⁵, a private market that conducts “boutique” auctions among certified carbon sellers and buyers. There are also two additional regional initiatives, the Western Climate Initiative and the Midwestern Regional Greenhouse Gas Reduction Accord, both of which are currently under development. Figure 6-10 illustrates the regions where each of these markets is active.

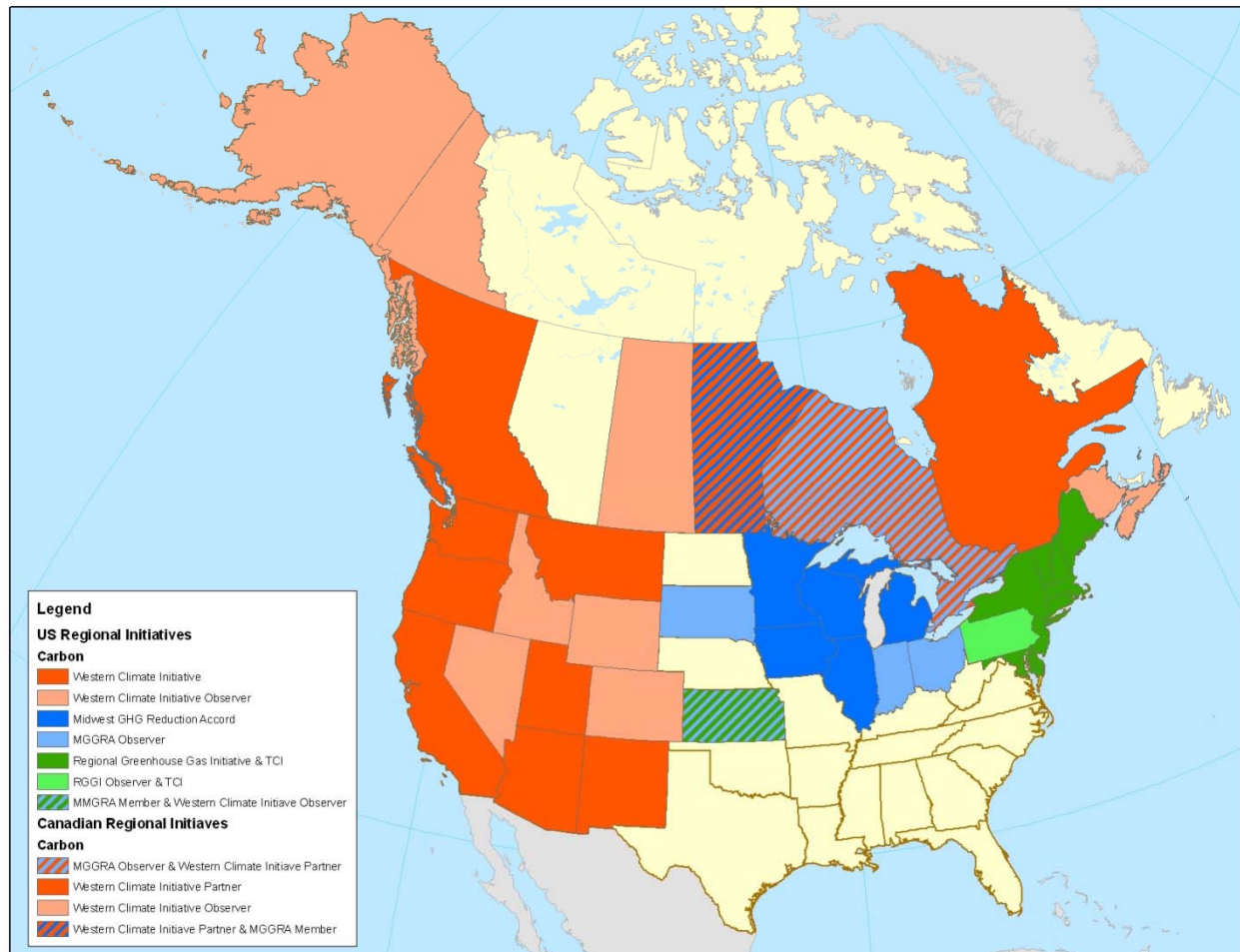


Figure 6-10
Regional Carbon Initiatives

Carbon credits, or offsets, can be generated by projects that offset the current use of fossil fuels with renewable fuels. Established accounting metrics for these credits, for example, describe how displacing a ton of coal can provide carbon credits that can then be sold in national or international markets. These carbon credits can be generated continuously for the first 10 years of the life of a project, after which time the substitution becomes considered "business as usual."

³⁵ Unfortunately, according to recent reports, the Chicago Climate Exchange will be ending operations by the close of 2010. The company that owned the exchange plans to continue to run its international business (CNNMoney.com, November 17, 2010).

It is assumed that RGGI will continue to serve as a model for other regional initiatives, as well as any national U.S. climate change legislation. Passage of national climate change legislation creating compliance mandates would greatly expand the domestic CO₂ markets. According to the June 26, 2009 edition of Point Carbon's "Carbon Market North America," officials from the Western Climate Initiative and the Midwestern Regional Greenhouse Gas Reduction Accord (together with RGGI representatives) agreed to back a federal cap-and-trade system if it is more stringent than the regional ones currently in place. A summary of the regional carbon initiative programs is provided below.

Northeastern Regional Greenhouse Gas Initiative

RGGI was the first mandatory cap-and-trade program in the United States to regulate carbon dioxide. The Initiative is a cooperative made up of 10 Northeast and Mid-Atlantic states, with the goal of capping CO₂ emissions by power plants larger than 25 MW and lowering this cap by 10% below 2009 levels by the year 2018. RGGI went into effect on January 1, 2009, with participating states including: Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

Participating states implement their state programs individually through regulations based on a model rule. Through these independent rules and regulations, the states set their own limits on CO₂ emissions and create CO₂ allowances. The states are required to reserve a minimum 25% of their allowances to support consumer benefit programs, by either auctioning the allowances and using the proceeds to fund programs, or by managing them directly for consumer benefit. The remaining 75% of the states' allowances can be sold to participating power plants through auctions, or can be allocated without auction.

Participating power plants are required to use approved systems to monitor emissions, and must bank allowances that are equivalent to their CO₂ emissions over a three-year control period. Allowances issued from within any of the participating states can be used to demonstrate compliance. If a participating plant does not have enough allowances to cover a given compliance period, the plant must either reduce its emissions, buy allowances, or secure offset allowances from an approved RGGI offset project. Any excess allowances may either be banked for future use or sold at auction.

Western Climate Initiative (WCI)

Participants in the WCI have committed to reducing regional GHG emissions to 15% below 2005 levels by 2020. The WCI plans include implementing a regional cap-and-trade program beginning in January 2012, with full implementation to be completed by 2015.

The Midwest Greenhouse Gas Accord

Program members have committed to establishing GHG reduction targets, as well as a cap-and-trade program that will reduce emissions from covered sources to 20% below 2005 levels by December 31, 2020, and further reduce them to 80% below 2005 levels by December 31, 2050.

The program will take effect one year after the implementation plan has been executed by all participants.

Methodology for Qualitative Analysis

Data used for the qualitative analysis was compiled from the resources described previously in this section. Because of the high-level nature of this assessment, various attributes are ranked on a three point scale (positive, negative, or neutral) for comparative purposes. The values for each attribute were divided into the top, middle, and bottom third, and then assigned their ranking accordingly. Values were summarized for the Standardized Federal Regions (Figure 6-1) for ease of evaluation. However, it must be noted that the administrative boundaries of the Federal Regions can obscure significant variations in attributes among the individual states within the regions. For this reason, a summary table of the state-level attribute rankings is also included in Appendix E. Each of the attributes was addressed as follows:

- To determine the availability of transportation for conveying biomass resources from source to plant, a GIS analysis was performed to calculate the total miles of roads (Freeways and Major Highways, shown in Figure 6-11) and railroads for each state. The resulting total was then divided by the area of the state, in thousand square miles, to arrive at a factor for determining the relative availability of transportation networks to serve the market area. The higher the factor, the greater the availability of roads and railroads.
- Greater quantities of available biomass were considered favorable.
- Lower median wage rates for power plant operators were considered to be more desirable than higher wage rates.
- Lower pellet prices were considered to be favorable.
- Higher cost of electricity was assumed to be favorable.
- If more than two thirds of the states in the region currently have an RPS or participated in a carbon initiative, each of these categories was positive, if between one third and two thirds of the states have an RPS or participated in a carbon initiative, it was neutral, and if fewer than one third have an RPS or participated in a carbon initiative, it was negative.

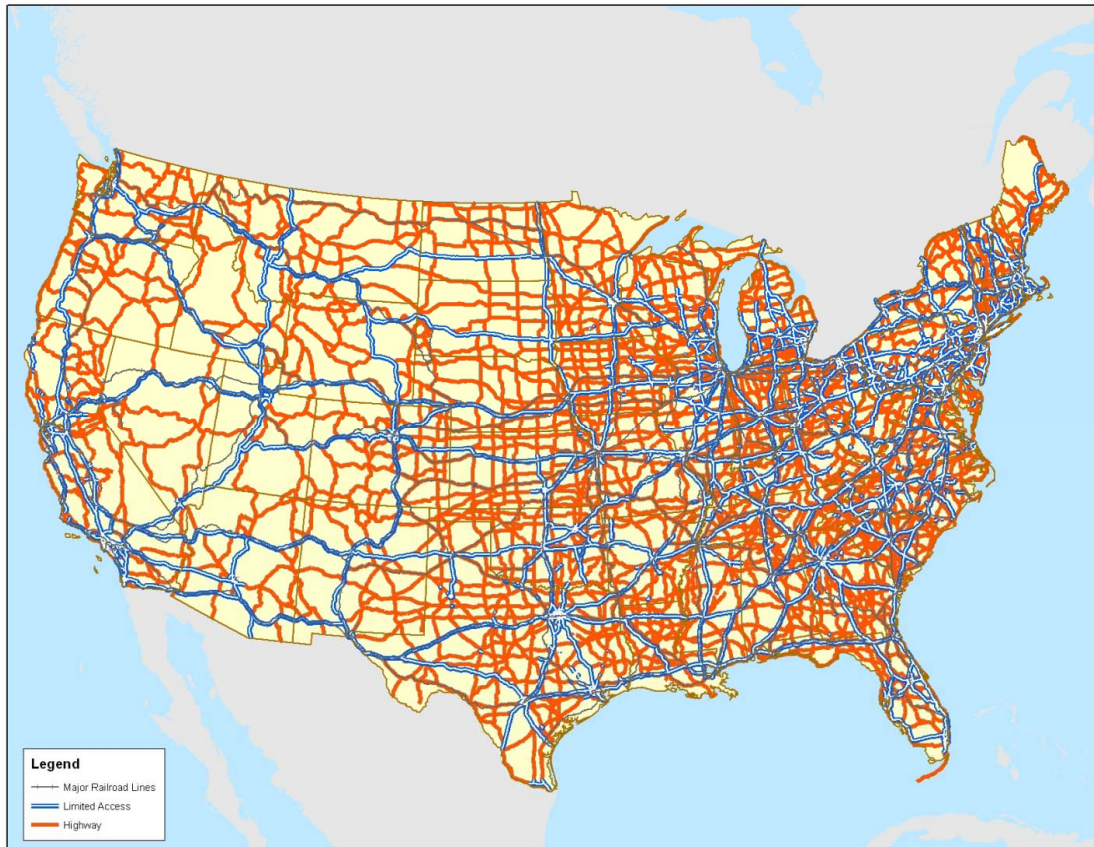


Figure 6-11
Roads and Railroads used for Transportation Availability Analysis

Table 6-1
Ranking of Regional Attributes

Region	Number of States in Region	Availability of Biomass	Hourly Wage Rate	Price of Electricity	Cost of Pellet Fuel	Transport: Roads	Transport: Rail	RPS Participation	Carbon Initiative Participation
I	6	negative	positive	positive	negative	positive	positive	positive	positive
II	2	negative	negative	positive	negative	neutral	neutral	positive	positive
III	6	neutral	positive	positive	neutral	positive	positive	positive	neutral
IV	8	positive	neutral	neutral	neutral	positive	positive	negative	negative
V	6	positive	neutral	neutral	positive	neutral	positive	positive	positive
VI	5	positive	positive	neutral	negative	neutral	neutral	negative	negative
VII	4	positive	neutral	negative	positive	neutral	neutral	positive	neutral
VIII	6	neutral	positive	negative	positive	negative	neutral	positive	positive
IX	4	neutral	negative	positive	neutral	negative	negative	positive	positive
X	4	neutral	neutral	neutral	negative	negative	negative	neutral	positive

- Region I: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
- Region II: New Jersey, New York, Puerto Rico, Virgin Islands
- Region III: Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia
- Region IV: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee
- Region V: Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin
- Region VI: Arkansas, Louisiana, New Mexico, Oklahoma, Texas
- Region VII: Iowa, Kansas, Missouri, Nebraska
- Region VIII: Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
- Region IX: Arizona, California, Hawaii, Nevada
- Region X: Alaska, Idaho, Oregon, Washington

Discussion

Although only qualitative, the matrix provided in Table 6-1 provides useful insight with respect to repowering opportunities nationwide. Regions III and V seem to offer either positive or neutral opportunities with respect to all categories. Region V seems to hold a slight edge, since it benefits from a slightly better biomass resource and RPS and carbon markets are both positive. The analysis suggests that region X is problematic with respect to repowering, with either “neutral” or “negative” ratings prevailing in all of the categories considered.

In prior chapters of this report, considerable discussion was offered regarding transportation logistics and costs. The economic analysis indicates that facilities that have a large local biomass resource would be prudent to consider repowering options that can process raw biomass directly for energy and avoid intermediate conversion or processing steps. That said, there are some additional considerations that have important implications for the industry:

- The projects evaluated in this report require large annual volumes of material to be processed and used. If sourced locally, there is the potential for impacting the fiber supply needed for other industries (such as pulp and paper), which are likely to be power customers for a regulated utility. In some cases, this may force a power generator to pass on a biomass repowering opportunity to avoid supply and consumer conflicts.
- The point above also provides an interesting alternative compliance pathway for power generators, in particular with respect to pulp and paper companies. This particular industry already cogenerates a significant amount of power from biomass in multiple forms. Some of these companies are interested in expanding their electric production capacity by repowering their own plants. In a public policy environment where utilities are given multiple alternative compliance options, it is possible that power generators and industry participants could work together to develop win/win biomass power generation scenarios that maximize supply sustainability.
- In regions such as the Southeast where biomass supplies are more significant than others, it may under certain circumstances be possible to generate power using local biomass supplies, and then sell the resulting RECs into states that have already enacted renewable portfolio standards and include provisions allowing purchases of RECs from out-of-state suppliers.
- As one would expect, the solid fuel transportation infrastructure for delivering biomass to coal plants is generally very good. However, moving large volumes of solid fuels to gas/oil plants may not be as practical, especially if the fuel has a low energy density. Here again, pelletized fuels may offer some strategic or siting advantages, simply by virtue of reducing the necessary plant footprint and the number of truck deliveries required.
- Pelletized fuels (especially torrefied fuels) may also be more economically viable in the short-term in certain niche opportunities where the cost difference between the displaced fuel and the pelletized biomass is smaller and yet a minimum investment in the plant would be required for conversion. There may be specific opportunities in the context of peaking plants, for example.

Chapter 2 provides a wide-angle view of the numerous repowering technologies that utilities can consider, generally in the context of achieving large-scale biomass-based power output. It is worth noting that there are also a variety of repowering options with considerably more modest goals. These include concepts such as feedwater heating repowering using biomass boilers. In situations where existing steam turbines have some extra flow capacity, avoiding extractions for feedwater heating will result in increased plant output. Steam for feedwater heating could instead be supplied by a new, relatively small biomass boiler. The boost is relatively small, but may be replicated across a wide number of units and would require no main boiler modifications, a much smaller capital outlay, and would put less pressure on local fuel supplies than the large-scale projects discussed in this report.

Recommendations for Additional R&D Efforts

Although the technical aspects of the repowering options discussed in this report should not be minimized, biomass power in any form comes down to fuel supply and cost. Pelletized fuels represent an evolution in biomass fuels with significant technical benefits, but to be competitive in the U.S. market, end-use costs still need to be lowered. Research that supports that objective is worthwhile. Specific areas worth considering include:

- Opportunities to integrate pelletized fuel production and power plant operations to lower costs by improving heat integration and minimizing fuel processing before firing.
- Improve production methods for pelletized fuels and evaluate fuel design options specifically targeted at repowering utility boilers.
- Pelletized fuel treatment options to minimize concerns regarding boiler/emission control impacts.
- Evaluate options for feedstock handling and processing that mitigate dust issues and other technical problems.
- Conducting more testing and research on the conversion of boilers to a variety of biomass fuels, and providing standardized information (such as a performance database) for use in fleet-wide assessments.
- Energy crop research to underpin efforts to minimize fiber/feedstock costs, a key element in all of the technologies evaluated.
- Development of a decision tree to assist power generators in determining the best biomass repowering options for their plants given a limited number of key inputs.

7

CONCLUSIONS

There are a variety of biomass repowering technology options (either available or emerging) that offer power generators the means to inject significant, baseload biomass-based generation into their portfolios. The data presented in this report suggest that leveraging existing assets is financially superior to building greenfield plants, reducing startup costs on the order of 40-60%. Technologies that rely on fuel switching to pelletized biomass fuels, especially torrefied wood pellets, may be able to avoid all or nearly all of the investment in boiler conversion, minimize the boiler derating associated with a fuel switch, and offer a route to rapid and flexible compliance with future regulations.

With respect to technical performance, the analysis presented in this report suggests that claims regarding the use of pelletized fuels are well justified. With relatively modest capital investment, it appears possible to achieve high firing rates relative to wood chip/boiler retrofit options. Some of the technical benefit accrues from the tendency to use better quality feedstock in the pellet manufacturing process, but much is also attributable to the lower moisture content of the fuels. Although wood pellets must be handled more carefully than wood chips in order to avoid issues associated with dust and rehumidification, the technology does exist to store, process, and fire the material, and European plants are employing this option in earnest. If torrefied wood pellets ever become a commercial reality, they offer a pathway to advancing biomass fuel pellet quality by overcoming many of the technical shortcomings of traditional wood pellets.

Despite the potential technical advantages, the economics of using pelletized fuels in the U.S. appear problematic in the short-term and potentially even in the long-term. Barring a significant decrease in costs from those stated in this report, current U.S. carbon policies are insufficient to allow pelletized fuels to demonstrate their greatest economic benefit – namely, their energy density. As shown in this and other reports, this characteristic facilitates more cost-effective long-range transport than can be achieved with wood chips. However, in the U.S. this benefit is unrealized since demand for these fuels is not sufficient to justify a change in current attitudes regarding biomass fuel sourcing. Projects are still developed primarily by targeting local fuel sources at the lowest sustainable price. Power generators are also required to consider the cost and availability of alternative energy resources (including wind and fossil fuels).

Two additional points on this topic are worth reiterating, each of which could swing the debate in opposite directions:

- Significant reduction in the cost of producing torrefied wood will close the gap between the cases examined. A combination of using low-grade heat from the power plant itself and eliminating pelletization could go a long way in reducing production costs. Although not examined in this report, the data generated could be used to build a model for predicting the performance of such an arrangement. The key question is whether a large-scale torrefied

wood processing facility and any plant modifications could be completed for less than the cost of retrofitting the boiler to use woodchips directly, recognizing that a large woodyard would be needed in both cases.

- Even in the presence of higher-demand scenarios, it is not a foregone conclusion that coal-fired plants will have to rely on distant sources of fuel. Energy crops, such as switchgrass, willow, and eucalyptus are on the verge of economic viability under existing market scenarios. These resources offer their own set of advantages, not the least of which is that these crops have a wide geographic applicability, including areas without abundant wood resources. Agricultural residues may also have a role to play in this context. The incentives that are likely to improve the outlook for using pelletized fuels will also improve the outlook for these fuels.

The economic analysis results presented in this report also indicate that retrofitting an existing boiler to fire wood chips can be an attractive option to add new renewable generation capacity. Levelized costs of electricity may be higher than fossil-fired generation in some cases, but at \$0.06-0.07/MWh, any premium appears manageable. There are some implicit assumptions to this conclusion that are worth revisiting:

- The economics assume that the candidate power plant is proximal to a sustainable, reasonably priced supply of biomass.
- Good units for conversion should have ample on-site space for biomass receiving, storage, and handling, good access for fuel deliveries, and a relatively attractive existing heat rate. Attractive existing heat rates lead to better heat rates after the biomass repowering retrofit, thus decreasing the fuel requirement.

There is also ample opportunity for the industry to improve the outlook for repowering technologies, and a few are listed below:

- Investigate opportunities to integrate pelletized fuel production and power plant operations to lower costs.
- Improve production methods for pelletized fuels and evaluate fuel design options specifically targeted at repowering utility boilers.
- Energy crop research to underpin efforts to minimize fiber/feedstock costs, a key element in all of the technologies evaluated.
- Development of a decision tree to assist power generators in determining the best biomass repowering options for their plants given a limited number of key inputs.

Based on the analyses performed in this report, there is ample opportunity and a variety of options for repowering fossil-fired plants to use biomass fuels. For now, the edge seems to remain with traditional boiler retrofit options. There is considerable technical promise for using pelletized fuels, especially torrefied wood, but policies driving the U.S. market pose challenges that may not be easily overcome. However, the fate of these technologies lie in the hands of technology developers seeking to identify innovative ways to drive down costs and bring the full potential of these fuels to bear.

8

REFERENCES

Antares Group, Inc. (2003) Assessment of Power Production at Rural Utilities Using Forest Thinnings and Commercially Available Biomass Power Technologies. Report to the U.S. DOE under Task Order No. TOA KDC-9-29462-19.

Arias, B.; Pevida, C.; Feroso, J.; Plaza, M.G.; and F. Rubiera. (2008) Influence of torrefaction on the grindability and reactivity of woody biomass. *Fuel Processing Technology* 89, 169-175.

Baxter, L. *Biomass-Coal Co-combustion: Opportunity for Affordable Renewable Energy*. Brigham Young University, Chemical Engineering.

Bergman, P.C.A. (2005, July) Combined Torrefaction and Pelletization: the TOP process. Energy Research Center of the Netherlands. Project number 2020-02-12-14-001.

Bradley, D. (2010) *Canadian Report on Bioenergy 2010*. Canadian Bioenergy Association and Natural Resources Canada - Canadian Wood Fibre Center.

Brown, R.C. (2003) *Biorenewable Resources: Engineering New Products from Agriculture*. Blackwell: Ames. Iowa.

California Energy Commission. (2008) *Renewable Energy Program; Overall Program Guidebook; Second Edition*. State of California.

City Utilities of Springfield. (2010) Torrefied Biomass Test Burn, August 13th, 2009. Report retrieved from Earth Care Products, International website on December 7, 2010 from http://ecpisystems.com/wcms/downloads/TestBurnReport_Rev2.pdf

DeFusco, J.P.; MacKenzie, P.A.; and M.D. Fick. (2007) Bubbling Fluidized Bed or Stoker—Which is the Right Choice for Your Application? Technical Paper, CIBO Fluid Bed Combustion XX Conference, May 21-23, 2007, Lexington, KY.

EPA. (2010). *PSD and Title V Permitting Guidance for Greenhouse Gases*. Research Triangle Park, North Carolina: Office of Air Quality Planning and Standards.

EPRI. (2010a) Biomass Repowering Study for Plant Scholz. EPRI, Palo Alto, CA: 2010. 1022383.

EPRI. (2010b) Conceptual Design Review for Biomass Repowering at Plant Barry. EPRI, Palo Alto, CA: 2010. 1022385.

References

- EPRI. (2010c) Conceptual Design Review for Biomass Repowering at Plant Mitchell. EPRI, Palo Alto, CA: 2010. 1022386.
- EPRI. (2010d) Conceptual Design Review for Biomass Repowering at Plant Sweatt. EPRI, Palo Alto, CA: 2010. 1022382.
- EPRI. (2010e) EPRI Biomass Interest Group European; Technology Review. EPRI, Palo Alto, CA: 2006. 1010430.
- EPRI. (2010f) Gasification Technology Commercialization. EPRI, Palo Alto, CA: 2010. 1022387.
- Exothermic Engineering, LLC. Practical PRB Coal Experiences. Technical Paper No. 20424, Missouri City, MO. Retrieved September 21, 2010 from <http://www.exoeng.com/papers/paper5.pdf>.
- European Bioenergy Networks (EUBIONET). (2003) *Biomass Co-firing - An Efficient Way to Reduce Greenhouse Gas Emissions*. Jyväskylä, Finland.
- Food and Agriculture Organization of the United Nations. (1986) Wood Gas as Engine Fuel. Rome, Italy.
- Greg Pifer. Bubbling Fluidized-Bed Technology Serves Combustion Need for Biomass, Pulp & Paper, January 2005.
- Hiltunen, M. (2004) Foster-Wheeler Atmospheric Gasification Technology: Development and Latest Experiences. Presentation to the 2nd World Conference and Technology Exhibition on Biomass for Energy, Industry and Climate Protection, Rome, Italy, May 10-14, 2004.
- Hitchko, M.; Bousquet, B.; and L. Sullivan. (2005) Northern Wood Power Project, Public Service of New Hampshire/Northeast Utilities: Repowering with a Dual Fuel (Wood/Coal) CFB at Schiller Station. Presented to PowerGen International, December 6 - 8, 2005, Las Vegas, Nevada.
- Hoeflich, Peter. (2009) *Biopower: A Utility Perspective*. Retrieved from http://www.entap.org/group/images/Biopower_A_Utility_Persp_4063.pdf
- Hunt, P. (2006, September) Boiler Conversion: Converting a Boiler from Burning Bituminous Coals to PRB Coals Can Be a Challenge. *Coal Power* online. Retrieved November 10, 2010 from http://www.coalpowermag.com/plant_design/Boiler-Conversion-Converting-a-Boiler-from-Burning-Bituminous-Coals-to-PRB-Coals-Can-Be-a-Challenge_61.html
- IEA Bioenergy. (2009) Workshop on Options for High Percentage Biomass Cofiring in New Power Plants. European Biomass Conference - Task 32: Biomass Combustion and Cofiring. Hamburg, Germany.

- Junginger, M., Bolkesjo, T., Bradley, D., Dolzan, P., Faaij, A., & al., e. (2008) Developments in international bioenergy trade. *Biomass and Bioenergy* , 717-729.
- Koppejan, S. V. (2008) *The Handbook of Biomass Combustion & Cofiring*. London, England: Earthscan.
- Kumar, A.; Cameron, J.; and P. Flynn. (2006) Pipeline Transport and Simultaneous Saccharification of Corn Stover. *Bioresource Technology* 96, 819–829.
- Laux, S., Grusha and Tillman. (2000) Co-firing of Biomass and Opportunity Fuels in Low NOx Burners. Foster Wheeler Energy Corporation, Clinton, NJ.
- Lehtikangas, P. (2000) Storage effects on pelletised sawdust, logging residues and bark. *Biomass and Bioenergy* 19, 287-293.
- Maciejewska, A. (2006) Co-firing of Biomass with Coal: Constraints and Role of Biomass Pre-Treatment. European Commission. European Communities.
- Mahmudi, H. and P. Flynn. (2006) Rail vs. Truck Transport. *Applied Biochemistry and Biotechnology* 129, 88-103.
- Mani, S. (2009) Grinding & Pelleting Economics. Presentation to the Agricultural Engineering Technology Conference, Louisville, KY Feb 09-11, 2009.
- Marshall, L. (2010, April 1) OPG Charts Move from Coal to Biomass. Retrieved June 8, 2010, from POWER: http://www.powermag.com/coal/OPG-Charts-Move-from-Coal-to-Biomass_2570_p3.html
- Melin, S. (2010) *Review of Off-gassing from Wood Pellets: A Canadian Perspective*. Wood Pellet Association of Canada.
- Michel, J. and M. Schmid. (2009) Combustion Evaluation of Torrefied Wood Pellets for Domestic Applications. 10th International Conference on Energy for a Clean Environment, Clean Air July 7, 2009, Lisboa, Portugal.
- Midwestern Greenhouse Gas Reduction Accord Advisory Committee. (2010, April) *Final Model Rule for the Midwestern Greenhouse Gas Reduction Accord*. Retrieved December 2010, from http://www.midwesternaccord.org/Final_Model_Rule.pdf
- Milbrandt, A. (2005) *A Geographic Perspective on the Current Biomass Resource Availability in the United States*. Golden, CO: National Renewable Energy Laboratory.
- Mitchell, P.; Kiel, J.; Livingston, B.; and G. Dupont-Roc. (2007) Torrefied Biomass: A Foresighting Study into the Business Case for Pellets from Torrefied Biomass as a New Solid Fuel. Presentation to All Energy, Aberdeen, UK, May 23-24, 2007.

References

- NETL. (2007) NETL's 2007 Coal Poer Plant DataBase. Retrieved September 2010, from NETL:Technology Analysis: <http://www.netl.doe.gov/energy-analyses/hold/technology.html>
- National Renewable Energy Laboratory. (2009, October 27) Biomass Resources in the United States. Golden, CO: NREL.
- Palonen, J.; Anttikoski, T; and T. Eriksson. (2005) The Forst-Wheeler Gasification Technology for Biofuels: Refuse-derived Fuels (RDF). Foster Wheeler Energia Oy, Finland.
- RISI. (2010). *Wood Biomass Market Report: October*. RISI.
- Robinson, A. et al. (1998) *Fireside Issues Associated with Coal-Biomass Cofiring*. Golden, CO: National Renewable Energy Laboratory.
- Ryckmans, Y; Allard, P.; Liegeois, B; and D. Mewissen. (2006, October) Wood fired future for '60s fossil veteran. *Modern Power Systems*.
- Saastamoinen, J., Aho, M.; Moilanen, A.; Sorensen, L.H.; Calusen, S.; and M. Berg. (2010) Burnout of pulverized biomass particles in a large scale boiler—Single particle approach model. *Biomass and Bioenergy* 34, 728-736.
- Spelter, H. (2009.) *North America's wood pellet sector. Research Paper FPL-RP-656*. Retrieved from U.S. Department of Agriculture, Forest Service, Forest Products Laboratory. Madison, WI: http://www.fpl.fs.fed.us/documnts/fplrp/fpl_rp656.pdf
- Thek, I. O. (2010) *The Pellet Handbook: the production and thermal utilisation of biomass pellets*. London, England: Earthscan.
- Toniato, G., Accordini, C., Cammarota, A., Chirone, R., Solimene, R., & Urciuolo, M. (2007) Design and set-up of a bi-fuel fluidized bed combustor prototype for residential applications. *Third European Combustion Meeting ECM 2007*.
- Trusty, K. and E.M. Malstrom. (1998) A Feasibility Assessment of Truck-Barge Intermodal Freight Transportation. Research Report FR-1079, Mack Blackwell Transportation Center, University of Arkansas.
- U.N. FAO. (1986) Wood Gas as Engine Fuel. Forestry Paper 72. Forest Industries Division FAO Forestry Department.
- U.S. Bureau of Labor Statistics. (2010) *Occupational Employment Statistics (OES)*. Retrieved from U.S. Department of Labor: <http://data.bls.gov:8080/oes/search.jsp>
- U.S. DOE. (2004, May) *Federal Technology Alert - Biomass Cofiring in Coal-Fired Boilers*. Retrieved May 27, 2010, from U.S. DOE Energy Efficiency and Renewable Energy: http://www1.eere.energy.gov/femp/pdfs/fta_biomass_cofiring.pdf

- U.S. Environmental Protection Agency. (2010, July) eGRID. Retrieved November 2010, from <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>
- U.S. Environmental Protection Agency. (2009, May 22) *Lean Government Process Improvement Initiatives*. Retrieved December 2010, from www.epa.gov/lean/starterkit/resources/2-02-lean-inventory.doc
- van den Broek, R.; Faaij, A.; and A. van Wijk. (1995, May) Energy from Biomass: an Assessment of Two Promising Systems for Energy Production, Background Report 4.1: Biomass Combustion for Power Generation Technologies. White paper, Department of Science, Technology, and Society, Utrecht University, the Netherlands.
- van Loo, S. and J. Koppoan. (2008) *The Handbook of Biomass Combustion and Cofiring*. Earthscan: London, England.
- Vattenfall AB. (2009) Fuel Flexibility in the New Coal, Biomass, and Oil-Fired CHP Plant Amager Unit 1 in Copenhagen. *European Bioenergy Conference*. Hamburg, Germany.
- Western Climate Initiative. (2010) About the WCI. Retrieved December 2010, from <http://www.westernclimateinitiative.org/about-the-wci>
- Willeboer, W. (2000) Amergas biomass gasifier starting operation. Proceedings of the EU Seminar on the Use of Coal in Mixture with Wastes and Residues II, Cottbus.
- Wiltsee, G. (2000, February) Lessons Learned from Existing Biomass Power Plants. Report to the National Renewable Energy Laboratories under Contract No. DE-AC36-99-GO10337. Golden, CO.
- Xcel Energy. (2008, November 29) PSCW Approves Application for Largest Biomass Plant in Midwest. Press Release. Retrieved on October 15, 2010 from <http://www.xcelenergy.com/Minnesota/Company/Newsroom/Current%20Issues/Pages/BayFrontBiomassGasificationProject.aspx>.
- Xcel Energy. (2010, November 29) Xcel Energy ends biomass gasification project at Bay Front Plant. Press Release. Retrieved on December 7, 2010 from <http://www.xcelenergy.com/Minnesota/Company/Newsroom/Pages/11-29-2010-XcelEnergyendsbiomassgasificationprojectatBayFrontPlant.aspx>.
- Xingya Kuang, T. J. (2008) Characterization and Kinetics Study of Off-Gas Emissions from Stored Wood Pellets. *The Annals of Occupational Hygiene* , 1-9.

A

DETAILED TECHNOLOGY OVERVIEW MATRIX

Detailed Technology Overview Matrix

OPTION	Technology Type/ Description	Capital Cost (\$/ kW) Low High		Non-Fuel O&M Requirements	Technical Notes	Deployment Status	Deployment Opportunity
1	Grate boiler replacement	similar to option 2, possibly somewhat lower. About \$1,000 to \$1,250.		Low (approx. \$0.01-\$0.02/ kWh)	It is anticipated that the capital cost will be towards the high end.	High	High
2	Fluid bed boiler replacement	\$1,150	\$1,500	Low (around \$0.02/ kWh)	Operational risks: (1) increased combustion control and operational complexity; (2) avoid emergency shutdowns; (3) maintaining boiler refractory linings. It is anticipated that the capital cost will be towards the high end.	High	High
3	Coal boiler grate modification	\$1,000	\$1,350	Low (approx. \$0.01-\$0.02/ kWh)	De-rate due to size constraints. It is anticipated that the capital cost will be towards the lower end.	High	High
4	Coal boiler fluid bed modification	\$1,000	\$1,400	Low (around \$0.02/ kWh)	Operational risks: (1) increased combustion control and operational complexity; (2) avoid emergency shutdowns; (3) maintaining boiler refractory linings. De-rate due to size constraints. It is anticipated that the capital cost will be towards the lower end.	High	High
5	Gas/ oil boiler grate modification	\$1,550		Low (approx. \$0.01-\$0.02/ kWh)	Gas/ oil normally requires more modification to the convection pass to reduce air velocity. Need space for fuel yard and conveying equipment. De-rate due to size constraints.	Moderate	Medium
6	Gas/ oil boiler fluid bed modification	similar to option 5, boiler retrofit portion somewhat higher		Low (around \$0.02/ kWh)	Gas/ oil normally requires more modification to the convection pass to reduce air velocity. Need space for fuel yard and conveying equipment. De-rate due to size constraints.	Moderate	Medium
7	High percentage cofiring (> 50% by heat)						
7a	Suspension firing of biomass in PC boiler	\$115	\$1,000	Low	Significant changes in ash and emissions need to be considered and evaluated.	Moderate to Low (at high cofiring levels)	Medium
7b	Gasify biomass and fire in coal boiler	\$1,050	\$1,450	High (approx. \$0.035-\$0.105/ kWh)	Placement of additional burners in boiler walls specific to geometry and fluid dynamics of existing system.	Low	High
7c	Gasify biomass and fire in gas/ oil boiler	Somewhat higher than option 7b		High (approx. \$0.035-\$0.105/ kWh)	Placement of additional burners in boiler walls specific to geometry and fluid dynamics of existing system.	Low	Medium

OPTION	Technology Type/ Description	Feedstock Flexibility		Project Time Horizon
		Characterization	Example Fuels	
1	Grate boiler replacement	Flexible design (MC, fuel types); inflexible operations (w/in 10% of design fuel specs). No fuels with low ash melting temps.	wood chips (wet or dry), municipal solid waste, pellets	3-4 years. Need revised air permits. Estimate 1-2 yrs financing/ permits, 1-3 yrs construction & commissioning
2	Fluid bed boiler replacement	More flexible in operation, particle size and moisture content can vary. Alkali content ≤ 0.79 lb/ MMBtu.	wood chips (wet or dry), municipal solid waste, agricultural residues, pellets	Need revised air permits. Estimate 3-4 yrs from feasibility to commercial operation. One example as low as 34 months.
3	Coal boiler grate modification	Flexible design (MC, fuel types); inflexible operations (w/in 10% of design fuel specs). No fuels with low ash melting temps.	wood chips (wet or dry), municipal solid waste, pellets	2-4 years. Need revised air permits. Estimate 1-2 yrs financing/ permits, 1-3 yrs construction & commissioning.
4	Coal boiler fluid bed modification	More flexible in operation, particle size and moisture content can vary. Alkali content ≤ 0.79 lb/ MMBtu.	wood chips (wet or dry), municipal solid waste, agricultural residues, pellets	Need revised air permits. Estimate 2-4 yrs from feasibility to commercial operation.
5	Gas/oil boiler grate modification	Flexible design (MC, fuel types); inflexible operations (w/in 10% of design fuel specs). No fuels with low ash melting temps.	wood chips (wet or dry), municipal solid waste, pellets	2-4 years. Need revised air permits. Estimate 1-2 yrs financing/ permits, 1-3 yrs construction & commissioning.
6	Gas/oil boiler fluid bed modification	More flexible in operation, particle size and moisture content can vary. Alkali content ≤ 0.79 lb/ MMBtu.	wood chips (wet or dry), municipal solid waste, agricultural residues, pellets	Need revised air permits. Estimate 2-4 yrs from feasibility to commercial operation.
7	High percentage cofiring (> 50% by heat)			
7a	Suspension firing of biomass in PC boiler	Very Inflexible; need dry (15-20% MC), uniform small particles <0.25".	wood or straw pellets, torrefied biomass pellets.	Estimate 1-4 years. Need revised permits, construct fuel handling equipment, etc. Les Awirs only took 7 months.
7b	Gasify biomass and fire in coal boiler	Fixed bed: Dry (20% MC), small particles 0.25" Fluidized bed: Wetter feedstocks (20-30% MC), particle size 3"	varies by gasifier type & vendor. wood chips, municipal solid waste, agricultural residues, switchgrass (fluid bed only), pellets	Estimate 3-5 years for permitting, engineering, construction, commissioning
7c	Gasify biomass and fire in gas/oil boiler	Fixed bed: Dry (20% MC), small particles 0.25" Fluidized bed: Wetter feedstocks (20-30% MC), particle size 3"	varies by gasifier type & vendor. wood chips, municipal solid waste, agricultural residues, switchgrass (fluid bed only), pellets	Estimate 3-5 years for permitting, engineering, construction, commissioning

Detailed Technology Overview Matrix

OPTION	Technology Type/ Description	Emissions Performance	Carbon Burnout	Availability of Incentives
1	Grate boiler replacement	Reduce SO _x , NO _x , Hg, and GHG relative to coal; increase CO and VOCs	relatively high unburned carbon in fly ash, high LOI	Limited federal incentives and eligibility for CA RPS (new power increment or cost > 80% of plant FMV)
2	Fluid bed boiler replacement	Lower CO and VOC emissions than stoker grate.	low levels of unburned carbon in ash	Limited federal incentives and eligibility for CA RPS (new power increment or cost > 80% of plant FMV)
3	Coal boiler grate modification	Reduce SO _x , NO _x , Hg, and GHG relative to coal; increase CO and VOCs	relatively high unburned carbon in fly ash, high LOI	Limited federal incentives (new power increment or cost > 80% of plant FMV). Not applicable for CA RPS.
4	Coal boiler fluid bed modification	Lower CO and VOC emissions than stoker grate.	low levels of unburned carbon in ash	Limited federal incentives (new power increment or cost > 80% of plant FMV). Not applicable for CA RPS.
5	Gas/oil boiler grate modification	Increase in NO _x and CO relative to gas and oil; decrease in GHG. Negligible sulfur emissions.	relatively high unburned carbon in fly ash, high LOI	Limited federal incentives (new power increment or cost > 80% of plant FMV). Not applicable for CA RPS.
6	Gas/oil boiler fluid bed modification	Lower CO and VOC emissions than stoker grate.	low levels of unburned carbon in ash	Limited federal incentives (new power increment or cost > 80% of plant FMV). Not applicable for CA RPS.
7	High percentage cofiring (> 50% by heat)			
7a	Suspension firing of biomass in PC boiler	Reduce SO _x , NO _x , Hg, and GHG relative to coal; increase CO and VOCs	low levels of unburned carbon in ash	Federal incentives probably not applicable except for energy crops cofiring with coal. Lower value for Maryland PTC.
7b	Gasify biomass and fire in coal boiler	Lower NO _x per MMBtu than coal. Increase in CO. Negligible sulfur emissions.	4-7% unconverted carbon in ash (downdraft)	Federal incentives probably not applicable except for energy crops cofiring with coal. Lower value for Maryland PTC.
7c	Gasify biomass and fire in gas/oil boiler	Higher NO _x per MMBtu than gas. Increase in CO. Negligible sulfur emissions.	4-7% unconverted carbon in ash (downdraft)	Federal incentives not applicable. Lower value for Maryland PTC.

B

TRANSPORTATION MODE ANALYSIS

One of the key advantages cited for densified biomass is its improved transportation cost per MMBtu of fuel. Higher energy densities allow for a larger quantity of fuel (on an energy basis) to fit into size-limited containers such as trucks, barges, or railcars. This section will present a brief analysis of the relative transportation benefits of the two densified fuels (wood pellets and torrefied wood pellets) over the unprocessed wood chips, including a discussion of volume and weight limits for truck transportation. It will also consider the relative distances from which each type of biomass will need to be shipped, and what mode of transportation will be most economical for its transportation.

Truck Trailer Transportation Limitations

The amount of biomass fuel that a truck trailer can safely deliver depends on the capacity of the trailer, the density of the biomass fuel, and the weight restrictions that have been placed on the gross trailer weight. The U.S. Department of Transportation (DOT) states that the maximum gross weight for commercial vehicles driving on interstate highways is 80,000 lbs. This includes the weight of the truck, the weight of the trailer, and the weight of any freight being transported.

Biomass chips are typically transported by trucks using walking floor trailers. Table B-1 presents the available shipping volumes and weights for walking floor trailers of various sizes.³⁶ An analysis was performed to determine whether these trailers would be weight- or volume-limited for each considered biomass fuel type. For material with bulk density greater than the threshold, the trailer will be weight limited, while loading materials with lower bulk will be limited by volume. The bulk densities of the considered biomass fuels range from 20 lb/ft³ for wood chips sized for gasification, to 47 lb/ft³ for wood pellet and TWP fuels. Since these are greater than the threshold bulk densities for the walking floor trailers, the trailers will be filled to maximum weight capacity before they are filled to volumetric capacity. As such, the fixed, per-trailer costs will be similar per ton of biomass among the three types of biomass.

³⁶ Values based on data from Hale Trailer Brake and Wheel.

Table B-1
Physical Limitations for Walking Floor Trailers

Trailer Size	Maximum Volume (ft ³)	Maximum Freight Weight (lb)	Threshold Bulk Density (lb/ ft ³)
53'	3,900	49,500	12.7
48'	3,100	51,500	16.6
45'	2,800	53,500	19.1

Modal Analysis

The analysis presented below shows expected costs for transporting each considered fuel type using different transportation modes. For each transport mode there is a fixed cost for loading and unloading (\$/ton), and a distance-variable cost for transportation (\$/ton-mile). In all cases the variable distance cost is assumed to be linear. This approach is consistent with the assumption that contributing factors such as wages, fuel, and capital recovery for the transportation equipment are directly proportional to the distance traveled (Mahmudi & Flynn, 2006). Furthermore, the analysis does not consider transfer of materials at any point, so the same fixed cost for loading and unloading is applied regardless of shipping distance. The cost of shipping fuel using multiple transportation methods (i.e. truck to rail, or truck to barge) is not considered either, such that in all cases the shipping cost for each mode is analyzed independently.

Truck Transportation

For this analysis, a variable cost of \$0.120/ton-mile and a fixed cost of \$3.21/ton were selected for freight transportation by truck in 53-foot tractor trailers, based on work presented by Kumar (2006) and Mahmoudi (2006). The costs from these studies were scaled to present value using the CPI and corrected for green rather than dry tonnage. In comparison, the authors generally use a cost of around \$0.12-\$0.20/ton-mile for biomass transportation at a small scale. Several other studies were referenced to confirm the reasonableness of this value. An older study by Trusty and Malstom (1998) cites a cost of \$1.80 per container-mile for a 40-foot trailer with a maximum capacity of 57,000 lb, or approximately \$0.063 per ton-mile at full load. The U.S. Bureau of Transportation Statistics (BTS) and the Bureau of Economic Analysis (BEA) indicate that the total 2009 GDP of the tractor trailer freight industry was \$210.5 billion. During the last annual mileage data collection in 2002, tractor trailers logged an average of 1,515 billion ton-miles. This would indicate that present freight costs average approximately \$0.14/ton-mile or less, depending on the rise in annual tractor trailer ton-miles since 2002.

In order to determine the relative costs of transporting wood chips, wood pellets, and torrefied wood pellets over various distances, the energy density of the fuel was calculated from bulk density and higher heating values. The cost per ton-mile was then applied to each fuel's energy density and a range of haul distances likely for truck transportation (50 to 200 miles). The cost per ton-mile was assumed to remain constant regardless of distance travelled (i.e., that there was no per-unit benefit to truck for long distances as opposed to locally, except for a leveraging of

fixed costs per ton). Trusty et al. (1998) indicate that the costs of haul distances between 50 and 500 miles can be predicted with the same function and slope. The distances included in this analysis are within this suggested range.

The resulting cost functions for each fuel type are presented in Figure B-1. The transportation cost benefits of densifying biomass are readily apparent, as wood pellets (WP) and torrefied wood pellets (TWP) show greatly reduced transportation costs per MMBtu compared to wood chips (WC) when transported over the same distance.

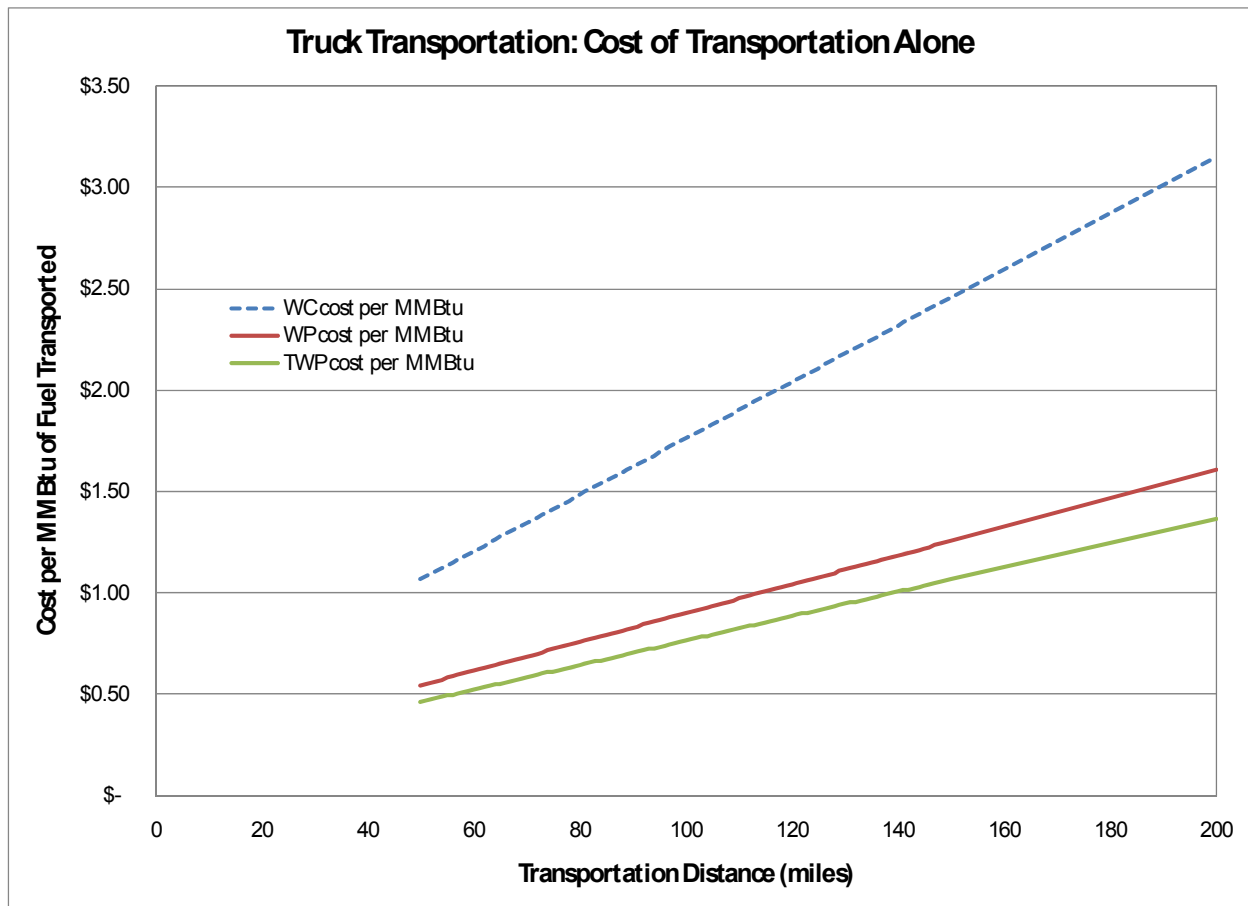


Figure B-1
Transportation Costs for Biomass Delivered by Truck

Rail Transportation

The estimated cost of rail transportation is based on CSX freight rate tariffs, which were used to calculate an average fixed cost per car and variable distance cost per ton-mile, as well as weight and volume limits for bottom-unloading grain cars.³⁷ The fixed cost is estimated to be \$2,446 per

³⁷ In contrast with truck trailers, which consistently reach weight limits before volume limits, rail cars reach their volume limits before their weight limits in the case of wood chips. This means that fixed, per-car costs are greater per ton of this fuel than for the other two fuels, which filled the rail cars to their full weight capacity without exceeding volume limits.

car, and the distance variable cost is \$0.68 per container-mile, which corresponds to \$0.0125/ton-mile for wood chips and \$0.006/ton-mile for pelletized fuels.

For comparison, Trusty and Malstom (1998) indicate a \$0.35/container-mile variable charge, plus \$125 in fixed fees per container at each end of the journey. The BTS/BEA data indicate \$43.6 billion in gross revenue by the railroad industry for 1,373 billion ton-miles traveled, or an approximate cost of \$0.032 per ton-mile. Both of these values are smaller than the expected costs based on the CSX data. However, since there are limitations to both of these datasets in terms of the age of the Trusty data and the lack of fixed and variable cost differentiation in the BEA/BTS data, the more conservative values from CSX are utilized here, as they are expected to be more representative of the costs of the rail transportation industry as a whole.

The profile of cost versus shipping distance is presented in Figure B-2 for a likely range of transportation distances by rail. Again, the economic benefits of densification are apparent. In this case, however, the distance-independent, per-car charges are far greater than the per-ton mile charges, making it even more important to be able to fill a rail car not just to its volumetric capacity, but to its weight capacity.

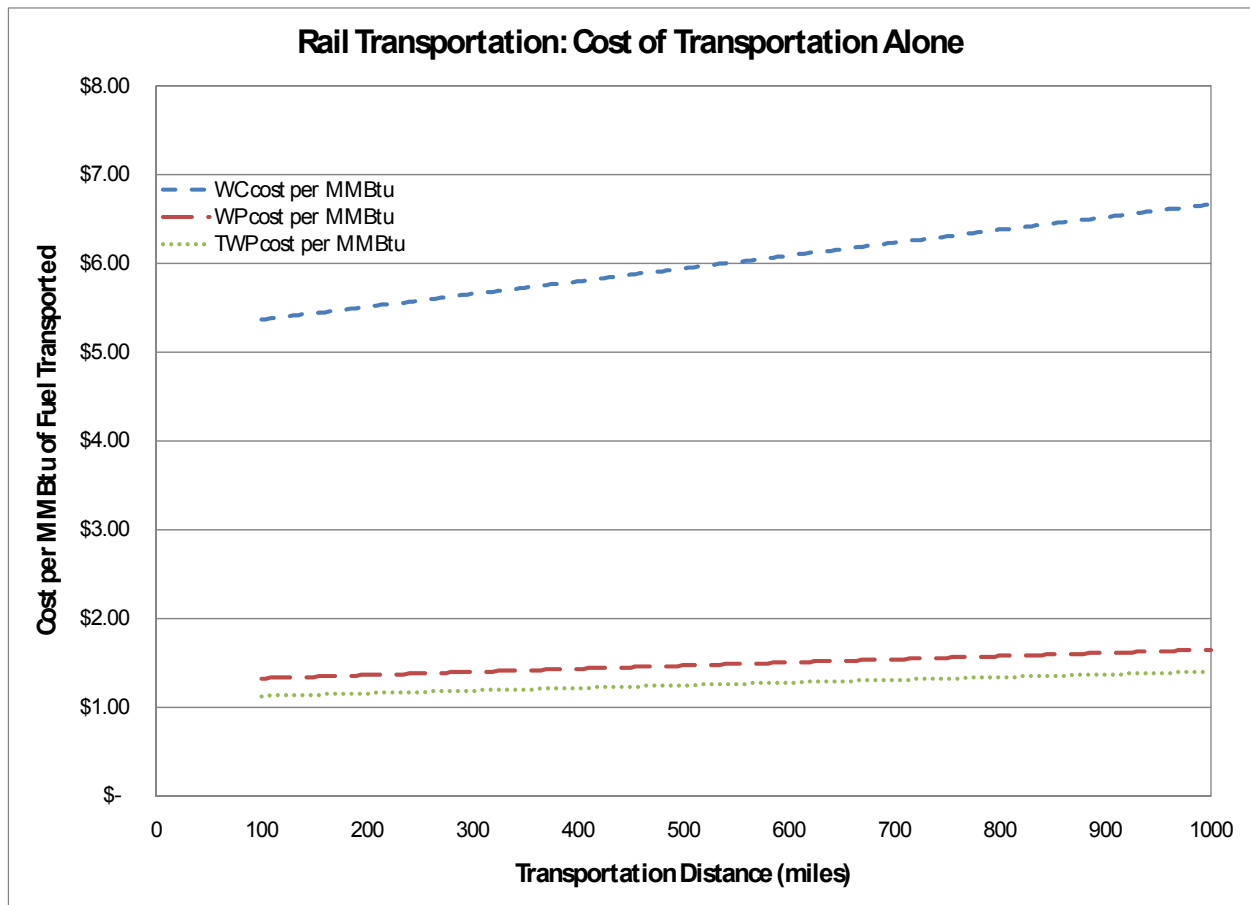


Figure B-2
Transportation Costs for Biomass Delivered by Rail

It is important to note that rail switches are a key driver for rail transportation costs, and the number of switches necessary to transport a unit train from one location to another is not always a function of distance, but rather of what rail corridor each location is near. This leads to a non-linearity in rail transportation costs as a function of distance (which is not present in trucking costs). Although these additional costs are not directly addressed in this simplified analysis, biomass project developers intending to use rail transportation should consider the number of switches as a potential cost indicator when evaluating suppliers at varying distances from the project site.

Barge Transportation

This analysis assumes a fixed fee handling cost of \$4/ton, and a distance variable cost of \$0.0193/ton-mile for all fuel types. This is based on recently acquired data from a southeastern barge company, as well as weight and volume limits for standard, 1,800-ton river barges.

For comparison, Trusty and Malstom's (1998) data indicate a \$0.12/container-mile variable charge plus \$144 in fixed fees per container for barge shipping. This is reasonably comparable to the value used in this analysis. The BTS/BEA data indicate \$28.8 billion in gross revenue by the railroad industry for 485 billion ton-miles traveled, which corresponds to about \$0.059 per ton-mile. This is significantly higher than the value calculated here. However, the BTS/BEA data do not present the data as a function of distance, only noting a total ton-mileage for the industry.

The profile of cost versus shipping distance is presented in Figure B-3 below for a likely range of transportation distances by barge. As with other transport modes, wood chips are more expensive to transport than the denser pellet fuels on a \$/MMBtu basis. Furthermore, the fixed fee charges represent a much greater fraction of the total costs for barge shipment, which makes it even more important to fill containers to their weight capacity.

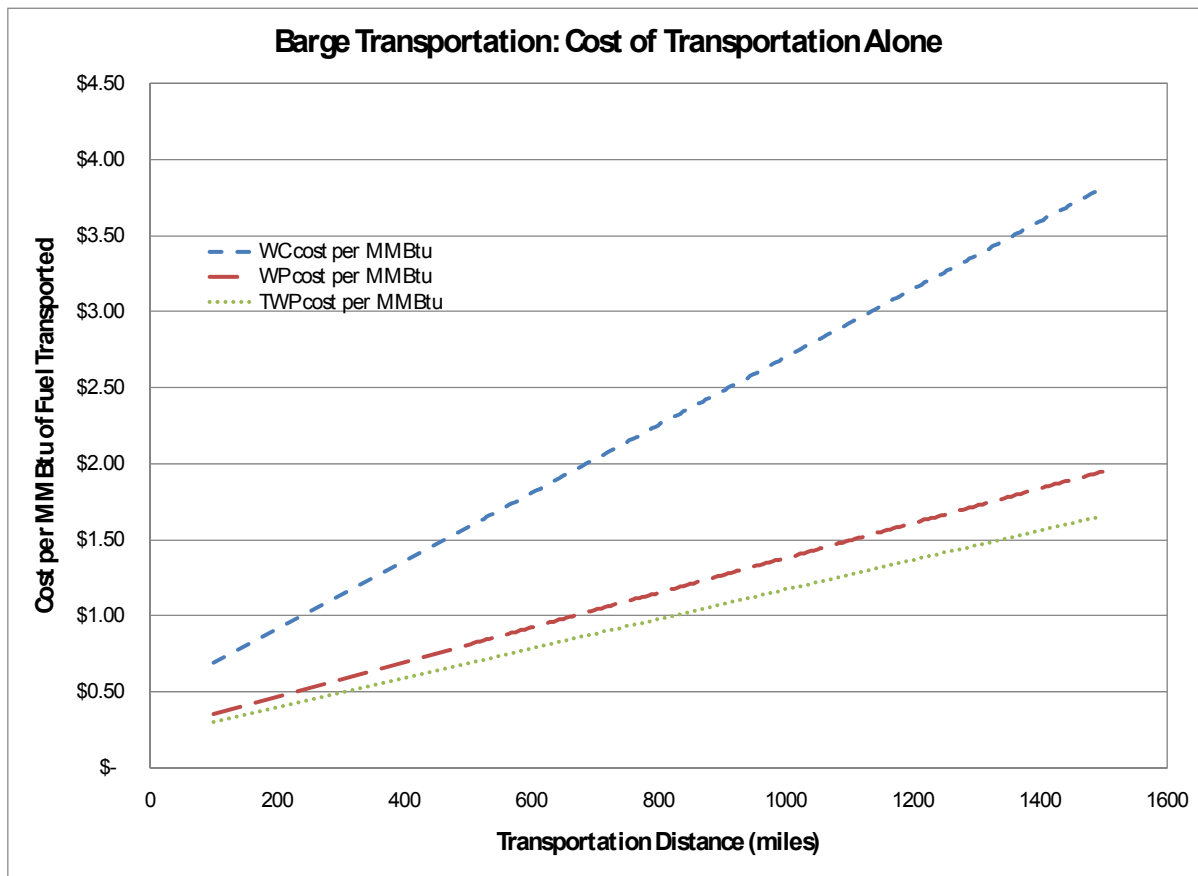


Figure B-3
Transportation Costs for Biomass Delivered by Barge

This analysis assumes that the fuel can be transported with the same barge for its entire journey, which is not always the case. River-going barges cannot generally be towed on the ocean, ocean barges with deep drafts cannot usually be taken on rivers, and standard river barges may have to be exchanged for smaller barges with shallower drafts in order to pass certain sections of a river. Any transfer of fuel from barge to barge will incur fixed loading and unloading costs, port fees, and other fixed costs that increase transportation costs without any increase in distance travelled. As with switches in rail transportation, this can result in nonlinear cost increases that are not accounted for here. Biomass repowering project developers, however, should consider these fees in detail as they evaluate fuel suppliers located at different distances from the plant. Distance may not be as important a cost driver as the number of transfers necessary. Further, in the case of fuel pellets, each transfer will degrade the fuel's quality, exposing it to more moisture, and will increase the breaking of pellets through impacts with hard surfaces, leading to higher fines content. Both of these can create material handling problems after the fuel reaches the plant. The fuel quality affects of the added handling associated with additional barge transfers should be evaluated carefully against transportation cost considerations.

Mode Comparison

One question that will concern repowering developers is the distance from which they will have to procure their fuels. Wood chips and sawdust are likely to come from local sawmills, landfills, and transfer stations, as well as timber harvesting operations generally within a 50- to 100-mile radius. These small, distributed sources are likely to supply wood from many locations within the region. Truck transportation is well suited to the small shipment sizes, relatively small haul distances, and geographic diversity typical of wood chips. It is unlikely, for example, that a single timber harvesting operation would be both in close proximity to a rail line or barge-navigable river and large enough to fill unit trains of rail cars or large tows of barges at reasonable intervals. Trucks, however, require only basic road infrastructure and have relatively small minimum load sizes, making them ideal for collecting wood chips from remote forest harvests or small sawmills.

Meanwhile, wood pellets and torrefied wood pellets are likely to be supplied to a power station in large shipments, possibly by only one or two major suppliers. The pellet suppliers effectively pre-aggregate local wood chips and other residues before processing and densification. Thus, instead of a multitude of small suppliers, only a few larger suppliers are likely to be present in a particular geographic area. The larger quantity of fuel sourced by the supplier (as well as the higher energy density of the fuel) makes it more economical to ship with rail or barge transportation over longer distances. The combination of fewer available suppliers and the availability of longer-distance transportation modes also makes it more likely that suppliers will be located further from the repowered generation station.

Figure B-4 compares the costs for transporting wood pellets over various distances for each considered transportation mode. A similar graph for transporting torrefied wood pellets is shown in Figure B-5. Each line shows how the estimated transportation cost per MMBtu increases as transportation distance increases. Truck transportation has the steepest slope, as the transportation cost increases the fastest with distance. Rail and barge transport are more economical over the long haul, they have higher fixed cost per container but lower distance variable costs. The line intersection points illustrate where it becomes cheaper to use different transport methods. Overall, it is assumed that for distances under 100 miles, truck transport will be the preferred option. For distances greater than 160 miles, rail transport is estimated to be less costly than truck transport. Barge is less expensive than both truck and rail transportation for any distance over 100 miles up to 1,340 miles, at which point rail transportation becomes less expensive.

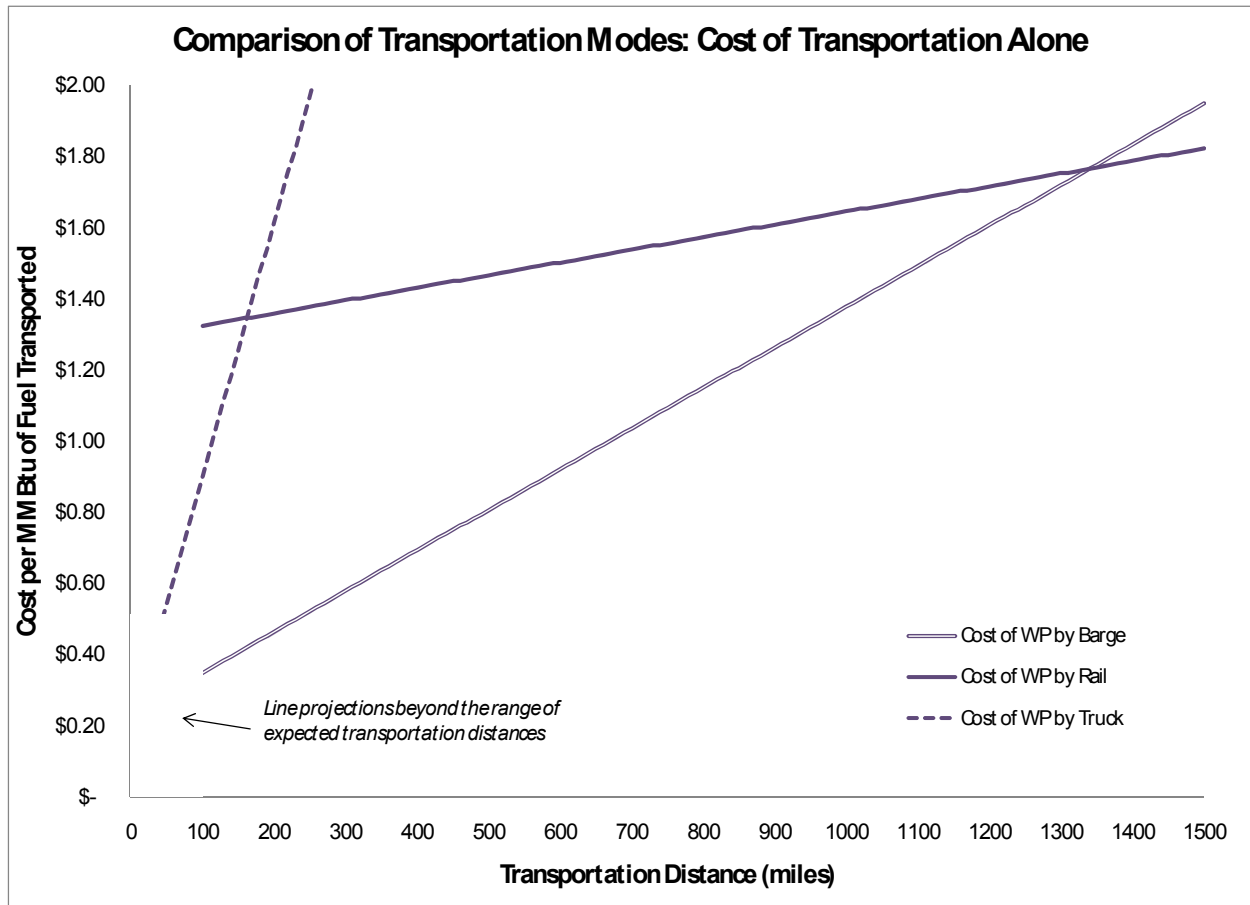


Figure B-4
Transportation Mode Comparison for Wood Pellets

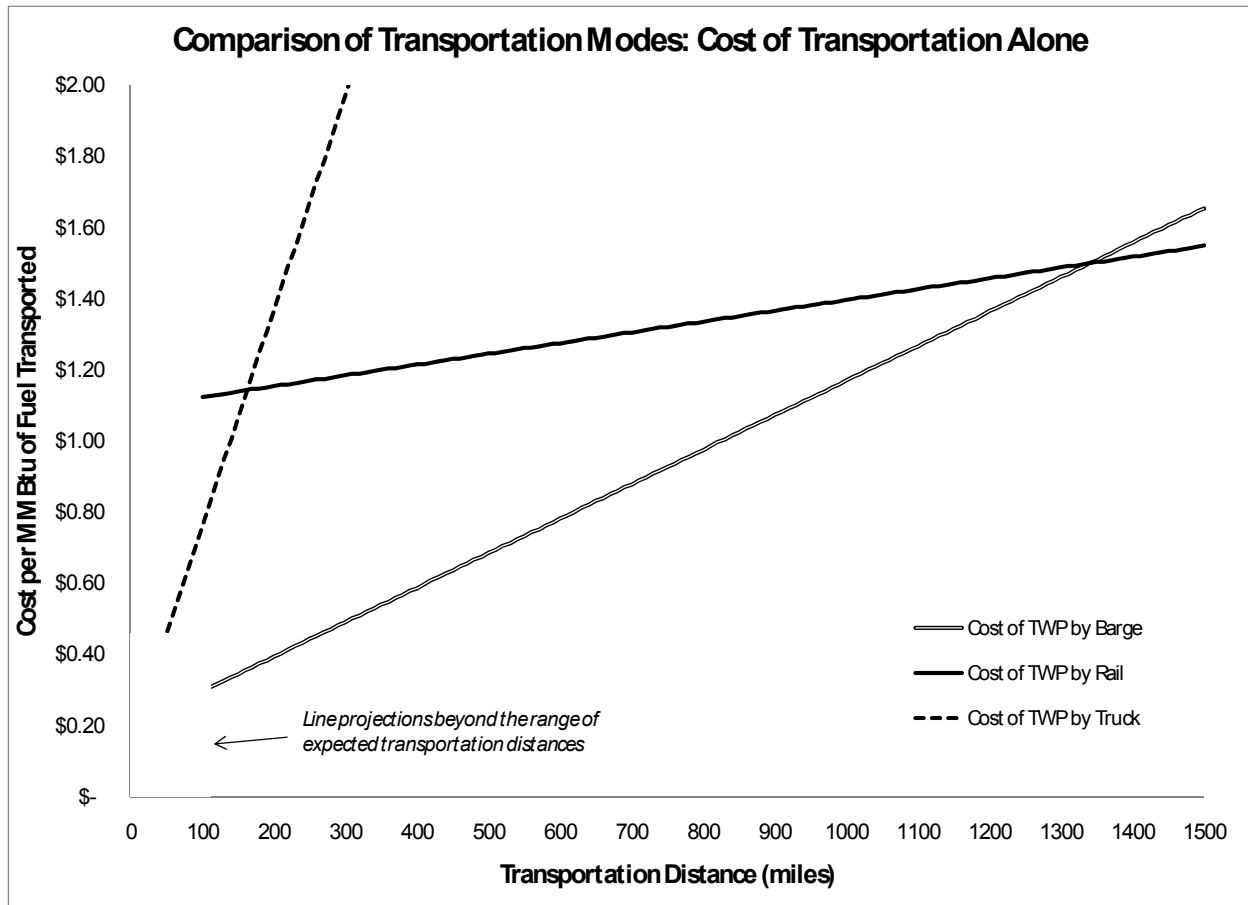


Figure B-5
Transportation Mode Comparison for Torrefied Wood Pellets

The local, distributed, truck-oriented nature of wood chip production and the aggregated, rail- and barge-friendly nature of pellet plants also lead to another important question: how far must densified biomass be shipped at a low cost per ton-mile before its cost becomes non-competitive with local biomass shipped for a small distance at a high cost per ton-mile?

The cost functions generated for the barge and rail transportation modes were plotted on the same axes for the two pellet types, then compared to “benchmark” values for wood chips transported by truck from various distances. This analysis, shown in Figure B-6, indicates that rail transportation of pellets is never competitive in transportation cost with wood chips from a 50-mile distance, although it does compete with wood chips shipped farther distances. Wood pellets can be shipped by rail for 350 miles and torrefied wood chips for 1,060 miles before their transportation costs per MMBtu exceed those of wood chips sourced from a 75-mile radius. Barge transportation appears to be more cost-competitive than rail with local trucking of wood chips. For example, wood pellets can be shipped by barge for 1,020 miles and torrefied wood pellets for 1,240 miles before their transportation costs per MMBtu exceed those of wood chips trucked from a 75-mile radius.

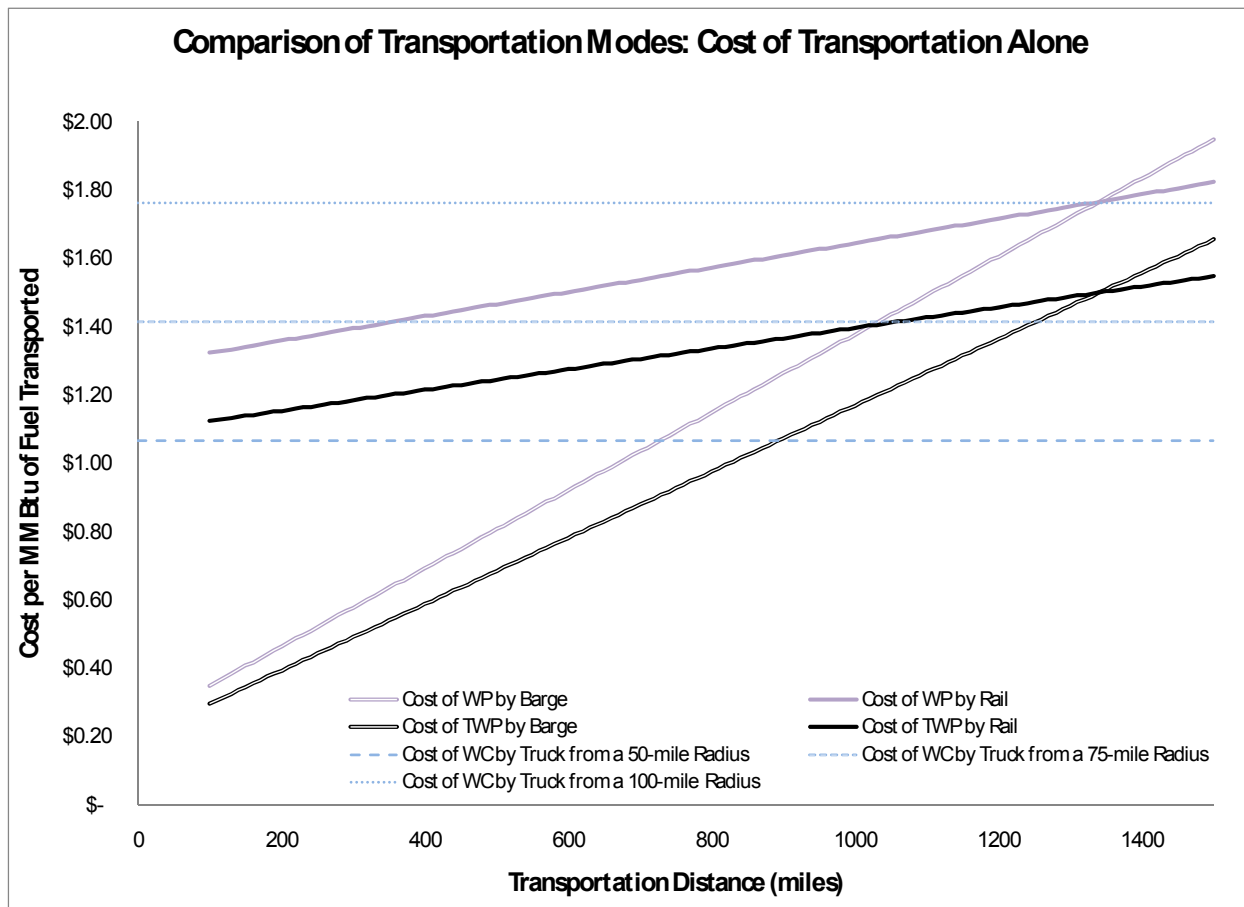


Figure B-6
Comparison of Transportation Costs by Fuel Type and Mode

This analysis would imply that rail and barge transportation of pelletized biomass can be competitive on a per-MMBtu basis with local shipping of wood chips. Pellet suppliers can be between four and a half times as far away (wood pellets by rail) and seventeen times as far away (torrefied wood pellets by barge) as local wood chip suppliers and remain competitive in freight costs.

One important parameter not presented in the transportation cost analysis is the free on board (FOB) cost of the fuel itself; the preceding analysis considered only transportation costs. As wood chips are a minimally processed fuel, wood pellets a moderately processed fuel, and torrefied pellets a highly processed fuel, one can expect significant differences in their FOB costs per MMBtu, before transportation costs are added. The FOB prices applied to chips, wood pellets, and torrefied pellets were presented in Chapter 5. These prices were added to the transportation costs to calculate a delivered price per MMBtu of fuel, shown in Figure B-7.

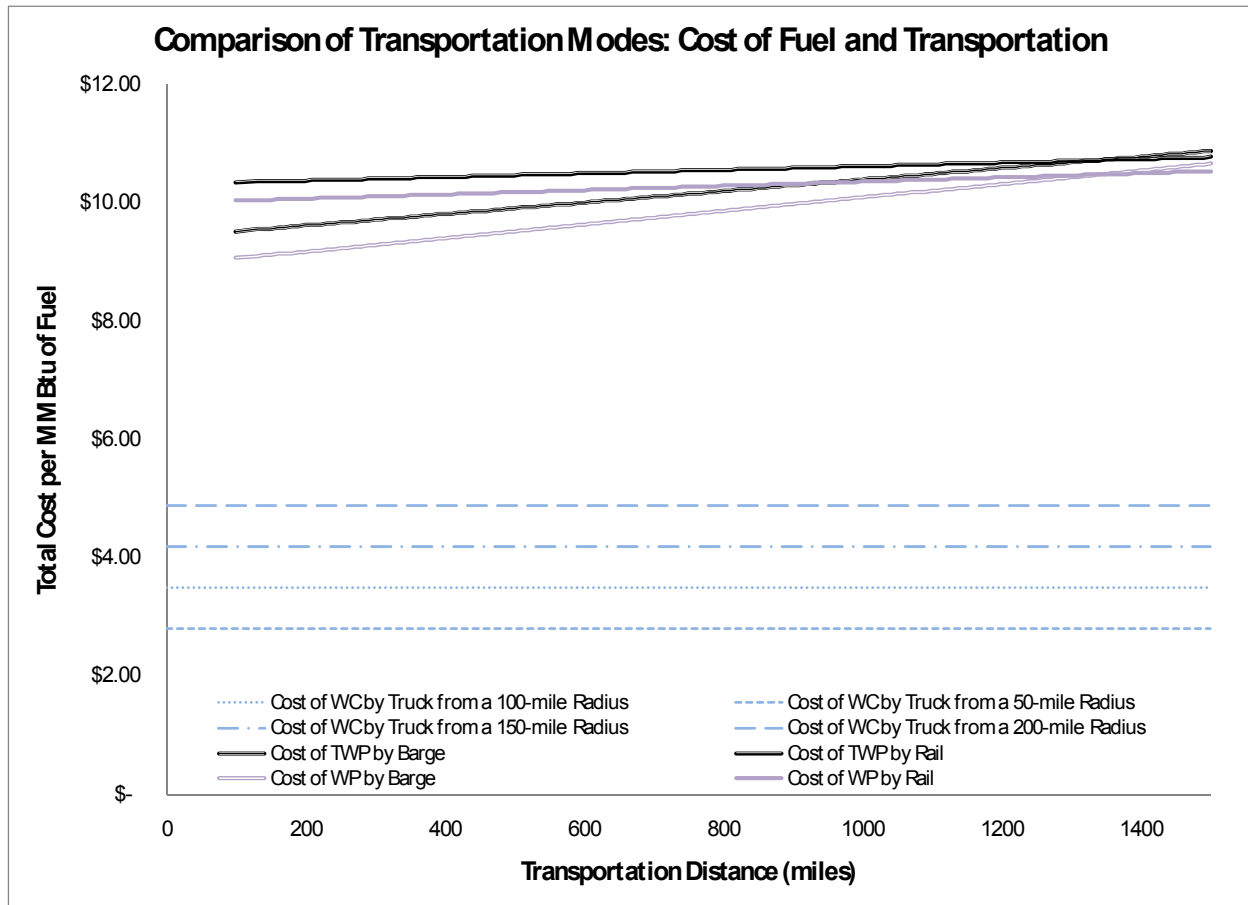


Figure B-7
Comparison of Delivered Fuel Costs by Fuel Type and Mode

These data show that while the transportation costs alone may be competitive with wood chips, the FOB costs per MMBtu are not. Wood chips must be transported by truck for more than 1,000 miles, a very atypical haul distance, before their cost reaches that of the closest available wood pellets shipped as cheaply as possible. Transportation cost alone will not overcome the large difference in fuel price between densified and non-densified fuels. Increased boiler efficiency, decreased capital costs, and fuel processing advantages must offer economic benefits to overcome the significant differences in the fuels' delivered prices. This question was considered in detail in Chapter 5.

C

THERMOFLEX MODELING; MASS BALANCE RESULTS

Gross power	143948	kW
Net power	133685	kW
Net heat rate (HHV)	9511	BTU/kWh
Net fuel input (HHV)	1271500	kBTU/h

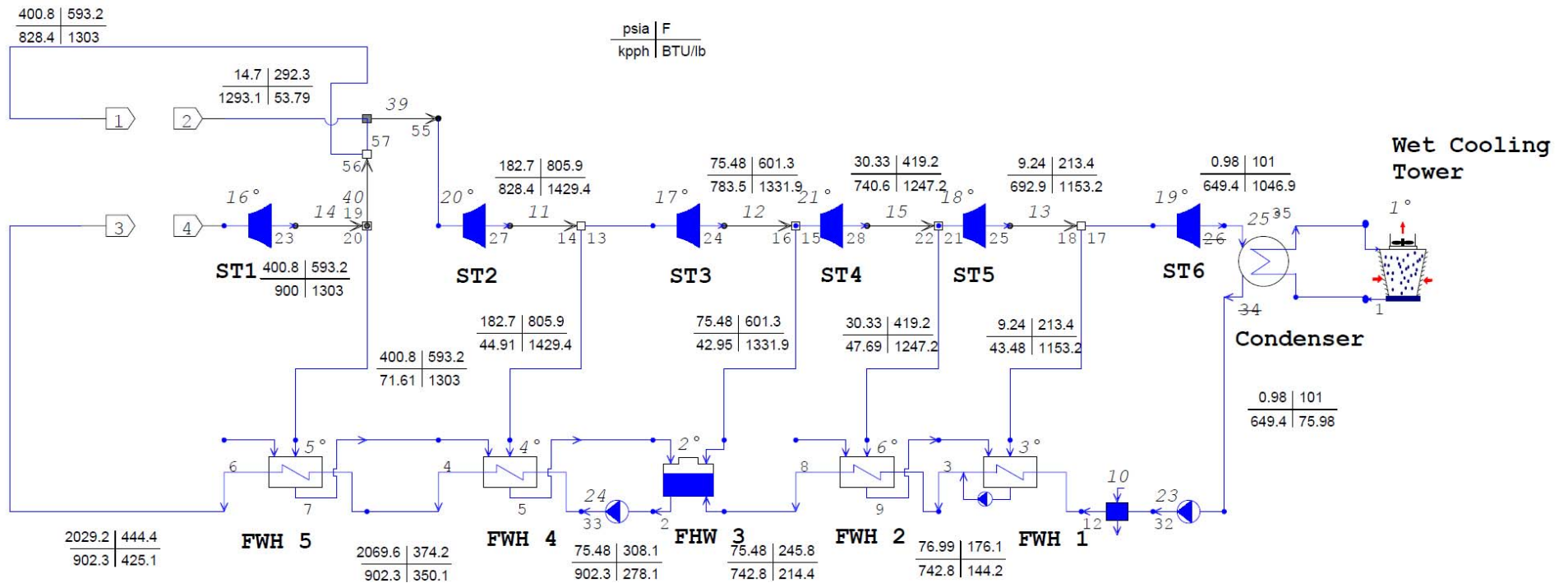


Figure C-1
Base Case Coal Model Process Diagram, Part 1

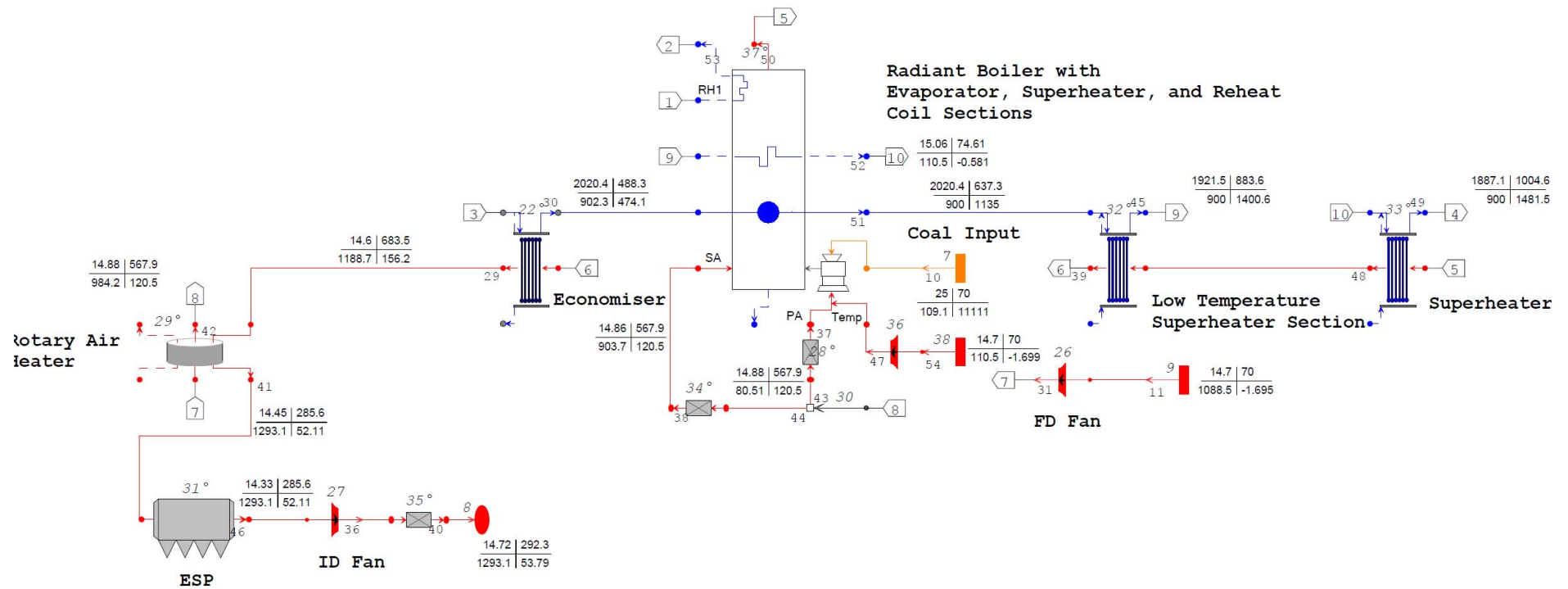


Figure C-2
Base Case Coal Model Process Diagram, Part 2

Thermoflex Modeling; Mass Balance Results

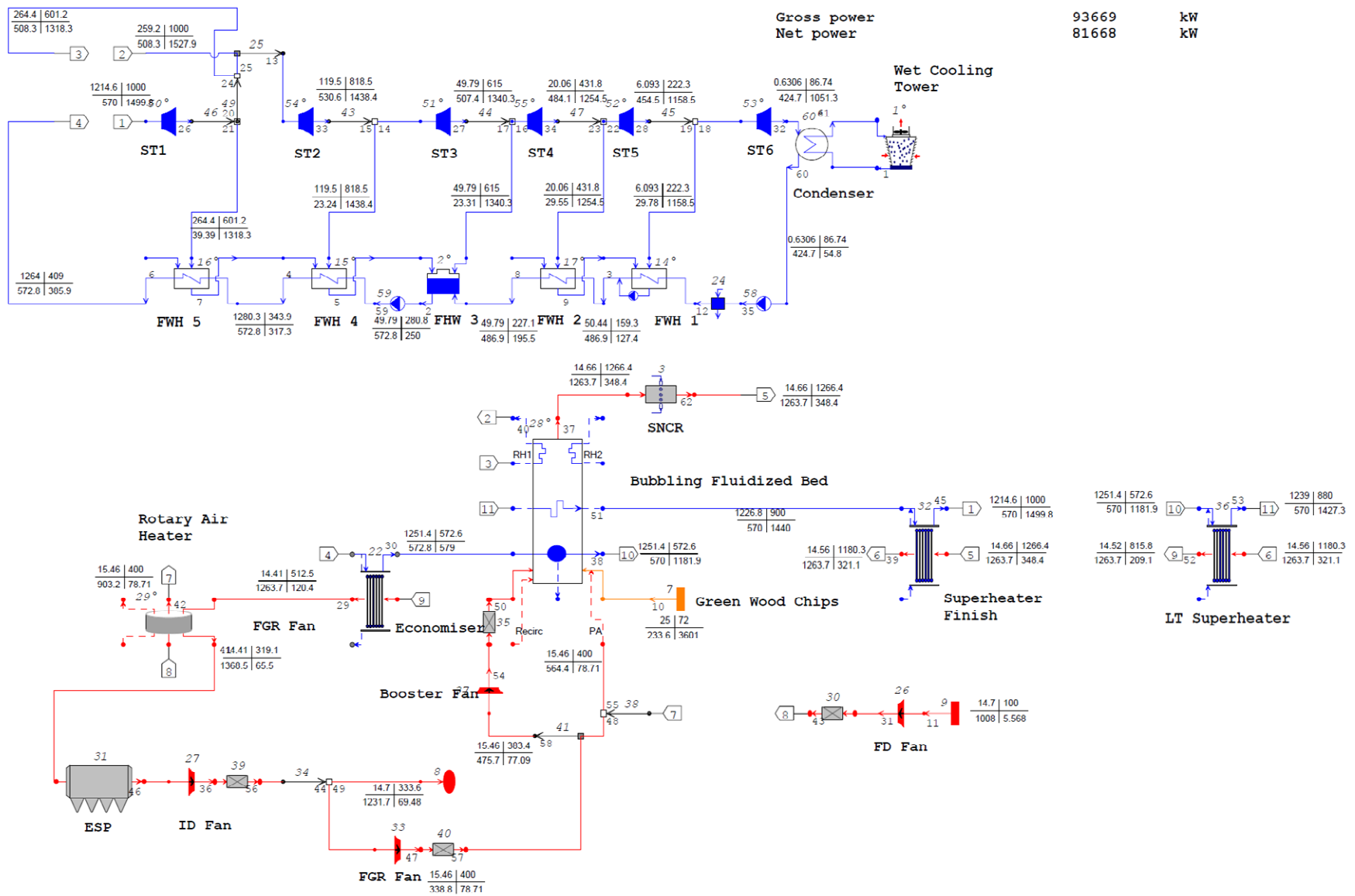


Figure C-3
Wood Chips Repowering Model Process Diagram

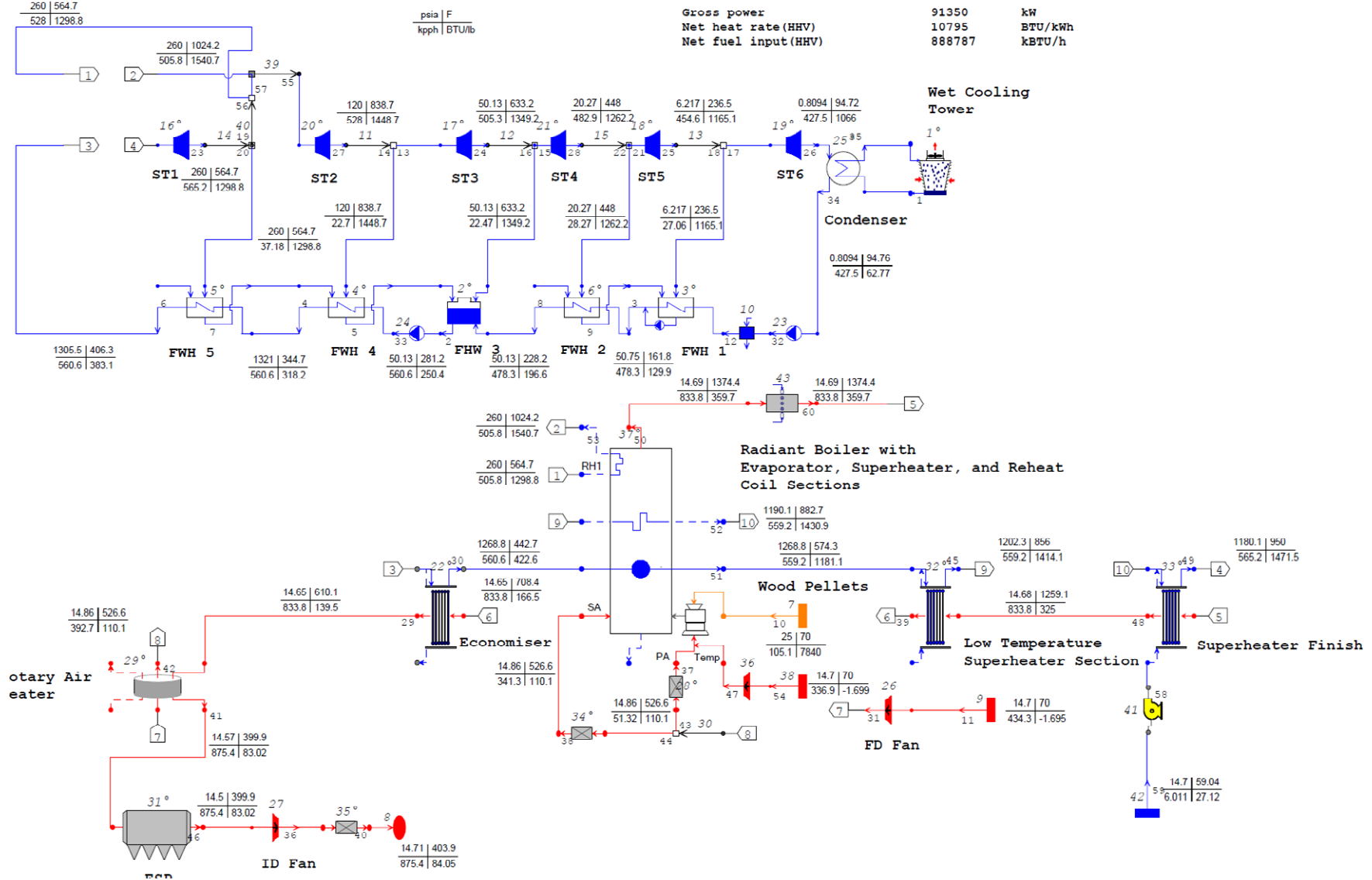


Figure C-4
Wood Pellets Repowering Model Process Diagram, Case 2a

Thermoflex Modeling; Mass Balance Results

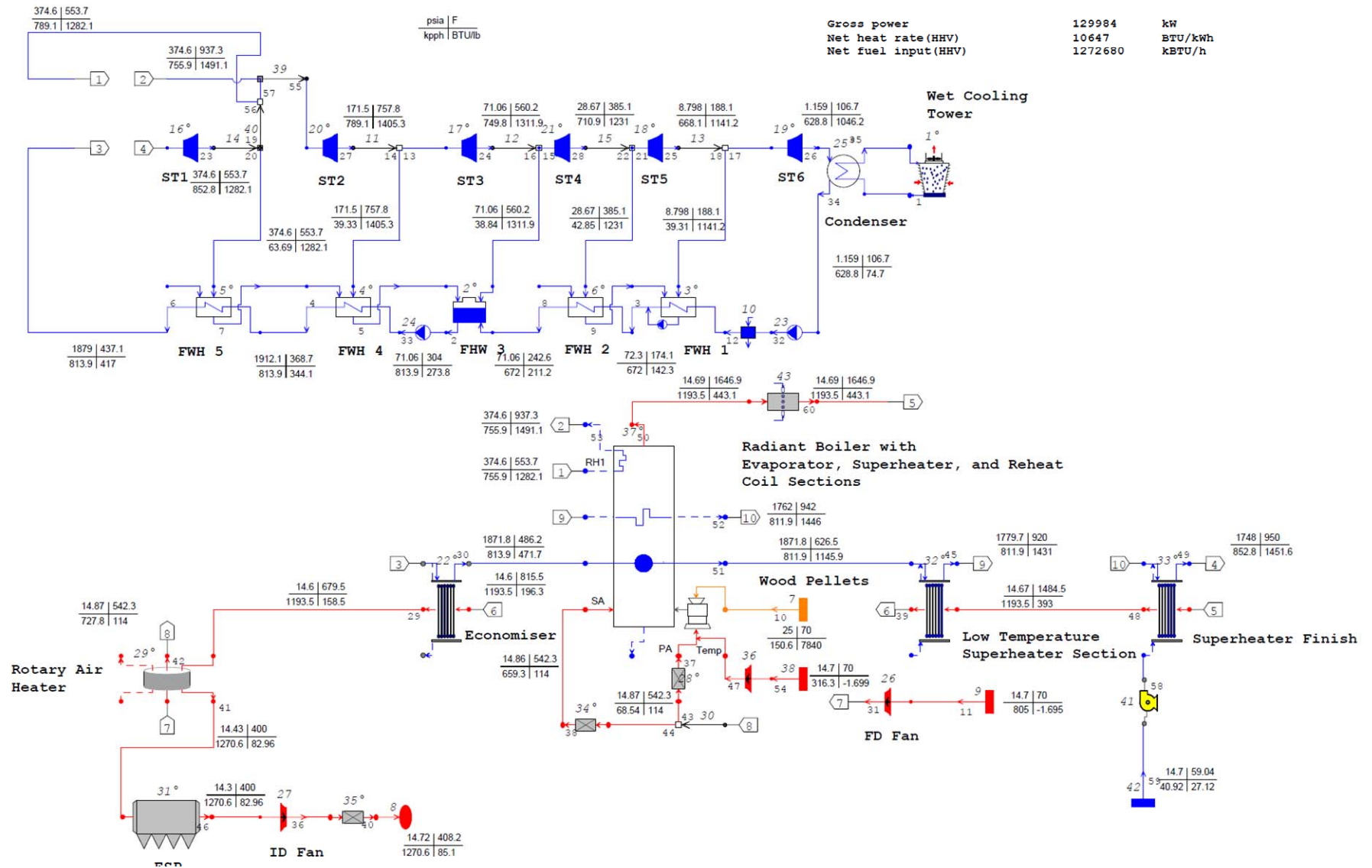


Figure C-5
Wood Pellets Repowering Model Process Diagram, Case 2b

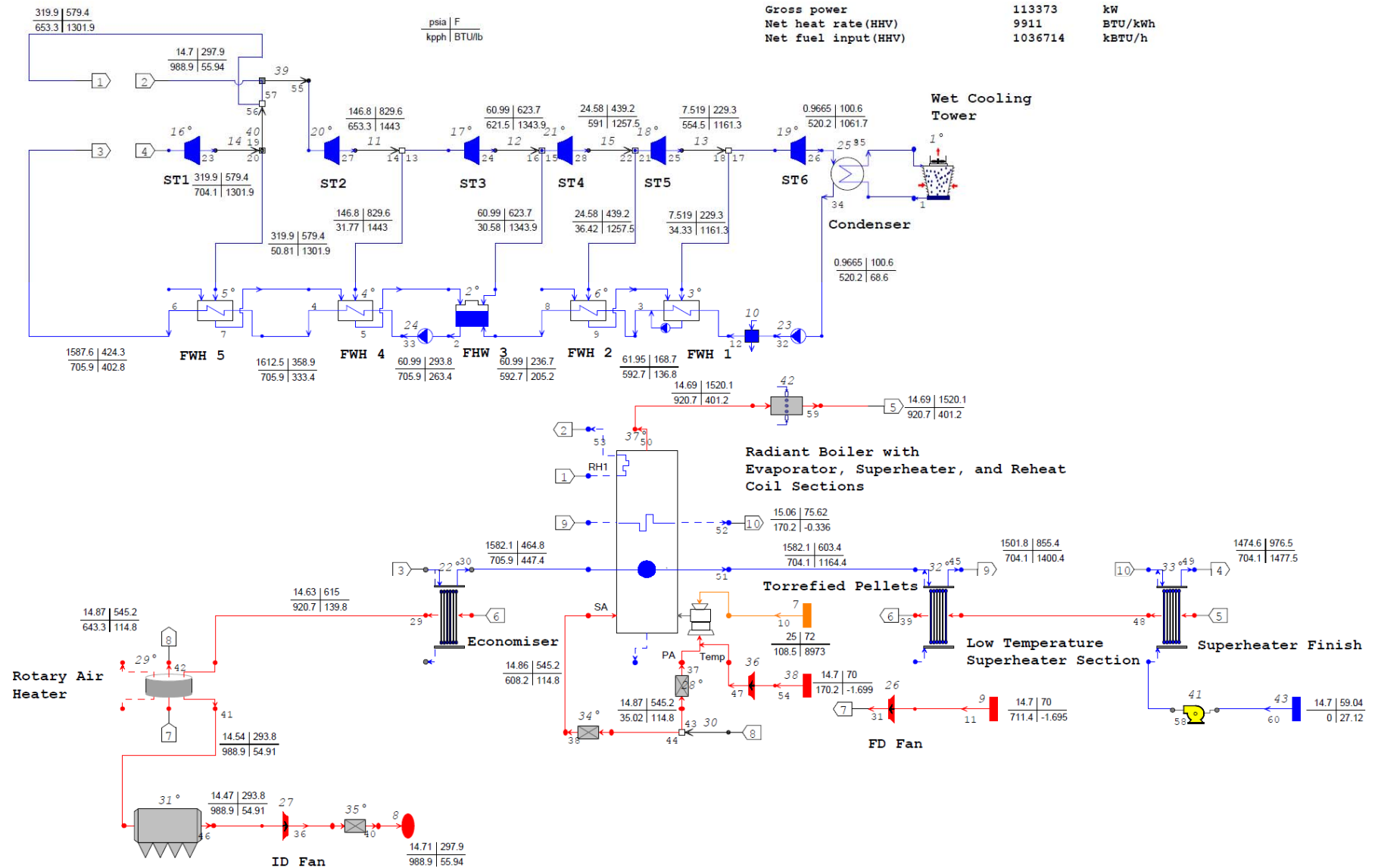


Figure C-6
Torrefied Wood Pellets Scenario 3.1 Repowering Model Process Diagram

The diagram illustrates a biomass gasification system. Feedstock enters at the top left, passing through a series of six steam turbines (ST1-ST6) and five feedwater heaters (FWH 1-FWH 5). The steam from these turbines is condensed in a condenser and then pumped back to the feedwater heaters. The gas from the gasifier passes through a radiant boiler with evaporator, superheater, and reheat coil sections. The gas then goes through a torrefied pellets section, a low temperature superheater section, and a superheater finish section. The gas is then cooled by an FD fan and an ID fan. The system also includes a wet cooling tower and a radiant boiler with evaporator, superheater, and reheat coil sections.

Key Components and Flow:

- Feedstock:** Enters at the top left, passing through a series of six steam turbines (ST1-ST6) and five feedwater heaters (FWH 1-FWH 5).
- Steam Cycle:** The steam from these turbines is condensed in a condenser and then pumped back to the feedwater heaters.
- Gasification:** The gas from the gasifier passes through a radiant boiler with evaporator, superheater, and reheat coil sections.
- Gas Treatment:** The gas then goes through a torrefied pellets section, a low temperature superheater section, and a superheater finish section.
- Cooling:** The gas is then cooled by an FD fan and an ID fan.
- Wet Cooling Tower:** The gas is cooled in a wet cooling tower.
- Radiant Boiler:** The gas is heated in a radiant boiler with evaporator, superheater, and reheat coil sections.

Energy and Mass Flow Data:

Component	Mass Flow (kg/h)	Temperature (°C)	Pressure (psia)	Enthalpy (BTU/lb)
Feedstock	14.7	324.7	1231.7	62.83
ST1	397.3	590.1	892.7	1301.5
ST2	181.3	802.2	822.4	1427.6
ST3	74.96	598.3	778.4	1330.4
ST4	30.15	416.9	736.3	1246.1
ST5	9.224	212.2	689.5	1152.6
ST6	1.211	108.2	646.9	1055.5
Condenser	1.211	108.2	646.9	76.2
FWH 1	76.43	176.2	730.9	144.3
FWH 2	74.96	245.6	730.9	214.2
FWH 3	74.96	307.6	887.3	277.6
FWH 4	2047.7	373.6	887.3	349.4
FWH 5	2008.5	443.6	887.3	424.2
Wet Cooling Tower	1.211	108.2	646.9	1055.5
Radiant Boiler	15.06	76.23	197.6	-0.1876
Torrefied Pellets	2000	635.9	885.1	1136.6
Low Temperature Superheater	1902.5	889.4	885.1	1405.4
Superheater Finish	1868.6	1000	892.7	1479.2
FD Fan	14.7	59.04	7.561	27.12
ID Fan	14.7	324.7	1231.7	62.83

Figure C-7
Torrefied Wood Pellets Scenario 3.2 Repowering Model Process Diagram

Gross power 99481 kW
 Net power 85023 kW
 Net heat rate (HHV) 11886 BTU/kWh
 Net fuel input (HHV) 1010564 kBTU/h

Gasification Island

Woody Biomass

Fuel Dryer

Fuel Gasification

Wet Cooling Tower

Condenser

Syngas Cooler Stage 1

Syngas Cooler Stage 2

Multicline (Pressure Drop)

Clean Syngas to Boiler

Radiant Boiler with Evaporator, Superheater, and Reheat Coil Sections

Economiser

Low Temperature Superheater Section

Superheater Finish

FD Fan

Alabama Bituminous Coal

Rotary Air Heater

ESP

ID Fan

C-9

D

OPERATIONS AND MAINTENANCE DETAILS

Operations and Maintenance Details

Parameter	1	2a	2b	3a.1	3a.2	3b.1	3c.1	4
Plant Type	Wood Chips in BFB Replacement Boiler	Existing Boiler with Wood Pellets-Mill Limited	Existing Boiler with Wood Pellets-Additional Mills and 115% of Flue Gas Volume Limit	Existing Boiler with Torrefied Wood Pellets-Mill Limited; Concrete Dome Storage	Existing Boiler with Torrefied Wood Pellets-Flue Gas Limited; Concrete Dome Storage	Existing Boiler with Torrefied Wood Pellets - Mill Limited; Open Pile Storage	Existing Boiler with Torrefied Wood Pellets - Mill Limited; Covered Rectangular Storage	Existing Boiler with Syngas Cofiring
Gross Capacity (MWe)	93.4	91.4	129.98	113.4	140.8	113.37	113.4	99.5
Net Capacity (MWe)	82.4	81.8	117.65	102.8	128.9	102.84	102.8	85.1
Fuel Feed Rate (tph) (At full load)	116.8	52.6	75.30	54.3	67.5	54.25	54.3	73.2
Capacity Factor	85%	85%	85%	85%	85%	0.85	85%	85%
Net Generation (MWh) (estimated)	613,294	609,419	876,044	765,725	959,839	765,725	765,725	633,634
Location	4	4	4	4	4	4	4	4
Variable O&M (\$/yr)	1,252,050	569,938	\$ 773,933	676,664	814,481	\$ 676,664	676,664	1,245,749
Non-Labor Fixed O&M (\$/yr)	2,725,964	2,723,185	\$ 2,756,294	2,742,059	2,765,540	\$ 2,742,059	2,742,059	3,218,428
Labor (\$/yr)	2,754,399	2,666,381	\$ 2,666,381	2,666,381	2,666,381	\$ 2,666,381	2,666,381	3,158,868
Total O&M (\$/yr)	6,732,413	5,959,504	\$ 6,196,608	6,085,104	6,246,403	\$ 6,085,104	6,085,104	7,623,045
Variable O&M (¢/kWh)	0.204	0.094	0.088	0.088	0.085	0.088	0.088	0.197
Fixed O&M (\$/kW-yr)	\$ 33.10	\$ 33.27	23.427	\$ 26.66	\$ 21.45	26.664	\$ 26.66	\$ 37.82
Labor (\$/ kW-yr)	33.44	32.58	22.663	25.93	20.68	25.928	25.93	37.12
Total O&M (¢/kWh)	1.10	0.98	0.707	0.79	0.65	0.795	0.79	1.20

E

STATE LEVEL QUALITATIVE ANALYSIS MATRIX

State	Region	RPS Participation	Carbon Initiative Participation	Availiity of Biomass	Hourly Wage Rate	Price of Electricity	Cost of Pellet Fuel	Transportation: Roads	Transportation: Rail
Alabama	IV	negative	negative	neutral	positive	neutral	no data	neutral	neutral
Alaska	X	negative	positive	negative	positive	positive	no data	negative	negative
Arizona	IX	positive	positive	negative	neutral	neutral	no data	negative	negative
Arkansas	VI	negative	negative	positive	negative	negative	no data	neutral	neutral
California	IX	positive	positive	positive	negative	positive	neutral	negative	neutral
Colorado	VIII	positive	positive	neutral	neutral	neutral	positive	negative	neutral
Connecticut	I	positive	positive	negative	neutral	positive	negative	positive	positive
Delaware	III	positive	positive	negative	negative	positive	no data	positive	neutral
District of Columbia	III	positive	negative	negative	no data	positive	no data	positive	positive
Florida	IV	positive	negative	neutral	positive	positive	no data	neutral	positive
Georgia	IV	negative	negative	positive	positive	neutral	no data	neutral	neutral
Hawaii	IX	positive	negative	negative	negative	positive	no data	neutral	negative
Idaho	X	negative	positive	neutral	positive	negative	no data	negative	negative
Illinois	V	positive	positive	positive	negative	neutral	no data	neutral	positive
Indiana	V	negative	positive	positive	neutral	negative	no data	positive	positive
Iowa	VII	positive	positive	positive	positive	negative	no data	neutral	neutral
Kansas	VII	positive	positive	positive	positive	negative	neutral	neutral	positive
Kentucky	IV	negative	negative	neutral	negative	negative	neutral	positive	neutral
Louisiana	VI	negative	negative	positive	positive	neutral	no data	neutral	neutral
Maine	I	positive	positive	neutral	positive	positive	neutral	neutral	negative
Maryland	III	positive	positive	negative	negative	positive	neutral	positive	positive
Massachusetts	I	positive	positive	negative	neutral	positive	negative	positive	positive
Michigan	V	positive	positive	neutral	neutral	neutral	positive	neutral	negative
Minnesota	V	positive	positive	positive	neutral	negative	positive	negative	negative
Mississippi	IV	negative	negative	positive	negative	neutral	positive	neutral	neutral
Missouri	VII	positive	negative	positive	neutral	negative	positive	neutral	positive
Montana	VIII	positive	positive	neutral	neutral	negative	negative	negative	negative
Nebraska	VII	negative	negative	positive	neutral	negative	no data	negative	neutral
Nevada	IX	positive	positive	negative	negative	positive	no data	negative	negative
New Hampshire	I	positive	positive	negative	positive	positive	neutral	positive	negative
New Jersey	II	positive	positive	negative	negative	positive	negative	positive	positive
New Mexico	VI	positive	positive	negative	no data	neutral	no data	negative	negative
New York	II	positive	positive	neutral	negative	positive	neutral	positive	positive
North Carolina	IV	positive	negative	positive	neutral	neutral	negative	positive	neutral
North Dakota	VIII	positive	negative	neutral	negative	negative	no data	negative	negative
Ohio	V	positive	positive	positive	neutral	neutral	positive	positive	positive
Oklahoma	VI	negative	negative	neutral	neutral	neutral	positive	neutral	neutral
Oregon	X	positive	positive	positive	negative	negative	no data	negative	negative
Pennsylvania	III	positive	positive	neutral	neutral	neutral	neutral	neutral	positive
Rhode Island	I	positive	positive	negative	no data	positive	negative	positive	positive
South Carolina	IV	negative	negative	neutral	positive	neutral	no data	positive	positive
South Dakota	VIII	positive	positive	neutral	no data	negative	no data	negative	negative
Tennessee	IV	negative	negative	neutral	positive	neutral	negative	positive	positive
Texas	VI	positive	negative	positive	neutral	positive	negative	negative	neutral
Utah	VIII	positive	positive	negative	positive	negative	positive	negative	neutral
Vermont	I	positive	positive	negative	positive	positive	negative	positive	neutral
Virginia	III	positive	negative	neutral	positive	neutral	negative	positive	positive
Washington	X	positive	positive	positive	negative	negative	neutral	negative	neutral
West Virginia	III	positive	negative	negative	negative	negative	no data	neutral	negative
Wisconsin	V	positive	positive	neutral	positive	neutral	positive	neutral	negative
Wyoming	VIII	negative	positive	negative	neutral	negative	no data	negative	negative

F

CAPITAL COST ANALYSIS METHODOLOGY DETAILS

Scaling Technique

When necessary, minor capital costs were scaled to develop cost estimates for various equipment items and configurations. The capacity-based scaling estimate used in this analysis relies on the non-linear relationship between capacity and costs as follows: $\$B/\$A = (\text{CapB}/\text{CapA})^e$. The \$A and \$B are the costs of the two similar plants with CapA and CapB being the capacities of the two plants, and the exponent “e” being the pro-rating factor. The value of the exponent “e” usually lies between 0.5 and 0.85 with an exponent of 0.6 used if no other exponent is given. This relationship is exponential rather than linear due to economies of scale; it is generally cheaper per square foot to build a large building, for example, than a small one. The same idea holds true for process equipment like boilers, engines, turbines, and pumps, and for facilities of a similar type such as fuel receiving yards.

Where necessary, cost indices were used to adjust costs developed or provided at an earlier time to account for inflation and changes in material costs. A cost index is a tool used to relate the costs of specific equipment and other items at various dates in the past. This assessment generally uses the Chemical Engineering Chemical Plant Index (CECPI) to adjust any cost data used from prior estimates in past years to a current value.

Contingency and Other Factors

Capital cost contingencies are evaluated for all scenarios using industry standard factors. Contingencies are used to “*cover costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope,*” and should be considered an integral part of the cost estimate (U.S. Department of Energy, 1997). Some expenses cannot be determined prior to inception of the project, but something must be added to the estimate to allow for this reality. The appropriate amount of contingency to apply for a particular scenario depends on the level of definition/design of the project, the uncertainties in the cost estimates, and the complexity of project components.

Although there are a variety of different types of contingencies, it is the authors’ experience that two factors are typically sufficient to reasonably capture overall contingency costs: project contingency and process contingency. Project contingency in this sense is intended to cover all unforeseen costs associated with a typical plant of a particular type and size. Process contingency is intended to cover extraordinary unforeseen costs associated with a unique piece of equipment or assembly. This would include early or pilot deployment of a new technology or a new configuration of existing equipment.

The application of these contingencies and their magnitude depend on the class of estimate being developed. Both uncertainty and contingency (two different, but related terms) are reduced as project definition is increased. It is therefore reasonable to assume that overall project contingency may go down as the project is more clearly defined, but it is possible that even late in project development, a high process contingency may still be reasonably applied to some key component of a novel plant. A project contingency of 20% was applied to the overall capital costs in each scenario evaluated in this study, based on the level of detail included in the cost estimates. An additional process contingency of 10% was also applied to Cases 3 and 4, as these have experienced particularly limited commercial deployment with biomass feedstocks.

Engineering and owner's costs are also included in the capital cost estimates, and are estimated as a percentage of the total costs. Engineering cost is estimated to be 10% of the total direct costs including contingency, and owner's costs are estimated at 4% of the total capital (including contingency and engineering). The owner's costs include owner's engineer, permitting, and legal fees related to start-up of the plant. General contractor's overhead (20%), legal costs (2%), performance bond costs (8%), and equipment cost escalation (4% per year) were also included.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute Inc., (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity