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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

TECHNOLOGIES FOR REDUCING CARBON DIOXIDE EMISSIONS: A RESOURCE MANUAL FOR PULP, PAPER, AND WOOD PRODUCTS MANUFACTURERS

SPECIAL REPORT NO. 01-05

DECEMBER 2001

by

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PRESIDENT'S NOTE

In 1997, the American Forest and Paper Association (AF&PA) requested that NCASI develop information that could be used to assess costs for reducing the industry's CO_2 emissions to levels commensurate with the target established for the US under the Kyoto Protocol. In response, NCASI launched a major project involving a variety of experts within and outside of the forest products industry. In June 1999, the results of this effort were published in NCASI Special Report No. 99-02, *Estimated Costs for the US Forest Products Industry to Meet the Greenhouse Gas Reduction Target in the Kyoto Protocol*.

To perform the required engineering cost calculations, NCASI retained EKONO Inc., an engineering consulting firm with extensive experience in the forest products industry. An important part of the work undertaken by EKONO Inc. was the development of a set of example calculations for a wide range of technologies and operating practices, illustrating how to estimate the costs for reducing emissions and energy use. In this manual, the example calculations developed by EKONO Inc. are presented in a format intended to be useful to companies interested in performing screening assessments of options for reducing energy use and CO_2 emissions. The preparation of this manual was funded in part by the Department of Energy Office of Industrial Technologies.

Descriptions are provided for over seventy technology options. In addition to production process technologies, a number of steam and power generation technologies are also reviewed. Each technology description includes applicability guidance and an overview of the technology's impact on energy use, CO_2 emissions, operating costs, and capital costs. Sample calculations illustrate how to estimate the impacts of each technology on costs and emissions at individual mills.

It is clear from the analyses included in this manual that the technical feasibility, costs, and effectiveness of specific technologies and operating practices may vary significantly between individual facilities.

Ronald A. Yeske

December 2001

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ABSTRACT

This resource manual provides an overview of the costs and carbon dioxide emissions associated with steam and electrical power generation and use. Descriptions are provided for over seventy technology options which could enhance energy efficiency and reduce carbon dioxide emissions at pulp, paper, and wood products manufacturing facilities. Each technology description includes applicability guidance and an overview of the technology's impact on energy use, CO_2 emissions, operating costs, and capital costs. Sample calculations are included to illustrate the estimation of each technology's impact on costs and emissions when applied to individual mill processes. Capital cost estimates are also provided for most technology options (±40% accuracy level), along with sufficient information to adjust costs corresponding to capacities other than those used in deriving the estimates.

It is clear from the analyses included in this manual that the technical feasibility, costs, and effectiveness of specific technologies and operating practices may vary significantly from facility to facility. Among the important factors contributing to this variability are (a) the types of fuels being used and their costs; (b) the methods used to produce electricity on-site and off-site; (c) the production processes being used; (d) the extent to which energy saving technologies and operating practices have already been implemented; and (e) assumptions about, and accounting methods for, off-site effects on electricity and raw material production. These and other facility-specific factors must be addressed in developing estimates of the costs for reducing CO_2 emissions.

KEYWORDS

carbon dioxide, climate change, CO_2, emissions, energy efficiency, global warming, greenhouse gases, Kyoto Protocol

RELATED NCASI PUBLICATIONS

Special Report No. 99-02 (June 1999). *Estimated costs for the U.S. forest products industry to meet the greenhouse gas reduction target in the Kyoto Protocol*.

Special Report No. 98-02 (December 1998). *Estimated CO_2 emissions resulting from compliance with U.S. federal environmental regulations in the forest products industry*.

Technical Bulletin No. 717 (June 1996). *Review and analysis of JABOWA and related forest models and their use in climate change studies*.

Technical Bulletin No. 690 (January 1995). *Global change and forest responses: Theoretical basis, projections, and uncertainties*.

Technical Bulletin No. 628 (March 1992). *Effects of forest management on soil carbon storage*.

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1.0 INTRODUCTION

1.1 General

The forest products industry has made significant strides in reducing the amount of energy required to manufacture its products. Between 1970 and 1997, for instance, the total amount of energy required, on average, to produce a ton of pulp, paper, or paperboard fell from 32,000 MBtu to 26,000 MBtu (AF&PA 2000). In addition, the industry's use of renewable biomass fuels has grown significantly. By 1995, 55% of the energy used by pulp, paper, and paperboard mills was generated from biomass (AF&PA 2000). These trends have been accompanied by comparable reductions in mill emissions of fossil fuel-derived CO_2 per unit of production.

The current debate on global climate change, however, has involved considerable discussion of the costs and benefits of additional reductions in emissions of "greeenhouse gases," including CO_2. To better understand the potential impacts of various policy options under discussion, the forest products industry is undertaking a number of studies into the effects of the industry on the global carbon budget as well as options and costs for accomplishing further reductions in greenhouse gas emissions.

In November 1997, as a first step in estimating the costs to the industry for reducing CO_2 emissions, NCASI retained EKONO Inc. to (a) identify energy-saving technologies of potential use to facilities producing pulp, paper, paperboard, lumber, or wood panels; and (b) illustrate an approach for estimating the costs and effectiveness of these technologies. This report contains the results of those analyses, and should be useful to facilities interested in performing screening-level assessments of alternative technologies for reducing CO_2 emissions.

1.2 Basic Data

This study has been based mainly on theoretical calculations with assumed initial data. EKONO's file data have been used as the basis for the assumed process conditions. Since 1974, EKONO has conducted energy conservation studies in more than 100 North American and about 30 European forest products facilities. The data and experience accumulated in these studies have formed a basis for this study.

EKONO's cost file data were used as the basis for estimating investment costs for most of the 73 technologies identified and included in this manual. The estimates represent total installed costs, including indirect costs. It is recognized that the difficulty and cost of installing new equipment or modifying existing processes vary from one facility to another. The capital cost estimates are therefore meant for illustration only and for screening of the energy reduction measures based on their preliminary feasibility.

The sample calculations contained in Section 3 often indicate positive operating cost savings as a result of implementing a technology option. It is important to realize that the estimated operating cost savings do not include any depreciation charges or capital costs (capital costs are estimated independently). Furthermore, the estimated operating cost savings are not discussed in the context of a company's investment criteria (e.g., minimum acceptable rate of return on investment).

1.3 Units and Nomenclature

English units have been used throughout this study. The units together with abbreviations and nomenclature used in this study are listed below.

Several deviations from what may be traditional nomenclature used in North America should be emphasized as follows:

- "M" is consistently mega or million instead of thousand in some connections (e.g., MBtu means million Btu, MBF means million board feet, etc.)
- "k" is consistently kilo or one thousand (e.g., kBtu means thousand Btu, kBF means thousand board feet, etc.)
- % moisture is consistently on wet basis; i.e., 50% moisture refers to material with one-half dry substance and one-half water

Units and Nomenclature

ADT	air dry short ton
BD	bone dry
BDT	bone dry short ton
BL	black liquor
BLS	black liquor solids
BOD	biological oxygen demand
Btu	British thermal unit
$CaCO_3$	calcium carbonate
CaO	calcium oxide
Cl	chlorine atom
Cl_2	chlorine gas
ClO_2	chlorine dioxide
CO_2	carbon dioxide
CTMP	chemi-thermo-mechanical pulp
°C	degrees Celsius
d	day
d.a.	dry air
D0	first bleaching stage in an ECF bleaching sequence
DCE	direct contact evaporator
DCS	distributed control system
DEOPDED	bleaching sequence
DOE	US Department of Energy
d.s.	dissolved dry solids
E	extraction stage in bleaching sequence
EMS	energy management system
EOP	extraction stage with oxygen and peroxide enforcement
EP	extraction stage with peroxide enforcement
EPA	US Environmental Protection Agency
ESP	electrostatic precipitator
°F	degrees Fahrenheit
ft	foot
g	gram
gal	gallon
gpm	gallons per minute
GT	gas turbine

HHV	high heating value
H_2O	water
hp	horsepower
HP	high pressure
hr	hour(s)
HRSG	heat recovery steam generator
HVAC	heating, ventilating, and air conditioning
HW	hardwood
kBF	thousand board feet
kft^2	thousand square feet
kg	kilogram
klb	kilopound
kWh	kilowatt hour
lb	pound
LP	low pressure
MBF	million board feet
MBtu	million Btus
MDF	medium-density fiberboard
MEE	multiple effect evaporator
Mft^2	million square feet
MP	medium pressure
MW	megawatt
MWh	megawatt hour
N/A	not applicable or not available
$NaClO_3$	sodium hypochlorate
NaOH	sodium hydroxide
NCASI	National Council for Air and Steam Improvement, Inc.
NCG	non-condensible gases
O_2	oxygen
O_3	ozone
OCS	operator contol system
O&M	operations and maintenance
OSB	oriented strand board
PGW	pressurized ground wood
PRV	pressure reducing valve
psig	pounds per square inch gauge
s	second
SBS	solid bleached sulfate
SOGs	stripper off-gases
stm	steam
SW	softwood
t	metric ton
T	short ton (2000 lb)
TG	turbogenerator
TMP	thermo-mechanical pulp
TPD	tons per day
TRS	total reduced sulfur
US	United States of America
VFD	variable frequency drive
VSD	variable speed drive

wk	week
yr	year

2.0 COSTS AND CO_2 EMISSIONS OF STEAM AND POWER SUPPLY

2.1 General

Steam generated at the facility is by far the largest energy supply to forest products industry processes. Power that is either purchased or generated at the site is the other major energy source.

Fuels for steam generation vary from one facility to another. Typically, a large portion of the steam in forest products facilities is derived from biomass such as wood, wood residues, spent liquors, and bark. To construct an accurate profile of the forest products industry's greenhouse gas emissions, biomass carbon must be properly accounted for. EPA has indicated that "[t]he combustion of biomass and biomass-based fuels … emits greenhouse gases. Carbon dioxide emissions from these activities, however, are not included in national emissions totals …" (USEPA 2000). In addition, the Intergovernmental Panel on Climate Change (IPCC) notes that "CO_2 emissions from biomass used as fuels are excluded from the total CO_2 emissions figure" (IPCC 1996). This carbon accounting convention is easily incorporated into emissions inventories by using a CO_2 emissions factor of zero for biomass fuels. The CO_2 emitted when pulping liquors are burned for energy, therefore, is not included in greenhouse gas inventories because the carbon is derived from trees. Likewise, the CO_2 from bark or wood waste burned in power boilers is not included. If these boilers are also burning fossil fuels, however, the fossil fuel-derived CO_2 is included in greenhouse gas emission inventories. In the calculations contained in this report, a CO_2 emission factor of zero was used for biomass fuels (including black liquor).

The cost of process steam was determined based on fuel cost and boiler efficiency. If the process steam was taken through a turbogenerator, the credit (i.e., savings in purchased power cost) was applied to the process steam cost.

2.2 CO_2 Emissions of Steam Generation

Emissions from fossil fuel burning were estimated using DOE emission factors (EIA 1996). Assumptions regarding boiler efficiencies for various fuels were also used in calculations. CO_2 emission factors and boiler efficiency assumptions for coal, oil, and natural gas are shown in Table 2.1. The emission factor for coal is a weighted average value considering the actual quantities of the various grades of coal consumed by the industrial sector (not including coke production) in the US. CO_2 impacts of biofuels were assumed to be zero.

Table 2.1. CO_2 Emissions Factors and Boiler Efficiencies

	lb CO_2/MBtu in Fuel	Efficiency	lb CO_2/MBtu in Steam
Coal	207.2	0.84	246.7
No. 6 fuel oil	173.7	0.82	211.8
Natural gas	117.0	0.80	146.3

In the sample calculations contained within this resource manual it is assumed that all mill process steam is taken through a turbogenerator. In other words, it is assumed that high pressure steam from the boiler is reduced to lower pressure by passing the steam through a turbogenerator which utilizes the enthalpy drop between the boiler steam and process steam for back-pressure power generation. Therefore, when energy conservation/CO_2 emission reduction measures result in process steam savings there is a concurrent reduction in the amount of electrical power generated on-site. The reduced on-site power generation requires increased purchase of utility power, with associated off-site emissions of CO_2. It is important to acknowledge this "CO_2 penalty" associated with steam savings. However, it is also important to realize that the generating capacity may be limited at some mills, and at these mills some boiler steam may be taken to process steam pressures via simple pressure reducing valves. In these latter cases, there will be no "CO_2 penalty" associated with reducing process steam consumption as long as the quantity of steam conserved is less than the amount that passes through the pressure reducing valve.

2.3 CO_2 Emissions from Purchased Power

In estimating CO_2 reductions associated with reduced purchased power consumption, it is necessary to select an emission factor for purchased power. Regionally dependent carbon dioxide emission factors (both average and marginal, corresponding to peak load generating) associated with the production of electrical power by utility companies were generated (Table 2.2) based on information from the Energy Information Administration (EIA 1994, which was derived from 1992 data), and were used to estimate the impact of off-site (or indirect) emissions of carbon dioxide associated with emission reduction technology options. Note that the emission factors, both average and marginal, corresponding to purchased power vary significantly from region to region. This reflects the different fuels and power generation methods used in different regions. Most of the discussion in this report involves incremental changes in purchased power consumption; therefore, marginal power emission factors have been used in many of the examples. Companies may determine, however, that it is more appropriate to use average power emission factors in specific situations. For mill-specific calculations the actual (local) emission factor should be used.

Table 2.2. CO_2 Emissions Factors for Purchased Power

Census Region	Average lb CO_2/MWh	Marginal lb CO_2/MWh
New England	934.1	1805
Middle Atlantic	1053	2009
East North Central	1630	2122
West North Central	1621	2116
South Atlantic	1419	2034
East South Central	1537	2103
West South Central	1479	1776
Mountain	1535	2088
Pacific Contiguous	230.7	1462
Pacific Noncontiguous	1542	1737
US Average	1350	2009

Over time, emission factors for utility-generated power may change as the fuels and generating methods used by utilities change. Furthermore, because fuels and generating practices for producing peak load power may change more rapidly than data associated with production of average power may indicate, the emission factors for marginal power in Table 2.2 may not be valid in the future. EIA revises its estimates of emission factors associated with utility-generated power as new data become available. Therefore, it is recommended that mills estimating emissions corresponding to purchased power consumption consider using the most recent EIA emission factors, which are available on the internet at http://www.eia.doe.gov/oiaf/1605/factors.html (June 1, 2001).

2.4 CO_2 Emissions of Power Generated at the Plant

Typical fuel supplies for in-plant power generation are coal, No. 6 fuel oil, and natural gas. The CO_2 emissions estimated for steam generation with these fuels are:

- Coal — 246.7 lb CO_2/MBtu (in steam)
- No. 6 oil — 211.8 lb CO_2/MBtu (in steam)
- Natural gas — 146.3 lb CO_2/MBtu (in steam)

Typical steam requirements for two methods of in-plant power generation are:

- Back-pressure power — 3.6 MBtu/MWh (theoretical 3.413 plus 5% losses)
- In-plant condensing power — 11 to 12 MBtu/MWh

Accordingly, CO_2 emissions from in-plant power generation are:

	Coal	Oil	Gas
• Back-pressure power (lb CO_2/MWh)	888	750	530
• In-plant condensing power (lb CO_2/MWh)	2960	2510	1750

Table 2.3 summarizes CO_2 emissions associated with reduced consumption of electrical power based on the EIA emission factor (US average) for purchased power and assuming that No. 6 oil is the marginal fuel for in-plant generation.

Table 2.3. Typical CO_2 Emissions from Marginal Power Supplies

	CO_2 lb/MWh
Purchased power (marginal, US average)	2009
In-plant back-pressure power (oil as the marginal fuel)	750
In-plant condensing power (oil as the marginal fuel)	2510

2.5 Cost of Steam

2.5.1 *General*

At most mills, the costs of steam and power are well characterized. This information is generally available to mill personnel for analyzing the costs or savings associated with changes in steam use at the mill. The following discussion provides an overview of how steam costs are determined.

Figure 2.1 illustrates a typical steam and power generation process in a forest products facility. High pressure steam is supplied by the boilers. It is assumed that boiler steam is desuperheated before process use.

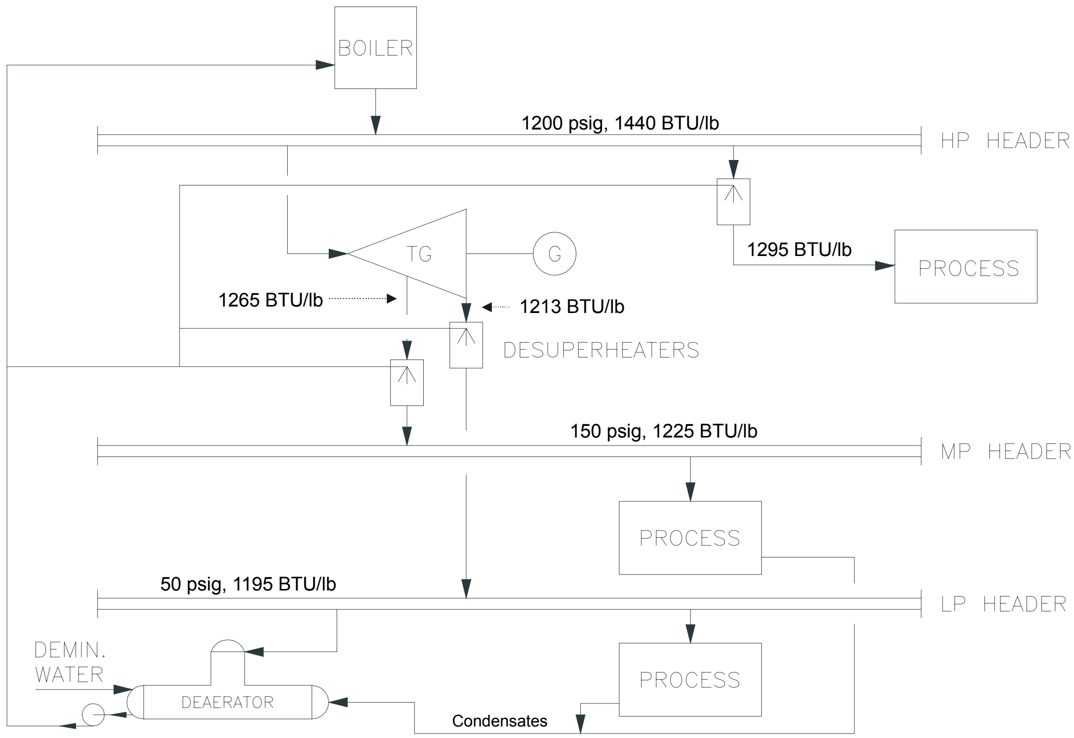

Figure 2.1. Example Steam and Power Generation System

The main "user" of boiler steam is the turbogenerator, which utilizes the enthalpy drop between boiler steam and process steam for back-pressure power generation. Typical boiler steam pressures are 600 to 1500 psig and typical process steam pressures are:

- Intermediate pressure steam 150 to 170 psig
- Low pressure steam 40 to 70 psig

Various plant processes use process steam. Most processes utilize the latent heat of the steam and send the condensates back to the powerhouse, although some require direct steam injection with the condensates remaining within the process. In this study:

process heat consumption =
(heat in steam) – (heat returned with steam condensates to the power house)

It is assumed that lost steam condensates are replaced with demineralized water.

The temperature of steam exiting the turbogenerator may be too high for efficient process use. Therefore, steam temperature is controlled in desuperheaters to a constant superheat.

2.5.2 *Steam Cost Calculation Basis*

The cost of steam depends primarily on the cost of fuel used for steam generation and boiler efficiencies. Fixed costs are normally added to steam costs in an actual mill situation. Energy savings are normally described in terms of their impact on purchased energy requirements unless, for example, a new boiler or turbogenerator installation can be avoided as a result of steam or power savings.

If all process steam is taken through a turbogenerator, a change in process steam demand will affect purchased power demand. For example, if process steam use increases, more back-pressure power will be generated. The energy consumption of back-pressure power is much lower than that of condensing power. Typically, heat consumption is 3.6 MBtu/MWh as steam, while heat consumption may be 2.5 to 3 times greater for condensing power. At an oil or gas cost of approximately $3/MBtu, the energy cost of back-pressure power is $10 to $15/MWh, which may be one-third or less of the cost of purchased power. It is customary to credit this energy cost difference to process steam in order to promote the use of low pressure steam.

2.5.3 *Cost of Steam Example Calculations*

The following steam, feedwater, and other data are assumed (note that many of these parameters are used in the sample calculations contained in subsequent sections of this report):

• Boiler steam temperature	900°F
• Boiler steam pressure	1200 psig
• Boiler steam enthalpy	1440 Btu/lb
• Boiler steam enthalpy to process	1295 Btu/lb
• Intermediate (extracted) steam pressure	150 psig
• Low pressure (exhaust) steam pressure	50 psig
• Isentropic enthalpy drop from 1200 to 150 psig	224 Btu/lb
• Isentropic enthalpy drop from 1200 to 50 psig	299 Btu/lb
• Isentropic efficiencies	
Extraction steam	78%
Exhaust steam	76%
• Enthalpies of steam before desuperheater	
Extraction steam	1265 Btu/lb
Exhaust steam	1213 Btu/lb
• Enthalpies of steam after desuperheater	
Extraction steam	1225 Btu/lb
Exhaust steam	1195 Btu/lb
• Deaerator pressure	50 psig
• Boiler feedwater enthalpy	265.7 Btu/lb
• Boiler feedwater temperature	297.7°F
• Demineralized water temperature	80°F
• Purchased power price	$35/MWh
• Fuel cost	$3/MBtu
• Boiler efficiency	82%
• Return of steam condensates	50%
• Temperature of returned condensates	210°F
• Turbogenerator losses (heat, mechanical, electrical)	5%

Table 2.4 outlines the calculated prices of steam from different sources within the mill power island (e.g., boiler steam (high pressure), turbogenerator extraction steam (medium pressure), and turbogenerator exhaust steam (low pressure)). The calculations are based on a 1.0 klb change (increase) in process steam demand. Especially if the steam is used at the boiler steam pressure level and desuperheated to a reasonable superheat, a significant portion of the process steam comes from the desuperheater water. Appendix A provides details on the calculations.

Table 2.4. Steam Cost Calculation Examples

	Units	Steam Pressure Level High (Boiler steam @ 1200 psig)	Medium (TG extraction steam @ 150 psig)	Low (TG exhaust steam @ 50 psig)
Change in process steam consumption (assumed)	klb	1.0	1.0	1.0
Change in steam to desuperheaters	klb	0.88	0.96	0.98
Change in process heat consumption	MBtu	1.18	1.11	1.08
Change in deaerator steam consumption	klb	0.16	0.16	0.16
Total change in steam flow to turbogenerator	klb	0.16	1.12	1.15
Change in heat to back-pressure power generation	kBtu	37.3	204.8	259.9
Change in back-pressure power generation	kWh	10.4	57.0	72.3
Change in purchased power cost	$	-0.36	-2.00	-2.53
Change in total fuel consumption	MBtu	1.49	1.61	1.64
Change in total fuel cost	$	4.46	4.82	4.91
Change in purchased energy cost	$/klb	4.1	2.8	2.4
Change in purchased energy cost	$/MBtu	3.5	2.5	2.2

Because part of the steam condensates are lost and replaced with fairly cold demineralized water and the condensates returned to the power house are significantly cooler than the deaerator temperature, a change in process steam use causes a change in the steam flow to the deaerator. This low pressure steam is assumed to come through the turbogenerator (exhaust) and contributes to back-pressure power generation.

A certain portion of heat flow to the turbogenerator is converted to power. This portion depends on the pressure and temperature of the turbogenerator throttle steam, the pressure levels of the turbogenerator, and the efficiency of the turbogenerator. Based on the calculations (Table 2.4), changes in back-pressure power generation corresponding to changes in process steam consumption are:

	kWh/klb	kWh/MBtu
• Process steam at boiler pressure	10.4	8.8
• Process steam at 150 psig	57.0	51.3
• Process steam at 50 psig	72.3	66.9

Assuming that all medium and low pressure process steam is extracted or exhausted through a turbogenerator, the change in back-pressure power will cause a corresponding change in the need for purchased power consumption. Considering the costs of this impact, process steam prices are:

	$/klb	$/MBtu
• HP steam (boiler pressure)	4.1	3.5
• Extraction steam (150 psig)	2.8	2.5
• Exhaust steam (50 psig)	2.4	2.2

The main parameters that affect process steam prices (assuming all low pressure steam is taken through the turbogenerator) are:

- Boiler steam temperature
- Process steam pressure levels
- Costs of purchased power and purchased fuel

Figures 2.2 and 2.3 illustrate the impact of some variables on back-pressure power generation and on the prices of process steam.

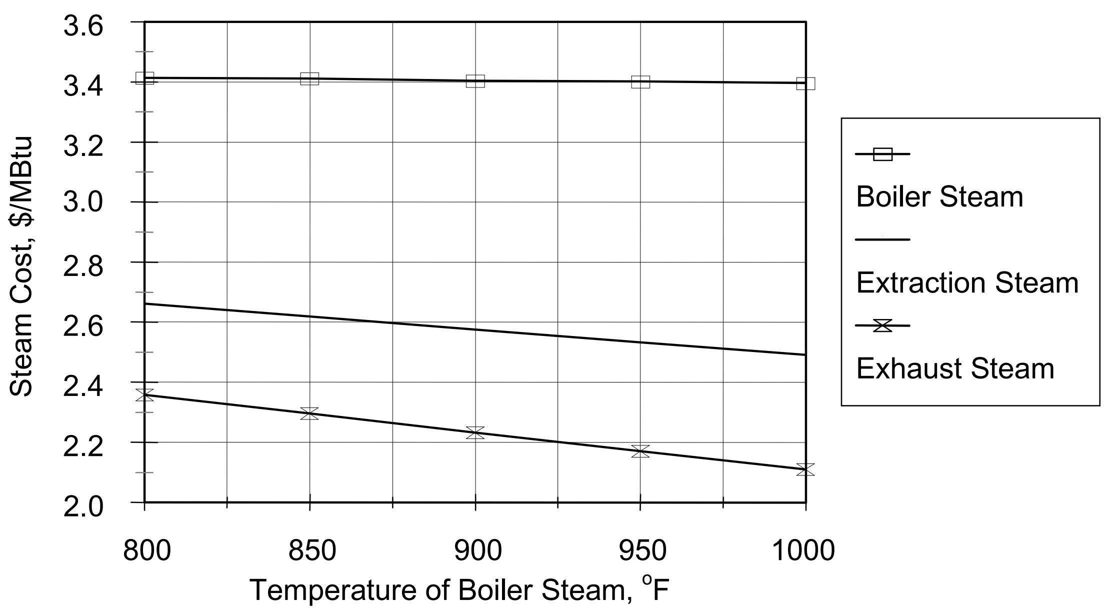

Figure 2.2. Calculated Process Steam Cost as a Function of Boiler Steam Temperature (based on assumed fuel and power costs as indicated in Section 2.5.3)

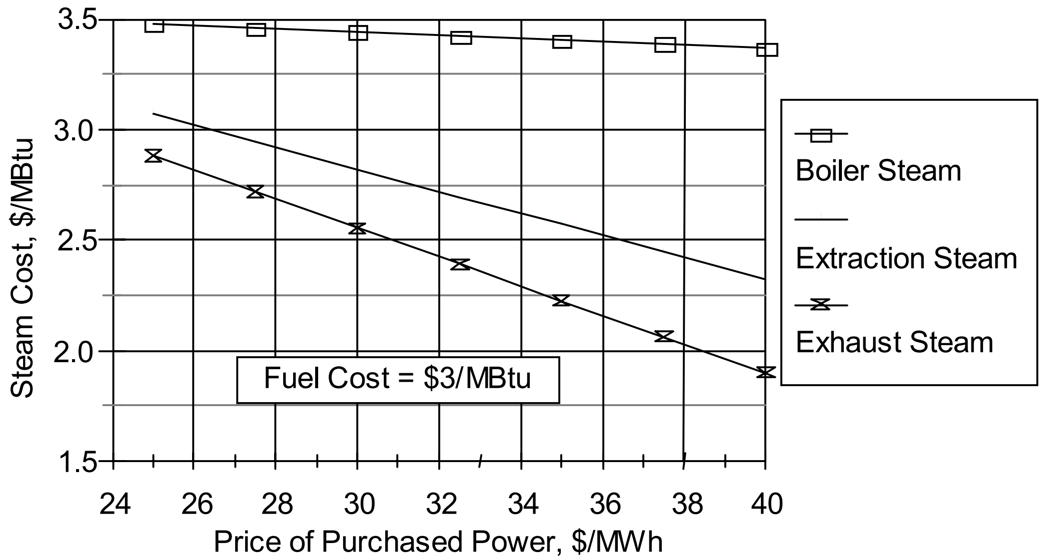

Figure 2.3. Calculated Process Steam Cost as a Function of Power Price (based on assumed fuel and power costs as indicated in Section 2.5.3)

3.0 ENERGY CONSERVATION TECHNOLOGIES

3.1 General

Seventy-three energy saving technologies were identified and their impacts on energy consumption, CO_2 emissions, and manufacturing costs were characterized. One criterion for selection was the readiness of the given technology for commercial implementation. In practice this implied that a successful mill-scale installation had to exist for each of the technologies selected.

As discussed in Section 2, the CO_2 impacts of the energy conservation technologies were calculated by estimating their impacts on energy use. Key parameters that affect CO_2 emissions are:

- Purchased fossil fuel usage
- Purchased power usage
- Bleaching chemical usage

Purchased fuel has an impact on CO_2 emissions from the facility (on-site), while purchased power and bleaching chemicals (predominately sodium chlorate) affect CO_2 emissions from utility power plants (off-site.)

In order to assess the feasibility of any given technology, changes in the costs of energy requirements were estimated as well.

<u>Annual emission reduction and energy cost estimates were computed based on 350 operating days per year (8400 operating hours per year), unless stated otherwise.</u>

In the estimates of energy costs and CO_2 emission impacts illustrated in the sample calculations of subsequent sections, it has been assumed that heavy fuel oil (No. 6 oil) is the marginal fuel in pulp and paper mills. Natural gas has been assumed to be the marginal fuel in solid and engineered wood product plants. The cost of the fuels have been assumed to be:

- $3/MBtu in oil

- $3/MBtu in natural gas

In evaluating certain technologies, it has been assumed that fuel oil or natural gas is replaced with hog fuel. The price of hog fuel has been assumed to be:

- $10/T of hog fuel (wet basis, 50% moisture)

The price of purchased power has been assumed to be:

- $35/MWh

Important Note:

The marginal fuel selections and energy prices listed herein have been used only to illustrate energy cost changes associated with implementing various technology options. Energy prices and marginal fuels, however, vary from mill to mill and from one region to another. Therefore, actual changes in energy costs must be calculated for any specific facility using site-specific prices and other local information as the basis.

For pulp and paper mills, it is assumed that back-pressure steam turbines rather than condensing turbines are used for electrical power generation (see Section 2.2 for details). It has also been assumed as the base case that turbogenerator capacity is not limiting in-house power generation. For solid and engineered wood product plants, it is assumed in most cases that there is no in-house power generation. Only fiberboard (hardboard with wet process) is assumed to generate back-pressure power.

Both "on-site" and "off-site" CO_2 emissions have been estimated. On-site CO_2 emissions originate from fossil fuel, while off-site CO_2 emissions are caused mainly by purchased power and purchased bleaching chemicals.

Important Note:

As discussed in Section 2.3, calculations of off-site CO_2 emissions were based on marginal emission factors associated with purchased power. Marginal power emission factors vary between geographic regions and, in some cases, mills may determine that it is appropirate to use average rather than marginal emission factors. When estimating off-site emissions corresponding to purchased power, a mill should use the appropriate regional emission factor.

A large number of energy saving opportunities have been evaluated. <u>Many of the measures are interactive, so implementation of one measure may impact the savings or CO_2 effectiveness of another.</u> For example, rebuilding a power boiler to increase its efficiency of steam generation (technology 1.4) may result in reduced fossil fuel use. Subsequent estimates of reduction in steam use (corresponding to additional technology implementation) must then consider the improved boiler efficiency when computing fossil fuel savings. The main emphasis of this study has been on the evaluation of energy and CO_2 reduction effectiveness of individual measures as if they were the only measure being implemented.

3.2 Technologies for the Study

Table 3.1 lists the technologies selected for further study in this project. The technologies are grouped by process and are not listed in any particular order (e.g., not in order of effectiveness at reducing emissions). A brief description of each technology was prepared as part of the study. These technology descriptions and sample calculations of energy and CO_2 reduction are presented in the following sections. Capital cost estimates for most of the technology options are provided in the following sections. Capital cost estimates for most of the technology options are provided in Appendix C. Section 4 presents a discussion of the capital cost estimation techniques and lists the size (equipment capacity) bases used in formulating the estimates.

Important Note:

Seemingly small modifications to mill processes, the power island and many other mill operations can trigger environmental regulatory requirements, even though the changes may seem to be unrelated to environmental releases. Therefore, it is important to consult company environmental professionals before making any changes.

Table 3.1. Technologies Covered in the Study

1	**STEAM AND POWER SUPPLY**
1.1	Replace low pressure boilers and install turbogenerator capacity
1.2	Switch power boiler from fossil fuel to wood (or build new wood boiler to utilize available biofuel)
1.3	Preheat demineralized water with secondary heat before steam heating
1.4	Rebuild or replace low efficiency boilers
1.5	Install a steam accumulator to facilitate efficient control of steam header pressures
1.6	Install an ash reinjection system in the hog fuel boiler
1.7	Install a bark press or bark dryer to increase utilization of biofuels
1.8	Install additional heat recovery systems to boilers to lower losses with flue gases
1.9	Implement energy management program to provide current and reliable information on energy use
1.10	Switch power boiler fuel from coal or oil to natural gas
1.11	Install gas turbine cogeneration system for electrical power and steam generation
2	**WOOD SUPPLY**
2.1	Replace pneumatic chip conveyors with belt conveyors
2.2	Use secondary heat instead of steam in debarking
3	**KRAFT PULPING**
3.1	Rebuild mill hot water system to provide for separate production and distribution of warm (120°F) and hot (160°F) water
3.2	Install blow heat (batch digesters) or flash heat (continuous digester) evaporators
3.3	Replace conventional batch digesters with cold blow systems
3.4	Use flash heat in a continuous digester to preheat chips
3.5	Use evaporator condensates on decker showers
3.6	Use two pressure level steaming of batch digesters to maximize back-pressure power generation
3.7	Optimize the dilution factor control
4	**KRAFT BLEACHING**
4.1	Optimize the filtrate recycling concept for optimum chemical and energy use
4.2	Preheat ClO_2 before it enters the mixer
4.3	Use oxygen based chemicals to reduce use of ClO_2 (O_2 or O_3 delignification, EP, EOP, etc.)
5	**PULP DRYER AND PAPER MACHINE**
5.1	Eliminate steam use in the wire pit by providing hot water from heat recovery and/or pulp mill and by reducing water use on the machine
5.2	Upgrade press section to enhance water removal
5.3	Enclose the machine hood (if applicable) and install air-to-air and air-to-water heat recovery
5.4	Install properly sized white water and broke systems to minimize white water losses during upset conditions
5.5	Implement hood exhaust moisture controls to minimize air heating and maximize heat recovery

(Continued on next page.)

Table 3.1. Continued

	5.6	Implement efficient control systems for the machine steam and condensate systems to eliminate excessive blowthrough and steam venting during machine breaks
6	**KRAFT RECOVERY**	
	6.1	Convert recovery boiler to non-direct contact and implement high solids firing
	6.2	Perform evaporator boilout with weak black liquor
	6.3	Convert evaporation to seven-effect operation (install additional evaporator effect)
	6.4	Install high solids concentrator to maximize steam generation with black liquor
	6.5	Implement an energy efficient lime kiln (lime mud dryer, mud filter, product coolers, etc.)
	6.6	Replace lime kiln scrubber with an electrostatic precipitator
	6.7	Integrate condensate stripping to evaporation
	6.8	Install a methanol rectification and liquefaction system
	6.9	Install a biofuel gasifier, use low Btu gas for lime reburning
7	**MECHANICAL PULPING**	
	7.1	Implement heat recovery from TMP process to steam and water
	7.2	Add third refining stage to the TMP plant
	7.3	Replace the conventional groundwood process with pressurized groundwood (PGW) operation
	7.4	Countercurrent coupling of paper machine and mechanical pulping white water systems
8	**DEINKING PLANT**	
	8.1	Supply waste heat from other process areas to deinking plant
	8.2	Install drum pulpers
	8.3	Implement closed heat and chemical loop
9	**MILL GENERAL**	
	9.1	Optimize integration and utilization of heat recovery systems
	9.2	Implement preventive maintenance procedures to increase equipment utilization efficiency
	9.3	Implement optimum spill management procedures
	9.4	Maximize recovery and return of steam condensates
	9.5	Recover wood waste that is going to landfill
	9.6	Install energy measurement, monitoring, reporting, and follow-up systems
	9.7	Convert pump and fan drives to variable speed drives
	9.8	Install advanced process controls
	9.9	Replace oversized electric motors
	9.10	Use high efficiency lighting
10	**SAWMILLS**	
	10.1	Use advanced controls to control the drying process
	10.2	Install heat recovery systems on the drying kiln exhaust
	10.3	Insulate the kiln and eliminate heat leaks
	10.4	Use heat pump for lumber drying
	10.5	Convert batch kiln to progressive kiln
	10.6	Implement steam load management system
11	**PLYWOOD PLANTS**	
	11.1	Use advanced controls to control the drying process
	11.2	Insulate the dryer and eliminate air and heat leaks
	11.3	Install heat recovery systems on the dryer exhaust
	11.4	Use boiler blowdown in the log vat
12	**PARTICLEBOARD MILLS**	
	12.1	Measure and control the dryer exhaust moisture content to minimize air heating
	12.2	Recover heat from dryer exhaust
	12.3	Use wood waste as fuel for drying (suspension burning)
13	**HARDBOARD MILLS**	
	13.1	Install heat recovery
	13.2	Preheat drying air with steam

(Continued on next page.)

Table 3.1. Continued

14 ORIENTED STRAND BOARD (OSB) PLANT	
14.1	Screen flakes before drying; dry fines separately
14.2	Use advanced controls to optimize the drying process
14.3	Use powdered resins

3.3 Technology Descriptions and Sample Calculations

3.3.1 *Steam and Power Supply*

3.3.1.1 *Replace low pressure boilers and install turbogenerator capacity*

Description

Most kraft pulp mills rely on internally generated fuels such as spent pulping liquor, bark, clarifier sludge, and other recovered fiber streams to supply the steam required for process heating. Older boilers generally operate in the 350 to 600 psig range. By replacing them with high pressure boilers with operating pressures in the 900 to 1800 psig range and passing all generated steam through a back-pressure turbine, maximum value can be obtained from the fuel. The higher steam pressure results in a larger enthalpy drop and an increase in power generation. The additional power can be used to offset purchased power demand or can be sold if a surplus exists.

To generate high pressure steam, low pressure boilers must be replaced with new units designed for the required pressure. A new turbogenerator designed to meet the boiler pressure and operating rate will need to be installed (Figure 3.1). Due to their smaller size and the capital expense involved, hog fuel and waste fuel boilers are the usual candidates for conversion to high pressure designs. Replacement of the recovery boiler with a high pressure design may be economically feasible only if a major recovery rebuild is required; e.g., for capacity reasons.

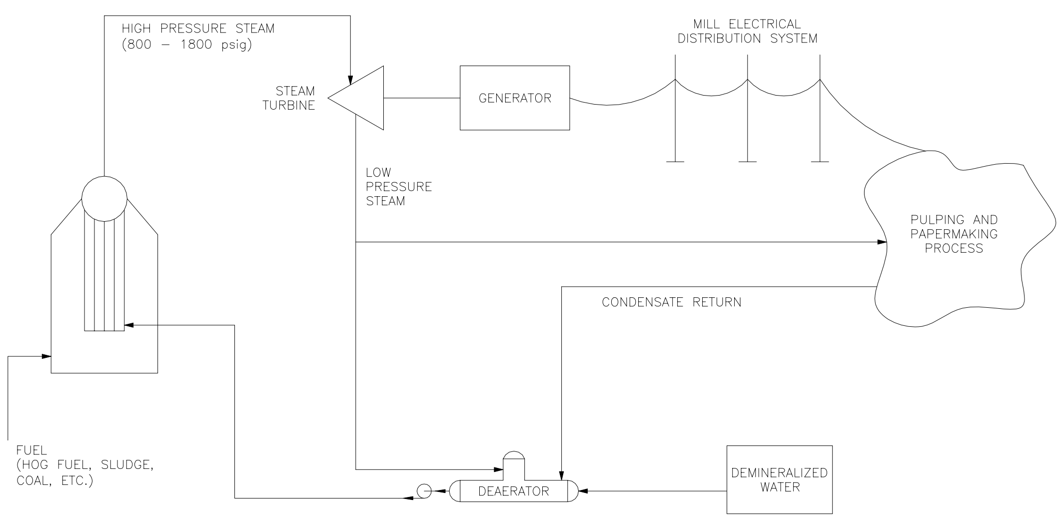

Figure 3.1. High Pressure Boiler and Turbogenerator Installation

Applicability and Limitations

High pressure boilers and back-pressure power generators are technically applicable to any forest products facility that uses steam. The cost may be very high, partly because the entire mill steam system may have to be replaced. Because of the high cost, this technology is primarily suited to facilities with large steam demands, and its application may be limited to situations where there is a need for increased steam due to production increases or significant process changes.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installation of a new high pressure boiler and turbogenerator will impact the energy situation both at the mill and off-site. Maximizing back-pressure power generation will reduce purchased power demand or generate surplus power for sale off-site, both of which reduce off-site generating demand. There are several possible side effects from replacing low pressure boilers. Replacing an older boiler may result in an efficiency increase which could be used to lower the steam load in other boilers. Using on-site generated fuels reduces the need for fossil fuels.

Impact on CO_2

Installation of a new high pressure boiler and back-pressure turbine will not have a major impact on the amount of CO_2 produced at the mill, although small reductions are possible with boiler efficiency improvements. The major reductions of CO_2 will occur off-site due to the decrease in purchased power demand and the corresponding decrease in fossil fuel consumption.

Impact on Operating Costs

Installation of a high pressure boiler in place of an existing low pressure boiler will reduce mill operating costs. There may be a small increase in maintenance for the new boiler, but this will be more than offset by the reduction in purchased power cost. Savings in purchased power could be several million dollars annually. If the high pressure boiler is replacing a boiler using fossil fuel, additional savings can be achieved by utilizing on-site generated fuel such as hog fuel.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass-derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3).

Assume that there is no existing turbogenerator on site to be powered by the high pressure steam that will be generated in the new boiler. Also assume:

- New boiler steam pressure — 1200 psig
- New boiler steam temperature — 900°F
- Low pressure (exhaust) steam pressure — 50 psig

- Intermediate pressure (extraction) process steam pressure 150 psig

From steam tables:

- Enthalpy of boiler steam 1440 Btu/lb
- Isentropic enthalpy drop to 150 psig 224 Btu/lb
- Isentropic enthalpy drop to 50 psig 299 Btu/lb

Assume the following isentropic efficiencies:

- For extraction (150 psig) steam 78%
- For exhaust (50 psig) steam 76%

Heat transferred to power:

- For extraction steam 78/100 x 224 Btu/lb = 174.7 Btu/lb
- For exhaust steam 76/100 x 299 Btu/lb = 227.2 Btu/lb

Heat to power conversion:

- Theoretical 3413 Btu/kWh
- With about 95% mech. efficiency 3600 Btu/kWh

Assume that the boiler steam rate is 300,000 lb/hr, of which 100,000 lb/hr is taken through extraction and 200,000 lb/hr through exhaust.

Power generation:

$$\frac{100{,}000 \text{ lb/hr} \times 174.7 \text{ Btu/lb} + 200{,}000 \text{ lb/hr} \times 227.2 \text{ Btu/lb}}{3600 \text{ Btu/kWh}}$$

= 17,475 kWh/hr ≈ 17.5 MW

Annual savings in purchased power cost, assuming 350 operating days per year (8400 operating hours per year):

Reduction in purchased power cost:
(17.5 MW x 8400 hr/yr) x ($35/MWh)
= $5.15 million/yr

Assume that the boiler is to be fired with oil and operates with an efficiency of 82%:

Increase in fuel cost:
(3600 Btu/kWh)/(0.82 Btu in stm/Btu in fuel) x (17,475 kWh/hr) x (8400 hr/yr) x
($3/MBtu) x (1 MBtu/1,000,000 Btu)
= $1.93 million/yr

Net savings:
$5.15 million - $1.93 million
= $3.22 million/yr

Assuming the CO_2 emission factor of 2009 lb CO_2/MWh for marginal power supply and oil as the fuel for mill back-pressure power generation, the reduction in net (including on-site and off-site) CO_2 emissions can be calculated:

Increase in on-site CO_2 emissions:
(17.5 MWh/hr) x (3.6 MBtu/MWh) x (211.8 lb CO_2/MBtu)
= 13,343 lb CO_2/hr

Reduction in CO_2 emissions from the utility power plant:
(17.5 MWh/hr) x (2009 lb CO_2/MWh)
= 35,157 lb CO_2/hr

Net reduction in CO_2 emissions:
35,157 - 13,343
= 21,814 lb/hr of CO_2

Reduction in CO_2 emission if the in-house boiler is burning biomass:
(17.5 MWh/hr) x (2009 lb CO_2/MWh)
= 35,157 lb CO_2/hr

3.3.1.2 S*witch power boiler from fossil fuel to wood (or build new wood boiler to utilize available biofuel)*

Description

Forest product industry facilities typically must generate large quantities of steam to satisfy process heat demands and often for generation of electrical power. Fuels used in industry power boilers include spent pulping liquors, hog fuel (wood residues), coal, oil, natural gas, and others. By convention, biomass fuels (such as spent pulping liquors and wood) are considered net zero emitters of greenhouse CO_2. Therefore, switching an existing power boiler from fossil fuel fired to wood fired will result in decreased CO_2 emissions. Other supplemental fuels (tire-derived fuels, wastewater treatment residuals, etc.) are assumed to remain at current consumption levels. Alternatively, a new boiler can be installed to take advantage of biomass fuel if an underutilized source exists at the mill.

Applicability and Limitations

If a fossil fuel fired boiler (or a combination fuel boiler burning some proportion of fossil fuel) is used at the mill and a source of wood based fuel is available (either on the local market or as a waste stream at the mill), fuel switching to wood is a viable technology option for reducing direct emissions of CO_2. The economic feasibility is dependent on the price of wood fuel (if purchased on the market) relative to fossil fuels, the extent of required boiler modifications, the proximity of the mill to wood fuel sources, and the costs of fuel and ash handling and pollution control associated with switching to wood fuel (predominantly a concern if switching from oil or gas fuels). If switching the boiler fuel from natural gas or oil to wood, ash disposal requirements will change and must be considered.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Power boiler fuel switching to wood will not result in any significant overall energy savings. The same quantity of steam will be produced. However, the steam will be produced by burning a net zero CO_2 emitting fuel, thereby reducing total emissions. Wood fired boilers are typically less efficient in converting the fuel's energy to steam heat than are fossil fuel fired boilers, primarily due to the high moisture content of wood based fuels. Therefore, a greater quantity of wood (on a Btu basis) will be required than the current amount of fossil fuel used. Wood fired boilers can be made more efficient by incorporating a fuel dryer upstream of the boiler, preferably using secondary heat (such as boiler flue gas) to dry the wood fuel. However, the capital costs of a wood dryer may not be justifiable. The sample calculations in this section are not based on inclusion of a wood dryer.

Impact on CO_2

Fuel switching of fossil fuel fired power boilers to wood will reduce on-site CO_2 generation, because biomass fuels are considered to have a net zero emission factor.

Impact on Operating Costs

The operating cost implications of fuel switching of fossil fuel fired power boilers to wood are highly variable, and are mainly influenced by the price and availability of wood and the fuel and ash handling concerns associated with wood fuel. An additional cost consideration is related to boiler efficiency differences, in that wood fired boilers are typically less efficient in converting the fuel's energy to steam heat than are fossil fuel fired boilers. This is primarily due to the high moisture content of wood based fuels, necessitating that a significant quantity of the fuel's heat be used to evaporate water from the incoming wood rather than to produce steam. Therefore, a greater quantity of wood (on a Btu basis) will be required than the current amount of fossil fuel used. Wood fired boilers can be made more efficient by incorporating a fuel dryer upstream of the boiler, preferably using secondary heat (such as boiler flue gas) to dry the wood fuel. However, incorporating a wood dryer would increase the capital costs of the fuel switching project and may not be justifiable. Wood fired boilers may require more stringent pollution control considerations (e.g., greater degree of particulate emissions) than do oil or natural gas fired boilers, which would contribute to additional operating costs. It may be assumed that fuel and ash handling expenses, ash disposal, and pollution control costs are similar for wood fired and coal fired boilers.

Estimates of the supplemental operating costs associated with fuel switching from oil or natural gas to wood (those other than the cost of fuel) were made based on information provided by R.W. Beck (Beck 1998, under contract to NCASI) and available in EPA documents, and on landfill cost data drawn from NCASI solid waste surveys. (Survey results are summarized in NCASI Technical Bulltein No. 793, *Solid Waste Management Practices in the U.S. Paper Industry* (NCASI 1999)). For a wood fired boiler producing 200,000 MBtu/hr steam, increased fuel and ash handling requirements are estimated to cost $160,000/yr and use of particulate control devices $160,000/yr. It is assumed that these costs associated with switching power boiler fuel from oil or natural gas to wood can be scaled linearly to boiler steam generation rates. Ash disposal represents an additional cost, which can be estimated at $1.57 per ton of wood fuel used (wet basis). The ash disposal cost is based on an ash generation rate of 0.04 tons of ash per ton of wood (wet basis), an ash disposal cost of $20 per cubic yard, and an ash density of 0.51 tons per cubic yard (based on information obtained during previous NCASI studies and surveys). New continuous air emission monitoring requirements represent an additional cost of $20,000/yr (it is assumed that this expense is relatively constant, regardless of boiler size). These additional operating costs are not applicable if converting from coal to wood.

Capital Costs

Capital costs of switching power boiler fuels are also variable. When switching from fossil fuel to wood, the adiabatic flame temperature decreases while the total flue gas flowrate increases. Both effects are due to the high moisture content of wood. These impacts would serve to decrease the capacity of a boiler, so if the original steam generation capacity is to be maintained, both the heat exchange area and the flue gas handling system of the boiler must be enlarged. Other modifications would include grate installation, ash handling system rebuild, and the potential for pollution control equipment installation, including an electrostatic precipitator. Boiler modifications would be more extensive for boilers which are currently fired with natural gas or oil and less extensive for coal fired boilers, because coal fired boilers typically must incorporate fuel and ash handling and pollution control considerations similar to those required for wood fired boilers.

Capital costs required for boiler modification or replacement were estimated by EKONO under contract to NCASI. The results indicated that capital costs associated with conversion to wood fuel are dependent on the current fuel mix of the boiler. For boilers currently fired with a fuel mix of predominately oil or natural gas, rebuild costs would be excessive and a boiler replacement would be more appropriate (replacement cost basis of $33 million for 200,000 lb/hr steam capacity). However, for boilers currently fired with coal (the fossil fuel most similar to wood) or a predominant fraction of wood fuel, a rebuild may be more attractive (basis rebuild cost of $23 million for 200,000 lb/hr steam capacity). The assumed fuel mix criteria are:

- If more than 75% of the fuel heat originates from wood fuel, no boiler modifications are required.
- If 10% to 75% of the fuel heat originates from wood fuel the boiler will require a rebuild.
- If greater than 90% of the fuel heat originates from coal the boiler will require a rebuild.
- If greater than 90% of the fuel heat originates from oil or gas or a combination of these fluid fuels the boiler will have to be replaced.
- For combination boilers burning less than 10% wood and the remainder a combination of fluid (oil and/or gas) and coal fossil fuels, if the amount of coal in the fuel mix is greater than the amount of fluid fuel a rebuild will be required. If the amount of coal in the mix is less than the amount of fluid fuel a new boiler will be required.

These criteria can be used to obtain an order of magnitude estimate of upgrade costs for converting fossil fuel and combination fired boilers to wood fuel. For boiler capacities other than 200,000 lb/hr of steam, the six-tenths rule can be used to scale the capital costs, as demonstrated in the sample calculation below.

Sample Calculations

The following sample calculation is based on reduced use of an assumed marginal fuel corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume that the boiler capacity is 300,000 lb/hr and the annual average steam flow is 200,000 lb/h. The present fuel is coal. Also assume:

• Enthalpy of boiler steam	1440 Btu/lb
• Boiler feedwater temperature	282°F
• Boiler feedwater enthalpy	250 Btu/lb
• Cost of coal	$2/MBtu
• Cost of wood fuel	$10/Ton
• Boiler efficiency with coal	84%
• Boiler efficiency with wood	65%
• Heating value of wood	8750 Btu/lb d.s.
• Moisture content of wood	50%

Fuel cost of present operation (coal):

$$\left(\frac{0.2\ \text{Mlb stm/hr} \times (1440 - 250\ \text{MBtu/Mlb})}{0.84\ \text{Btu in stm/Btu in fuel}}\right) \times \$2\,/\,\text{MBtu in fuel}$$

= $567/hr or $4.76 million/yr (based on 8400 operating hours per year)

Change in fuel and ash handling/disposal and pollution control costs, based on steam use rather than capacity: None, because assumed costs for coal and for wood are similar (for an example of how to calculate these costs for switching from oil or gas to wood, see the sample calculations for fuel switching from coal to natural gas, Section 3.3.1.10.).

CO_2 emissions from coal:
(0.2 Mlb stm/hr) x ((1440 - 250) MBtu/Mlb) x (246.7 lb CO_2/MBtu stm)
= 58,715 lb CO_2/hr

Fuel cost of operation with wood:

$$\left(\frac{0.2\,\text{Mlb stm/hr} \times (1440 - 250\,\text{MBtu/Mlb})}{0.65\,\text{Btu in stm/Btu in fuel}}\right) \times \frac{10^6\,\text{Btu}}{\text{MBtu}} \times \frac{1\,\text{lb d.s.}}{8750\,\text{Btu}} \times \frac{1\,\text{lb wood}}{0.5\,\text{lb d.s.}} \times \frac{1\,\text{T}}{2000\,\text{lb}} \times \$10/\text{T}$$

= $418/hr or $3.52 million/yr

CO_2 emissions from wood:
Zero; biomass fuels are considered net zero greenhouse gas emitters

Savings in operating costs associated with fuel conversion:
$4.76 million - $3.52 million
= $1.24 million/yr

Reduction in CO_2 emissions associated with fuel conversion from coal to wood:
58.7 - 0
= 58.7 klb CO_2/hr *or* 246,500 T CO_2/yr

Capital costs associated with fuel conversion are:

Cost of boiler modification (based on steam capacity):

$$\$23\,\text{million} \times \left(\frac{300{,}000\,\text{lb steam per hour}}{200{,}000\,\text{lb steam per hour basis}}\right)^{0.6}$$

= $29 million

3.3.1.3 *Preheat demineralized water with secondary heat before steam heating*

Description

After being taken through the demineralizers, the boiler feedwater is preheated. The water may be heated in indirect heat exchangers with steam, surface condensers, and so on. Preheating the demineralized water with secondary heat before steam heating would reduce steam usage in the deaerator and thus result in fuel savings.

The demineralized water would be heated in an indirect contact heat exchanger (Figure 3.2). There are several possible sources of secondary heat, and the choice will depend on the mill's configuration. Possible secondary heat sources include stripper reflux condenser evaporator condensates, boiler blowdown, evaporator surface condensers, and condensate from other mill processes. Additional pumps and piping may be needed, depending on the location of the heat source and demineralized water.

Applicability and Limitations

Generally, demineralizers have to be operated at temperatures of 90°F or below. Therefore, mill water is normally used as the supply. Heating the demineralized water with secondary heat instead of steam would save low pressure steam in most facilities. Generation of back-pressure power will decrease. The cost of the additional purchased power has to be taken into account in the economic evaluation.

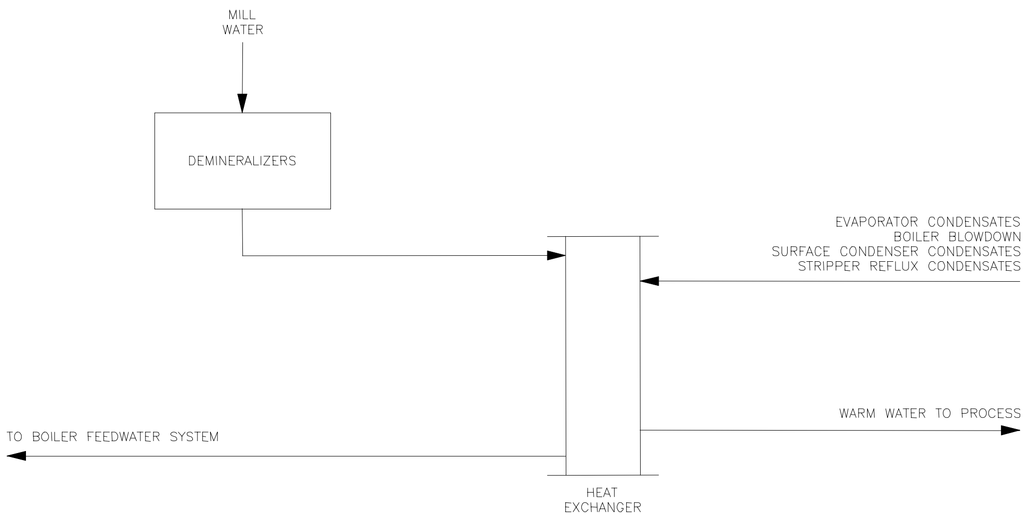

Figure 3.2. Preheating Demineralized Water with Secondary Heat

This technology partly overlaps the technology of increasing steam condensate recovery (Section 3.3.9.4). If a high percentage of steam condensate is recovered and returned to the power house, the amount of demineralized water is low, so savings from using secondary heat are low.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Preheating the demineralized water will result in steam savings and thus fuel savings. This will reduce energy consumption at the mill. If the low pressure steam to demineralized water heating (or to deaerator) is taken through a turbogenerator, back-pressure power generation will decrease, leading to an increase in demand for purchased power.

Impact on CO_2

The steam savings from preheating the demineralized water will reduce fuel consumption in the boilers, which translates into CO_2 reduction. Steam savings may reduce the back-pressure power generation and, accordingly, off-site CO_2 emissions may increase because of increased utility power generation.

Impact on Operating Costs

Preheating the demineralized water will reduce operating costs through fuel savings. Actual savings will depend on the mill's fuel and purchased power costs, which may increase because of reduced back-pressure power generation and possible increased power consumption for pumps that may need to be added.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume that all demineralized water was previously heated with low pressure steam and that the steam is being replaced with secondary heat. Also assume:

• Demineralized water flow	1000 gpm
• Temperature before heating	80°F
• Temperature after heating with secondary heat	170°F
• Enthalpy of water at 80°F	48 Btu/lb
• Enthalpy of water at 170°F	138 Btu/lb
• Back-pressure power yield	72.43 kWh/klb of 50 psig process steam
or	66.9 kWh/MBtu of process heat
• Operating hours	8400 hr/yr
• Net steam cost (Section 2)	\$2.2/MBtu of 50 psig steam
(Note: steam cost includes credit from back-pressure power generation)	
• CO_2 generated per MBtu of steam from oil	211.8 lb/MBtu (Section 2)

Steam saving from using secondary heat:
((138 - 48) Btu/lb) x (1000 gpm) x (8.3 lb/gal) x (60 min/hr) x (10^{-6} MBtu/Btu)
= 45 MBtu/hr

Cost savings per year if back-pressure steam is saved:
(45 MBtu/hr) x (8400 hr/yr) (\$2.2/MBtu)
= \$831,600/yr

CO_2 impact:

On-site reduction:
(211.8 lb CO_2/MBtu stm) x (45 MBtu/hr)
= 9531 lb CO_2/hr

Off-site increase (purchased power to replace reduced back-pressure power):
(45 MBtu/hr) x (0.0669 MWh/MBtu) x (2009 lb CO_2/MWh)
= 6048 lb CO_2/hr

Net CO_2 reduction:
9531 - 6048
= 3483 lb CO_2/hr *or* 14,629 T CO_2/yr

3.3.1.4 *Rebuild or replace low efficiency boilers*

Description

All process machinery has a useful life span after which performance and reliability drop until failure occurs. Many boilers in operation today may have exceeded their useful life span and would benefit from replacement or rebuilding. As the boiler ages, air leaks may form in the furnace walls, around doors, and in solid fuel delivery systems. Air leaks reduce combustion temperature and increase furnace air flow, which reduces combustion efficiency and increases fan power consumption. Older boilers may also suffer from outdated designs and lack of air preheating, secondary and tertiary air ports, automatic computer control, and process instrumentation such as O_2 analyzers, all of which reduce boiler efficiency.

Rebuilding or replacing these boilers would result in an efficiency improvement by eliminating these problems and by incorporating modern designs which make use of high steam pressures, steam economizers, and improved air and flame control. Boiler design, sizing, and fuel type will depend on specific mill requirements.

Applicability and Limitations

Rebuilding or replacement of low efficiency boilers is technically applicable to facilities that operate such boilers. Efficiency calculations in this section are based on a series of assumptions as specified in the sample calculations, and may not be applicable to all boilers.

The calculated boiler efficiencies given in Figure 3.3 are representative and may not correspond to actual boiler efficiency, as boilers are complex and cannot be fully represented by the calculations. Thus the slope of the curves (i.e., the change between two points) may be more accurate than the actual efficiency. For more information on boiler balance calculations see Chapter 1.3 in Adams 1997, Chapter 9 in Kitto and Shultz 1992, or the American Society of Mechanical Engineers (ASME) Standards for boiler balance calculations (short and long forms).

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Replacing low efficiency boilers will favorably impact the mill energy situation. Fan power consumption will drop with the elimination of air leaks and reduction of flue gas velocities. Fuel economy will improve with increased combustion temperature, air preheating, secondary and tertiary air ports, and improved process controls. Improving boiler efficiency will reduce the fuel required to meet mill steam demand.

Impact on CO_2

Replacing or rebuilding low efficiency boilers will reduce the mill's fuel consumption. This reduction in fuel usage will result in a reduction in the mill's CO_2 emissions.

Impact on Operating Costs

Replacing or rebuilding low efficiency boilers will lower the mill's operating costs. Electrical cost will decrease if fan power can be reduced. The decrease in fuel usage will further reduce operating costs.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

The following sample calculations are based on detailed boiler balances created using a boiler balance computer program. Output from the boiler balance program for the two boilers used in these sample calculations is contained in Appendix B. A thorough description of boiler balance calculations is beyond the scope of this project. However, for a detailed explanation of boiler balance calculations see:

- For kraft recovery boilers see Chapter 1.3 of: Adams, T.N. (ed.). 1997. *Kraft Recovery Boilers*. Atlanta, GA: TAPPI Press.
- For other boilers see Chapter 9 of: Kitto, J.B., and Shultz, S.C. (eds.). 1992. *Steam: Its Generation and Use*, 40th ed. Barberton, OH: The Babcock & Wilcox Company.

There are two general methods for performing combustion calculations, the mole method and the Btu method. The mole method was used in the following sample calculations. For this method the required inputs are:

• Amount of excess air	%
• Moisture in air	lb/lb dry air
• Fuel heating value	Btu/lb
• Fuel elementary analysis	
• Uncombustible material in fuel	%

Based on these inputs, the flue gas composition can be calculated on a molal basis. The boiler heat balance is then calculated based on the following inputs:

• Ambient air temperature	°F
• Flue gas temperature	°F
• Feedwater temperature before heating	°F
• Feedwater temperature after heating	°F
• Boiler steam enthalpy	Btu/lb
• Unburned combustible loss	%
• Radiation and other heat losses	%

Using these inputs and the calculated flue gas composition, specific heats of various flue gas components are determined. This allows the adiabatic flame temperature and heat lost with flue gases to be calculated. Total heat input minus flue gas and other heat losses gives the heat transferred to steam. Since most of the heat lost from the boiler leaves with flue gases, flue gas temperature has a large impact on the efficiency of the boiler. Figure 3.3, based on computer boiler balances, shows the effect of flue gas temperature and oxygen content on boiler efficiency for an oil fired boiler, where efficiency is calculated as:

$$\% \text{ Efficiency} = \frac{\text{Heat to Steam}}{\text{Fuel Higher Heating Value (HHV)}} \times 100$$

where: HHV = 18,520 Btu/lb

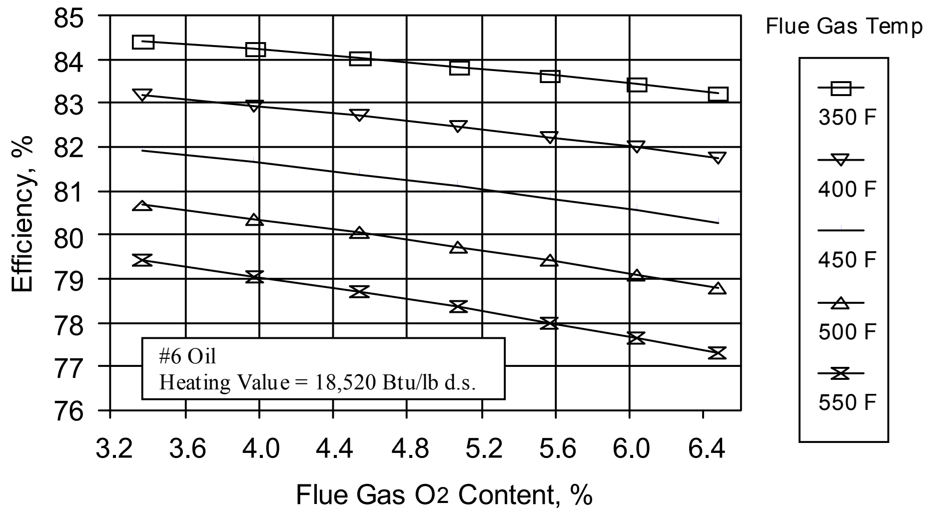

Figure 3.3. Efficiency of an Example Oil Fired Boiler as a Function of the Oxygen Content of the Flue Gas at Various Flue Gas Temperatures

For the sample calculations, assume the boiler in question is an old oil fired boiler without an economizer and with air leakage to the furnace.

Boiler parameters:

• No. 6 fuel oil HHV	18,520 Btu/lb
• Uncombustibles	0%
• Moisture	0.1%
• Carbon	85.5%
• Hydrogen	11.2%
• Oxygen	0.8%
• Nitrogen	0.0%
• Sulfur	2.5%
• Ash/other	0.1%
• Ambient air moisture content	0.006 lb/lb dry air
• Fuel consumption	100 T/d
• Ambient air temperature	80°F
• Feedwater temperature after heating	282°F
• Feedwater temperature before heating	100°F
• Boiler steam enthalpy (1200 psig, 900°F)	1440 Btu/lb
• Unburned combustible	0.4%
• Other losses	2.1%
• Radiation losses	0.8%

Key operating parameters:

- Flue gas temperature 500°F
- O_2 content of flue gases 6.5%

Respective parameters after rebuilding:

- Flue gas temperature 350°F
- O_2 content of flue gases 3.7%

Figure 3.3 and the boiler balance calculation sheets in Appendix B show that the efficiency improvement is from 78.8 to 84.3%. If the boiler average steam generation is 200,000 lb/hr the savings are:

$$(0.2\text{ Mlb/hr})\times((1440-250)\text{ MBtu/Mlb})\times\left(\frac{1}{0.788}-\frac{1}{0.843}\right)\times\$3/\text{MBtu}$$

= $59.1/hr *or* $496,440/yr

Reduction in CO_2 emissions, respectively:

$$(0.2\text{ Mlb stm/hr})\times((1440-250)\text{ MBtu/Mlb})\times\left(\frac{1}{0.788}-\frac{1}{0.843}\right)\times 173.7\text{ lb CO}_2\text{ / MBtu oil}$$

= 3423 lb CO_2/hr *or* 14,377 T of CO_2/yr

3.3.1.5 *Install a steam accumulator to facilitate efficient control of steam header pressures*

Description

Mills often experience peaks in steam demand due to process conditions such as batch digester loading and cooking, paper machine grade changes and sheet breaks, spill evaporation, and so on. Steam demand peaks in most mills are handled by increasing the combustion of auxiliary fossil fuels, because it is difficult to respond to sudden demand changes with biofuels.

The use of fossil fuels can be reduced by installing a steam accumulator to handle the steam demand surge. The steam accumulator would store high pressure steam as hot water in a pressurized tank. During periods of high steam demand the hot water would be released as steam by flashing it through an expansion valve to the predetermined steam pressure. The accumulator would be recharged when the steam load was steady or low again. A makeup flow to the steam accumulator would be needed to account for the enthalpy difference between the entering and leaving steam. An overall concept is shown in Figure 3.4.

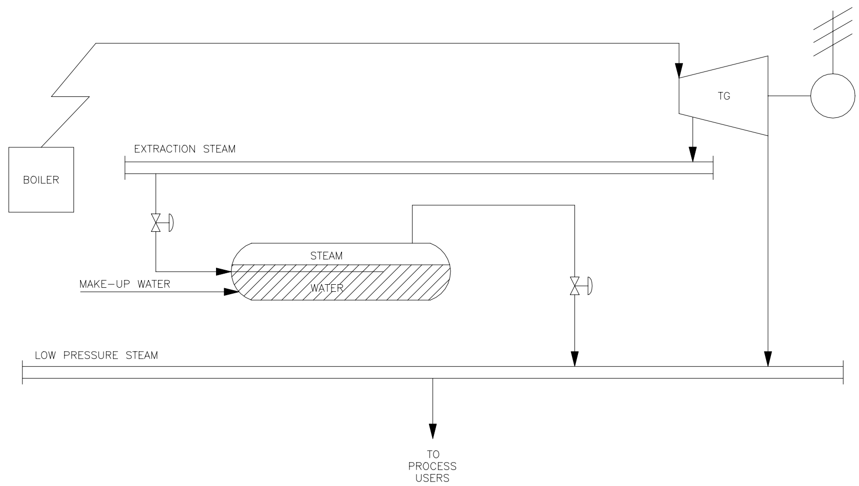

Figure 3.4. Steam Accumulator Installed between Two Steam Headers

Applicability and Limitations

The steam accumulator is most beneficial to mills that have difficulty in header pressure control due to rapid swings in process steam demand. The economic feasibility is normally reasonably good if fossil fuels are currently used to control header pressures. A steam accumulator may, in some cases, eliminate the need for additional boiler capacity by suppressing steam demand peaks.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

A steam accumulator will reduce the burning of fossil fuels by leveling the steam load. This will reduce energy usage at the mill.

Impact on CO_2

Installing a steam accumulator to control process steam surges will reduce CO_2 emissions at the mill by decreasing fossil fuel usage.

Impact on Operating Costs

Installing a steam accumulator will result in an operating cost reduction due to fuel savings. The amount will depend on the cost of fuel and the frequency and magnitude of steam demand swings.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section

2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume that oil is burned in the hog fuel boiler in order to respond to steam demand swings. Also assume:

- Average operating rate — 200,000 lb/hr
- Amount of oil burnt — 5% of total fuel
- Fuel oil cost — \$3/MBtu
- Cost of available hog fuel — \$10/T
- Installing steam accumulator will eliminate the need for oil use
- Boiler efficiency improvement due to more stable load — 2% (from 63.5% to 65.5%)
- Boiler steam enthalpy — 1440 Btu/lb
- Boiler feedwater enthalpy — 250 Btu/lb

Savings from reduced oil use (oil with boiler efficiency of 82%):
(0.2 Mlb stm/hr) x ((1440 - 250) MBtu/Mlb) x 0.05/0.82 x (\$3/MBtu oil)
= \$43.5/hr *or* \$365,400/yr

Increase in hog fuel usage (with boiler efficiency of 65.5%):
(0.2 Mlb stm/hr) x ((1440 - 250) MBtu/Mlb) x 0.05/0.655
= 18.2 MBtu/hr

Heating value of hog fuel:

$$\left(8750\ \frac{\text{Btu}}{\text{lb d.s.}}\right)\times\left(\frac{45\ \text{lb d.s.}}{100\ \text{hog fuel}}\right)\times\left(\frac{2000\ \text{lb d.s.}}{\text{T}}\right)\times\left(\frac{1\text{MBtu}}{10^{6}\ \text{Btu}}\right)$$

= 7.875 MBtu/T

Cost of increased hog fuel use:
(\$10/T) x (18.2 MBtu/hr)/(7.875 MBtu/T)
= \$23.1/hr *or* \$194,040/yr

The methods used to perform boiler balance calculations and determine boiler efficiency are explained in Section 3.3.1.4. For these sample calculations assume that a more stable boiler load results in an efficiency improvement from 63.5% to 65.5%. This saves hog fuel as follows:

$$(0.2\ \text{Mlb stm/hr})\times((1440-250)\ \text{MBtu/Mlb})\times\left(\frac{1}{0.635}-\frac{1}{0.655}\right)$$

= 11.4 MBtu wood/hr

or with a hog fuel heating value of 7.875 MBtu/T:
(11.4 MBtu/hr) / (7.875 MBtu/T)
= 1.4 T/hr of hog fuel

Savings from boiler efficiency improvement:
(\$10/T) x (1.4 T/hr)
= \$14/hr *or* \$117,600/yr

Net savings from steam accumulator:
365,400 - 194,040 + 117,600
= $288,960/yr

Reduction of oil usage will reduce CO_2 emissions as follows:
(0.2 Mlb/hr) x ((1440 - 250) MBtu/Mlb) x 0.05 x (211.8 lb CO_2/MBtu)
= 2520 lb CO_2/hr *or* 10,584 T CO_2/yr

A small decrease in back-pressure power generation will be experienced because any steam going through the steam accumulator will come from the 150 psig header rather than the 50 psig header. Dynamic simulation has to be performed for the steam system in order to be able to estimate the loss in back-pressure power generation.

3.3.1.6 *Install an ash reinjection system in the hog fuel boiler*

Description

In a hog fuel boiler, ash is collected from the grate, air-heater hoppers, and flue gas dust collectors such as electrostatic precipitators. This ash contains unburned carbon or char from incomplete combustion of the hog fuel. This represents a significant loss in heating value of the fuel. Recovering this material can result in a significant improvement in boiler efficiency; improvements of 5% are possible. The heating value of the unburned char is recovered using an ash reinjection system. An ash reinjection system is usually used on spreader-stoker fed boilers. Usually the larger pieces of char from the grate and air heater hoppers are collected for reinjection and the fine particles from the dust collector are disposed of.

Applicability and Limitations

High carbon content in the ash is normally a sign of poor combustion conditions in the furnace. This is typically because of the design of the grate and/or air supply systems. Improvements in boiler design and operation may be an alternative to ash recirculation.

If all the dust collected is reinjected, the dust load in the boiler will increase. This may increase particulate emissions from the boiler, which may necessitate changes to existing pollution control equipment.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing an ash reinjection system will improve the energy efficiency of the boiler. More heat for steam generation will be liberated from the same amount of fuel. This means either less fuel is required for an equivalent steaming rate or a capacity increase for the boiler.

Impact on CO_2

An ash reinjection system will allow more steam to be produced from the same quantity of fuel in the hog fuel boiler. This will facilitate decreased use of fossil fuels in other boilers, with an associated decrease in CO_2 emissions.

Impact on Operating Costs

Installing an ash reinjection system will lower operating costs. More steam will be generated for the same amount of fuel or less fuel can be used to generate the same amount of steam. Thus the fuel usage will drop, lowering operating costs. Some additional electrical power will be required for the collection and conveyance of ash to the reinjection point.

Capital Costs

Costs of the project will include conveyors and motors for collection and transportation of the ash. A surge bin for ash storage to provide a constant feed of ash to the reinjection system may also be needed.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Enthalpy of boiler steam (900°F, 1200 psig)	1440 Btu/lb
• Enthalpy of boiler feedwater (282°F)	250 Btu/lb
• Total ash	10% of fuel solids
• Carbon content of ash	20%
• Combustible carbon	70% of carbon in ash
• Average steam flow	200 klb/hr

Boiler efficiency can be calculated from detailed boiler balances as explained in Section 3.3.1.4 or it can be estimated from Figure 3.5. This figure is based on a boiler balance computer program and shows the effect of unburned combustible material in the ash leaving the boiler on boiler efficiency for various flue gas temperatures and excess air amounts.

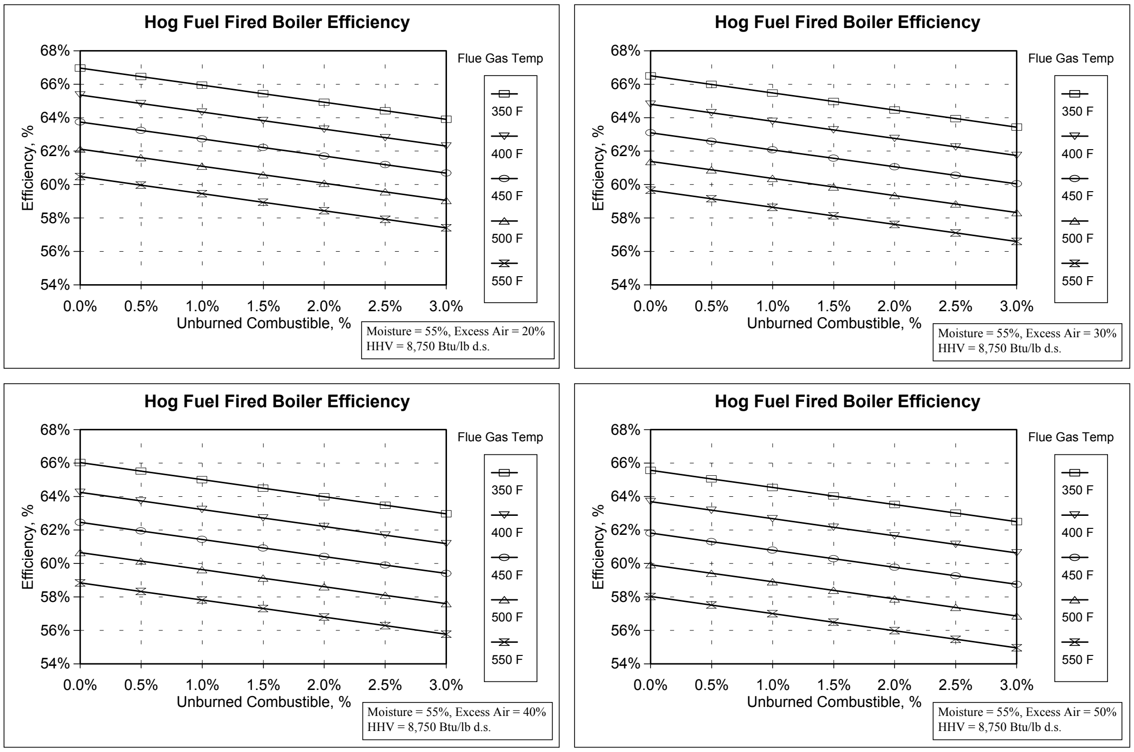

Figure 3.5. Efficiency of an Example Hog Fuel Fired Boiler as a Function of the Unburned Combustible in the Ash Leaving the Boiler at Various Flue Gas Temperatures and Excess Air Amounts

The boiler balance calculations indicate that in the assumed conditions the overall efficiency improves by about 1.8% (i.e., from 64.3% to 66.1%) when the unburned carbon is recycled and burnt completely. Increased efficiency translates into increased steam production in the hog fuel boiler, allowing lower fuel consumption in fossil fuel fired boilers.

Fuel savings are approximately:

$$\left(\frac{1}{0.643}-\frac{1}{0.661}\right)\times\left(0.2\ \text{Mlb stm/hr}\right)\times\left(\left(1440-250\right)\text{MBtu/Mlb}\right)$$

= 10.1 MBtu/hr in fuel

Cost savings if oil use is reduced (efficiency of oil fired boiler assumed to be 82%):

$$\left(\frac{0.661\ \text{MBtu stm}}{\text{MBtu hog fuel}}\right)\times\left(\frac{\text{MBtu oil}}{0.82\ \text{MBtu stm}}\right)\times 10.1\ \text{MBtu/hr}\times \$3/\text{MBtu}$$

= \$24.4/hr *or* about \$205,000/yr

Respective CO_2 emissions decrease:

$$\left(\frac{0.661\ \text{MBtu stm}}{\text{MBtu hog fuel}}\right)\times 10.1\ \text{MBtu/hr}\times 211.8\ \text{lb}\ CO_2/\text{MBtu steam from oil}$$

= 1414 lb CO_2/hr *or* about 5939 T CO_2/yr

3.3.1.7 Install a bark press or bark dryer to increase utilization of biofuels

Description

The hog fuel burned at most mills is typically high in moisture. Reducing the moisture content of hog fuel has several benefits. Reducing the moisture content below 55% will allow self-sustaining combustion. It will also allow more hog fuel to be burned, effectively increasing capacity. The moisture content of the bark can be decreased by pressing, drying, or both.

The bark dryer can use direct firing of fossil fuels or biofuel as the heat source. A more efficient approach is to integrate the dryer with the boiler and use hot flue gases to dry the hog fuel. The dryer may also be equipped with a classifier to separate fuel into large and fine fractions. The large fraction can be burned on the grate and the fines can be fed to suspension burners. The dryer can be either a rotary drum type or a suspension type.

Applicability and Limitations

Moisture content can often be reduced to 50 to 55% with a bark press. If the processing of wood and hog fuel is done without water (or steam), the moisture content of the hog fuel may not be much higher. Obviously the press would not be of much help in those circumstances.

Hog fuel drying may be of interest if a heat source for dryer operation exists (e.g., boiler flue gases). Hog fuel can also be used for drying. This may be feasible if hog fuel is in excess at the site or is available at a reasonable cost.

VOC emissions from the dryer may limit the application of a hog fuel dryer. Hog fuel gasification and incineration of the low Btu gas could be an option to manage VOC emissions.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Lowering the moisture content of hog fuel through pressing or drying will favorably impact energy usage at the mill. It reduces the amount of water which must be evaporated before the fuel will burn, thereby reducing the amount of auxiliary fossil fuel and energy required to produce steam in the boiler. Drying fuel to below 55% moisture content will allow self sustaining combustion, which further reduces or eliminates auxiliary fuel requirements. Electrical power will be required by the press and the dryer, and the latter will also require a heat supply.

Impact on CO_2

Reducing the hog fuel moisture content through pressing or drying increases use of biofuels and reduces use of fossil fuels. The drop in auxiliary fuel usage will reduce CO_2 emissions.

Impact on Operating Costs

Overall, installing a bark press or dryer should reduce operating costs. Electrical power usage may increase due to the bark press, conveyors for the fuel, and other equipment. Fuel may also be required for the dryer if boiler flue gases are not used. Savings will result from the decrease in auxiliary fuel usage in the boiler and from an increase in the use of less expensive biofuels, reducing the cost of producing steam.

Capital Costs

The installation of a bark press and/or dryer can be implemented as a stand-alone project or as part of a larger project such as a hog fuel boiler replacement or rebuild. The financial return requirement may be different for each type of project. Installing a bark dryer would be more expensive than a bark press. The capital cost should also include necessary conveyors and electric motors to integrate the new equipment into the existing hog fuel system. Bark dryers may also need to be equipped with particulate and VOC controls.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Hog fuel cost at 50% moisture content	\$10/T
• Hog fuel moisture content without press	65%
• Hog fuel moisture content with press	55%
• Flue gas temperature	400°F
• Flue gas O_2 content	4.9%
• Boiler steam generation	200 klb/hr

The heat transferred to steam can be calculated from detailed boiler balances as explained in Section 3.3.1.4 or it can be estimated from Figure 3.6. This figure is based on a boiler balance computer program and shows the effect of hog fuel moisture content on heat transferred to steam at various flue gas temperatures. Based on detailed boiler balances:

• Heat to steam from hog fuel with a 65% moisture content	4762 Btu/lb dry fuel
• Heat to steam from hog fuel with a 55% moisture content	5523 Btu/lb dry fuel

Fuel demand at 65% moisture content:
(200,000 lb stm/hr) x ((1440 - 250) Btu/lb) / (4762 Btu/lb d.s)
= 49,979 lb d.s./hr

Fuel demand at 55% moisture content:
(200,000 lb stm/hr) x ((1440 - 250) Btu/lb) / (5523 Btu/lb d.s.)
= 43,093 lb d.s./hr

At a fuel cost of \$20/T d.s. or \$0.01/lb d.s.:

Savings in hog fuel:
(\$0.01/lb d.s.) x (49,979 - 43,093 lb/hr)
= \$68.9/hr *or* \$578,400/yr

If oil is saved instead of hog fuel, the savings are estimated as follows:

Assume that current use of hog fuel at 65% moisture content is enough to produce 150,000 lb/hr of steam (or 178.5 MBtu/hr).

Steam generation at 55% moisture content:

$$\left(\frac{5523}{4762}\right) \times (178.5 \text{ MBtu/hr})$$

= 207.0 MBtu/hr

Oil savings:

$$((207.0 - 178.5)\text{ MBtu/hr}) \times \frac{1}{0.82}$$

= 34.8 MBtu oil/hr

Cost savings:
(34.8 MBtu/hr) x ($3/MBtu)
= $104.4/hr *or* $876,960/yr

CO_2 emission reduction if oil use is reduced:
((207.0 - 178.5) MBtu stm/hr) x (211.8 lb CO_2/MBtu stm)
= 6036 lb CO_2/hr *or* 25,351 T/yr

Figure 3.6 illustrates steam generation from hog fuel as a function of the moisture content of the fuel. As shown, the biggest impact with a bark press or dryer is achieved if the fuel currently has high moisture content. The hog fuel heating value has been assumed to be 8750 Btu/lb d.s. and the operating conditions are as specified.

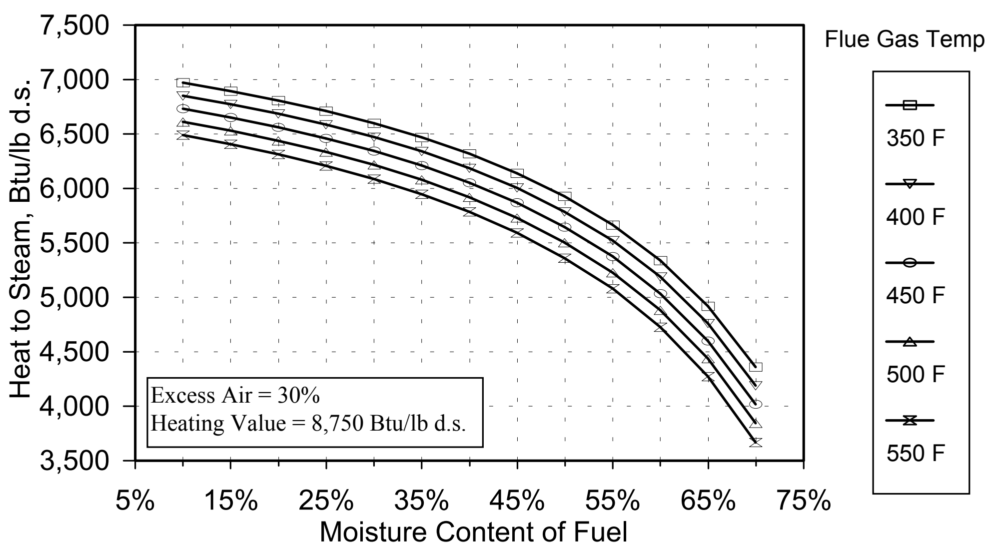

Figure 3.6. Steam Generation from Hog Fuel as a Function of Moisture Content of Fuel (assumptions are the same as in sample calculations)

3.3.1.8 *Install additional heat recovery systems to boilers to lower losses with flue gases*

Description

Modern boilers operating at high steam pressures generally have high flue gas temperatures because the temperature at the superheater must be high to maintain high steam temperature. As a result, boiler thermal efficiency is lowered. Installing a heat recovery device will improve boiler thermal efficiency and reduce the mill's steam load, resulting in savings.

Heat can be recovered from the flue gas in several ways. An air-to-air heat exchanger can be installed to preheat boiler combustion air. This will reduce energy required in the boiler for air heating. An economizer, or air-to-water heat exchanger, can be installed on the boiler, and can heat boiler feedwater or mill water for use in other processes (Figure 3.7). An economizer usually reduces the temperature of the flue gas to a point that is above the condensation temperature of the vapors in it. This is because the vapors are usually corrosive when condensed. However, a specially designed condensing economizer, built with corrosion resistant material, can be used to maximize heat recovery from the flue gas. The use of either type of economizer will result in steam savings.

Applicability and Limitations

In general, heat recovery from boiler flue gases to either boiler feedwater or combustion air is possible. Depending on the fuel composition (e.g., sulfur, potassium, and/or chloride content), the safe low temperature limit for flue gases vary. Typically, 350°F is considered the minimum flue gas temperature because corrosion becomes a concern below this point.

The impact of increased heat recovery from flue gases on the capacity and performance of the boiler (e.g., steam temperature) has to be studied carefully before implementing the heat recovery project. Also, space requirements and required down time for installation may limit the applicability of the heat recovery project.

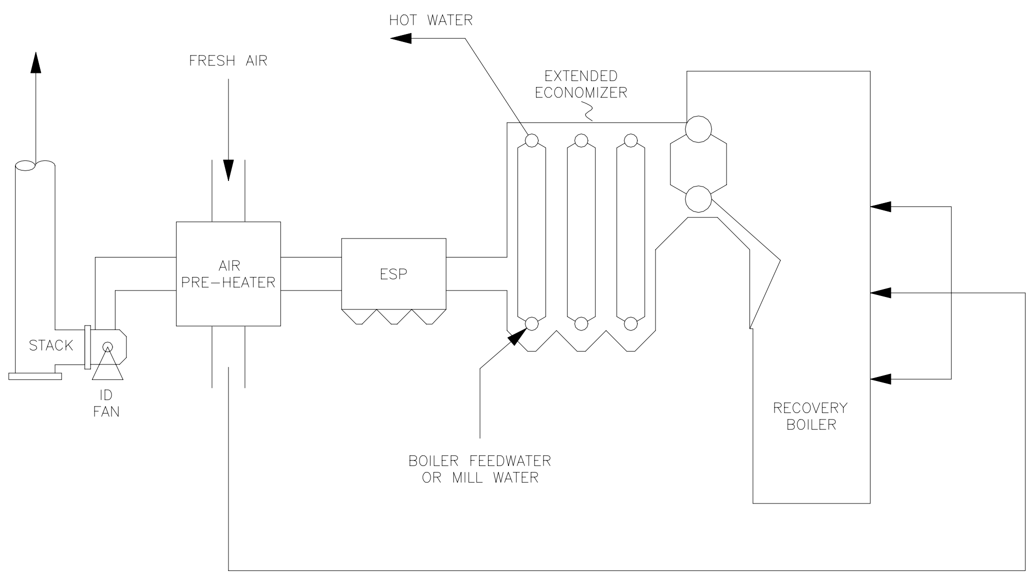

Figure 3.7. Installation of Additional Heat Recovery Systems to a Boiler

Figure 3.8 illustrates the relation between steam generation and flue gas temperature for a hog fuel fired boiler. Figures 3.9, 3.10, 3.11, and 3.12 show similar curves for coal, oil, natural gas, and black liquor fired boilers, respectively. If the percentage of excess air and the flue gas temperature are known, the heat to steam can be estimated.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

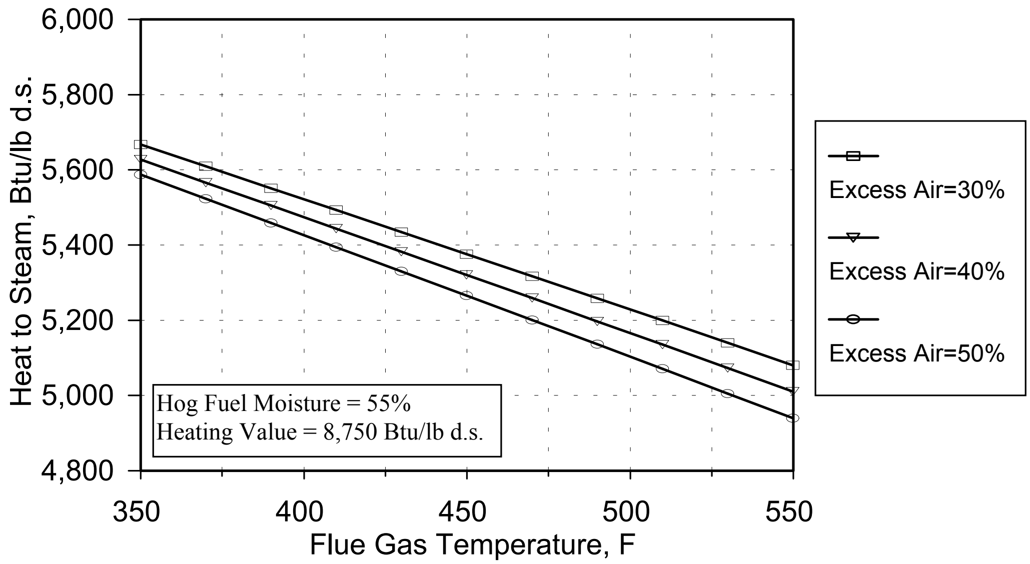

Figure 3.8. Relationship between Steam Generation and Flue Gas Temperature for a Hog Fuel Fired Boiler (using the same assumptions as in sample calculations)

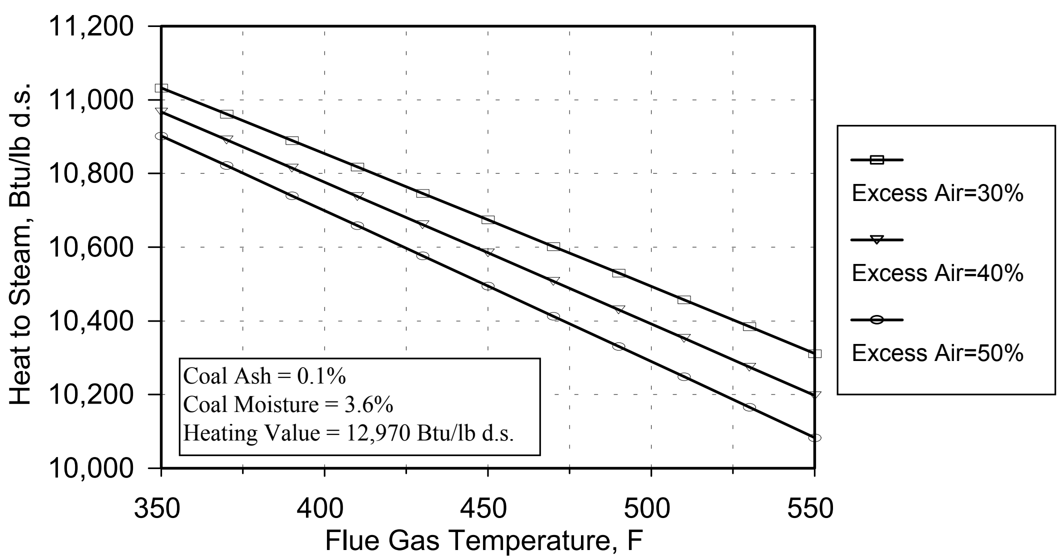

Figure 3.9. Relationship between Steam Generation and Flue Gas Temperature for a Coal Fired Boiler (using the same assumptions as in sample calculations)

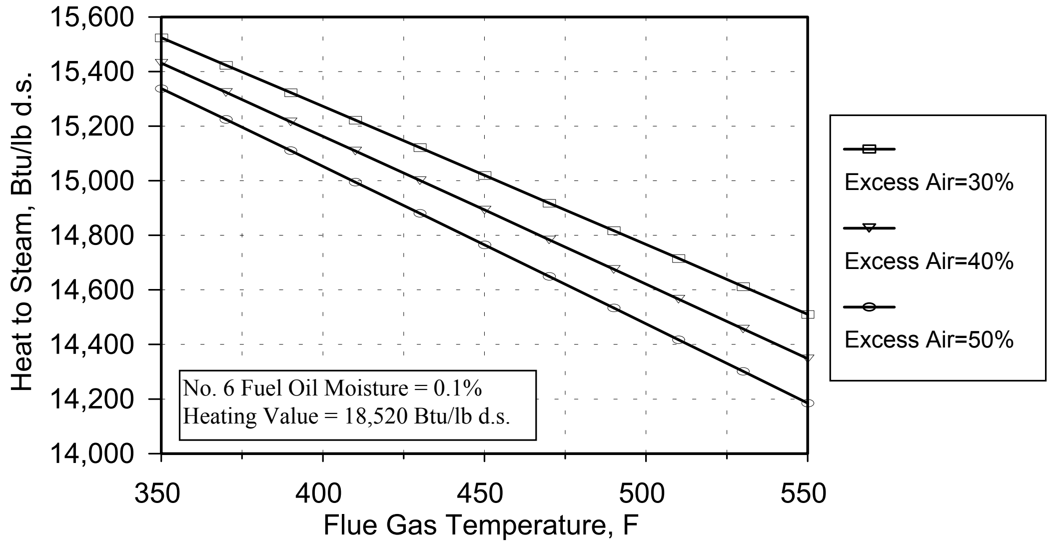

Figure 3.10. Relationship between Steam Generation and Flue Gas Temperature for an Oil Fired Boiler (using the same assumptions as in sample calculations)

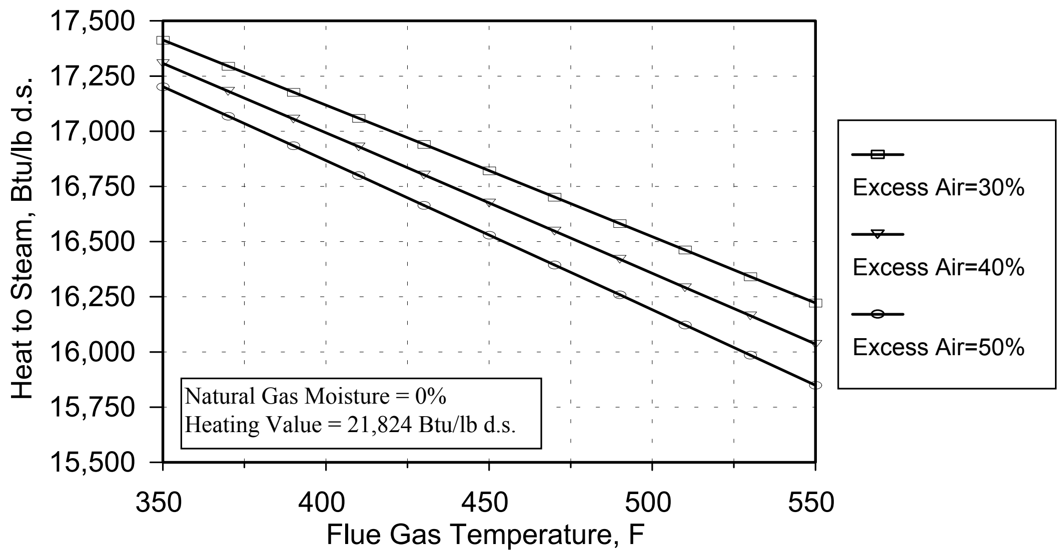

Figure 3.11. Relationship between Steam Generation and Flue Gas Temperature for a Natural Gas Fired Boiler (using the same assumptions as in sample calculations)

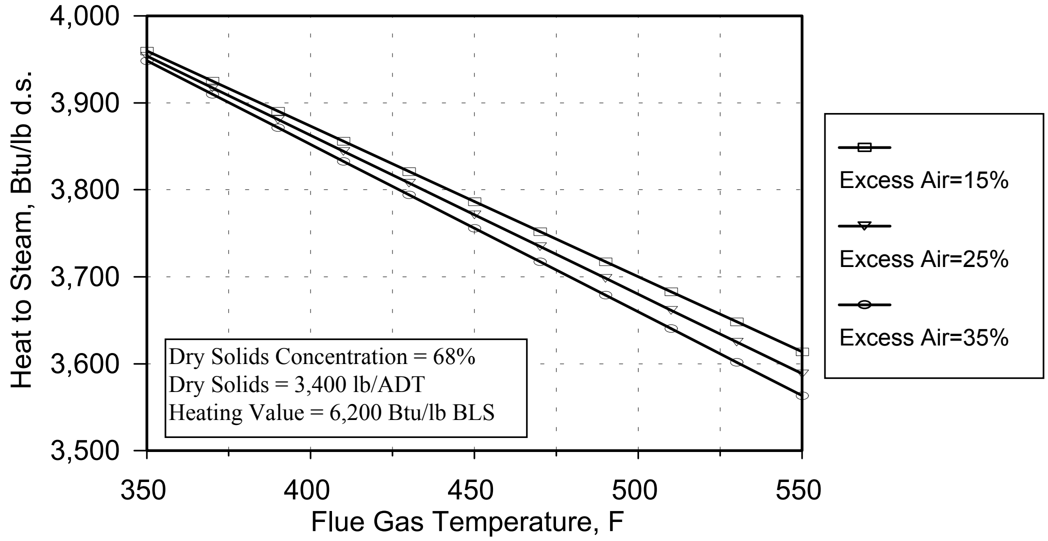

Figure 3.12. Relationship between Steam Generation and Flue Gas Temperature for a Kraft Recovery Boiler (using the same assumptions as in sample calculations)

Impact on Energy

Installing heat recovery systems on a boiler will reduce energy consumption in the boiler and steam demand in other process areas. The thermal efficiency of the furnace will increase and less energy will be required to produce the necessary steam. Using hot water produced in the economizer or the scrubber in other processes, like the bleach plant, will reduce steam consumption and result in energy savings. Additional electrical power would be used if fans and pumps must be installed for the new heat recovery systems. This would normally be outweighed by the energy saved.

Impact on CO_2

Installing heat recovery systems on a boiler will reduce CO_2 emissions per ton of product. Increasing boiler thermal efficiency through combustion air and feedwater preheating will reduce the fuel burned per steam produced, reducing CO_2 emissions. Heating mill water will reduce the steam load, decreasing fuel consumption and CO_2 emissions.

Impact on Operating Costs

Installing heat recovery systems on a boiler will reduce operating costs. Electrical cost may increase due to installation of new pumps and fans and a possible decrease in electrical generation (if steam load is reduced and steam is used in a generator). Normally, the savings in fuel usage from improvement in the boiler's thermal efficiency and reduction in the steam load will more than compensate for the increase in power cost. Actual savings will depend on the amount of heat recovered and the cost of marginal fuel.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil

fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Figure 3.8 illustrates the relation between steam generation and flue gas temperature for a hog fuel fired boiler. Assuming, for example, that the excess air is 30% and flue gas temperature is reduced from 550°F to 350°F by heating up boiler feedwater, heat to steam is increased from about 5081 to 5668 Btu/lb d.s. This is about a 12% increase in steam generation with the same amount of fuel. If this replaces oil and the boiler steam generation with hog fuel is originally 200,000 lb/hr, the reduction in oil use is:

Assume:

• Enthalpy of boiler steam (900°F, 1200 psig)	1440 Btu/lb
• Boiler feedwater temperature	282°F
• Enthalpy of boiler feedwater	250 Btu/lb
• Oil fired boiler efficiency	82%

$$\left(0.2 \text{ Mlb stm/hr}\right) \times \left(\left(1440 - 250\right) \text{MBtu/Mlb}\right) \times \left(\frac{5668}{5081} - 1\right) \times \frac{1}{0.82}$$

= 33.5 MBtu/hr

Savings:
($3/MBtu) x (33.5 MBtu/hr)
= $100.5/hr *or* $844,200/yr

Corresponding reductions in CO_2 emissions:
(33.5 MBtu/hr) x (173.7 lb CO_2/MBtu)
= 5819 lb CO_2/hr *or* 24,440 T CO_2/yr

3.3.1.9 *Implement energy management program to provide current and reliable information on energy use*

Description

An energy management program that provides current and accurate information about steam use, steam losses, and condensate losses will help the mill reduce process energy usage and costs. One component of an effective program is an on-line energy management system (EMS).

The EMS should be integrated into existing distributed control systems (DCSs) and operator control systems (OCSs) and should have the following capabilities:

- On-line reporting and accounting of energy usage and cost at the mill and in various production departments;
- On-line monitoring of power house performance, including boilers, turbines, and utilization of back-pressure power generation potential;
- Optimization of power house operations, including load allocation between boilers and turbogenerators, PRV control, and tie-line control;
- On-line reporting and accounting of steam condensate return.

Applicability and Limitations

Improved energy management systems have broad applications. The benefits vary enormously from mill to mill depending upon a variety of factors; for instance, the extent to which such systems are already in place. Like any higher level control and process management system, the EMS is only a tool that can either be utilized or be turned off-line if the user does not trust its guidance.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

An EMS with the features described will result in energy savings from increased boiler efficiencies, back-pressure power generation, and steam condensate return, and reduced process steam usage. Most of the energy savings will be from reduced fuel usage in the boilers. Electrical power generation may increase through reduced use of PRVs and increased flow to back-pressure turbines. Typical steam savings are 0.5 MBtu/ton product.

Impact on CO_2

An EMS will reduce emissions of CO_2 per ton of product due to reduced fuel usage associated with the energy savings.

Impact on Operating Costs

The EMS will reduce operating costs due to reduced fuel usage, increased power generation, and better usage of process energy. Savings will depend on the processes included in the EMS, marginal fuel costs, and the extent to which the EMS is used.

Capital Costs

The cost of the EMS will include any additional field instruments, hardware to tie new and existing instrumentation into the DCS or OCS, and software development to perform the desired tasks (reporting, etc.). The cost will depend on the number of boilers, turbines, and so on to be included in the system, and any additional controls required on the boilers and turbines.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Development of a generic estimate of savings from improved energy management systems (EMS) is nearly an impossible task. One difficulty is that many energy management systems rely on a human operator to implement the optimum management procedures. Thus the results often depend on how well the optimum energy management procedures are implemented in everyday operation. The figure referred to above, 0.5 MBtu/T, for an older integrated mill is not overly optimistic, based on the reported success of energy management systems in the industry.

For the calculation basis, the following is assumed:

• Mill production	1000 T/d
• Savings due to EMS (heat in steam)	0.5 MBtu/T

- Marginal fuel is oil $3/MBtu

Savings (with boiler efficiency 82%):

$$(1000 \text{ T/d}) \times (350 \text{ d/yr}) \times (0.5 \text{ MBtu/T}) \times \frac{1}{0.82} = 213{,}415 \text{ MBtu/yr in oil}$$

213,415 MBtu/yr oil x $3/MBtu
= $640,245/yr

Reduction in CO_2 emissions:
(213,415 MBtu/yr) x (173.7 lb CO_2/MBtu)/(2000 lb/T)
= 18,535 T/yr

3.3.1.10 *Switch power boiler fuel from coal or oil to natural gas*

Description

Forest product industry facilities typically must generate large quantities of steam to satisfy process heat demands and often for generation of electrical power. Fuels used in industry power boilers include spent pulping liquors, hog fuel (wood residues), coal, oil, natural gas, and others. By convention, biomass fuels (such as spent pulping liquors and wood) are considered net zero emitters of greenhouse CO_2. Of the fossil fuels, natural gas emits less CO_2 per Btu of heat than either coal or oil. Therefore, switching a power boiler's fuel from coal or oil to natural gas will result in decreased CO_2 emissions. Wood or other supplemental fuels (tire-derived fuels, wastewater treatment residuals, etc.) are assumed to remain at current consumption levels.

Applicability and Limitations

If a coal or oil fired boiler (or a combination fuel boiler burning some proportion of coal or oil) is used at the mill and natural gas is available, switching to natural gas is a viable technology option for reducing direct emissions of CO_2. Economic feasibility is dependent on the price of natural gas relative to other fossil fuels, the extent of required boiler modifications, and the proximity of the mill to the natural gas pipeline.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Power boiler fuel switching to natural gas will not result in any significant overall energy savings. The same quantity of steam will be produced. However, the steam will be produced by burning a lower CO_2 emitting fuel, thereby reducing total emissions. Gas fired boilers are typically less efficient in converting the fuel's energy to steam heat than are coal or oil fired boilers. Therefore, a greater quantity of natural gas (on a Btu basis) will be required than the current amount of coal or oil used.

Impact on CO_2

Fuel switching of coal or oil fired power boilers to natural gas will reduce on-site CO_2 generation because higher emitting fossil fuels are replaced with natural gas, which has a lower emission factor.

Impact on Operating Costs

Fuel switching of coal or oil fired power boilers to natural gas may increase operating costs in regions of the country where gas is more costly than oil or coal (note that natural gas is almost always more expensive than coal). An additional cost consideration is related to boiler efficiency differences, in that gas fired boilers are typically less efficient in converting the fuel's energy to steam heat than are coal or oil fired boilers. Natural gas fired boilers, however, have lower fuel and ash handling requirements and potentially require less stringent pollution control considerations (e.g., less significant particulate emissions) than do coal fired boilers, which can partially offset increased fuel costs. Although it is non-trivial to quantify these savings, estimates were made based on information provided by R.W. Beck (Beck 1998, under contract to NCASI) and available in EPA documents, and on landfill cost data drawn from NCASI solid waste surveys. For a coal fired boiler producing 200,000 MBtu/hr steam, reduced fuel and ash handling requirements are estimated to represent a $160,000/yr savings, discontinued use of particulate control devices a $160,000/yr savings, and reduced ash disposal costs an approximate $170,000/yr savings (based on $1783 per thousand tons of coal used as fuel). It is assumed that savings associated with switching power boiler fuel from coal to gas can be scaled linearly to boiler steam generation rate. Discontinued continuous monitoring requirements represent an additional savings of $20,000/yr (it is assumed that this savings is relatively constant, regardless of boiler size). These savings are not applicable for converting from oil to gas.

Capital Costs

Capital costs of switching power boiler fuels are variable. They include the costs of boiler modifications (burners, pipe racks, control systems, and superheater), and lateral pipeline installation from the trunk line to those mills which do not have natural gas available on-site or for which excess transport capacity is not available in existing laterals. Representative costs to modify various types of boilers to natural gas-fired operation were prepared by R.W. Beck under contract to NCASI. A relationship between upgrade cost and boiler capacity (in terms of steam production capacity, in thousands of pounds per hour) was developed from the results of this analysis (Figure 3.13). This relationship can be used to obtain an order of magnitude estimate of upgrade costs for converting coal and oil fired boilers to natural gas. The relationship can also be used to estimate costs of upgrades required to substitute natural gas for the portion of coal or oil used in combination wood fired boilers (those boilers firing a combination of coal and wood fuel, or oil and wood fuel).

If required at the mill, the cost of lateral installation can greatly exceed the cost of boiler modifications. For example, the cost of installing a six-inch gas lateral, which is capable of supplying approximately 550,000 cubic feet per hour of gas over a 25 mile distance, is about $100 per foot. In practice, the cost of lateral installation is typically included in the gas delivery price negotiated with the supplier. In the current example, however, the cost of lateral installation will be considered a capital cost to be incurred at the time of hookup to the main trunk line.

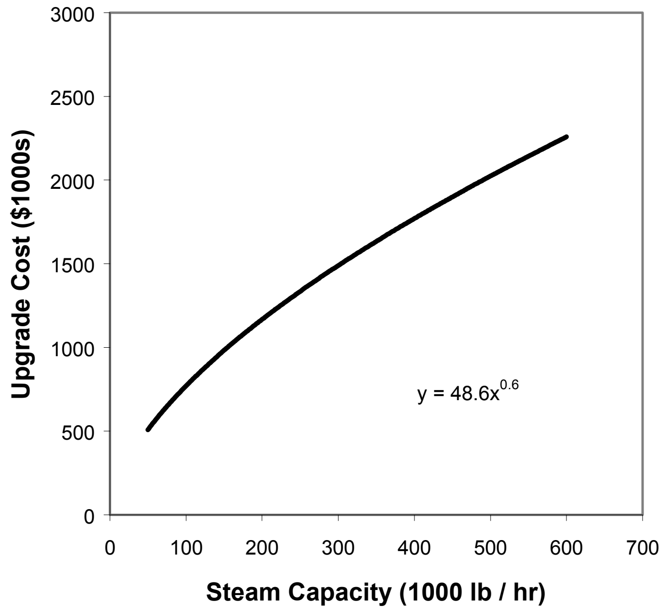

Figure 3.13. Capital Cost Estimate to Upgrade Boilers for Gas Fuel Switching

Sample Calculations

The following sample calculation is based on reduced use of an assumed marginal fuel corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume that the boiler capacity is 300,000 lb/hr and the average annual steam flow is 200,000 lb/hr. The current fuel is coal. Also assume:

• Enthalpy of boiler steam	1440 Btu/lb
• Boiler feedwater temperature	282°F
• Boiler feedwater enthalpy	250 Btu/lb
• Cost of coal	\$2/MBtu
• Cost of gas	\$3/MBtu
• Boiler efficiency with coal	84%
• Boiler efficiency with gas	80%

Fuel cost of current operation (coal):

$$\frac{0.2\times10^6 \text{ lb stm}}{\text{hr}}\times\frac{1440-250 \text{ MBtu}}{10^6 \text{ lb stm}}\times\frac{1 \text{ Btu fuel}}{0.84 \text{ Btu stm}}\times\frac{\$2}{\text{MBtu}}$$

= \$567/hr *or* \$4.76 million/yr

Fuel and ash handling/disposal and pollution control savings based on steam use rather than capacity (only applicable when switching from coal to gas fuel):
\$160,000 + \$160,000 + \$170,000 + \$20,000
= \$510,000/yr *or* \$0.51 million/yr

CO_2 emissions from coal:
(0.2 Mlb stm/hr) x ((1440 - 250) MBtu/Mlb) x (246.7 lb CO_2/MBtu stm)
= 58,715 lb CO_2/hr

Fuel cost of operation with gas (boiler efficiency estimated to be 80%):
(0.2 Mlb stm/hr) x ((1440 - 250) MBtu/Mlb)/(0.80 Btu in stm/Btu in fuel) x (\$3/MBtu)
= \$893/hr *or* \$7.50 million/yr

CO_2 emissions from gas:
(0.2 Mlb stm/hr) x ((1440 - 250) MBtu/Mlb) x (146.3 lb CO_2/MBtu stm)
= 34,819 lb CO_2/hr

Additional operating costs associated with fuel conversion:
\$7.50 - \$4.76 - \$0.51
= \$2.23 million/yr

Reduction in CO_2 emissions associated with fuel conversion from coal to gas:
58.7 klb CO_2/hr - 34.8 klb CO_2/hr
= 23.9 klb CO_2/hr *or* 100,400 T CO_2/yr

Cost of boiler modification (from relationship in Figure 3.13):
(48.6 x (300 klb stm/hr capacity)$^{0.6}$) x \$1000
= \$1.49 million

Cost of lateral installation (assuming mill does not currently have access to additional natural gas and is 15 miles from trunk line):
(15 miles) x (5280 ft/mile) x (\$100/ft)
= \$7.92 million

Capital costs associated with fuel conversion:
\$1.49 + \$7.92
= \$9.41 million

3.3.1.11 *Install gas turbine cogeneration system for electrical power and steam generation*

Description

Although many forest product industry facilities cogenerate electrical power from boiler steam, most mills also purchase additional power from utility companies. As discussed in Sections 2.3 and 2.4, carbon dioxide emissions associated with purchased electrical power can be significantly greater than those associated with power cogenerated at the mill site. Therefore, one potential strategy for reducing total CO_2 emissions would be to minimize consumption of utility generated electrical power. Gas turbine (GT) cogeneration technology can be used to efficiently cogenerate steam and electricity. In GT cogeneration systems, natural gas (some systems are configured to use liquid fuels) is burned in a turbine which drives an electrical power generator. Hot exhaust gases from the gas fired turbine are routed to a heat recovery steam generator (HRSG) to produce process steam. In some systems supplemental fuel is burned in the HRSG to increase steam production. In a simple cycle GT cogeneration system, steam from the HRSG can be used for process heat directly or after passing through a pressure reducing valve. In a combined cycle GT cogeneration system, steam from the HRSG drives a steam turbine which is used to generate additional electrical power. Most combined cycle systems in the pulp and paper industry utilize back-pressure turbines in this application, allowing extraction or exhaust steam to be used for process heat. Illustrative diagrams of simple and combined cycle GT cogeneration systems are presented in Figures 3.14 and 3.15.

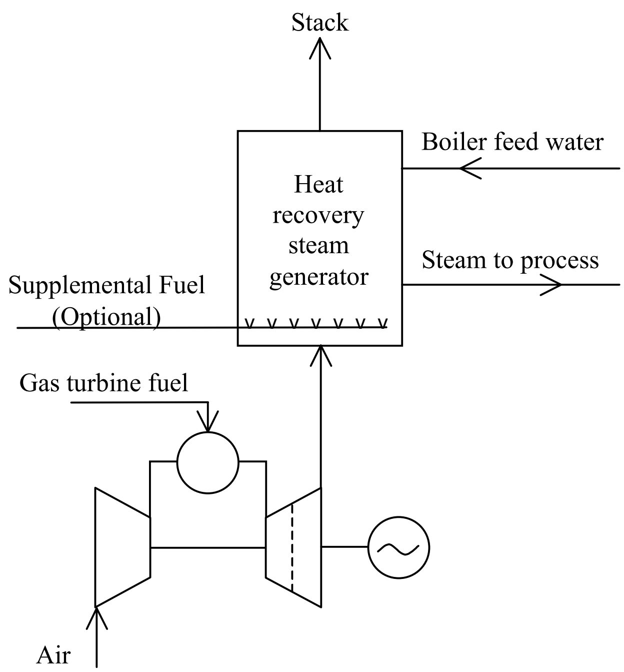

Figure 3.14. Simple Cycle Gas Turbine Cogeneration System

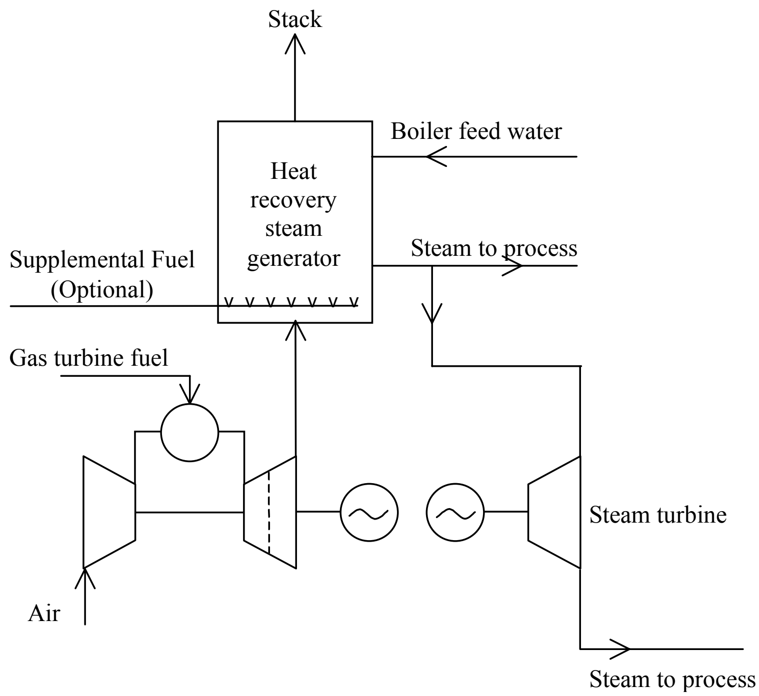

Figure 3.15. Combined Cycle Gas Turbine Cogeneration System

For a given steam production rate, electricity production from a GT cogeneration system (either simple or combined cycle) can be significantly greater than that achievable via conventional boilers mated with back-pressure turbines. The power coefficient, which is the amount of power generated divided by the steam energy produced by the cogeneration system, in consistent units (e.g., MW:MJ/s) can range from about 0.2 to as high as 2.0 for either simple or combined cycle units. Supplemental firing of fuels in the HRSG tends to decrease the power coefficient. Because steam is produced by the hot exhaust gases of the GT, total efficiency (or total fuel heat utilization) for GT cogeneration systems can be much higher than that available via conventional boilers mated with steam turbine driven generators. Total efficiency can range from about 65% to as high as 95%, depending on system configuration. Total efficiency refers to the total electrical power (produced via the gas turbine and via the back pressure steam turbine driven by HRSG steam) plus the total steam heat to the process (consisting of extracted and exhausted steam from the back pressure steam turbine plus any steam from the HRSG that is directly used in the process) divided by the total energy content of the fuel (including fuel fired in the gas turbine plus any supplemental firing fuel in the HRSG). However, in order to achieve total efficiencies above approximately 75 to 80%, supplemental firing in the HRSG or extensive heat recovery to lower the HRSG stack temperature must be implemented. Either of these practices can significantly increase the required capital expense of the project.

Several design parameters can influence the power coefficient and total efficiency of GT cogeneration systems. Therefore, these systems can be designed to meet a wide range of desired operating conditions. Additional information on the details of designing or selecting GT cogeneration systems can be found in GTW 1998; Harman 1981; Kehlhofer et al. 1999; and Stromberg, Franck, and Berntsson 1993.

This technology is available for implementation in a wide range of power generating capacities (e.g., less than 10 MW to greater than 700 MW, with smaller gas turbines available for generation of electrical power only). GT cogeneration systems can be used to provide incremental steam and/or electrical power generating capacity, which would typically result in a decrease in or elimination of the amount of power purchased from the grid. Alternatively, a GT cogeneration system can be designed to replace aging or inefficient conventional boilers, which could result in sufficient power generation to fully satisfy the mill's power demands or allow export of surplus power to the grid. In either case, the mill may receive credit for reduced off-site emissions corresponding to those which would have resulted from utility generation of the same quantity of power.

Applicability and Limitations

Cogeneration of steam and electricity by way of gas turbine technology is possible at any facility with access to natural gas fuel. However, the technology's economic attractiveness and optimum configuration and capacity is a function of several parameters. The considerable uncertainty in regard to future fuel and power prices and the course of energy deregulation brings into question the economic attractiveness of this technology. It is probably unattractive to size a GT cogeneration system to produce more steam than is required for mill processes. Sizing GT cogeneration systems to produce more electrical power than needed at the facility requires arrangements to sell the surplus power to the grid. In some cases, mills have contracted for electrical utility companies to build and operate GT cogeneration plants adjacent to mill property, with the mill contracting to use the steam and a portion of the electrical power produced. The discussions in this guide regarding off-site carbon dioxide emissions are based on the assumption that a facility which reduces demand for utility generated power would receive credit for the corresponding emission reductions. However, the manner in which these emission credits will be allocated with respect to compliance with potential future greenhouse gas reduction policies is far from certain.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installation of GT cogeneration capacity at a mill can have a profound impact on a mill's energy systems. For a given steam generation rate, more fuel may be required by a GT cogeneration system than would be required in conventional boilers. However, much more electrical power could be cogenerated in the GT system. The "extra" electrical power would reduce the mill's dependence on utility-generated power, and could enable the mill to export power to the grid. The net effect would be a decrease in total energy consumption (including energy in fuel burned at the mill and fuel used off-site by utilities to produce purchased power) due to the high power yield of GT cogeneration systems.

Impact on CO_2

Replacing boiler steam capacity with GT cogeneration capacity may increase on-site emissions of CO_2. However, demand for utility generated power will be reduced or eliminated, with concurrent reductions in off-site emissions. In some configurations a GT cogenerator could allow export of surplus electrical power to the grid.

Impact on Operating Costs

Installation of GT cogeneration capacity would generally decrease operating costs. Although fuel consumption on-site will increase, decreased costs for purchased electrical power should more than compensate for increased fuel costs. In some scenarios, installation of a GT cogeneration system could enable export of power to the grid. It is uncertain what selling price a mill might receive for power exports. NCASI information indicates that the selling price could range from approximately 20% to greater than 75% of the mill's current purchase price for utility generated power and, in some cases, may vary from hour to hour depending on the demand for power on the grid.

Operating and maintenance (O&M) costs associated with gas turbine cogeneration systems can be different than those associated with operation of power boilers and steam turbines. Data from a US Department of Energy study of options for reducing greenhouse gas emissions, more commonly known as the DOE 5-Lab Study (USDOE 1997), indicate that for the case of converting a coal fired boiler to a GT cogeneration system, annual fixed O&M costs should be reduced by \$30/kW and variable O&M costs reduced by \$1/MWh. In the case of a conversion to GT cogeneration from an oil fired boiler, fixed annual O&M costs were about the same but variable O&M costs were \$1/MWh lower than the oil fired boiler. For conversion from a gas fired boiler, annual fixed O&M costs were \$5.5/kW higher for the GT cogeneration system, while variable O&M costs were about the same. These values for fixed annual O&M costs and variable O&M costs can be reduced to a single number, in terms of changes in O&M costs per MW of capacity, assuming 8400 operating hours per year. Considering both fixed and variable O&M costs, changing from coal fired boilers results in an annual cost reduction of approximately \$38,800/MW capacity, changing from oil fired boilers results in an approximate \$8,400/MW annual O&M cost savings, and changing from natural gas fired boilers represents an additional \$5,500/MW annual O&M cost.

Capital Costs

Several sources may be consulted for GT cogeneration system prices. The annual *Gas Turbine World Handbook* (Gas Turbine World 1998) includes a survey of, among other things, turnkey combined cycle budget price levels for gas turbine systems. Another source of information is material contained in the DOE 5-Lab Study (USDOE 1997). Both sources were used to prepare a plot (Figure 3.16) of installed cost as a function of GT cogeneration output. Regression analysis was used to develop an equation describing each set of data, with resulting equations shown in the figure.

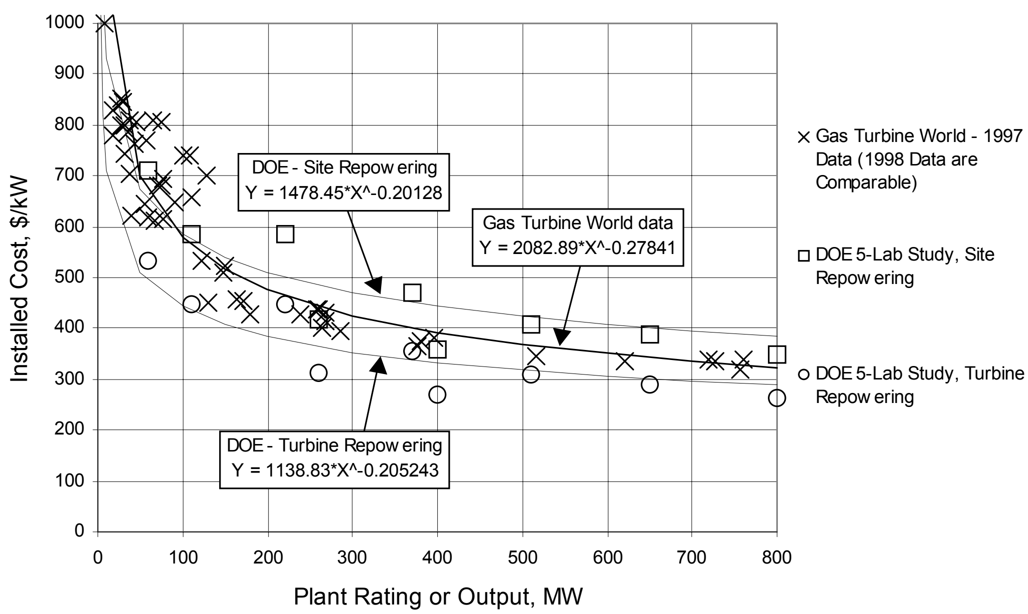

Figure 3.16. Installed Gas Turbine Combined Cycle System Prices

Although either set of data can be used to estimate total installed costs of gas turbine systems, the sample calculations below are based on the DOE cost data, primarily because they were specifically developed for the case where an existing power plant was to be repowered, a situation perhaps more relevant to a mill than to a greenfield GT cogeneration plant. Also, the DOE capital cost data were accompanied by operating cost data, which are used in the sample calculations below, while the *Gas Turbine World* data were not. An important deficiency in both databases was the lack of data pertaining to GT cogeneration systems (systems producing both electricity and process steam). *Gas Turbine World* had data for two such systems, only one of which was equipped with a turbine driven by steam from a heat recovery steam generator. These two systems had power outputs of 2.65 and 5.72 MW with installed costs of $825 and $725 per kW, respectively. These costs are in the same range as those plotted in Figure 3.16 for non-cogeneration systems (systems producing electricity but not steam for use in manufacturing processes).

The sample calculations make use of DOE cost data for site repowering using a combined cycle GT cogeneration system (requiring installation of a new steam turbine) rather than turbine repowering (making use of the existing turbine). Although use of this data set may result in overestimating costs for the steam turbine component of the system, this is compensated for because DOE's site repowering costs do not include, for instance, (a) demolition costs; (b) costs for upgrading the power transmission system; (c) cogeneration steam or utility tie-ins; or (d) a variety of indirect costs. For these reasons, the site repowering costs are probably better estimates of what a mill would encounter. However, it is important to note that the costs presented herein are now several years old. Recent power shortages have further heightened demand for gas turbine systems, suggesting that current costs could be higher than those presented in this manual.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3).

For the purposes of the sample calculations, assume that a mill is interested in replacing an older oil fired power boiler. The boiler capacity is 300,000 lb/hr steam and the average steam flow is 200,000 lb/hr. Assume that the mill has access to a sufficient source of natural gas on-site (see Section 3.3.1.10 for an example of how to compute the costs associated with installing a natural gas line to the mill).

Assume:

• Enthalpy of boiler steam	1440 Btu/lb
• Enthalpy of boiler feedwater	250 Btu/lb
• Cost of oil	$3/MBtu
• Cost of gas	$3/MBtu
• Boiler efficiency with oil	82%
• Combined cycle operation with no supplemental firing in the HRSG, back-pressure steam turbine	
• Power coefficient of 1 MW/MW (293 kWh of power generated for every 1 MBtu of steam produced)	
• Cost of purchased electricity	$0.035/kWh
• Price for selling generated power to the grid	$0.0175/kWh

- Total efficiency of gas turbine combined cycle system 75%

Fuel cost of current operation:

$$(200{,}000\ \text{lb/hr steam})\times(1440-250\text{Btu/lb})\times\left(\frac{1\text{MBtu}}{10^6\ \text{Btu}}\right)\times\left(\frac{1\ \text{Btu in fuel}}{0.82\ \text{Btu in steam}}\right)\times(\$3/\text{MBtu})$$

= $870.7/hr *or* $7.31 million/yr

Gas turbine system steam production:
(200,000 lb/hr stm) x (1440 - 250 Btu/lb)
= 238 MBtu/hr *or* 69.7 MJ/s stm

Gas turbine system cogenerated power:
(69.7 MJs) x (1 MW power/MW heat)
= 69.7 MW power

Gas turbine system fuel consumption:
((238 MBtu/hr stm) + (69.7 MW) x (3.412 MBtu/MWh)) x (1/0.75) = 634 MBtu gas/hr
634 MBtu/hr gas x $3/MBtu
= $1903/hr *or* $16.0 million/yr

Savings due to decreased need for purchased power (assuming that all power generated via the gas turbine system is used at the mill site):

$$(69.7\ \text{MW})\times\left(\frac{1000\ \text{kW}}{\text{MW}}\right)\times\left(\frac{8400\ \text{operating hr}}{\text{yr}}\right)\times(\$0.035/\text{kWh})$$

= $20.5 million/yr

If all power generated via the GT cogeneration system is not used at the mill and some percentage of generated power is to be sold to the energy grid, this must be considered when computing the savings due to decreased need for purchased power. It is uncertain what selling price a mill might receive for power exports. NCASI information indicates that the selling price could range from approximately 20% to greater than 75% of the mill's current purchase price for utility generated power. Indeed, the contractual arrangements for sale of excess power vary enormously from site to site.

O&M cost impact of changing from oil fired boiler to gas turbine system:
(-$8400/MW) x (69.7 MW)
= -$585,000/yr *or* $0.585 million/yr

Therefore, the total change in annual operating cost is:
-$7.31 million + $16.0 million - $20.5 million - $0.585 million
= -$12.4 million/yr

The CO_2 emission impacts of the change from an oil fired power boiler to a GT cogeneration system must consider reduced combustion of oil in the current boiler, increased combustion of natural gas in the GT, and reduced demand for purchased electrical power generated off-site. These impacts may be estimated as follows.

Reduced CO_2 from oil combustion in the boiler:

$$(200{,}000\ \text{lb/hr steam})\times(1440-250\ \text{Btu/lb})\times\left(\frac{1\ \text{MBtu}}{10^6\ \text{Btu}}\right)\times\left(\frac{211.8\ \text{lb}\ CO_2}{\text{MBtu steam from oil}}\right)$$

= 50,400 lb CO_2/hr

Emissions from combustion of natural gas in the gas turbine:

$$(634\ \text{MBtu gas/hr}) \times \left(\frac{117.0\ \text{lb}\ CO_2}{\text{MBtu gas fuel}}\right)$$

= 74,200 lb CO_2/hr

Emissions associated with reduced need to purchase power from the grid:

$$(69.7\ \text{MW}) \times \left(1\frac{\text{hr}}{\text{hr}}\right) \times \left(\frac{2009\ \text{lb}\ CO_2}{\text{MWh}}\right)$$

= 140,000 lb CO_2/hr

Net impact on CO_2 emissions:

$$-50{,}400\ \text{lb}\ CO_2/\text{hr} + 74{,}200\ \text{lb}\ CO_2/\text{hr} - 140{,}000\ \text{lb}\ CO_2/\text{hr}$$

= -116,200 lb CO_2/hr *or* -488,000 tons CO_2/yr

Capital costs associated with installing the 69.7 MW gas turbine combined cycle system can be estimated from DOE data for site repowering, as were fitted to the following equation (also see Figure 3.16).

Installed cost ($/kW):
1478.45 x (output in MW)$^{(-0.20128)}$
(1478.45 x (69.7)$^{(-0.20128)}$) x 69,700 kW
= $43.9 million

3.3.2 *Wood Supply*

3.3.2.1 *Replace pneumatic chip conveyors with belt conveyors*

Description

Two common methods of transportation of the chips within the mill site are:

- Pneumatic conveyors
- Mechanical (belt) conveyors

Belt conveyors normally require more space, as the inclination of a belt is typically limited to less than 20%. Pneumatic conveyors, on the other hand, can be designed to work in any kind of layout.

In addition to the chip conveyors, bark transportation to the power house could be by either pneumatic or belt conveyor.

Applicability and Limitations

Mechanical transportation is applicable in principle for all situations. The only limitation is mill layout. As mentioned above, the angle of the belt normally cannot exceed 20%, while pneumatic transportation is not sensitive to rate of rise.

Mechanical transportation of chips is better from the wood yield and pulp quality point of view. A pneumatic transportation system consumes more energy and generates fines, and the overall wood yield is reduced accordingly.

Impact on Energy and CO_2

A pneumatic conveyor consumes more electricity than a belt conveyor. Typical blower motor size for a 1000 T/d kraft mill would be 1000 to 1400 HP. The mill normally has at least three chip transportation systems:

- From reclaim to pile
- From pile to screening
- From screening to digesters.

Sample Calculations

The following sample calculation is based on reduced electrical power consumption corresponding to energy conservation/CO_2 reduction measures, and incorporates an emission factor and an assumed price for purchased electrical power. When estimating the impacts of implementing this technology option at a mill, current or projected prices for and emission factors corresponding to purchased electricity should be used (see Section 2.3). Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Most mills transport only part of the chips by pneumatic conveyors. Assume that the mill has a blower from the chip pile to screening. The capacity is about 300 m^3/hr of chips. The blower motor is 1000 hp or connected power is about 18.2 kWh/T of pulp. Mechanical conveyor motor size would be about 50 hp or about 1 kWh/T pulp. Replacement of the pneumatic conveyor would save about 17.2 kWh/T of pulp for only one segment of the transportation system.

Corresponding reduction in purchased power cost:
(17.2 kWh/ADT) x ($0.035/kWh)
= $0.6/ADT

Annual savings in purchased power (1000 ADT/d mill, replacing one conveyor system):
($0.6/ADT) x (1000 ADT/d) x (350 d/yr)
= $210,000/yr

Reduction in CO_2 emissions (replacing one pneumatic conveying system with a mechanical conveyor):
(0.0172 MWh/ADT) x (1000 ADT/d) x (350 d/yr) x (2009 lb CO_2/MWh) / (2000 lb/T)
= 6047 T CO_2/yr

3.3.2.2 *Use secondary heat instead of steam in debarking*

Description

In northern climates, the logs to the debarking operation are often frozen in the winter. In order to improve the debarking operation, the ice has to be melted. Steam thawing of the logs is one method to accomplish this; hot water sprinklers and hot ponds are others.

Even with hot water sprinklers, steam is typically used for hot water heating. Hot water may be in excess, especially in pulp mills. Any excess hot water can be used to replace steam.

Applicability and Limitations

This improvement measure is a valid energy conservation measure only in a northern climate where logs freeze in outdoor storages during the winter. In those conditions, use of hot water as the means for melting frozen logs is a valid and proven method.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Capital Costs

Capital costs of secondary heat utilization in the wood room normally consist of piping costs. Some heat recovery systems may have to be installed to recover heat from the streams that cannot be used as such in the wood room.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Typical steam consumption in winter (northern conditions) is 0.5 MBtu/ADT of pulp. As an annual average this represents a steam consumption of about 0.2 MBtu/ADT. If this steam can be replaced with free secondary heat, savings in purchased energy cost for a 1000 ADT/d (350,000 ADT/yr) mill will result:

(0.2 MBtu/ADT) x (350,000 ADT/yr) x ($2.2/MBtu)
= $154,000/yr

These savings assume that turbogenerator exhaust steam usage is reduced (net cost $2.2/MBtu, see Section 2).

Reduction in CO_2 emissions from oil burning (includes reduced steam to power generation):
((0.2 MBtu/ADT) + (0.2 MBtu/ADT) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(350,000 ADT/yr) x (211.8 lb CO_2/MBtu) / (2000 lb/T)
= 9198 T CO_2/yr

Increased CO_2 due to increased power generation in the utility power plant:
(0.2 MBtu/ADT) x (0.0669 MWh/MBtu) x (350,000 ADT/yr) x (2009 lb CO_2/MWh) / (2000 lb/T)
= 4704 T CO_2/yr

Net reduction of CO_2 emissions:
9198 - 4704
= 4494 T CO_2/yr

3.3.3 *Kraft Pulping*

3.3.3.1 *Rebuild mill hot water system to provide for separate production and distribution of warm (120°F) and hot (160°F) water*

Description

A mill's warm water system often allows for the preparation of water at one temperature. Processes that require higher temperatures are either heated with steam or the water can be heated with steam before being added to the process. Rebuilding the mill water system to provide for separate production and distribution of warm (120°F) and hot (160°F) water using secondary heat could eliminate the use of steam for water heating and reduce steam usage elsewhere.

Some processes, such as brownstock washing and bleaching, operate more efficiently when high temperature water is used. Increasing the water temperature also reduces steam demand. For example, using hot water on the bleach plant showers will decrease bleach plant steam usage. Likewise, raising the paper machine white water temperature will reduce steam demand on the paper machine. There are many sources of secondary heat that can be utilized for warm and hot water production, such as evaporator and concentrator condensates, surface condenser condensates, turpentine condensers, boiler blowdown, stripping column overheads, deaerator vents, turbine generator blow-off steam, vacuum pump seal water, black liquor coolers, bleach plant effluent, and cooling water.

The actual system used by each mill will vary based on the mill's configuration and the demand for warm and hot water.

Applicability and Limitations

In principle, separate warm and hot water systems are technically applicable to all mills, especially to bleached pulp mills. Blow heat recovery in particular can produce hot water at 160 to 180°F, which, from an energy optimization standpoint, should not be mixed with warm water at 120 to 140°F.

The availability and temperature levels of the secondary heat sources have to be confirmed for both winter and summer conditions before committing to any major rebuild of the warm and hot water systems.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Rebuilding the mill water system to produce warm and hot water using secondary heat will improve energy efficiency. Using secondary heat will eliminate the use of steam for water heating. Increasing water temperatures to certain processes will reduce steam usage in those processes. Actual energy savings will depend on how the project is implemented and the extent to which the mill already generates warm and hot water separately. The amount of savings from reduction in steam demand could be substantial. For major system changes, reductions of up to several MBtu/ton product are possible in older mills.

Impact on CO_2

Rebuilding the mill water system to produce warm and hot water separately using secondary heat will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. Steam savings from using secondary heat will reduce boiler fuel consumption, reducing CO_2 emissions.

Impact on Operating Costs

The operating costs of the mill will drop when the water system is rebuilt to produce warm and hot water separately. The cost savings will be due to reduction in steam demand and fuel savings. The total savings will depend on the mill, but for a complete system rebuild the savings can be substantial.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

• Bleached kraft mill production	1000 ADT/d
• Batch digesters	
• Bleaching sequence	DEOPDED
• Bleach plant hot water use	4600 gal/ADT
or	3200 gpm
• Hot water temperature from tank	140ºF
• Bleach plant shower water heaters	160ºF

This example mill has only one hot water system and hot water tank. Hot water from various secondary heat sources and at different temperatures are combined and collected in one centralized tank. Bleach plant shower waters are heated to 160°F with steam before application on the showers of two bleach plant washers.

Steam consumption for shower water heating:
(3200 gpm) x (8.34 lb/gal) x (60 min/hr) x (20°F) x (1 Btu/°F/lb) x (10^{-6} MBtu/Btu)
= 32 MBtu/hr

Hot water at 160°F can be produced in the blow heat recovery system without using live steam. This requires additional heating surfaces in order to be able to cascade the heat recovery system, a new hot water tank, and a hot water distribution system. The savings are 32 MBtu/hr of low pressure steam.

Corresponding cost savings:
(32 MBtu/hr) x ($2.2/MBtu)
= $70.4/hr *or* $591,360/yr

CO_2 reduction is a combination of reduced oil use and increased demand for purchased power, since the steam saved is assumed to reduce the turbogenerator load.

Assume:

• Change in back-pressure power generation due to reduced extraction	66.9 kWh/MBtu
• Heat (steam) consumption of back-pressure power	3.6 MBtu/MWh

Total reduction in heat generation from oil:
(32 MBtu/hr) + (32 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)
= 39.7 MBtu/hr

Reduction in CO_2 from oil:
(39.7 MBtu/hr) x (211.8 lb CO_2/MBtu)
= 8408 lb CO_2/hr *or* 35,314 T/yr

Increased purchased power:
(0.0669 MWh/MBtu) x (32 MBtu/hr)
= 2.14 MWh/hr

Increased CO_2 due to increased utility power generation:
(2.14 MWh/hr) x (2009 lb CO_2/MWh)
= 4299 lb CO_2/hr *or* 18,056 T CO_2/yr

Net reduction in CO_2 emissions:
8408 - 4299
= 4109 lb CO_2/hr *or* 17,258 T CO_2/yr

3.3.3.2 *Install blow heat (batch digesters) or flash heat (continuous digester) evaporators*

Description

In the kraft cooking process, steam is produced when hot pulp and cooking liquor is reduced to atmospheric pressure. In batch digesters this steam is stored as hot water in the accumulator tank. In continuous digesters it is released to flash tanks. The heat energy in this steam can be used throughout the mill. One use is to evaporate water out of weak black liquor. For a batch digester the system is called a blow heat evaporator, and for a continuous digester it is called a flash heat evaporator.

With batch digesters the batch cooking process is turned into a continuous heat recovery process with the blow heat accumulator. Hot water stored in the accumulator can be converted to steam by flashing to a lower pressure tank. This flash steam is then used as feed vapor for a multiple effect evaporator. A blow heat evaporator generally has fewer effects, two to four, than a conventional multiple effect evaporator because the feed steam is at a much lower pressure, a slight vacuum. Condensates from the flash tank along with vapor from the evaporator effect can be used to supply vapor to subsequent effects.

For continuous digesters the extracted black liquor flows to a tank where it is flashed. Flash vapor can be used in other processes, such as chip pre-steaming or for black liquor evaporation. In each subsequent stage of a flash heat evaporator vapor from the flashing of weak black liquor is used to provide heat for evaporation. The general concepts are shown in Figure 3.17.

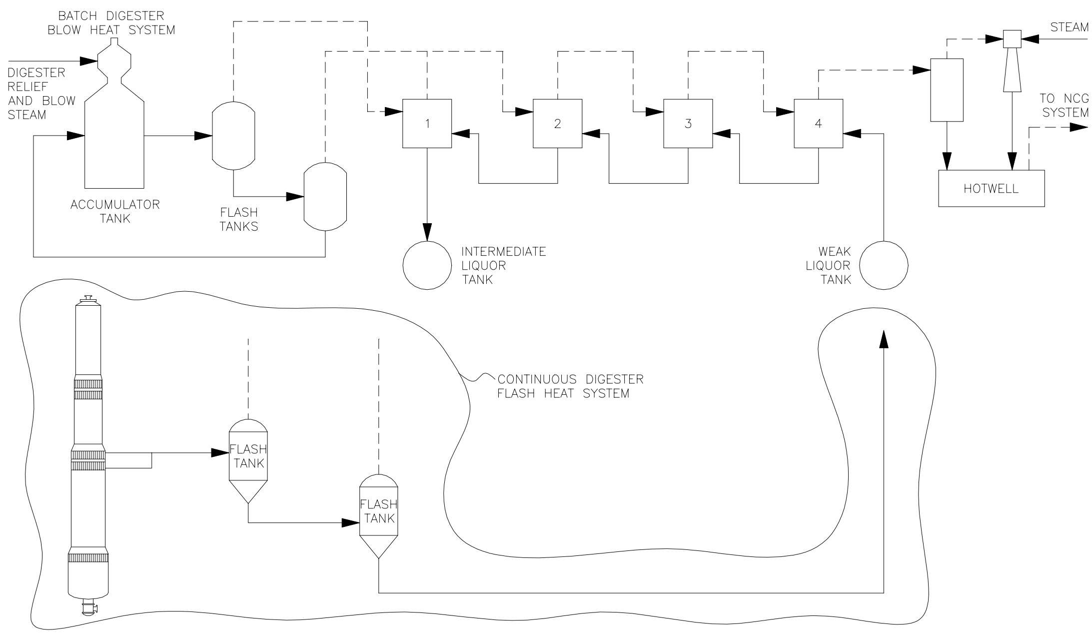

Figure 3.17. Blow Heat (Batch Digesters) or Flash Heat (Continuous Digesters) Evaporators

Applicability and Limitations

A pre-evaporator may not be economically feasible unless additional evaporation capacity is needed. An additional benefit of pre-evaporation may be the possibility of segregating methanol into a reasonably small stream when properly designing the pre-evaporation system.

Hot water demand is typically high, especially in an older bleached kraft mill. Excess blow heat may already be used to heat water for the bleach plant (especially in a mill with continuous digesters), and therefore may not be available for blow heat evaporation. Unbleached kraft mills may thus be more likely candidates for installation of the pre-evaporator operated with digester blow or flash heat.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using blow heat or flash heat evaporation will reduce energy consumption per ton of product. Recovering this heat for black liquor evaporation will reduce the steam that must be generated in the boilers for evaporation.

Impact on CO_2

Installing blow heat or flash heat evaporators will reduce total (considering both direct plus indirect) CO_2 produced per ton of product. This reduction will occur through steam savings and the associated decrease in fuel consumption. The potential reduction in CO_2 emissions is high due to the large steam savings that are possible. CO_2 reduction will depend on the system installed.

Impact on Operating Costs

The use of blow heat or flash heat will reduce operating costs. The savings will occur due to the reduction in steam usage in the evaporation process. Savings will depend on marginal fuel costs.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

- Production of bleached kraft 1000 ADT/d
- Batch digesters
- Blow steam available for evaporation 2 klb/ADT

A two- or three-effect evaporation train could be installed. If a two stage evaporation system is installed, the steam economy is 1.6 to 1.8 lb evaporation/lb of blow steam. Steam economy is high for a two-effect plant because the pre-evaporated liquor leaves the system at a fairly low temperature (about 160°F).

Evaporation in the pre-evaporator:

$$(1.6\ \text{klb}\ H_2O/\text{klb stm})\ \text{x}\ (2\ \text{klb stm}/\text{ADT})\ \text{x}\ (1000\ \text{ADT/d})\ \text{x} \left(\frac{1\ \text{d}}{24\ \text{hr}}\right)$$

= 133 klb H_2O/hr

Assume that the steam economy is 4.2 for the multiple effect evaporator set. If evaporation in the multiple effect set is reduced by the amount of evaporation done in the pre-evaporator, the steam savings are:
(133 klb H_2O/hr) / (4.2 klb H_2O/klb stm)
= 31.7 klb stm/hr

Heating liquor by 15°F before it enters the multiple effect evaporator is assumed to be necessary, and will consume approximately 12 klb stm/hr.

Net savings:
31.7 - 12
= 19.7 klb stm/hr *or* about 20 MBtu/hr

Fuel cost savings:
(20 MBtu/hr) x ($2.2/MBtu)
= $44/hr *or* $369,600/yr

Savings could be higher if liquor reheating is not necessary from a capacity or operational point of view.

The CO_2 impact is a combination of reduced oil use and increased purchased power consumption.

Total reduction in heat generation from oil (including heat to process and back-pressure power):
(20 MBtu/hr) + (20 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)
= 24.8 MBtu/hr

Reduction in CO_2 from oil burning:
(24.8 MBtu/hr) x (211.8 lb CO_2/MBtu)
= 5253 lb CO_2/hr *or* 22,063 T CO_2/yr

Increase in purchased power:
(0.0669 MWh/MBtu) x (20 MBtu/hr)
= 1.34 MWh/hr

Increase in CO_2 due to increased utility power generation:
(1.34 MWh/hr) x (2009 lb CO_2/MWh)
= 2692 lb CO_2/hr *or* 11,306 T CO_2/yr

Net reduction in CO_2 emissions:
5253 - 2692
= 2561 lb CO_2/hr *or* 10,756 T/yr

3.3.3.3 *Replace conventional batch digesters with cold blow systems*

Description

Kraft batch digesters consume large amounts of energy because the digester contents (chips, cooking liquor, air, etc.) must be heated to high temperature and pressure. This is usually done either directly or indirectly with steam. When the contents of the digester are released, this energy is transferred to the blow heat recovery system as steam. The process is repeated for each cook. This creates a large swing in the steam demand of the digester. By converting batch digesters to a cold blow system, heat and steam demands of the digester can be reduced. At the beginning of the cook in a cold blow system, the digester is filled with warm, then hot, liquor (Figure 3.18). At the end of the cook, the spent pulping liquor is displaced from the digester contents using brownstock washer filtrate. Thus, heat is recovered from spent liquor for heating subsequent cooks and less steam is required for heating the digester contents. Washing will also improve because the digester acts as an additional washing stage. Brownstock washing can be optimized by keeping the dilution factor fixed and reducing washing losses, or by reducing the dilution factor and keeping washing losses fixed. By replacing conventional digesters with a cold blow system, blow steam will be eliminated.

Applicability and Limitations

Cold blow techniques are technically applicable for all kraft pulping, both softwood and hardwood. The only negative feature is the cost of complete replacement of the existing digesters. Replacement normally cannot be justified unless a production increase or the condition of the present equipment motivates complete replacement of existing digesters.

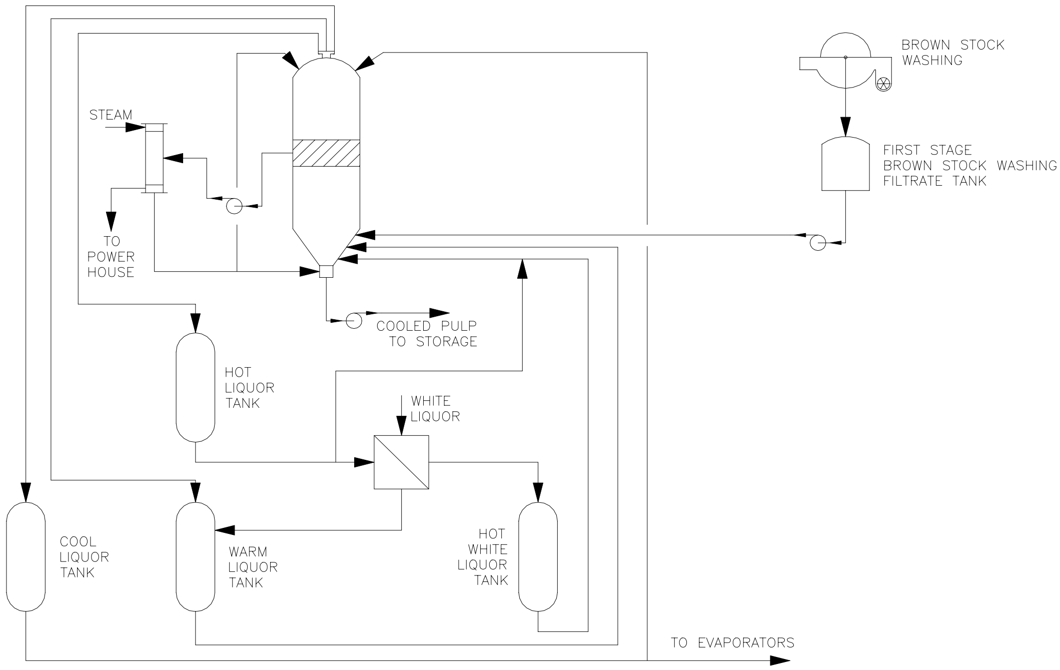

Figure 3.18. Cold Blow Techniques for Batch Digesters

The heat and power consumption of the digester system is determined through detailed balance calculations. In general, cold blow systems result in lower steam and heat consumption because part of the heat in the black liquor is recovered for use in the next cooking cycle. This is usually accomplished by pumping the black liquor to various pressurized accumulator tanks that contain liquor at different temperature levels. This recovered black liquor can be used for preheating and impregnating incoming chips or for heating white liquor or process water. This method of cooking requires additional pumps to transfer the liquor between various tanks and pressure accumulators. Thus, power consumption will increase.

Lower digester kappa levels can be achievable with cold blow techniques. Replacement of the existing batch digester system with a cold blow system has, on some occasions, been motivated by the possibility of extended delignification and, as a result, reduction in the use of bleaching chemicals.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Replacing batch digesters with a cold blow system will reduce digester energy demand. Lowering digester steam demand will lower the fuel consumption of the boilers and possibly reduce steam demand elsewhere, such as the deaerators. If a blow heat system is being used for the evaporator, etc., live steam will be required in those sources when blow steam is eliminated. Additional electrical power will be used by new pumps, but this will be small compared to the steam savings.

Impact on CO_2

Using a cold blow system for pulp cooking will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. A cold blow system reduces digester steam demand and boiler fuel consumption. This will lower CO_2 emissions.

Impact on Operating Costs

Reduced steam consumption in cooking will reduce operating costs. The reduction will depend on the number and size of the digesters, but savings will be substantial.

Capital Costs

A cold blow system will be a major capital cost. Replacement of existing digesters is often not feasible because of high cost. Most applications have been implemented in connection with major production expansions or modernization projects.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

- Existing batch digesters are replaced with a cold blow system
- Pulp production (bleached softwood) — 1000 ADT/d
- Heat consumption, current digesters (see, e.g., TAPPI 1989) — 4.2 MBtu/ADT
- Heat consumption, cold blow system (see, e.g., Gullichsen and Fogelholm 1999) — 2.0 MBtu/ADT

The digesters are assumed to use 150 psig steam; net cost after back-pressure power credit is \$2.5/MBtu (see Section 2).

Savings in steam:
(1000 ADT/d) x ((4.2 - 2.0) MBtu/ADT) / (24 hr/d)
= 91.7 MBtu/hr

Corresponding cost savings:
(\$2.6/MBtu) x (91.7 MBtu/hr)
= \$238/hr *or* \$2.0 million/yr

For each MBtu of process use of extraction steam through turbogenerators, 51.3 kWh of back-pressure power is generated (see Section 2). The heat consumption of back-pressure power generation is estimated to be 3.6 MBtu/MWh (theoretical is 3.413 MBtu/MWh plus about 5% losses).

Net change in steam generation (steam to digesters plus steam to back-pressure power):
(91.7 MBtu/hr) + (91.7 MBtu/hr) x (0.0513 MWh/MBtu) x (3.6 MBtu/MWh)
= 108.6 MBtu/hr

Reduction in CO_2 emissions corresponding to heat use reduction:
(108.6 MBtu/hr) x (211.8 lb CO_2/MBtu)
= 23,000 lb CO_2/hr *or* 96,600 T CO_2/yr

Purchased power is assumed to replace the lost back-pressure power and will also provide for increased power consumption in the cooking process. The increase in power consumption is estimated at about 20 kWh/ADT or 833 kWh/hr. This estimate is very preliminary and has to be verified based on the actual pumps added, as pumping requirements vary depending on the existing installation and selected design.

Total purchased power increase:
(0.83 MWh/hr) + (91.7 MBtu/hr) x (0.0513 MWh/MBtu)
= 5.53 MWh/hr

Increase in CO_2 emissions due to increased utility power generation:
(5.53 MWh/hr) x (2009 lb CO_2/MWh)
= 11,110 lb CO_2/hr *or* 46,662 T CO_2/yr

Net reduction in CO_2 emissions:
23,000 - 11,110
= 11,890 lb CO_2/hr *or* 49,938 T CO_2/yr

3.3.3.4 *Use flash heat in a continuous digester to preheat chips*

Description

In a continuous digester the spent pulping liquor is withdrawn at the extraction screens and then flashed to atmospheric pressure in two or three stages. The flash vapor from the first flash stage is normally used for chip heating in the steaming vessel. The vapors from the second flash stage can be used to replace live steam in the chip bin. If the chips are being pre-steamed with live steam, the vent gases from the chip bin will have to be collected and sent to the non-condensible gases (NCG) or turpentine system in connection with flash steam use in the chip bin. Figure 3.19 shows the general concept.

Applicability and Limitations

Use of flash steam in the chip bin has been proven at the mill scale at a number of North American facilities. The limitation and regulatory requirement is that the vent from the chip bin has to be collected and treated if flash steam is used for preheating chips. The Cluster Rule specifically identifies the chip bin vent as the source that has to be collected and treated unless live steam is used in the chip bin. For old, partly open chip bins this may mean that the replacement of the bin has to be included in the cost of implementation.

Some mills have experienced operational problems (i.e., poor chip column movement) when using 100% flash steam in the chip bin. In this case, it may be necessary to use some combination of flash and fresh steam in the chip bin.

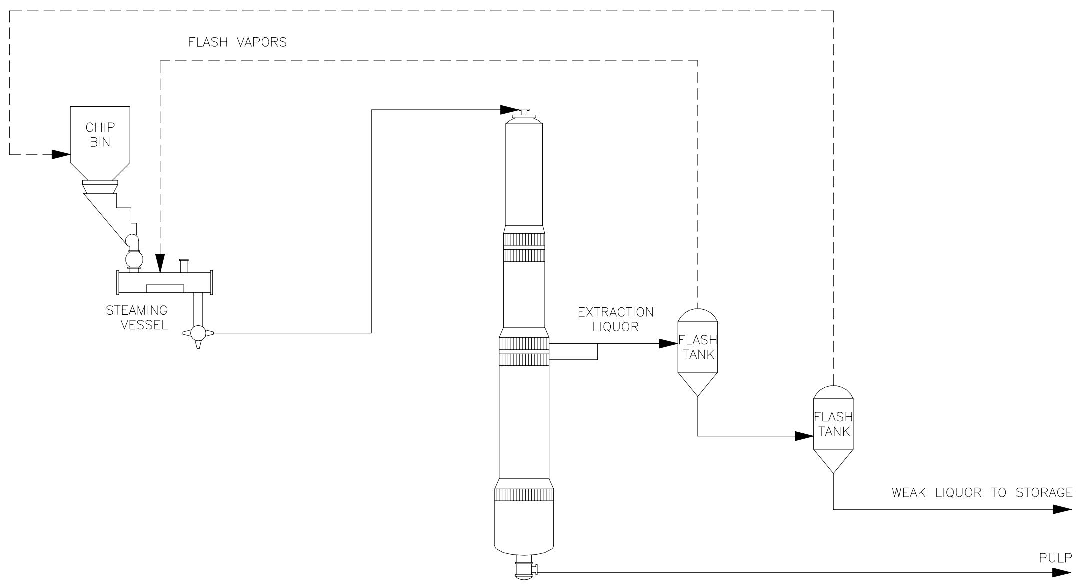

Figure 3.19. Use of Flash Heat in a Continuous Digester to Preheat Chips

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using flash heat to preheat chips in a continuous digester will reduce energy consumption by eliminating live steam usage for mills already pre-steaming chips. For mills not pre-steaming chips, preheating the chips with flash heat will also reduce steam usage in digester liquor heaters.

Impact on CO_2

The energy savings from using flash steam to pre-steam chips will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. The reduction will result from steam savings.

Impact on Operating Costs

The reduction in live steam usage from using flash heat will reduce operating costs through fuel savings. Some additional electric power may be required when a new air lock for chip feeding or fans for the NCG system are added.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a “CO_2 penalty” associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Estimated or assumed data:

• Chips are preheated from 70ºF to 150ºF	
• Chip moisture content	50%
• Flash vapor enthalpy (at 0 psig)	1150 Btu/lb
• Steam enthalpy (50 psig, 350ºF)	1200 Btu/lb
• Production rate	1000 ADT/d
• Chips to digester	2.2 BDT/ADT
• Specific heat of wood	0.35 Btu/lb/°F
• Specific heat of water	1.0 Btu/lb/°F
• Cost of low pressure steam	\$2.2/MBtu

Heat consumption in chip heating:

$$\frac{2.2\ \text{BDT}}{\text{ADT}} \times \frac{1000\ \text{ADT}}{\text{d}} \times \frac{2000\ \text{lb d.s.}}{\text{BDT}} \times \left(\frac{1+0.35\text{Btu}}{\text{lb}\ {}^{\text{o}}\text{F}}\right) \times \frac{1\ \text{d}}{24\ \text{hr}} \times \left(150 - 70\ {}^{\text{o}}\text{F}\right) \times \frac{1\ \text{MBtu}}{10^{6}\ \text{Btu}}$$

= 19.8 MBtu/hr

Corresponding cost savings:
(\$2.2/MBtu) x (19.8 MBtu/hr)
= \$43.6/hr *or* \$366,240/yr

CO_2 reduction:

The total reduction in boiler steam generation is the process steam reduction plus reduced heat consumption in back-pressure power generation. The cost of low pressure steam takes into account this reduction. For CO_2 calculations, this heat generation (reduction) is taken into account separately using back-pressure power yield of 66.9 kWh/MBtu of process heat use.

On-site:

Decrease in boiler heat generation (process heat plus heat to back-pressure power):
(19.8 MBtu/hr) + (19.8 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)
= 24.6 MBtu/hr

Corresponding CO_2 reduction (from oil burning):
(24.6 MBtu/yr) x (211.8 lb CO_2/MBtu)
= 5210 lb/hr *or* 21,882 T CO_2/yr

Off-site:

Reduction in back-pressure power generation:
(19.8 MBtu/hr) x (0.0669 MWh/MBtu)
= 1.32 MWh/hr

Increase in off-site CO_2 emissions:
(1.32 MWh/hr) x (2009 lb CO_2/MWh)
= 2652 lb CO_2/hr *or* 11,133 T CO_2/yr

Net reduction:
5210 - 2652
= 2558 lb CO_2/hr *or* 10,744 T CO_2/yr

3.3.3.5 *Use evaporator condensates on decker showers*

Description

Deckers are used by pulp mills for the final washing and thickening of pulp before high density storage. Hot water is used in showers on most deckers for mat washing and wire cleaning. The filtrate may then flow countercurrently to the previous stage of washing. The use of fresh hot water in decker showers can be reduced or eliminated by using secondary heat in the form of hot water generated in other processes. This will reduce hot water production.

One source of secondary heat is evaporator condensates (Figure 3.20). In mills with pre-evaporators or condensate segregation, the combined condensate can be used provided the concentration of volatile compounds (i.e., methanol and TRS) will not cause a problem. Mills with stripping of foul condensates can use the stripped condensates as well as combined condensates from evaporator bodies.

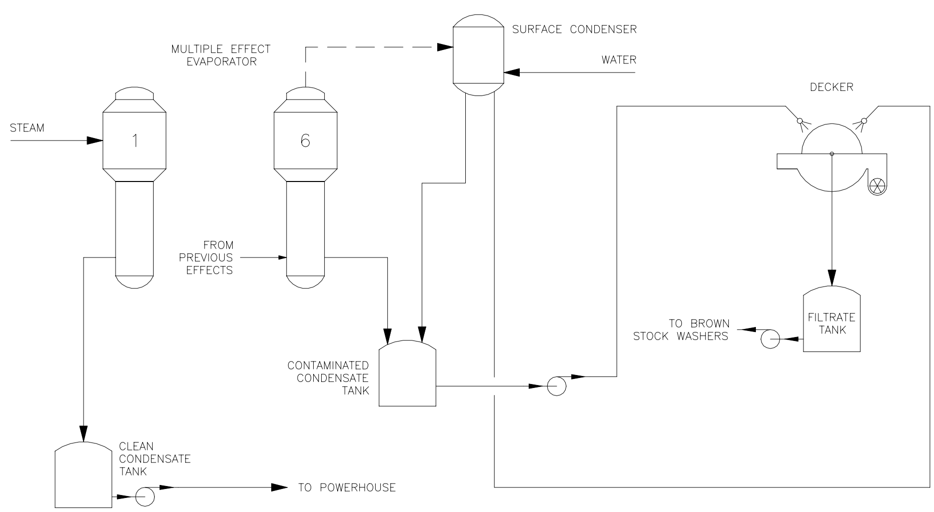

Figure 3.20. Use of Evaporator Condensates on Decker Showers

Applicability and Limitations

Evaporator condensates normally contain some sulfur compounds. This may have a negative impact on ambient conditions in the pulp mill area unless the decker hood is enclosed and vented. The MACT portion of the 1998 Cluster Rule requires that kraft pulp mills collect and treat (by stripping or biological treatment via the "hard piping" option) all digester and evaporator foul condensates unless they are reused in an enclosed system where the vent gases are collected and incinerated. Clean or stripped condensates can be reused without additional controls. In 2006, regulations will require that all brownstock washer vents be collected and controlled if the shower water used on the decker contains more than 400 ppm methanol. For more information on the MACT requirements, see Pinkerton 1998.

The other negative effect for bleached kraft mills is COD in the condensates. This COD will, at least partially, follow the pulp to the bleach plant. The COD with the condensates will slightly increase the consumption of bleaching chemicals. In order to avoid excessive COD contamination of the pulp to bleaching, the conductivity of the condensates before entering the decker showers should be monitored. Condensates are normally sewered at a preset conductivity level, and hot clean water is used in the decker showers until the problem with high COD of the condensates has been solved.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Reusing evaporator condensates on decker showers will reduce energy consumption per ton of product. Replacing hot water with evaporator condensates will reduce mill hot water flow, which will reduce steam heating demand and lower fuel consumption.

Impact on CO_2

Replacing hot water in decker showers with evaporator condensates will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. The drop in CO_2 will occur from fuel savings as a result of hot water steam heating reduction.

Impact on Operating Costs

The use of evaporator condensates in decker showers may reduce operating costs. Savings will come from reduced steam load and the associated reduction in fuel usage. The savings will depend on marginal fuel costs.

Capital Costs

Capital costs for using evaporator condensates in decker showers will depend on the pumps, piping, and tankage required. The hot water system may still be needed as a backup when evaporators are down.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume that evaporator condensates will replace 80% of the hot water flow going to the decker showers:

- Decker shower hot water flow — 1900 gpm
- Hot water temperature — 150°F, 118 Btu/lb
- Mill hot water temperature before steam heating — 140°F, 108 Btu/lb

Heat from steam used for heating decker shower water:
(118 - 108 Btu/lb) x (1900 gpm) x (8.34 lb/gal) x (60 min/hr) x (10^{-6} MBtu/Btu)
= 9.5 MBtu/hr

Cost savings (assume 80% of heat is saved by using hot evaporator condensates):

- Cost of 50 psig steam $2.2/MBtu
- Operating hours 8400 hr/yr

0.8 x (9.5 MBtu/hr) x (8400 hr/yr) x ($2.2/MBtu)
= $140,448/yr

CO_2 reduction:

On-site:

Reduction due to reduced steam generation in the boiler (heat to process plus heat to back-pressure power):
0.8 x ((9.5 MBtu/hr) + (9.5 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (211.8 lb CO_2/MBtu)
= 1997 lb CO_2/hr

Off-site:

Increase due to increased power generation in the utility power plant:
0.8 x (9.5 MBtu/hr) x (0.0669 MWh/MBtu) x (2009 lb CO_2/MWh)
= 1021 lb CO_2/hr

Net CO_2 reduction:
1997 - 1021
= 976 lb CO_2/hr *or* 4099 T CO_2/yr

3.3.3.6 *Use two pressure level steaming of batch digesters to maximize back-pressure power generation*

Description

In kraft batch digesters, high pressure steam is used either directly or indirectly to heat the digester contents in a heat exchanger. Conversion to two pressure level steaming in batch digesters will maximize back-pressure power generation. In two pressure level steaming, low pressure steam is used to heat the digester contents and high pressure steam is used for final temperature control. Heating digesters in this manner allows more low pressure steam to be taken through the turbine to generate electrical power. Two pressure level steaming can be accomplished either directly or indirectly. Figure 3.21 shows the general concept for two pressure level steaming of batch digesters.

Applicability and Limitations

The provisions for two level steaming are:

- Batch digesters currently steamed with extraction steam only
- Enough turbogenerator exhaust capacity that any low pressure steam to the digesters will be taken from the turbogenerator exhaust

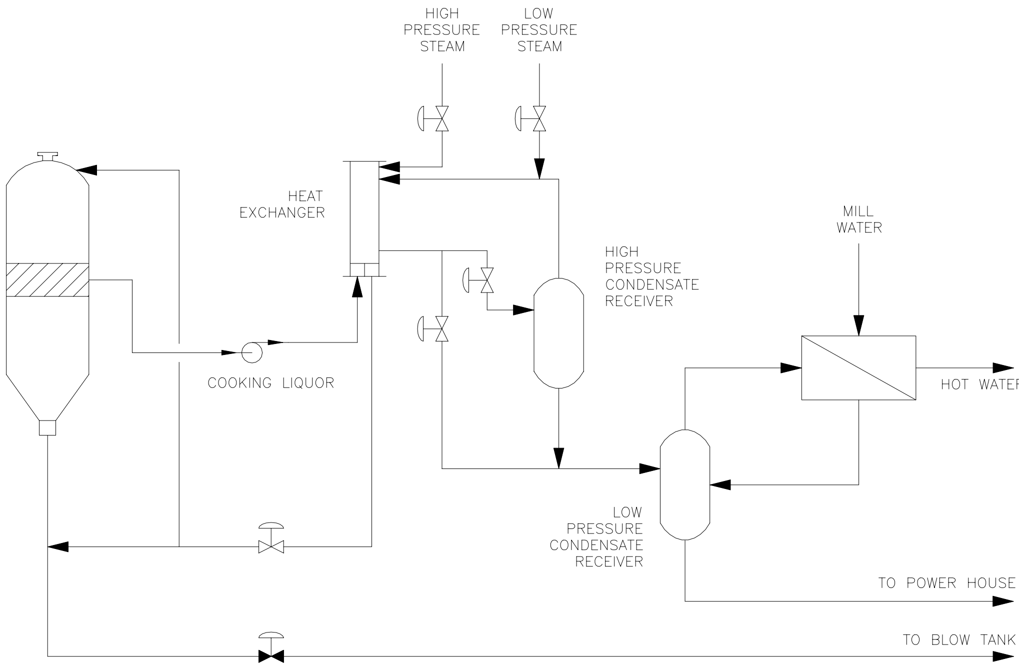

Figure 3.21. Two Pressure Level Steaming of Batch Digesters

If these two conditions can be met, two level steaming is technically possible. The technology has been applied in several US mills, and is a standard practice in Nordic batch digester mills.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using two pressure level steaming of the batch digester will increase power generation. The increase in back-pressure power generation will increase boiler heat demand.

Impact on CO_2

Increased on-site power generation will decrease purchased power demands, with concurrent reductions in off-site CO_2 emissions. The increase in back-pressure power generation will increase boiler heat demand, so fuel consumption will increase slightly. Therefore total emissions will decrease, although on-site emissions will increase slightly due to increased fuel consumption.

Impact on Operating Costs

Using two pressure level steaming of batch digesters will reduce operating costs. The increase in back-pressure power generation will reduce purchased power. Some additional fuel will be required due to the increase in boiler heat demand. However, this will be offset by the electrical power savings.

Capital Costs

Capital costs for this project will include low pressure steam piping, valves, and a temperature control system. If indirect heating is going to be used, additional heat exchanger capacity and steam condensate receivers may be required.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3).

Assume that all process steam (high and low pressure) is taken through the turbine and not a pressure reducing valve.

Assume the following back-pressure power yields (see Section 2 for details):

- Extraction steam 0.0513 MWh/MBtu
- Exhaust steam 0.0669 MWh/MBtu

Estimated heat consumption in the digesters is 4.2 MBtu/ADT (see, e.g., TAPPI 1989). Direct steaming of the digesters is assumed.

For one pressure level steaming:

Back-pressure power generation with TG extraction steam:
(4.2 MBtu/ADT) x (0.0513 MWh/MBtu) x (1000 ADT/d) / (24 hr/d)
= 8.98 MWh/hr

Total heat from boiler for digesters and matching back-pressure power:
(4.2 MBtu/ADT) + (4.2 MBtu/ADT) x (0.0513 MWh/MBtu) x (3.6 MBtu/MWh)
= 4.98 MBtu/ADT *or* 207 MBtu/hr

For two pressure level steaming:

Assume the following split between 150 psig and 50 psig steam:

- 150 psig 2.2 MBtu/ADT
- 50 psig 2.0 MBtu/ADT

Back-pressure power generation:
(2.2 MBtu/ADT) x (0.0513 MWh/MBtu) + (2.0 MBtu/ADT) x (0.0669 MWh/MBtu)
= 0.25 MWh/ADT *or* 10.3 MWh/hr

Total heat from boiler for digesters and back-pressure power generation:
(4.2 MBtu/ADT) + (0.25 MWh/ADT) x (3.6 MBtu/MWh)
= 5.1MBtu/ADT *or* 212.5 MBtu/hr

Cost savings:

Reduction in purchased power:
((10.3 - 8.98) MWh/hr) x ($35/MWh)
= $46.2/hr *or* $388,080/yr

Increase in boiler fuel (oil at $3/MBtu, boiler efficiency 82% assumed):
($3/MBtu) x ((5.1 - 4.98) MBtu/ADT) x (1000 ADT/d) / (24 hr/d) / 0.82
= $18.3/hr *or* $153,720/yr

Net savings:
$388,080 - $153,720
= $234,360/yr

CO_2 emissions:

Increase due to increased oil use:
((5.1 - 4.98)MBtu/ADT) x (211.8 lb CO_2/MBtu) x (1000 ADT/d) / (24 hr/d)
= 1059 lb CO_2/hr *or* 4448 T CO_2/yr

Reduction due to reduced utility power generation:
((10.1 - 8.98) MWh/hr) x (2009 lb CO_2/MWh)
= 2250 lb CO_2/hr *or* 9450 T CO_2/yr

Net reduction of CO_2 emissions:
2250 - 1059
= 1191 lb CO_2/hr *or* 5002 T CO_2/yr

3.3.3.7 *Optimize the dilution factor control*

Description

Brownstock washing removes organic solids and spent cooking chemicals from pulp. Efficient brownstock washing maximizes chemical recovery while minimizing dilution of black liquor. In the past, washer dilution factor control may have been by manual control or no control at all. Optimizing the dilution factor control will stabilize the black liquor solids concentration and reduce evaporation demand. The dilution factor can be optimized by controlling shower water flow on the last washing stage to an optimum level that can be determined by taking into account the cost of steam, the cost of bleaching chemicals, the impact on effluent quality, and any potential operational considerations.

Applicability and Limitations

Many mills are optimizing control of the dilution factor. The evaporation plant is often the bottleneck, in which case the best optimization may be to add as much water on the washers as the evaporation plant can handle. Even if the evaporation capacity exists the savings may not be accomplished if the capacity is better used for other purposes, such as spill reclamation. This would reduce the BOD/COD load to the effluent treatment system, but might not yield the energy savings and reduction of CO_2 emissions outlined herein.

Determination of optimum shower flows on brownstock washers involves calculation of the cost of bleaching chemicals, evaporator steam, recovery boiler steam, and makeup chemicals as a function of washer dilution factor. This can be done best by modeling washer operation and by simulating process performance and the costs involved. For more information on washer optimization, see Freyaldenhoven and McSweeney (1979); Nierman (1986); Sande et al. (1988); and Wigsten (1988).

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Optimizing the brownstock washer dilution factor control will probably reduce energy consumption. Automatic dilution factor control will lower the average amount of water that must be evaporated from weak black liquor. This will reduce steam consumption in the evaporators.

Impact on CO_2

Installing automatic dilution factor control on the brownstock washer will reduce total (considering both direct plus indirect) CO_2 emissions. The decrease in black liquor dilution will off-load the evaporators, reducing steam demand for evaporation. This drop in steam demand will result in fuel savings, lowering CO_2 emissions.

Impact on Operating Costs

Optimizing the dilution factor control will reduce operating costs. Savings will come from reductions in steam demand in the evaporators and/or savings in bleaching chemicals. Savings will depend on the reduction in black liquor dilution, increased dry solids recovery, and reduced bleaching chemicals.

Capital Costs

Capital costs will include control valves and percent solids detection meters, such as conductivity meters. An on-line optimization system is best implemented on a DCS system. Some computing capacity is required for calculation of the optimum dilution factor.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

In one example of this technology at a 1000 ATPD mill, it was concluded through simulation that the average dilution factor could be reduced by 0.5 T/ADT of pulp without adversely affecting washing losses. In principle, all water that is added on the washer showers has to be evaporated.

A rule of thumb for approximating heat consumption in a multiple effect evaporator set is:

$$\frac{1200}{n} \text{ Btu/lb } H_2O \text{ evaporated}$$

where: n = number of evaporation effects

Heat consumption in evaporator (assume a five-effect evaporator):
1200 / 5
= 240 Btu/lb H_2O evaporated

Reduction in heat consumption (assume heat consumption of 240 Btu/lb H_2O evaporated in the evaporation plant) (dilution factor reduction = 0.5 T/ADT, or 1000 lb H_2O/ADT):
(1000 lb/ADT) x (240 Btu/lb) x (10^{-6} MBtu/Btu)
= 0.24 MBtu/ADT *or* 10.0 MBtu/hr

Savings:
(10.0 MBtu/hr) x ($2.2/MBtu)
= $22/hr *or* $184,800/yr

Reduction in total heat generation (process plus back-pressure power):
(10.0 MBtu/hr) + (10.0 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)
= 12.4 MBtu/hr

Reduction in CO_2 emissions:
(12.4 MBtu/hr) x (211.8 lb CO_2 /MBtu)
= 2626 lb CO_2 /hr *or* 11,029 T CO_2/yr

Increased purchased power:
(10.0 MBtu/hr) x (0.0669 MWh/MBtu)
= 0.67 MWh/hr

Increased CO_2 emissions from utility power plant:
(0.67 MWh/hr) x (2009 lb CO_2/MWh)
= 1346 lb CO_2/hr *or* 5653 T CO_2/yr

Net reduction in CO_2 emissions:
2626 - 1346
= 1280 lb CO_2/hr *or* 5376 T CO_2/yr

3.3.4 *Kraft Bleaching*

3.3.4.1 *Optimize the filtrate recycling concept for optimum chemical and energy use*

Description

In many mills, hot water is used for washing and wire cleaning in bleach plant washers. Overall mill water and hot water usage can be reduced by using seal tank filtrate for wire cleaning. The filtrate recycling concept must be optimized for chemical and energy consumption.

In many cases, filtrate can be recycled countercurrently to the previous bleach plant washer (Figure 3.22). Filters will be needed to remove fiber from the seal tank water to prevent shower nozzle plugging. Booster pumps will be needed to raise the water pressure to provide effective wire cleaning.

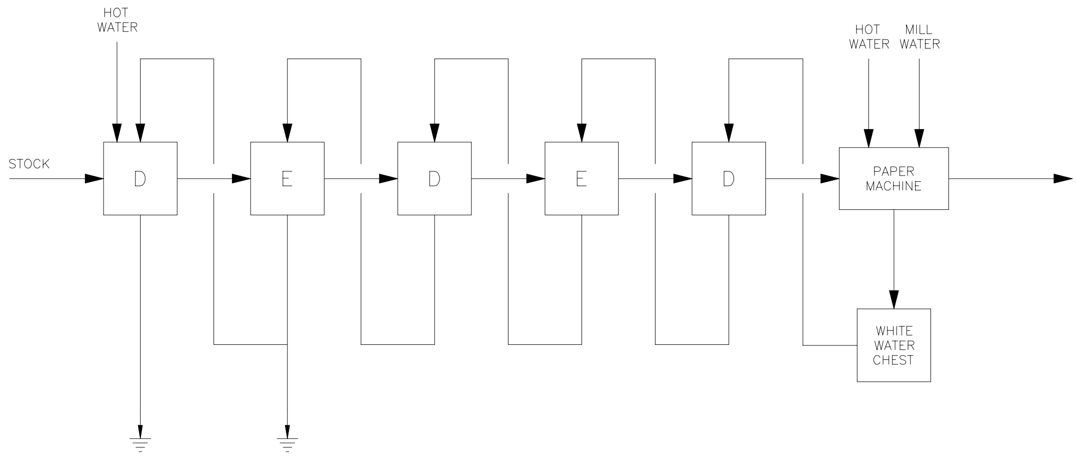

Figure 3.22. An Example of a Bleach Plant Filtrate Recycling Concept

Applicability and Limitations

Many bleach plants are going to be modified to an ECF sequence in order to meet Cluster Rule requirements. Optimization of the filtrate recycling concept may be performed as part of the conversion. The recycling concept and optimum degree of closure of bleach plant water systems will vary from one mill to another, and similarly, the savings and impact on CO_2 emissions will also vary. Closing the filtrate system too tightly may affect bleaching chemical consumption and thus have an adverse effect on CO_2 emissions from bleaching chemical manufacturing. There may also be corrosion concerns or potential difficulties with scale development or pitch deposition if the bleach plant is closed too tightly. For an overview, see Histed, McCubbin, and Gleadow (1996).

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Optimizing filtrate recycling will reduce steam demand in the bleach plant due to reduction in hot water steam heating. Additional booster pumps and fiber filters will generate a small increase in electrical power consumption. Any increase in chemical consumption may result in a small increase in the energy required.

Impact on CO_2

Increased use of filtrate recycling will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. Increased recycling of filtrates will reduce bleach plant hot water usage and steam demand. This will reduce CO_2 emissions through fuel savings.

Impact on Operating Costs

The optimization of filtrate recycling will reduce energy costs through fuel savings from reduced steam demand. Electrical power costs will increase slightly due to the use of additional motors for booster pumps and fiber filters. Chemical costs will increase due to increased chemical usage. This increase should be balanced against energy savings to determine the optimum amount of filtrate recycle.

Capital Costs

Capital costs for optimizing filtrate recycling will include any piping changes, pumps, and filters needed to upgrade the current system. In order to reach very low water use levels, the seal tanks and washer material may also need to be upgraded.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

In an example mill with production of 1000 ADT/d the simulated low pressure steam consumption was reduced by 0.4 MBtu/ADT through optimization of the filtrate recycling concept. Potential increases in chemical costs or power for additional pumping are not considered in this example.

Implied cost savings:
(0.4 MBtu/ADT) x ($2.2/MBtu)
= $0.88/ADT *or* $308,000/yr

Total heat generation (process plus heat for back-pressure power) reduced by:
((0.4 MBtu/ADT) + (0.4 MBtu/ADT) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(1000 ADT/d) / (24 hr/d)
= 20.7 MBtu/hr

Corresponding CO_2 reduction (based on decreased combustion of oil in boilers):
(20.7 MBtu/hr) x (211.8 lb CO_2/MBtu)
= 4384 lb CO_2/hr *or* 18,413 T CO_2/yr

The reduced power generation will be replaced by purchased power. Increased utility power generation will increase CO_2 emissions correspondingly:
(0.4 MBtu/ADT) x (0.0669 MWh/MBtu) x (1000 ADT/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 2240 lb CO_2/hr *or* 9408 T CO_2/yr

Net reduction in CO_2 emissions:
4384 - 2240
= 2144 lb CO_2/hr *or* 9005 T CO_2/yr

3.3.4.2 *Preheat ClO_2 before it enters the mixer*

Description

As mills move away from chlorine bleaching, consumption of chlorine dioxide will increase. Increased use of ClO_2 will increase bleach plant steam demand. This increase can be minimized by heating the ClO_2 going to the first D stage. The ClO_2 solution could be heated in a heat exchanger using alkaline stage effluent as a heat source (Figure 3.23).

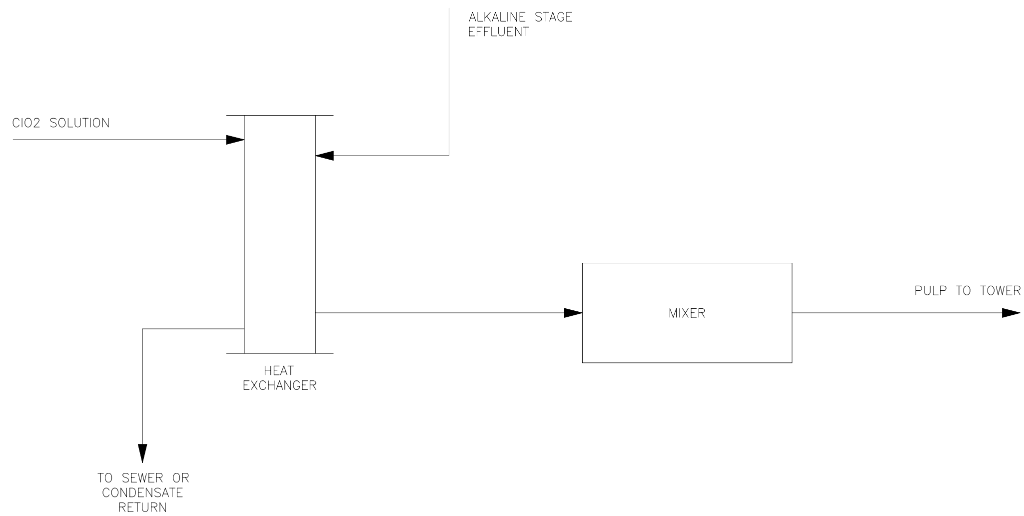

Figure 3.23. Preheating ClO_2 before It Enters the Mixer

Applicability and Limitations

Because of the conversion to ECF, ClO_2 usage will be high in the bleached kraft industry. The ClO_2 solution is normally chilled in order to maximize ClO_2 concentration. Therefore, heating of ClO_2 solution is an energy conservation measure with wide applications in the industry.

Many energy conservation technologies are related to optimum use of secondary heat. Before the availability of secondary heat for all potential applications can be determined, an overall secondary heat balance should be established.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using secondary heat to preheat the ClO_2 solution will reduce bleach plant steam demand.

Impact on CO_2

The drop in bleach plant steam demand from the preheating of the ClO_2 solution will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product through fuel savings.

Impact on Operating Costs

Cost savings will be achieved by preheating the ClO_2 solution before it enters the mixer. The savings will be due to reduced steam demand in the mixers and the associated fuel savings.

Capital Costs

Capital costs for this project will be due largely to the heat exchanger. Additional piping may also be needed.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

• Production of bleached pulp	1000 ADT/d
• ClO_2 usage (as ClO_2)	73 lb/ADT
• Temperature of ClO_2 solution before heating	37°F
• Temperature of ClO_2 solution after heating	110°F
• Kappa to bleaching	30
• Concentration of ClO_2 solution	9.5 g/l (0.0095 lb/lb)

Heat consumption for heating ClO_2 solution from 37 to 110°F:
(73 lb/ADT) / (0.0095 lb ClO_2/lb solution) x ((110 - 37)°F) x (1 Btu/lb/°F) x (10^{-6} MBtu/Btu)
= 0.56 MBtu/ADT

Steam savings of the magnitude shown will be accomplished if secondary heat is used to preheat the ClO_2 solution.

Cost savings:
(0.56 MBtu/ADT) x ($2.2/MBtu) x (1000 ADT/d) / (24 hr/d)
= $51.3/hr *or* $430,920/yr

Total reduction in steam generation:
((0.56 MBtu/ADT) + (0.56 MBtu/ADT) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (1000 ADT/d) / (24 hr/d)
= 29.0 MBtu/hr

Reduction in CO_2 emissions from oil burning:
(29.0 MBtu/hr) x (211.8 lb CO_2/MBtu)
= 6142 lb CO_2/hr *or* 25,796 T CO_2/yr

Increase in CO_2 emissions from utility power plant:
(0.56 MBtu/ADT) x (0.0669 MWh/MBtu) x (1000 ADT/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 3136 lb CO_2/hr *or* 13,171 T CO_2/yr

Net decrease in CO_2 emissions:
6142 - 3136
= 3006 lb CO_2/hr *or* 12,625 T CO_2/yr

3.3.4.3 *Use oxygen-based chemicals to reduce use of ClO_2 (O_2 or O_3 delignification, EP, EOP, etc.)*

Description

As mills move away from the use of chlorine, the use of chlorine dioxide is increasing. Installation of O_2 delignification, EP, EOP, etc., may reduce the amount of ClO_2 required. Chlorine dioxide must be generated on-site from sodium chlorate ($NaClO_3$). From a wider perspective, the sodium chlorate used in ClO_2 generation is formed in a reaction using sodium chloride (or chlorine), water, and electricity. Thus, reducing ClO_2 usage will also lower electrical power demand off-site. Although several oxygen-based technologies have the potential to lower ClO_2 use, only oxygen delignification is illustrated here. Figure 3.24 shows the typical concept for a one-stage oxygen delignification system.

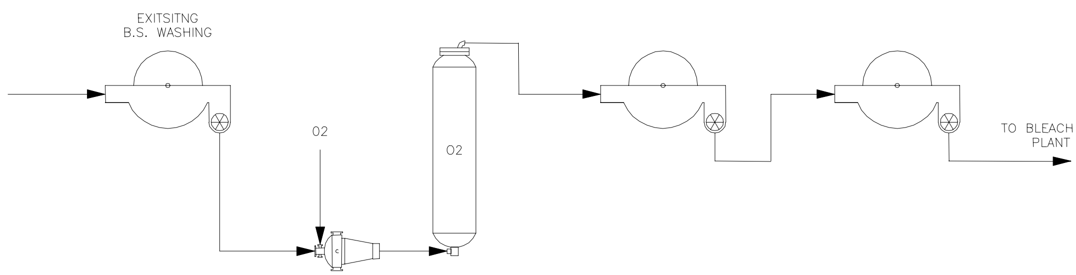

Figure 3.24. An Example of the Use of Oxygen-Based Chemicals to Reduce the Use of ClO_2

Applicability and Limitations

In general, use of oxygen-based chemicals to reduce use of ClO_2 is applicable to any papergrade pulp mill that uses ClO_2 for bleaching pulp. However, the manner in which oxygen-based chemicals could be used is very site-specific. Use of oxygen-based chemicals may affect many of a mill's operating characteristics, such as evaporation demand and steam required for evaporation, recovery boiler loading, lime kiln heat requirements, bleach plant steam usage, and mill power consumption. The use of oxygen-based chemicals can impact pulp characteristics. Changes in an existing bleach sequence can also affect water re-use practices at the mill, which may have an influence on total energy use and associated CO_2 emissions. Bleach sequence modifications have the potential to directly impact CO_2 and volatile organic compound (VOC) production in the bleach plant. The energy issues involved in capturing and destroying any additional VOCs, among other issues, should be examined prior to bleach plant modification. Therefore, the use of oxygen-based chemicals has to be studied carefully before any projects are planned.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

The impact of oxygen delignification is very mill-specific and general data are difficult to apply. The oxygen stage usually operates at temperature ≥212°F under high pressure, thus requiring steam, which adds to the mill energy demand. Depending on required pulp washing efficiency, mill evaporation demand and the steam required for evaporation may increase.

The decrease in chlorine dioxide consumption depends on how much the unbleached kappa number is reduced. Bleach plant steam consumption may decrease, especially if steam is used to heat stock to the temperature of the first chlorine dioxide stage.

Oxygen delignification recovers additional dry solids to the recovery cycle, but may also reduce their fuel value.

The oxygen stage typically uses oxidized white liquor as the alkali source, thus adding to lime kiln heat requirements and power demand for the white liquor oxidizer.

Impact on CO_2

Use of oxygen-based chemicals to reduce use of ClO_2 will lower off-site CO_2 emissions associated with sodium chlorate production. Although electricity is used to produce oxygen, it is significantly less than that required to produce chlorine dioxide and its precurser, sodium chlorate. For example, the electricity required to produce chlorine dioxide (including production of sodium chlorate) is approximately 11 kWh/kg ClO_2 while that required to produce oxygen is approximately 1 kWh/kg O_2 (USEPA 1997). This difference is accounted for in the sample calculations.

Impact on Operating Costs

Using oxygen based chemicals to reduce usage of ClO_2 will lower operating costs due to decreased use of the chemicals used to generate ClO_2 solution. The cost of other chemicals (oxygen, peroxide, etc.) will raise operating costs. Additional on-site power is required for the oxygen stage equipment and white liquor oxidation, but there is a significant reduction in off-site power due to reduced demand for sodium chlorate production. Savings associated with reduced steam used for heating stock may also be realized.

Capital Costs

Costs of this project will depend on which processes are used. The cost of an oxygen delignification system will be greater than oxygen and peroxide reinforced alkaline extraction stages.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3).

The following assumes a single stage O_2 delignification system is to be installed. Assume:

• Production rate	1000 ADT/d
• Kappa to O_2 stage	30
• Kappa from O_2 stage	18
• Oxygen usage in O_2 stage	30 lb/ADT
• ClO_2 usage	73 lb/ADT
• NaOH usage	65 lb/ADT

Integration of oxygen delignification to an existing pulp mill will affect many operating parameters. The impact cannot be calculated with straightforward techniques. The key changes (based on simulation results) are:

• 150 psig steam consumption	+0.4 MBtu/ADT
• 50 psig steam consumption	+/- 0 MBtu/ADT
• Recovery boiler steam generation	+0.4 MBtu/ADT
• Lime kiln oil usage	+0.1 MBtu/ADT
• Mill power demand	+55 kWh/ADT
• Purchased power demand	+43 kWh/ADT
• ClO_2 usage	-24 lb/ADT
• NaOH usage	-20 lb/ADT
• Oxygen usage	+20 lb/ADT
• Off-site power for purchased chemicals preparation	-117 kWh/ADT

Impact on site energy costs:

Increased fossil fuel at 0.1 MBtu/ADT
(0.1 MBtu/ADT) x (350,000 ADT/yr) x ($3/MBtu)
= $105,000/yr

Increased purchased power demand at 43 kWh/ADT
(43 kWh/ADT) x (350,000 ADT/yr) x ($35/MWh) x ($10^{-3}$ MWh/kWh)
= $526,750/yr

Mill chemicals costs will decrease approximately $12/ADT, valued at about $4.2 million/yr.

Net impact on operating costs:
$105,000 + $526,750 - $4,200,000
= -$3,570,000/yr

Impact on CO_2 emissions:

On-site:

Increase in CO_2 from fossil fuel:
(0.1 MBtu/ADT) x (173.7 lb CO_2/MBtu)
= 17.4 lb CO_2/ADT

Off-site:

Increase in CO_2 due to increase in purchased power:
(43 kWh/ADT) x (2009 lb CO_2/MWh) x (10^{-3} MWh/kWh)
= 86.4 lb CO_2/ADT

Decrease in CO_2 due to changes in bleaching chemicals:
(117 kWh/ADT) x (2009 lb CO_2/MWh) x (10^{-3} MWh/kWh)
= 235 lb CO_2/ADT

Net impact on CO_2:
17.4 + 86.4 - 235
= -131.2 lb CO_2/ADT
or at 1000 ADT/d production, reduction in CO_2
= 5308 lb CO_2/hr *or* 22,294 T CO_2/yr

3.3.5 *Pulp Dryer and Paper Machine*

3.3.5.1 *Eliminate steam use in the wire pit by providing hot water from heat recovery and/or pulp mill and by reducing water use on the machine*

Description

On the paper machine or pulp dryer, maximum water removal is achieved in the press section by maintaining a high mat temperature. To maintain the mat temperature, white water must often be heated, frequently by steam in the wire pit (Figure 3.25). Savings can be achieved by replacing live steam with a secondary heat source. Secondary heat can come from several sources, and each mill should conduct a study to determine which source matches their needs. Possible sources of secondary heat within the paper mill are the condensate flash tank vents and hot water from machine hood heat recovery equipment. Sources of secondary heat from the pulp mill include evaporator and surface condenser clean condensates and digester blow heat. Heat exchangers, piping, and pumps will be required to accomplish heat recovery and distribution of hot water.

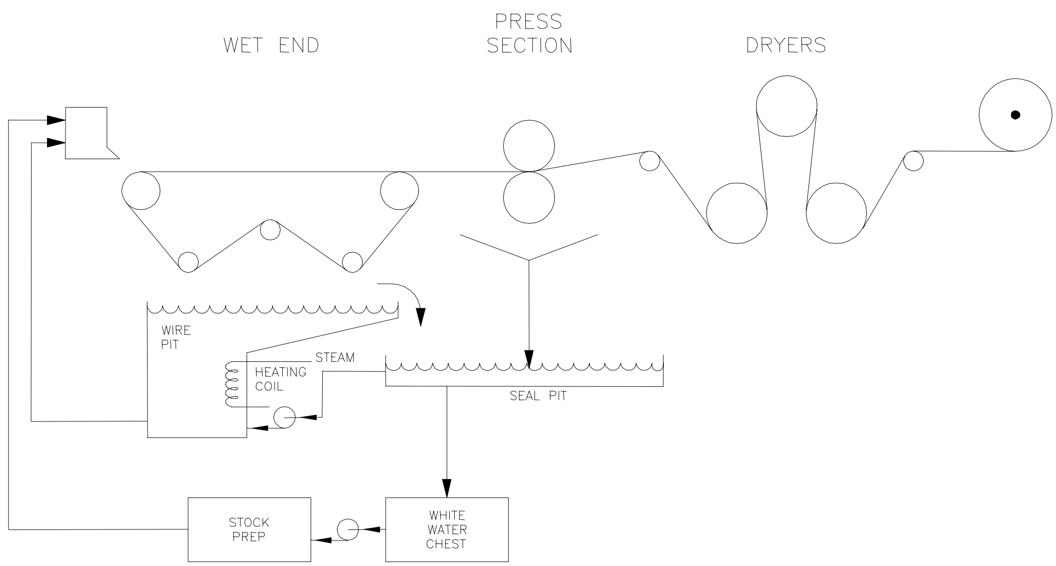

Figure 3.25. Steam Use in the Wire Pit

Applicability and Limitations

For mills using steam in the wire pit, this measure is a viable opportunity to save energy and reduce CO_2 emissions. As with any other secondary heat recovery and utilization project, the availability of secondary heat has to be verified through overall balances.

Because of the difference in mill water temperatures between summer and winter, steam to the wire pit may not be needed in summer conditions. The application of heat recovery and utilization in the wire pit is thus often limited to winter conditions only. This obviously reduces the economic feasibility of the technology.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Eliminating live steam in the wire pit through the use of secondary heat will reduce the energy demand of the mill. The savings will occur from a fuel consumption decrease caused by a drop in steam demand. Additional electrical power will be needed for any pumps that have to be installed.

Impact on CO_2

CO_2 emitted per ton of product will decrease from using secondary heat to heat white water in the wire pit. The reduction will occur due to fuel savings from reduced steam load. This should more than offset the small increase in emissions from increased electrical power usage.

Impact on Operating Costs

This technology will reduce operating costs. Electrical costs will increase slightly due to additional pumping needs. However, this will be compensated for by reduced steam demand and the associated fuel savings.

Capital Costs

Capital costs for this project will include piping, pumps, and any heat exchanging equipment needed.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume that wire pit heating is needed to heat fresh water used for head box, breast roll, couch roll, trim, save-all showers, etc.

- Fresh water flow rate 900 gpm
- Fresh water temperature 75°F, 43 Btu/lb
- Wire pit temperature 120°F, 88 Btu/lb

Heat required for water heating (steam savings):
(88 - 43 Btu/lb) x (900 gal/min) x (8.34 lb/gal) x (60 min/hr) x (10^{-6} MBtu/Btu)
= 20.3 MBtu/hr

Cost savings using secondary heat:

- Operating hours 8400 hr/yr
- Steam cost \$2.2/MBtu

(20.3 MBtu/hr x 8400 hr/yr) x \$2.2/MBtu
= \$375,144/yr

CO_2 impact:

On-site reduction:

CO_2 generated per MBtu of steam = 211.8 lb CO_2/MBtu
((20.3 MBtu/hr) + (20.3 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(211.8 lb CO_2/MBtu)
= 5335 lb CO_2/hr

Off-site increase (at utility power plant):

(20.3 MBtu/hr) x (0.0669 MWh/MBtu) x (2009 lb CO_2/MWh)
= 2728 lb CO_2/hr *or* 11,458 T CO_2/yr

Net CO_2 reduction:
5335 - 2728
= 2607 lb CO_2/hr *or* 10,949 T CO_2/yr

3.3.5.2 *Upgrade press section to enhance water removal*

Description

Energy consumption in paper machine dryers is highly dependent on the entering moisture content of the paper. A high moisture content on the web can also increase web breaks and reduce production. Raising web dryness can be accomplished by upgrading the press section. There are several options. Existing presses can be rebuilt for higher loadings or be replaced with shoe presses (Figure 3.26). Steam boxes can also be added to increase web temperature, which will improve press performance. Finally, if space allows, an additional press can be added.

Applicability and Limitations

Improved press performance is applicable to nearly all paper machines and pulp dryers that are not new or recently rebuilt. The target (maximum) dryness of the sheet before drying varies from one grade to another. Some grades can be pressed harder than others without affecting desired sheet properties, such as density. Accordingly, the entire range shown in Figures 3.27 and 3.28 for the sheet dryness may not be applicable for any single grade or machine.

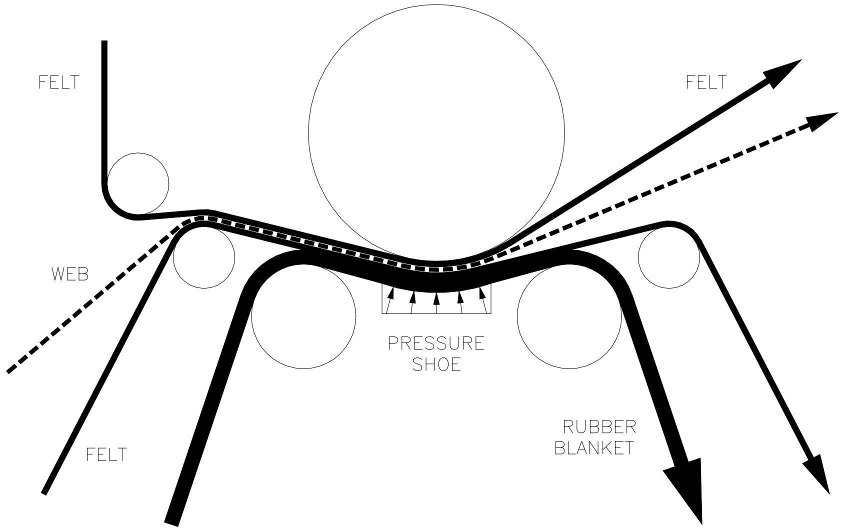

Figure 3.26. General Principle of a Shoe Press

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Reducing sheet moisture through press section improvements will reduce steam demand in dryers and result in energy conservation. Increased press loading and new presses may increase the mechanical energy requirement, but this should be more than compensated for by reduced steam demand.

Impact on CO_2

Reduced steam demand in the dryer from improvements in the press section will reduce total (considering both direct plus indirect) CO_2 emissions.

Impact on Operating Costs

Press section modifications will result in cost savings derived from the reduction of steam use in dryers. Power costs may increase due to higher press loadings and an additional press, if added.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current emission factors corresponding to purchased electricity should be used when estimating off-site emission impacts at a mill (see Section 2.3).

Figure 3.27 illustrates the calculated impact of the dryness of the sheet entering the dryer section on dryer steam consumption. The impact of heat recovery on pocket ventilation and hood makeup air is illustrated as well. The steam consumption shown does not include any heat consumption for the dryers following the size press or coaters, if any exist. As shown, sheet dryness has a major impact on dryer heat consumption.

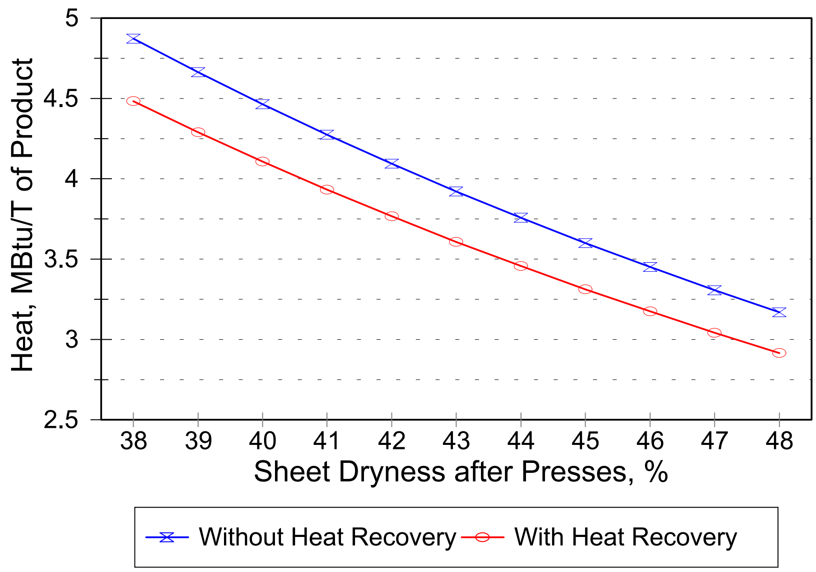

Figure 3.27. Example of the Impact of Sheet Dryness from the Press Section on Heat Consumption during Paper Drying

The impact of sheet dryness before the dryer section on CO_2 emissions is illustrated in Figure 3.28.

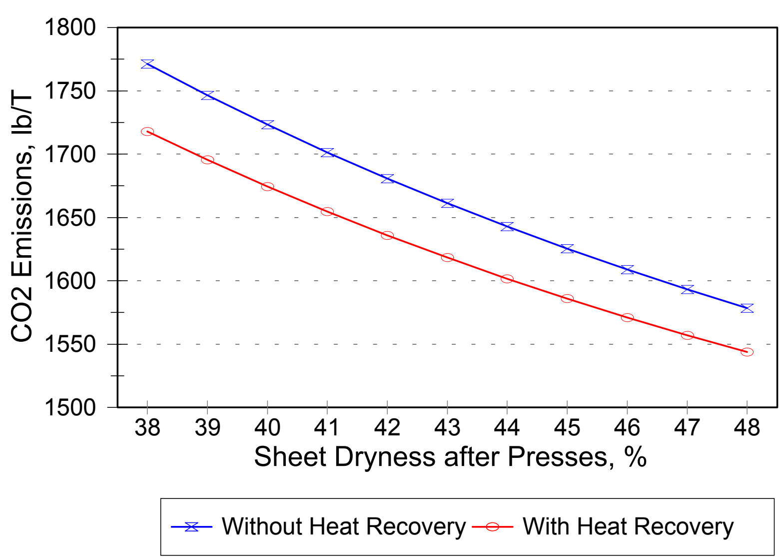

Figure 3.28. Sample Calculation for CO_2 Impact of Paper Machine Drying Operations

In the calculation of the change in CO_2 emissions, assume:

- All steam to the dryer is generated using oil as the fuel

- All steam is taken through a turbogenerator
- Back-pressure power yields:
  150 psig steam of process steam consumption 51.3 kWh/MBtu
  50 psig steam 66.9 kWh/MBtu
- Power consumption of machine at 38% sheet dryness 550 kWh/T paper
- Power consumption of machine drives and vacuum pumps increases by 20 kWh/T when going from 38% to 48% in sheet dryness

Figure 3.28 shows calculated CO_2 emissions caused by:

- Steam generated from oil for drying and back-pressure power
- Purchased power, which is needed in addition to back-pressure power

As shown, the sample paper mill CO_2 emissions are about 1770 lb CO_2/T at 38% sheet dryness from the press section for the machine without heat recovery. At 48% sheet dryness to the steam dryer and with heat recovery to the pocket ventilation and hood makeup air, CO_2 emissions are reduced to about 1550 lb CO_2/T of product.

These calculations assume that all process steam is taken through the turbogenerator. If the mill does not have back-pressure power generation, the situation will change drastically (Figure 3.29). The CO_2 impact of the sample paper machine is 15 to 20% higher with no back-pressure power generation than with all steam going through an efficient turbogenerator.

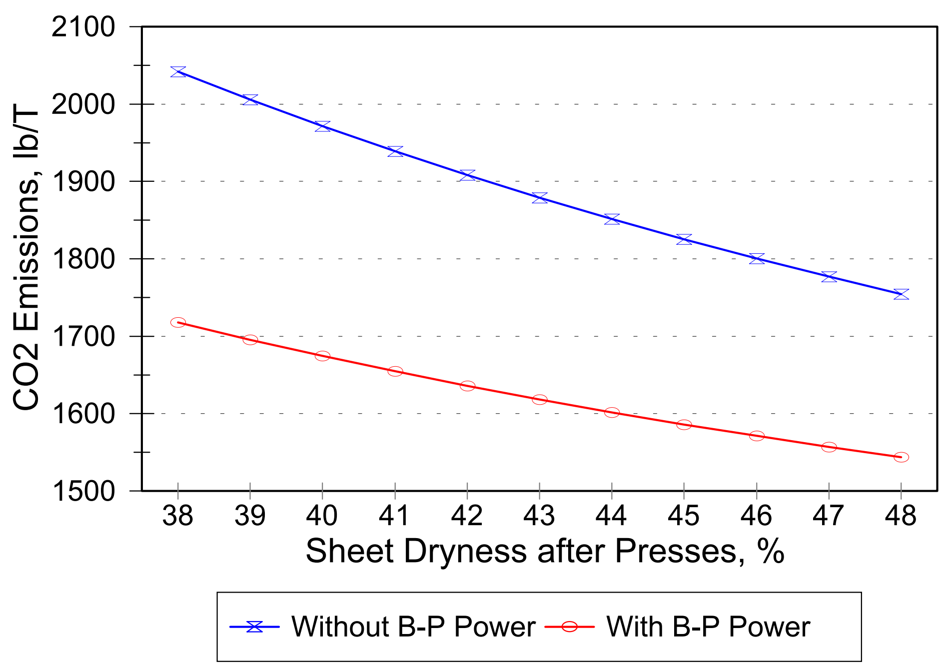

Figure 3.29. Calculated CO_2 Contribution of a Sample Paper Machine Dryer with and without Back-Pressure Power Generation

3.3.5.3 *Enclose the machine hood (if applicable) and install air-to-air and air-to-water heat recovery*

Description

Paper machines and pulp dryers use large amounts of steam in the dryers to remove moisture from the paper. After being used for drying, heat from this steam can be recovered and used elsewhere. Heat recovery from paper machines can be achieved by closing the machine hood and installing heat recovery equipment on the hood exhaust.

Closing the machine hood involves encasing the dryer section of the machine with an insulated cover with sliding panels. This prevents mixing of hot air from the dryer with cooler air in the machine room. Closing the hood will increase the humidity and temperature of hood exhaust, which increases the heat recovery potential. It will affect pocket ventilation, and additional venting may be required.

Heat can be recovered from the hood exhaust using several technologies. One method is to use an air-to-air heat exchanger. The hot, humid air from the hood exhaust would be passed through a heat exchanger, such as a cross flow type, to heat incoming air. The preheated air could be used to supply the machine room or the dryer hood. A second method of heat recovery from the hood exhaust is air-to-water. This method usually employs a spray scrubber in which water is sprayed into a chamber with the hood exhaust flowing in the opposite direction. This system is generally the most efficient for recovering heat from the hood exhaust. Hot water generated in this system can be used on machine showers and other places where hot water is beneficial.

Applicability and Limitations

On newer machines, an enclosed hood and air-to-air heat recovery have normally been implemented. For old machines, enclosing the hood is normally too expensive to be justified on the basis of steam savings. Technically, however, heat recovery is feasible and is a proven technology for any type of paper machine.

Climate conditions affect the economic justification of heat recovery. In northern mills, of course, heat recovery to machine room makeup air is more justifiable than in southern mills.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Enclosing the machine hood and installing heat recovery systems on the hood exhaust will decrease energy consumption in the paper mill. Enclosing the machine hood will reduce dryer steam consumption. Power savings may occur if fan speeds can be reduced due to lower exhaust flow volumes. Exact savings will depend on the heat recovery method and utilization.

Impact on CO_2

The reduction of energy consumption from closing the machine hood and installing heat recovery on the hood exhaust will reduce total (considering both direct plus indirect) CO_2 emissions through fuel savings from steam load reduction.

Impact on Operating Costs

Enclosing the machine hood and installing heat recovery equipment on the hood exhaust will lower operating costs. The majority of the savings will be due to steam load reduction and fuel savings. If air-to-water heat recovery equipment is used, electrical power costs may increase due to increased pumping requirement. Actual cost savings will depend on the heat recovery technology employed and the closure level of the machine hood. Annual savings from implementing both projects could be substantial.

Capital Costs

Capital costs will vary depending on the heat recovery equipment used. Air-to-air heat recovery will require a heat exchanger and fans to direct the flow of warm air. Air-to-water heat recovery will require a spray scrubber, pumps, and piping to transport the water. Enclosing the machine hood will include the cost of the dryer cover plus any pocket ventilation equipment that must be added.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

- Machine room air flow rate is three times the hood exhaust air flow rate
- Machine room air used to supply hood air is 15°F higher than air used to supply the machine room
- Hood supply air is 65% of hood exhaust air flow rate, the rest is infiltrated air
- Humidity of supply air is 0.027 lb H_2O/lb d.a. (dry air)
- Machine production rate is 500 T/d
- Sheet dryness is 42% before dryer and 94% after dryer.

Evaporation of water in the dryer is:

$$(500\text{ T/d}) / (24\text{ hr/d}) \times \left(\frac{1}{0.42} - \frac{1}{0.94}\right) \times (0.94) \times (2000\text{ lb/T})$$

= 51,587 lb/hr

Heat recovery to hood supply air:

- Exhaust air humidity 0.14 lb H_2O/lb d.a
- Temperature (dry bulb) 180ºF
- Enthalpy 203 Btu/lb

Exhaust air flow:

$$\frac{1\text{ lb d.a.}}{0.14 - 0.027\text{ lb }H_2O} \times 51{,}587\text{ lb }H_2O\text{/hr}$$

= 456,522 lb d.a./h

Hood supply air flow:
0.65 x 456,522 lb d.a./hr
= 296,739 lb d.a./hr

- Average supply air temperature before heating 90ºF
- Supply air temperature after heating 150ºF
- Enthalpy of supply air before heating 52 Btu/lb d.a.
- Enthalpy of hood supply air after preheating 68 Btu/lb d.a.

Heat recovery to hood supply air:
((68 - 52) Btu/lb d.a.) x (296,739 lb d.a./hr) x (10^{-6} MBtu/Btu)
= 4.7 MBtu/hr

Machine room supply air:
3 x (456,522 lb d.a./hr)
= 1,369,566 lb d.a./hr

Temperature of room supply air temperature:

- Before heat recovery (annual average) 50ºF
- After heat recovery 75ºF

Humidity of room supply air: 0.008 lb H_2O/lb d.a.

Enthalpy of room supply air:

- Before heating 20 Btu/lb d.a.
- After heating 27 Btu/lb d.a.

Heat recovery to room supply air:
((27 - 20) Btu/lb d.a.) x (1,369,566 lb d.a./hr) x (10^{-6} MBtu/Btu)
= 9.6 MBtu/hr

Total heat recovery to hood and machine room supply air:
4.7 + 9.6
= 14.3 MBtu/hr *or* 0.69 MBtu/T of paper

Steam savings:
(14.3 MBtu/hr) x ($2.2/hr)
= $31.5/hr *or* $264,600/yr

CO_2 reduction of oil fired boiler:
((0.69 MBtu/T) + (0.69 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (500 T/d) / (24 hr/d) x (211.8 lb/MBtu)
= 3778 lb CO_2/hr *or* 15,868 T CO_2/yr

CO_2 increase due to increased power purchase:
(0.69 MBtu/T) x (0.0669 MWh/MBtu) x (500 T/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 1932 lb CO_2/hr *or* 8114 T CO_2/yr

Net reduction in CO_2 emissions:
3778 - 1932
= 1846 lb CO_2/hr *or* 7753 T CO_2/yr

3.3.5.4 *Install properly sized white water and broke systems to minimize white water losses during upset conditions*

Description

During machine breaks and upset conditions the white water and broke systems may become overloaded and overflow to the process sewer. This results in a loss of process heat. This problem can be alleviated by installing properly sized white water and broke systems. The white water from a paper machine is heated in the wire pit either directly with steam or indirectly with hot water or steam. Heating white water maximizes stock temperature and improves paper machine performance. In closed white water systems only makeup water may be heated. White water is then used on the machine and the broke system. During upsets on the machine an undersized white water and broke system will overflow to the sewer. Thus valuable process heat is lost along with fiber. A properly sized white water system will have enough storage to handle all the white water generated by the machine during an extended upset. This water will be returned to the process. A properly sized broke system will be able to handle the full production of the machine. The broke system should have enough storage for all broke generated during an extended upset period. The broke is then bled to the blend tank.

Applicability and Limitations

Most paper machines could benefit from increased white water and broke handling capacity. No technical or operational drawbacks are foreseen. Together with expansion of the white water storage system, the mill should develop white water control and management techniques. The benefits of increased buffer volumes are highly dependent on how well the extended buffer storages are managed and operated and on the frequency of upsets that currently result in unplanned losses of white water.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

A properly sized white water and broke system will reduce energy consumption. Reducing white water losses means less heat loss and lower makeup water flow and heating. Lowering white water and broke losses will also reduce fiber losses and loading to the treatment system.

Impact on CO_2

A properly sized white water and broke system will reduce heat losses. This will result in a drop in steam demand for water heating, which corresponds to lower boiler fuel consumption and lower total (considering both direct plus indirect) CO_2 emissions.

Impact on Operating Costs

Reducing heat losses by installing a properly sized white water and broke system will lower operating costs. Savings will come from lower fiber losses and lower steam demand. Reducing the treatment system loading by reducing fiber going to the sewer will lower treatment costs.

Capital Costs

Capital costs for properly sized white water and broke systems will include pumps, piping, and tankage. If the broke pulper is undersized, a new one will be required.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

The amount of heat savings can only be determined by studying the operating statistics and white water loss patterns from an existing machine. The other method is to develop a dynamic simulation model for the machine water systems from mill-specific data and assess the benefits from increased white water and broke handling systems. In this example it is assumed that a savings opportunity of 0.3 MBtu/T of paper has been estimated from expanded white water system capacity.

Summary of the basic data is:

• Paper machine capacity (fine paper)	500 T/d
• Heat savings (low pressure steam)	0.3 MBtu/T
• Reduction in fiber losses	0.5%
• Cost of fiber on machine	$400/ADT

Steam cost savings:
(0.3 MBtu/T) x (500 T/d) / (24 hr/T) x ($2.2/MBtu)
= $13.8/hr *or* $115,920/yr

Savings in fiber losses:
(0.005 T/T) x (500 T/d) x (350 d/yr) x ($400/T)
= $350,000/yr

CO_2 reduction due to reduced oil burning:
((0.3 MBtu/T) + (0.3 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (500 T/d) /
(24 hr/d) x (211.8 lb CO_2/MBtu)
= 1643 lb CO_2/hr *or* 6901 T CO_2/yr

CO_2 increase in utility power plant:
(0.3 MBtu/T) x (0.0669 MWh/MBtu) x (500 T/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 840 lb CO_2/hr *or* 3528 T CO_2/yr

Net reduction in CO_2 emissions:
1643 - 840
= 803 lb CO_2/hr *or* 3373 T CO_2/yr

3.3.5.5 *Implement hood exhaust moisture controls to minimize air heating and maximize heat recovery*

Description

In the drying process, water is evaporated from paper or board. Moist air is exhausted through the machine hood. Exhaust air is used in heat recovery equipment to preheat incoming ventilation air. The preheated air then flows to the machine hood. If the exhaust air leaving the dryer is not near its saturation point, energy is wasted. Implementing hood exhaust moisture controls will minimize losses of heat energy. Air exhausted below the saturation point has been heated but still has the capacity to carry additional water vapor. Air exhausted near the saturation point has used all its energy to absorb water. Hood exhaust moisture controls maintain the exhaust air moisture content near the saturation point by adjusting ventilation and exhaust rates.

Applicability and Limitations

The sample calculation assumes that air-to-air heat recovery has been implemented (see Section 3.3.5.3). Some savings can be accomplished even without heat recovery.

The major limitation to wide application for this technology has been poor reliability and high maintenance requirements of exhaust air moisture measurement devices. Presumably a reliable measurement device exists today, and applicability of moisture control of hood exhaust should be technically valid.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing hood exhaust moisture controls will reduce energy consumption. By exhausting air near saturation no energy is wasted on air heating and all energy recovered from the exhaust air is used by the ventilation air to remove water vapor. Controlling hood exhaust moisture content may also allow a decrease in electrical power consumption by reducing ventilation and exhaust fan speed.

Impact on CO_2

Controlling the moisture content of the hood exhaust will reduce total (considering both direct plus indirect) CO_2 emissions. For paper machines that use steam heated dryers, a small drop in steam consumption and a corresponding drop in boiler CO_2 emissions may be realized. For dryers that use direct firing of fossil fuels for heat, a large drop in CO_2 emissions may be possible.

Impact on Operating Costs

This project will reduce operating costs of the dryer. Less energy will be used solely to heat ventilation air and more will be used to absorb and remove evaporator water. This will lower the energy consumption of the dryer. Exhausting air near saturation may also allow the fan speed to be reduced, which would lower electrical power costs.

Capital Costs

Capital costs will include instruments for measuring exhaust air moisture and controls.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Typically, overall savings in heat consumption are on the order of 0.1 MBtu/T of product. For a 500 T/d machine this would mean savings of:
(0.1 MBtu/T) x (500 T/d) / (24 hr/d) x ($2.2/MBtu)
= $4.6/hr *or* $38,640/yr

CO_2 reduction of oil fired boiler:
((0.1 MBtu/T) + (0.1 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(500 T/d) / (24 hr/d) x (211.8 lb CO_2/MBtu)
= 548 lb CO_2/hr *or* 2302 T CO_2/yr

CO_2 increase due to increased power purchases:
(0.1 MBtu/T) x (0.0669 MWh/MBtu) x (500 T/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 280 lb CO_2/hr *or* 1176 T CO_2/yr

Net reduction in CO_2 emissions:
548 - 280
= 268 lb CO_2/hr *or* 1126 T CO_2/yr

3.3.5.6 *Implement efficient control systems for the machine steam and condensate systems to eliminate excessive blowthrough and steam venting during machine breaks*

Description

During a break when there is no web on the paper machine, the steam demand of the machine is reduced. If the steam flow to the machine remains constant, excessive blowthrough and vented steam is wasted because it is not used for evaporation of water from the web. Some blowthrough is required in the dryers to aid in removal of steam condensates from inside the dryer shell. Excessive blowthrough can be reduced by implementing efficient control systems. On some paper machines the different sections are cascaded and are thus interconnected. In most North American paper machines, blowthrough from a dryer section is recycled, minus a small amount of bleed-off stream, to the same section and pressure is boosted in a thermocompressor. This allows the flow of steam and the drying rate to be adjusted individually for each dryer section. Controlling the flow to each dryer section allows blowthrough to be minimized.

Applicability and Limitations

Steam savings from improved steam system controls are likely to be obtainable on old machines that have frequent grade changes and sheet breaks. On newer machines the controls are normally implemented and taken into account in the original design.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Reducing excessive blowthrough and steam venting during machine breaks will improve the energy efficiency of the paper machine. Reducing the amount of blowthrough means less steam is lost without doing work, so less steam is used to produce a ton of product.

Impact on CO_2

Reducing excessive blowthrough during a machine break will reduce total (considering both direct plus indirect) CO_2 emissions. Reducing the amount of steam lost reduces the amount of steam generated in the boilers per ton of product. This reduces CO_2 emissions through fuel savings.

Impact on Operating Costs

Minimizing blowthrough in the dryers during a machine break will reduce operating costs. Less blowthrough means less wasted steam. This improvement in thermal efficiency will lower operating costs.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Typical blowthrough steam varies between 2 and 5% of the total steam used on the dryer section. In steady operating conditions, blowthrough steam is condensed and utilized to heat shower water. In unsteady conditions, blowthrough condenser capacity is normally not sufficient, and part of the steam is vented to the atmosphere. The amount of heat lost varies widely from one machine to another. The following sample calculation assumes that 1% of the total dryer steam consumption can be saved.

Assume:

• Paper production	500 T/d
• Dryer heat consumption	4.5 MBtu/T
• Reduction in steam venting	1%
• Steam saved replaces 50 psig steam	
• Cost of 50 psig steam	$2.2/MBtu

Savings for 1% steam reduction:
(0.01) x (4.5 MBtu/T) x (500 T/d) / (24 hr/d) x ($2.2/MBtu)
= $2.1/hr *or* $17,640/yr

CO_2 reduction of oil fired boiler:
((0.045 MBtu/T) + (0.045 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(500 T/d) / (24 hr/d) x (211.8 lb CO_2/MBtu)
= 246 lb CO_2/hr *or* 1033 T CO_2/yr

CO_2 increase due to increased power purchases:
(0.045 MBtu/T) x (0.0669 MWh/MBtu) x (500 T/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 126 lb CO_2/hr *or* 529 T CO_2/yr

Net reduction in CO_2 emissions:
246 - 126
= 120 lb CO_2/hr *or* 504 T CO_2/yr

3.3.6 *Kraft Recovery*

3.3.6.1 *Convert recovery boiler to non-direct contact and implement high solids firing*

Description

Older recovery boilers often use direct contact evaporators (DCEs) for final concentration of black liquor before combustion in the recovery boiler. The use of DCEs results in emissions of malodorous TRS compounds from the recovery boiler stack. Black liquor oxidation through the mixing of liquor with air or oxygen is often used to reduce emissions of these odorous compounds. By converting older recovery boilers to modern non-DCE designs and implementing high solids firing, boiler efficiency will improve, steam generation will increase, and TRS emissions will drop.

Conversion to non-DCE design involves replacing the DCE with an indirect contact high solids concentrator, shutting down the black liquor oxidation system, and installing an economizer section on the boiler (see Figure 3.30). Installation of the concentrator will allow the solids concentration in the liquor to be increased, which will increase solids burning capacity and steam generation

Applicability and Limitations

Replacement of the direct contact evaporator is applicable to any pulp mill that operates a DCE. In many cases the physical layout of the boiler plant is such that the conversion is very expensive. Many mills may find that the conversion is too expensive, and instead of boiler conversion a completely new boiler that may facilitate an incremental production increase is a more economical solution on a long-term basis. Energy savings alone are seldom adequate to justify the high cost of a new or rebuilt recovery furnace.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

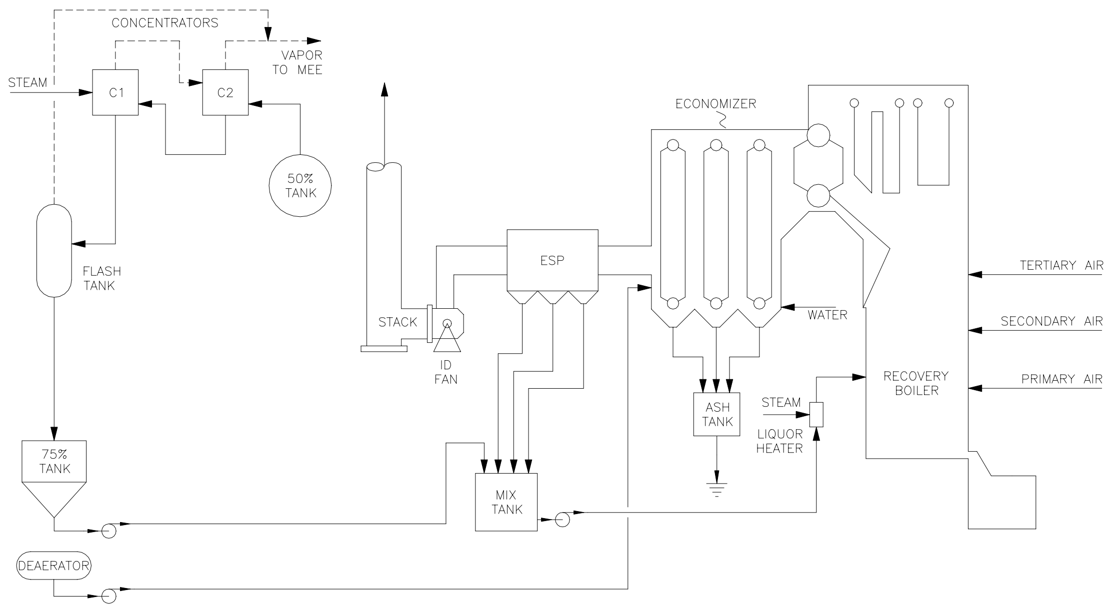

Figure 3.30. Non-Direct Contact Recovery Boiler Concept

Impact on Energy

Conversion of the recovery boiler to a non-DCE design will improve the thermal efficiency of the boiler. The high solids concentrator will reduce the water that must be evaporated from black liquor, which will increase steam generation and result in energy savings. Use of an economizer will also improve boiler thermal efficiency by recovering heat from flue gases.

Impact on CO_2

CO_2 emissions per ton of product will be reduced by converting the recovery boiler to a non-DCE design. The reduction in CO_2 will occur due to thermal efficiency improvement in the boiler, which allows more steam to be generated from spent liquor (biomass fuel). Since more steam is produced via biomass fuel (with corresponding net zero emission of greenhouse CO_2), reductions in fossil fuel use at other boilers will be facilitated, resulting in a net reduction in fossil CO_2 at the mill.

Impact on Operating Costs

Improvement in the boiler's thermal efficiency due to conversion to a non-DCE design will reduce the mill's operating costs. The reduction is due to increased steam generation, which translates into fuel savings.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section

2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Figures 3.31 and 3.32 are based on detailed boiler balances created using a kraft recovery boiler balance computer program. A thorough description of kraft recovery boiler calculations is beyond the scope of this manual. However, for a detailed explanation of kraft recovery boiler balance calculations, see Chapter 1.3 of Adams 1997.

Figures 3.31 and 3.32 use results of kraft recovery boiler calculations and several assumptions to calculate heat to the processes (excluding the concentrator) and changes in CO_2 emissions.

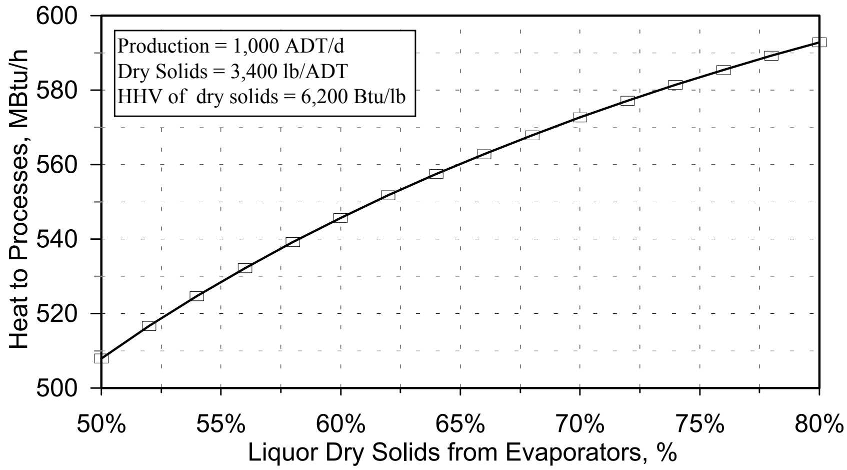

Figure 3.31. Sample Calculation for Heat Available from the Recovery Boiler in Excess of Boiler's Own Use and Steam to Concentrator (based on an example bleached market kraft pulp mill)

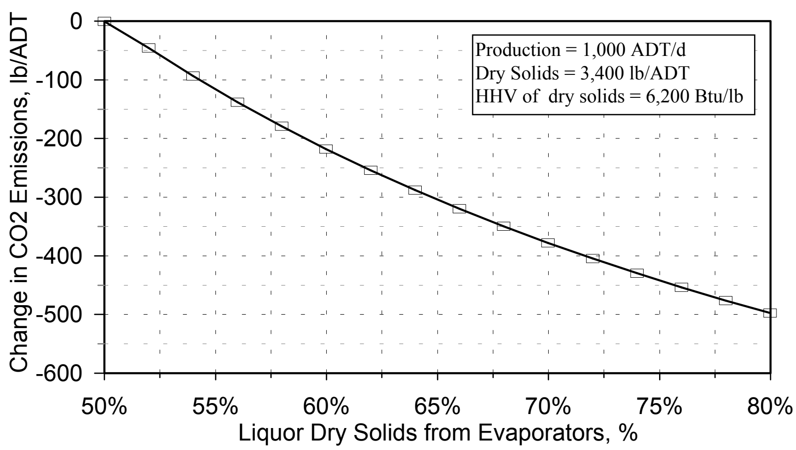

Figure 3.32. Impact of Black Liquor Dry Solids Concentration on CO_2 Emissions (reference (=zero) point is 50% solids concentration) (based on an example bleached market kraft pulp mill)

Assume:

• Bleached market pulp (softwood)	1000 ADT
• Black liquor solids from pulp mill	3400 lb/ADT
• Heating value of dry solids	6200 Btu/lb d.s.
• Heat consumption in concentrator	250 Btu/lb H_2O evaporated
• Power consumption in concentrator	5 kWh/T H_2O evaporated
• Marginal fuel type	No. 6 oil
• CO_2 emissions form burning marginal fuel	211.8 lb CO_2/MBtu in steam
• Back-pressure power from change in process heat	0.0669 MWh/MBtu
• CO_2 emissions from purchased power generation	2009 lb CO_2/MWh
• Base case reference point is liquor from evaporators to direct contact evaporator at 50% d.s. concentration	
• All steam used in concentrators is 50 psig exhaust steam from the turbogenerator	

Using these assumptions, the following calculations can be performed:

BL dry solids (lb d.s./hr) = (3400 lb/ADT) x (1000 ADT/d) x (1 d/24 hr) (Eq. 1)

$$\text{Evap. in conc.}\left(\text{lb/hr}\right)=\left(2-\frac{100}{\text{conc. prod. solids}\left(\%\right)}\right)\times \text{lb d.s./hr}\left(\text{from Eq.1}\right) \qquad \text{(Eq. 2)}$$

(Note: concentrator product solids (%) varies from 50 to 80% for Figures 3.31 and 3.32)

Heat consumed in concentrator (MBtu/hr):
(250 Btu/lb) x (lb/hr from Eq. 2) x (1 MBtu/10^6 Btu) (Eq. 3)

Heat from recovery boiler (MBtu/hr):
heat to steam (Btu/lb BLS) x (1000 ADT/d) x (1 d/24 h) x (1 MBtu/10^6 Btu) (Eq. 4)
(Note: heat to steam (Btu/lb BLS) is from detailed kraft recovery boiler calculations)

Heat to processes (MBtu/hr):
heat from recovery boiler (Eq. 4) - heat consumed in concentrator (Eq. 3) (Eq. 5)
(Note: the results of Eq. 5 are shown in Figure 3.31)

CO_2 reduction from steam (lb/hr):
base case CO_2 emissions (lb/hr) - (211.8 lb CO_2/MBtu x MBtu/hr from Eq. 5) (Eq. 6)
(Note: base case CO_2 emissions = 211.8 lb CO_2/MBtu x MBtu/hr from Eq. 5 for base case)

Power consumption in concentrator (MWh/hr):
(5 kWh/T) x (lb/hr from Eq. 2) x (1T/2,000 lb) x (1 MWh/10^3 kWh) (Eq. 7)

Back-pressure power from concentrator (MWh/hr):
(0.0669 MWh/MBtu) x (MBtu/hr from Eq. 3) (Eq. 8)

CO_2 from power generation (lb/hr):
(-1) x (MWh/hr from Eq. 8 - MWh/hr from Eq. 7) x (2009 lb CO_2/MWh) (Eq. 9)

Net CO_2 reduction (lb/hr):
(lb/hr from Eq. 6) + (lb/hr from Eq. 9) (Eq. 10)

Net CO_2 reduction (lb/ADT):
(lb/hr from Eq. 10) x (24 hr/d) / (1000 ADT/d) (Eq. 11)
(Note: The results of Eq. 11 are shown in Figure 3.32)

Figure 3.31 illustrates steam available from the recovery boiler for other processes. The available heat has been calculated as the difference between recovery boiler steam production and consumption in the boiler itself and the concentrator (from 50% up). As shown, the solids concentration of liquor from the evaporator/concentrator has a major impact on steam generation from biofuels.

Because of the zero contribution to CO_2 emissions by black liquor, CO_2 emissions are also reduced with increased solids concentration of black liquor. Figure 3.31 illustrates this impact. As shown in the figure, increasing the black liquor solids concentration from 50 to 80% would reduce CO_2 emissions by about 500 lb/ADT.

Savings in steam going from 50 to 80% d.s. concentration (assume low pressure steam generated with oil is replaced):
((593 - 508) MBtu/hr) x ($2.2/MBtu)
=$187/hr *or* $1.6 million/yr

Savings assume that the steam from the oil fired boiler goes through the turbogenerator as well.

3.3.6.2 *Perform evaporator boilout with weak black liquor*

Description

The performance of the black liquor evaporators depends on the heat transfer across the evaporator tube. This heat transfer is reduced by scaling and fouling of the tube surface. The evaporators are cleaned when the heat transfer of the evaporator is reduced to some critical level. A common method of cleaning is to boil the evaporators with fresh (mill) water or with condensates. This procedure is fast but results in heat and black liquor solids losses, as the boilout condensates are often sewered or re-evaporated. These losses can be reduced and savings realized by washing the evaporators with weak black liquor. This process is slower than using fresh water, but the boilout solution is not wasted because it can be stored in a tank and returned to the evaporator. Thus the solids removed in the boilout procedure are recovered.

Applicability and Limitations

Most mills in North America use either fresh water or evaporator condensates for evaporator boilout. In many mills weak liquor can be used for boilout instead. If the cleaning effect can be accomplished with weak liquor, both energy savings and increased capacity may be achieved. Some mills have reported that weak liquor boilout has not been successful. Many times the piping changes to test weak liquor boilout are very minor. It is therefore recommended that mills that are interested in this technology arrange a test to verify the performance of weak liquor boilout. Evaporator-limited mills will find this option less attractive.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Performing evaporator boilout with weak black liquor will improve energy consumption at the mill by increasing solids to recovery and eliminating heat loss through the sewering of hot condensates.

Impact on CO_2

Improving solids recovery and reducing heat loss will reduce total (considering both direct plus indirect) CO_2 emissions per ton of pulp. The reduction of CO_2 will occur from improving process heat usage at the mill.

Impact on Operating Costs

Using weak black liquor for evaporator boilouts will provide cost savings. The savings will result from reduced heat loss and increased black liquor solids generation.

Capital Costs

Capital costs for using weak black liquor to boil out the evaporator will include piping, pumps, and a tank for the boilout liquor if one does not already exist.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

• Pulp production	1000 ADT/d
• Evaporation	20,000 lb/ADT
• Evaporation	830,000 lb/hr
• Steam economy (five-effect evaporation)	4.2 lb/lb
• Steam consumption during normal year	198,000 lb/hr
• Boilout with condensates	8 hr/wk
• Steam consumption during boilout	180,000/hr

Steam savings if weak liquor boilout can be implemented:
(180 klb stm/hr) x (8 hr/wk) / (168 hr/wk)
= 8.6 klb stm/hr
(8.6 klb stm/hr) x (1 MBtu/klb) x (24 hr/d) /(1000 ADT/d)
= 0.21 MBtu/ADT

Savings:
(8.6 klb stm/hr) x (1 MBtu/klb) x ($2.2/MBtu)
= $18.9/hr *or* $158,760/yr

In addition to steam savings, a marginal increase in evaporation capacity (1 to 3%) can be gained because weak liquor is being evaporated during the boilout.

CO_2 reduction of oil fired boiler:
((0.21 MBtu/ADT) + (0.21 MBtu/ADT) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(1000 ADT/d) / (24 hr/d) x (211.8 lb/MBtu)
= 2300 lb CO_2/hr *or* 9660 T CO_2/yr

CO_2 increase due to increased power purchases:
(0.21 MBtu/ADT) x (0.0669 MWh/MBtu) x (1000 ADT/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 1176 lb CO_2/hr *or* 4939 T CO_2/yr

Net reduction of CO_2 emissions:
2300 - 1176
= 1124 lb CO_2/hr *or* 4721 T CO_2/yr

3.3.6.3 *Convert evaporation to seven-effect operation (install additional evaporator effect)*

Description

Kraft mill evaporation plants are designed to evaporate water out of black liquor using a minimum amount of steam. To accomplish this, most mills have an evaporator set that uses four to six effects. Each effect operates at a lower pressure than the previous one and uses vapors from the prior effect to evaporate water from liquor. Adding another effect or converting the set to a seven-effect operation will improve evaporator energy efficiency. A general concept is shown in Figure 3.33.

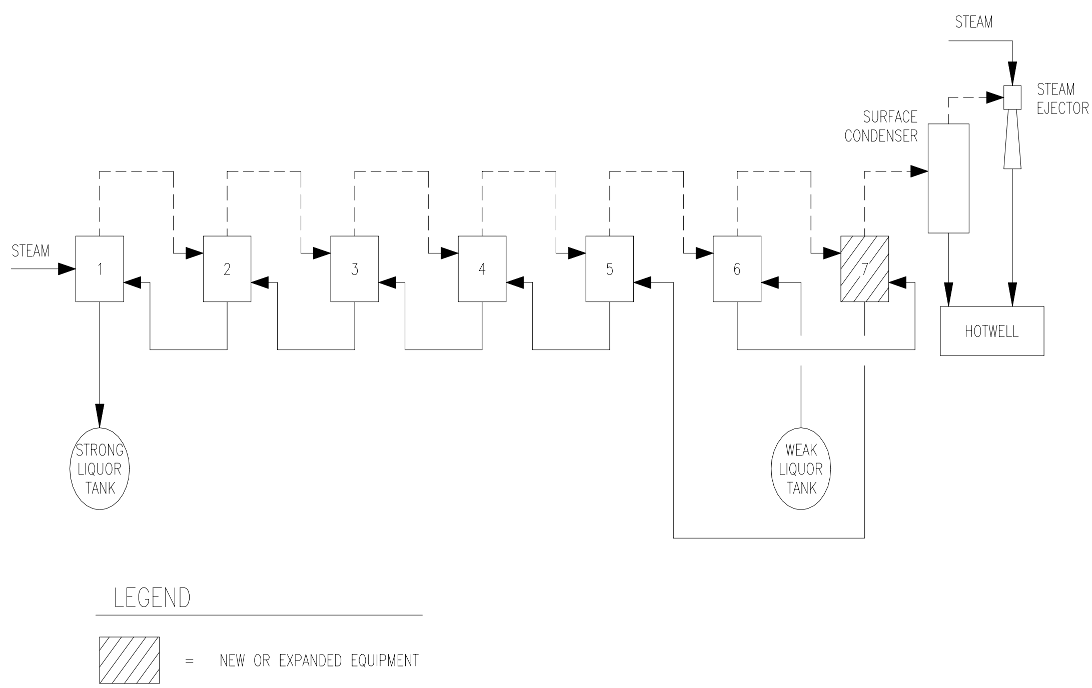

Figure 3.33. Conversion of Evaporation to a Seven-Effect Operation

Applicability and Limitations

The sample calculation assumes that a five-effect evaporator can be converted to a seven-effect set. This would normally require fairly extensive rebuilding of the evaporator set. It may be more practical to convert a five-effect set to a six-effect set and gain about 60% of the benefits that are achievable from conversion of the five-effect set to a seven-effect set. In any event, the conversion will be fairly capital intensive and a careful study must be performed in order to assess potential effects of conversion on the capacity and runnability of the set.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Adding an additional effect or converting the evaporator to a seven-effect operation will reduce the energy required for evaporation. Thus, the steam demand of the evaporation plant will decrease. The decrease in steam demand will depend on the number of additional effects added.

Impact on CO_2

Converting evaporation to a seven-effect operation or adding additional evaporator effects will reduce total (considering both direct plus indirect) CO_2 emissions. Adding evaporator effects reduces evaporator steam demand, resulting in lower fuel consumption and CO_2 emissions.

Impact on Operating Costs

Operating costs of the evaporator plant will be reduced by adding an additional evaporator effect or by converting evaporation to a seven-effect operation. The reduction in heat consumption will save steam and fuel, reducing operating costs. There will be an increase in power costs if any liquor transfer pumps are added. Evaporation demand may increase due to additional water from boilouts and seal water.

Capital Costs

Capital costs of an additional evaporator effect will include the cost of the body, piping for liquor and vapor, and liquor transfer pumps. Additional surface condenser capacity may also need to be installed to maintain the vacuum.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

A rule of thumb for approximate heat consumption in multiple effect evaporation is:

$$\frac{1200}{n}\ \text{Btu/lb}\ H_2O\ \text{evaporated}$$

where: n = the number of evaporation effects

Assume:

- Bleached market pulp production 1000 ADT/d
- Evaporation in multiple-effect set 750 klb/hr
- Number of current evaporator effects 5

- Number of effects after conversion 7
- Current heat consumption in evaporation 180 MBtu/hr
- Heat consumption after conversion 129 MBtu/hr

Reduction in heat consumption:
((180 - 129) MBtu/hr) x (24 hr/d) / (1000 ADT/d)
= 1.2 MBtu/ADT

Corresponding savings in steam consumption:
(1.2 MBtu/ADT) x (1000 ADT/d) / (24 hr/d) x ($2.2/MBtu)
= $110/hr *or* $924,000/yr

CO_2 reduction of oil fired boiler (process heat plus heat to back-pressure power):
((1.2 MBtu/ADT) + (1.2 MBtu/ADT) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(1000 ADT/d) / (24 hr/d) x (211.8 lb CO_2/MBtu)
= 13,140 lb CO_2/hr *or* 55,188 T CO_2/yr

CO_2 increase due to increased power purchases:
(1.2 MBtu/ADT) x (0.0669 MWh/MBtu) x (1000 ADT/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 6720 lb CO_2/hr *or* 28,224 T CO_2/yr

Net reduction of CO_2 emissions:
13,140 - 6720
= 6420 lb CO_2/hr *or* 26,964 T CO_2/yr

3.3.6.4 *Install high solids concentrator to maximize steam generation with black liquor*

Description

Maximizing the dry solids content of black liquor fired in the recovery boiler minimizes the amount of water to be evaporated from the liquor and improves the boiler's thermal efficiency. Maximum solids concentrations can be achieved by using a specially designed high solids concentrator. The objective of the high solids concentrator is to concentrate the liquor while minimizing scaling and fouling. Figure 3.34 illustrates the general concept. Two types of concentrators are commonly used: falling film and submerged tube. The falling film concentrator operates similarly to an effect in a multiple effect evaporator (MEE). The liquor is fed to a preheater, a falling film section, and then a rising film section where water is evaporated. A portion of the liquor product is recirculated to help prevent scaling. The heat source is usually live steam, and vapors from the concentrator can usually be integrated into a MEE set.

The second type of concentrator is the submerged tube type. In this concentrator, liquor is circulated in submerged tubes where it is heated but not evaporated. The liquor is then flashed to the concentrator vapor space, causing evaporation.

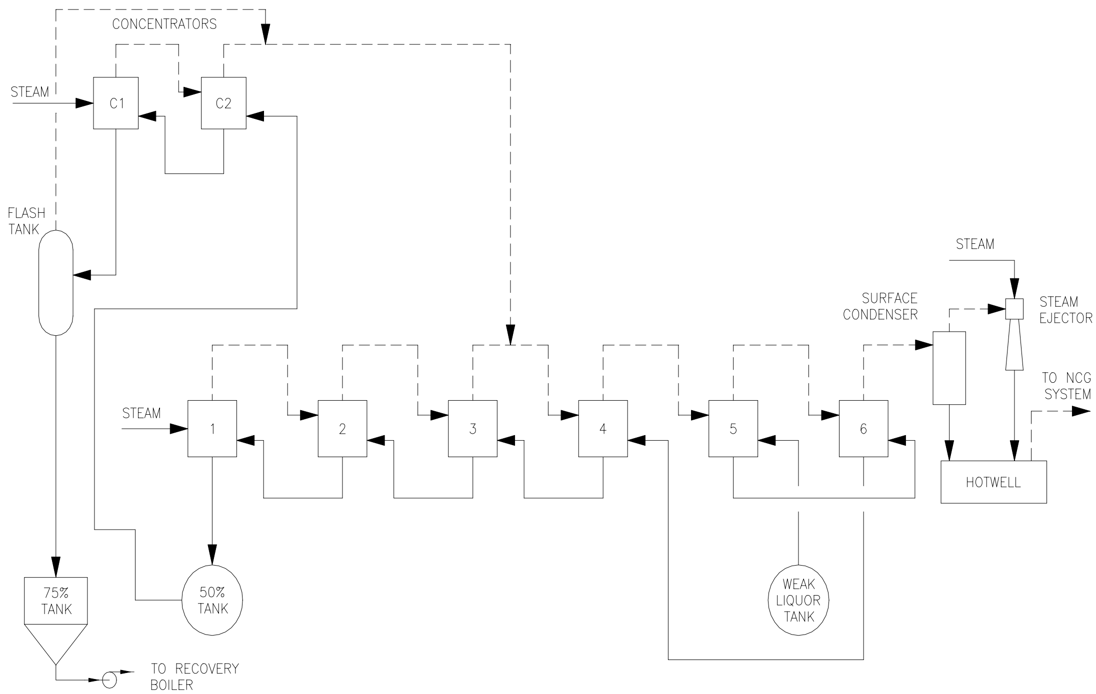

Figure 3.34. High Solids Concentrator Integrated to the Multiple Effect Evaporator

Applicability and Limitations

High solids firing in the kraft recovery boiler is applicable to non-DCE boilers. The viscosity of black liquor at high solids concentrations normally sets the limit that can be reached at any specific installation.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using a high solids concentrator improves the thermal efficiency of the recovery boiler. Less water must be evaporated from the liquor, so more energy is available for steam generation. Some energy will be required for liquor pumps (electrical) and evaporation (steam). However, by using concentrator vapors in the MEE the impact on energy and steam demand can be minimized. Energy gained from burning high solids liquor will more than offset the steam demand of the concentrator.

Impact on CO_2

Increasing the solids content of black liquor going to the recovery boiler will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. The reduction will occur due to improvements in the boiler's thermal efficiency, which will allow the same amount of steam to be generated with less fuel.

Impact on Operating Costs

There are some operating costs associated with a high solids concentrator. Electrical power usage will increase due to new transfer and circulating pumps. The concentrator will require a heat supply, usually live steam, which will impact mill steam demand. However, these increases will be offset by improvements in the recovery boiler from burning higher solids liquor. Gains in boiler thermal efficiency will result in energy savings which will reduce operating costs, although the potential to realize these gains will vary.

Capital Costs

Costs of the high solids concentrator will include concentrator bodies, piping for liquor and steam supplies, and pumps.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Figure 3.35 illustrates incremental additional quantities of steam available from the recovery boiler for other processes compared to steam available at 66% d.s. concentration of strong black liquor. The additional heat available has been calculated as the difference between recovery boiler steam production at high solids firing versus that at 66% solids, taking into consideration the steam consumption of the boiler itself and that of the concentrator. As shown, the solids concentration of liquor from the evaporator/concentrator has a significant impact on steam generation from biofuels.

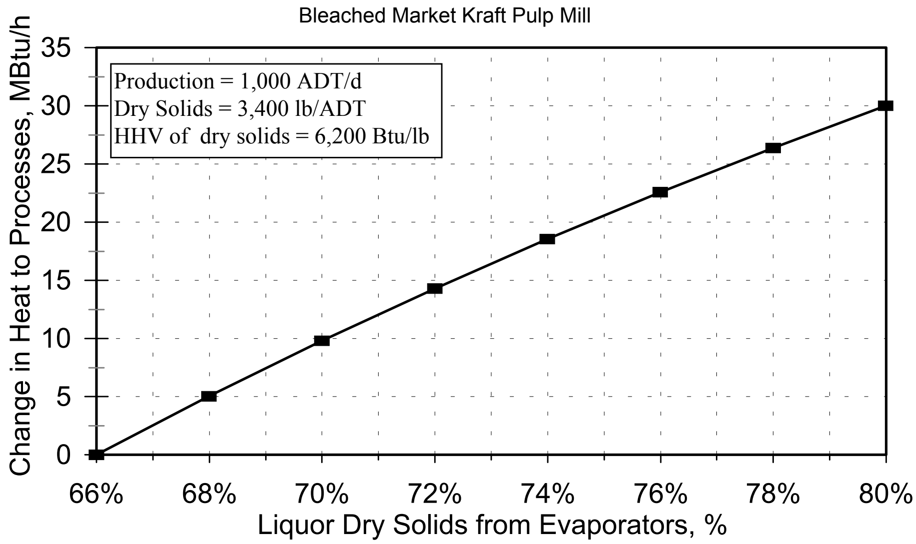

Figure 3.35. Sample Calculation for Additional Heat Available from the Recovery Boiler Compared to Heat Available at 66% Solids Concentration of Black Liquor (based on an example bleached market kraft pulp mill)

Because of the zero contribution to CO_2 emissions by black liquor, CO_2 emissions are also reduced with increased solids concentration of black liquor. Figure 3.36 illustrates this impact. Figures 3.35 and 3.36 are based on detailed kraft recovery boiler balances and other calculations explained in Section 3.3.6.1, except that the reference point is 66% dry solids instead of 50% dry solids concentration in the black liquor leaving the generator. The bases for the sample calculations are:

- Bleached market pulp (softwood) 1000 ADT/d
- Dry solids from pulp mill 3400 lb/ADT
- Heating value of dry solids 6200 Btu/lb d.s
- Reference point: Liquor from evaporators to DCE at 66% d.s. concentration
- All steam to the concentrators is 50 psig exhaust steam from turbogenerator
- Concentrator power consumption has been estimated to be 5 kWh/T H_2O

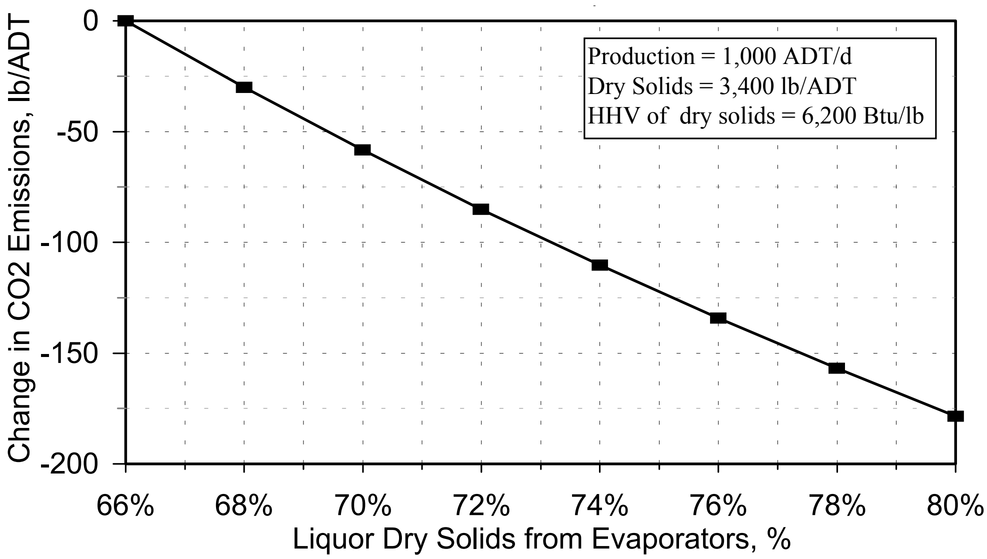

Figure 3.36. Impact of Black Liquor Dry Solids Concentration on CO_2 Emissions (reference (=zero) point is 66% solids concentration) (based on an example bleached market kraft pump mill)

As shown in Figure 3.36, increasing the black liquor solids concentration from 66% to 80% would reduce CO_2 emissions by about 178 lb CO_2/ADT (based on using the additional steam from the recovery boiler to replace steam currently produced by burning oil).

Savings in steam going from 66 to 80% d.s. concentration (assume low pressure steam generated with oil is replaced):
(30 MBtu/hr) x ($2.2/MBtu)
= $66/hr *or* $554,400/yr

The savings assume that steam from the oil fired boiler also goes through the turbogenerator.

With higher solids at the boiler nozzles, the capacity of the boiler can normally be increased. Also, many mills have experienced reduced sootblowing requirements. This may, in some cases, be on the same order of magnitude as the increased steam generation.

3.3.6.5 ***Implement an energy efficient lime kiln (lime mud dryer, mud filter, product coolers, etc.)***

Description

In the lime kiln, lime mud ($CaCO_3$) is converted to lime (CaO) and CO_2. This calcining reaction must be carried out at a high temperature, around 2200°F. This high temperature is maintained by burning fuels such as natural gas or No. 6 fuel oil. Large amounts of heat exit the lime kiln with the lime product and flue gases. This heat can be recovered and the energy efficiency of the kiln improved, resulting in fuel savings. Several ways exist to improve the energy efficiency of the lime kiln. These include using lime mud filters, lime mud dryers, and lime product coolers.

The causticizing reaction used to generate white liquor is carried out in an aqueous state, so the lime mud byproduct from this reaction has a high moisture content. If more moisture is removed from the lime mud before it enters the kiln, kiln energy efficiency will improve because less water will need to be evaporated and more heat will be available for the calcining reaction. One method to remove water from lime mud is to use a rotary vacuum drum filter. After leaving the filter, lime mud can be further dried using a lime mud dryer. This dryer uses hot flue gases from the lime kiln to dry the mud before feeding it to the kiln.

The hot lime product leaving the kiln can be used to preheat air entering the kiln using tubular coolers. In these coolers hot lime and cool air flow countercurrently and the air is heated.

A general concept for an energy efficient lime kiln is shown in Figure 3.37.

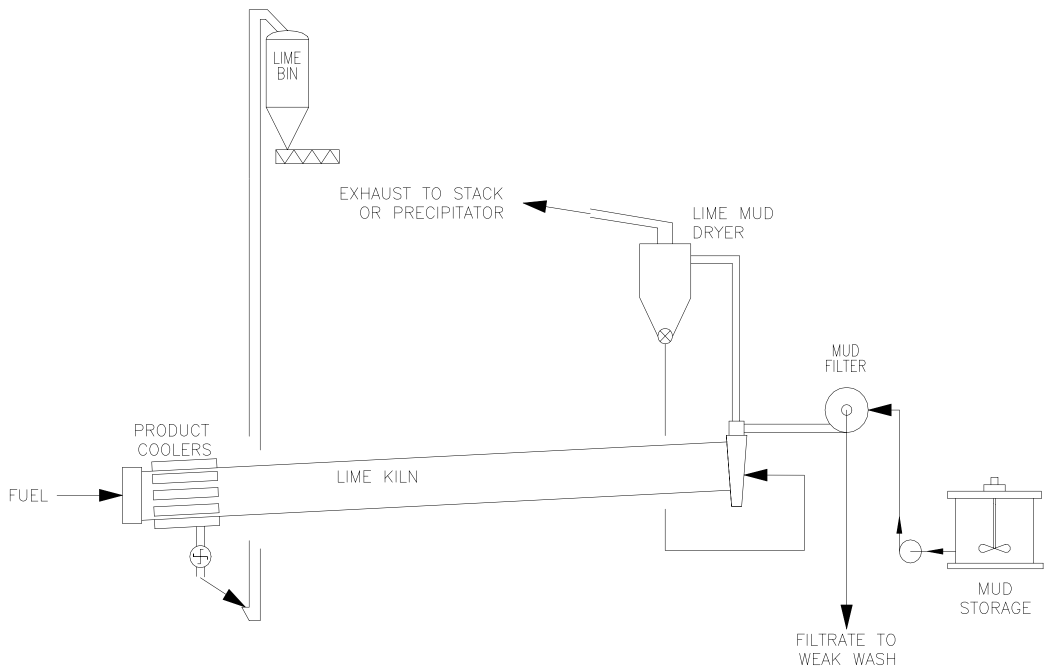

Figure 3.37. Implementation of an Energy Efficient Lime Kiln (lime mud dryer, mud filter, product coolers, etc.)

Applicability and Limitations

Kiln modernization is technically applicable to any old lime kiln. The benefits can, however, vary enormously from mill to mill depending on a variety of factors; for instance, the extent to which such systems are already in place. The economic feasibility of kiln modernization is not very attractive on the basis of energy cost savings alone. The measures involved in modernization will typically provide higher capacity for the kiln. Therefore, kiln modernization is normally justified on the basis of increased capacity.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using a lime mud filter, a lime mud dryer, and product coolers will improve the energy efficiency of the kiln. Filters and dryers will reduce the amount of water that must be evaporated in the kiln, and product coolers will reduce the amount of air heating in the kiln. These will increase available heat for the calcining reaction, and fuel savings will result. The total amount of energy savings will depend on which technologies are used.

Impact on CO_2

The CO_2 emissions from kraft mill lime kilns can be difficult to properly characterize because they contain a combination of fuel- and process-derived carbon of both fossil and biomass origin. The carbon dioxide from kraft mill lime kilns is from two, or sometimes three, sources. These are biomass CO_2 released from lime mud ($CaCO_3$) in the calcining process, fossil CO_2 from fossil fuel burned in the kiln, and, in some cases, biomass CO_2 from pulp mill-derived gases burned in the kiln. NCASI has developed methods for estimating biomass- and fossil fuel-derived emissions of CO_2 from line kilns, which may be useful to mills interested in this technology option (Miner and Upton 2001).

Improving the lime kiln's energy efficiency through the use of lime mud filters, dryers, or product coolers will reduce CO_2 emissions per ton of product. CO_2 reduction will occur due to fuel savings, and will depend on which technologies are used.

Impact on Operating Costs

Energy efficiency improvements in the lime kiln will reduce operating costs. Most of the savings will be from an increase in the fuel economy of the kiln. Some additional electrical power may be required for the lime mud filter and dryer.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used.

Assume:

• Bleached kraft production	1000 ADT/d
• Lime kiln fuel usage before modification (typical energy consumption of a short lime kiln with no product coolers,overloaded mud filter, and scrubber for particulate control)	8.5 MBtu/T CaO
• Lime usage	0.27 T/ADT
• Fuel consumption of improved kiln (see, e.g., Gullichsen and Fogelholm 1999)	6.5 MBtu/T CaO

Current fuel usage in the kiln:
(8.5 MBtu/T CaO) x (0.27 T CaO/ADT) x (1000 ADT/d) / (24 hr/d)
= 95.6 MBtu/hr

Future fuel usage in the kiln:
(6.5 MBtu/T CaO) x (0.27 T CaO/ADT) x (1000 ADT/d) / (24 hr/d)
= 73.1 MBtu/hr

Fuel savings:
95.6 - 73.1
= 22.5 MBtu/hr

Savings from conversion to energy efficient kiln:
($3/MBtu) x ((8.5 - 6.5) MBtu/T CaO) x (0.27 T/ADT) x (1000 ADT/d) / (24 hr/d)
= $67.5/hr *or* $567,000/yr

Reduction in CO_2 emissions (see Section 2 for CO_2 emissions from oil):
(173.7 lb CO_2/MBtu) x (22.5 MBtu/hr)
= 3908 lb CO_2/hr *or* 16,414 T CO_2/yr

3.3.6.6 *Replace lime kiln scrubber with an electrostatic precipitator*

Description

Scrubbers have traditionally been used as the means for controlling particulate emissions in lime kilns. Slurry from the scrubber overflow is returned to the mud handling system. The circulating dust ends up loading the mud filter.

For the past 10 to 15 years, electrostatic precipitators (ESPs) have been installed instead of scrubbers on many new kilns. In other cases, existing scrubbers have been replaced with ESPs. Dust from the kiln can be collected from the precipitator as dry material. Because it is dry, it is returned directly to the kiln feed without unnecessarily loading the lime mud filter.

Applicability and Limitations

An ESP can be installed in any old or new lime kiln. The performance of a lime kiln ESP can be impacted by inlet loading and particle size distribution, particle resistivity, mud soda content, applied power, rapping frequency, and specific collection area. These factors should be considered when evaluating the applicability of this technology.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Because of lower loadings of the mud filter, the dryness of the lime kiln feed goes up and less fuel is needed for the kiln. The scrubber has a higher pressure drop than the ESP. The power consumption of the kiln fan will thus go down with the implementation of an ESP.

Impact on CO_2

Because less fuel is required per ton of lime processed, CO_2 emissions will go down. Reduced power consumption will also drive total CO_2 emissions down (including those off-site).

Impact on Operating Costs

Operating costs for the kiln will decrease because of reduced fuel and power use. If the lime mud filter on the kiln is the production bottleneck, installation of an ESP may increase capacity and reduce makeup lime and mud disposal costs as well.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil

fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3).

Assume:

• Bleached pulp production	1000 ADT/d
• Lime usage	0.27 T/ADT
• Kiln fuel use reduction due to ESP	0.4 MBtu/T lime
• Reduction in kiln power consumption	4 kWh/ADT

It has been estimated that mud dryness increases from 70 to 75% because of the electrostatic precipitator. The dryness increase is due to:

- Return of recirculating dust to the kiln as dry dust
- Reduced loading of the mud filter

Increasing mud dryness from 70% to 75% is estimated to reduce fuel consumption by 0.4 MBtu/T lime (Gullichsen and Fogelholm 1999).

An efficient scrubber has a fairly high pressure drop (20 to 30 inches H_2O) and requires a larger flue gas fan than an electrostatic precipitator. Additionally, the scrubber requires a water recirculation pump. The difference in power consumption between a scrubber and an electrostatic precipitator is estimated to be 4 kWh/ADT.

Savings:
((0.4 MBtu/T lime x 0.27 T lime/ADT) x (\$3/MBtu) + (0.004 MWh/ADT) x (\$35/MWh)) x
(1000 ADT/d) / (24 hr/d)
= \$19.3/hr *or* \$162,400/yr

Reduction in CO_2 emissions:
((0.4 MBtu/T lime x 0.27 T lime/ADT) x (173.7 lb CO_2/MBtu) + (0.004 MWh/ADT) x
(2009 lb CO_2/MWh)) x (1000 ADT/d) / (24 hr/d)
= 1116 lb CO_2/hr *or* 4689 T CO_2/yr

3.3.6.7 ***Integrate condensate stripping to evaporation***

Description

Digester and evaporator area condensates are increasingly being stripped to remove pollutants and reduce BOD loading to the wastewater treatment system. Stripping will become more prevalent at mills as they comply with new environmental regulations. The most commonly used process is steam stripping. This is essentially a distillation process in a column with trays or internal packing. The stripper off-gases (SOGs) leaving the top of the stripper are rich in volatile compounds removed from the condensates. The relatively clean condensates leave the bottom of the stripper. The stripper can use live steam and SOGs can be sent directly to incineration, or the stripper can be integrated into the evaporator system and various heat recovery measures can be implemented.

The stripper can be partially or totally integrated into the evaporator system. Live steam can be replaced with vapors from an evaporator or concentrator effect. SOGs can then be returned to a lower pressure effect for black liquor heating or evaporation, or they can be used to make warm or hot water or heat boiler feedwater. SOGs can also be used in pre-evaporator and concentrator systems. The optimum method of integrating condensate stripping into the evaporation plant will depend on each mill's operating limitations.

Figure 3.38 shows one example of integration of stripping into the evaporation plant.

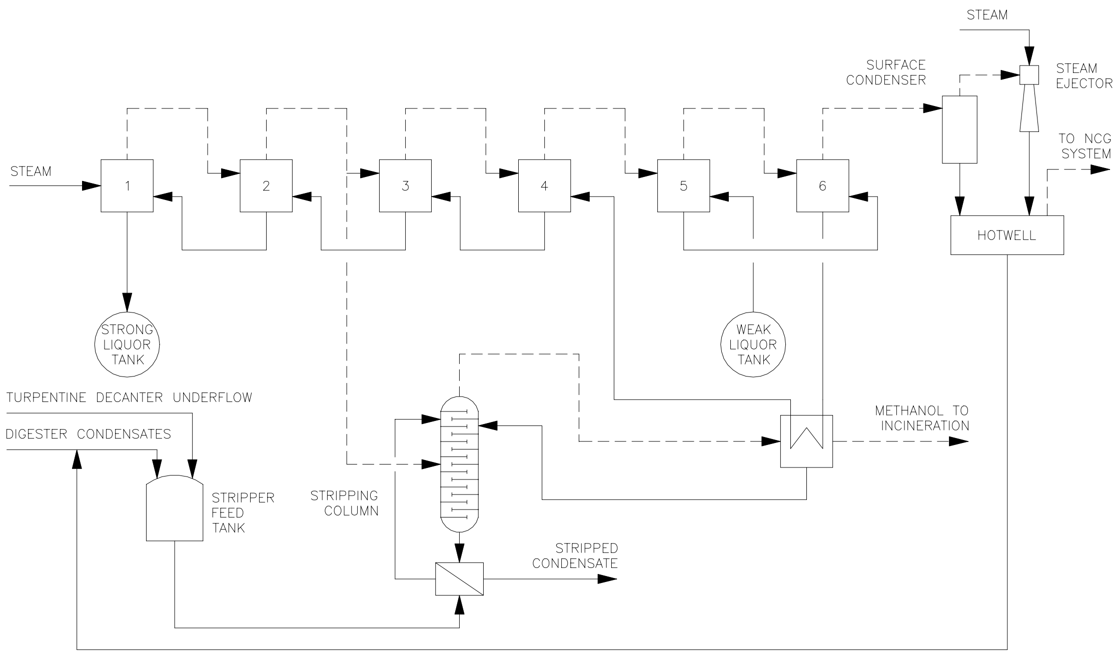

Figure 3.38. Integration of Condensate Stripping into Evaporation

Applicability and Limitations

Integration of an isolated stripping column in an existing evaporator set has to be planned very carefully in order to avoid any capacity reduction of the evaporators. The benefits and costs will be very mill-specific. Other options for recovery of SOGs should be considered:

- Hot process water preparation
- Heating boiler feedwater
- Production of low pressure steam in a reboiler

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Integrating the condensate stripping column into the evaporation plant will result in energy savings in the form of reduced steam demand. Actual energy savings will depend on how the stripping column is integrated into the evaporation plant. Based on information from similar projects at mills, fully integrating a stripping column into the evaporation plant can result in steam savings of up to 1.0 MBtu/ton of product.

Impact on CO_2

Total (considering both direct plus indirect) emissions of CO_2 per ton of product will be reduced by integrating the stripping column into the evaporation plant. The steam savings described will result in a CO_2 reduction.

Impact on Operating Costs

Steam savings achieved by fully integrating the stripping column into the evaporator plant will lower the mill's operating costs.

Capital Costs

Capital costs for a fully integrated stripping column will be very dependent on how the column is integrated and whether any additional equipment such as pre-evaporators or high solids concentrators are installed.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

The following data have been estimated based on information from similar projects at mills:

• Bleached kraft mill production	1000 ADT/d
• Condensate to stripping	400 gpm
• Steam to stripping	40 klb/hr
• Temperature of condensates to stripping	165°F
• Temperature of stripped condensates	190°F
• Heat available with stripper off-gases	42 MBtu/hr
• Stripping column is currently an isolated column with heat disposed of in a cooling tower	

The integration of the column can be implemented, for example, by using secondary vapors from an evaporator body and using the consecutive body as the reflux condenser. A steam amount equivalent to the heat available in stripper off-gases, 42 MBtu/hr, will be saved. Stripped condensates are returned from the stripping system at 190°F. Heat contained by stripped condensates (6 MBtu/hr additional to heat going in with condensates) can potentially also be utilized to save steam.

Assume:

- Heat in stripper off-gases can be fully utilized to replace live (50 psig) steam
- 70% of heat added in stripped condensates (6 MBtu/hr) can be utilized to replace live steam
- All 50 psig steam is taken through a turbogenerator

Savings:
(42 MBtu/hr + 0.7 x 6 MBtu/hr) x ($2.2/MBtu)
= $101.6/hr *or* $853,440/yr

CO_2 reduction from oil burning:
(42 MBtu/hr + 0.7 x 6 MBtu/hr) x (211.8 lb CO_2/MBtu)
= 9785 lb CO_2/hr *or* 41,097 T CO_2/yr

Increase of CO_2 because of increased purchased power:
(42 MBtu/hr + 0.7 x 6 MBtu/hr) x (0.0669 MWh/MBtu) x (2009 lb CO_2/MWh)
= 6209 lb CO_2/hr *or* 26,078 T CO_2/yr

Net reduction in CO_2 emissions:
9785 - 6209
= 3576 lb CO_2/hr *or* 15,019 CO_2/yr

3.3.6.8 *Install a methanol rectification and liquefaction system*

Description

Conventional condensate stripping systems leave stripper off-gases in gaseous form. The water content of the gases is 50 to 60%. The gases are transported to the incineration point using steam ejectors or by pressurizing the column enough so no additional means are needed for the transportation of gases.

Incineration of stripper off-gases in gaseous form ties the stripping and incineration systems together very closely. If either of the systems is unavailable, the other has to be taken off-line from stripping duty as well. Liquefaction of stripper off-gases has been applied in some mills. However, high and variable water content in the stripper product caused problems in incineration. Rectification of the stripper product (purification, or concentration of the methanol in the liquified stripper off-gases by a distillation process) has recently been implemented in several kraft mills. This involves a small rectification column for the stripper product and the production of liquid with about 80% concentration of methanol, pinenes, etc.; i.e., about 20% water content.

Liquid methanol from the liquefaction system can be stored in a buffer tank. The level of the tank can be varied according to the operation of the stripper or the incinerator. Thus the operation of the stripper and the incineration systems can be separated from each other, and overall reliability will improve.

Applicability and Limitations

Methanol liquefaction is technically feasible with any methanol stripping system. Economic feasibility is not very attractive based on energy benefits alone. Because the liquid product can be stored, the overall availability and reliability of the stripping and incineration systems are better than those for a conventional system.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Reduction of the water content of a stripper product will increase its heating value. It is estimated that the effective heating value is about 20% higher for the rectified stripper product than for the off-gases from a conventional single stage stripping system.

The rectification column uses some steam, typically 1 to 2% that of main stripping column consumption.

Impact on CO_2

Improvement of the heating value of the stripper product reduces either the support fuel requirement in the incinerator or fuel consumption at another point of incineration. There may be some increase in steam consumption due to operation of the rectification column; however, this should be offset by the increased fuel value of the more concentrated methanol solution.

Capital Costs

The rectifier column and liquefaction condensers are the main cost items, along with the methanol tank.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Pulp production	1000 ADT/d
• Methanol in stripper off-gases	15 lb/ADT
• Heating value of methanol	20 kBtu/lb
• Water content of stripper off-gases	55%
• Water content of rectified methanol	20%
• Efficiency when burning off-gases	63%
• Efficiency when burning rectified methanol	78%
• Boiler efficiency	82%
• Power boiler is used for incineration	

Fuel savings in power boiler due to incineration of stripper product:

Gaseous product:

$$\left(\frac{0.63}{0.82}\right) \text{x } (15 \text{ lb/ADT}) \text{ x } (0.02 \text{ MBtu/lb}) \text{ x } (1000 \text{ ADT/d}) / (24 \text{ h r /d}) \text{ x } (\$3 \text{ /MBtu})$$

= $28.8/hr *or* $241,920/yr

Liquid product:

$$\left(\frac{0.78}{0.82}\right) \text{x } (15 \text{ lb/ADT}) \text{ x } (0.02 \text{ MBtu/lb}) \text{ x } (1000 \text{ ADT/d}) / (24 \text{ h r /d}) \text{ x } (\$3 \text{ /MBtu})$$

= $35.7/hr *or* $299,880/yr

Savings from rectification:
$299,880 - $241,920
= $57,960/yr

Reduction in CO_2 emissions:

$$\left(\frac{0.78-0.63}{0.82}\right)\times\frac{15\text{ lb}}{\text{ADT}}\times\frac{0.02\text{ MBtu}}{\text{lb}}\times\frac{1000\text{ ADT}}{\text{d}}\times\frac{\text{d}}{24\text{ hr}}\times\frac{211.8\text{ lb CO}_2}{\text{MBtu}}$$

= 484 lb CO_2/hr *or* 2033 T CO_2/yr

3.3.6.9 ***Install a biofuel gasifier, use low Btu gas for lime reburning***

Description

Biofuels such as hog fuel that are generated on-site can be burned directly in a boiler to produce steam or their heating value can be used for other processes. One alternative is to gasify the fuel and use the low Btu gas generated for lime reburning. The gasification process is usually carried out in a fluidized bed reactor. This type of reactor has a bed of inert material, such as sand, and has high turbulence due to the injection of air or steam. This promotes a high rate of heat transfer. The biofuel is injected into the bed, where high turbulence causes rapid combustion and gasification of the char. Low Btu gases generated in the reactor are withdrawn. The gases are cooled and can be scrubbed if needed to remove moisture or pollutants, and can then be fired in the lime kiln to displace fossil fuel used for lime reburning.

Applicability and Limitations

Both direct firing of hog fuel (dried to a minimum of 85% dryness) and hog fuel gasification and low Btu gas incineration in the lime kiln have been practiced in the Nordic countries since the late 1970s. The technology is viable, but it may not be economically attractive unless free hog fuel is in excess at the site.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing a biofuel gasifier and using the gas for lime burning will lower the mill's fossil fuel consumption.

Impact on CO_2

A biofuel gasifier will reduce CO_2 emissions from fossil fuel combustion.

Impact on Operating Costs

Using gasified biofuel in the lime kiln will lower operating costs of the kiln. Biofuels are less expensive than fossil fuels, so using more biofuel and less fossil fuel will reduce operating costs. A biofuel gasifier will require a fuel delivery system, reactor bed fluidizing system (air or steam), and gas treatment system that will deduct from fossil fuel savings.

Capital Costs

Costs of a biofuel gasifier will include the fluidized bed reactor, solid fuel delivery and injection system, gas treatment system (scrubber, absorber, etc.), and piping for the gas to the lime kiln.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Bleached kraft mill production	1000 ADT/d
• Lime usage	0.27 T CaO/ADT
• Lime kiln energy usage with oil as the fuel	7 MBtu/T CaO
• Hog fuel available at	$10/T
• Hog fuel moisture	50%
• Heating value of hog fuel	8750 Btu/lb d.s. (17.5 MBtu/T d.s.)
• Dried hog fuel is used as the energy supply for dryer	
• Dryness of hog fuel before gasification	85%
• Low Btu gas requirement in the kiln (fuel consumption with low Btu gas is higher than that with oil)	9 MBtu/T CaO
• Losses from dryer/gasifier	1 MBtu/T CaO

Hog fuel requirement for gasification:
(1000 ADT/d) x (0.27 T CaO/ADT) x ((9 + 1) MBtu/T CaO) / (17.5 MBtu/T d.s.)
= 154 T d.s./d *or* 308 T hog fuel at 50% dryness

Hog fuel drying itself consumes additional hog fuel. Evaporation of water in the dryer:

$$\left(\frac{50\text{ lb H}_2\text{O}}{50\text{ lb d.s.}} - \frac{15\text{ lb H}_2\text{O}}{85\text{ lb d.s.}}\right) \times 154\text{ T d.s./d} = 126.8\text{ T H}_2\text{O/d}$$

= 253,600 lb H_2O/d

Heat consumption (approximate heat consumption in drying is 1000 Btu/lb H_2O):
1000 Btu/lb x 253,600 lb H_2O/d x 1 MBtu/10^6 Btu
= 253.6 MBtu/d

Hog fuel required for drying (net heat recovery from hog fuel at 50% dryness is 5300 to 6000 Btu/lb d.s., Figure 3.6):
42 - 48 klb d.s./d

Allowing for some extra losses compared to a boiler, hog fuel demand for drying is roughly 25 T d.s. *or* 50 T of hog fuel per day.

Total hog fuel requirement:
(308 + 50)
= 358 T/d at 50% dryness

Cost of hog fuel:
($10/T) x (358 T/d)
= $3580/d *or* $1,253,000/yr

Cost of oil:
(7 MBtu/T CaO) x (0.27 T CaO/ADT) x (1000 ADT/d) x ($3/MBtu)
= $5670/d *or* $1,984,500/yr

Net savings:
5670 - 3580
= $2090/d *or* $731,500/yr

Reduction in CO_2:
(1000 ADT/d) x (0.27 T CaO/ADT) x (7 MBtu/T CaO) x (173.7 lb CO_2/MBtu) /(2000 lb/T)
= 164.1 T CO_2/d *or* 57,435 T CO_2/yr

3.3.7 *Mechanical Pulping*

3.3.7.1 *Implement heat recovery from TMP process to steam and water*

Description

The thermo-mechanical pulp (TMP) process uses refiners to defiber chips that are softened in a pre-steaming vessel. The refiners use large amounts of electrical power, which is converted to heat and steam through friction. This steam is exhausted from the refiner along with the chips. Exhaust steam can be recovered and used as a secondary heat source. The TMP process often uses two refiners in series. Maximum heat recovery can be achieved by using pressurized refining in both stages. Exhaust steam from the refiners is often contaminated and contains entrained air. Therefore, clean steam must be produced before it can be used in certain processes. Clean steam can be produced in a reboiler (Figure 3.39). This secondary heat can be used to replace primary heat. Different uses include the paper machine dryer, black liquor evaporation, and water or stock heating. The pressure of the steam may need to be boosted by a thermocompressor for some applications, such as the paper machine dryers. Exhaust steam can also be used to heat water in a heat exchanger. To further increase heat recovery, the chip steaming vessel and the refiner can be isolated from each other. This will allow a higher pressure in the refiner, which maximizes heat recovery.

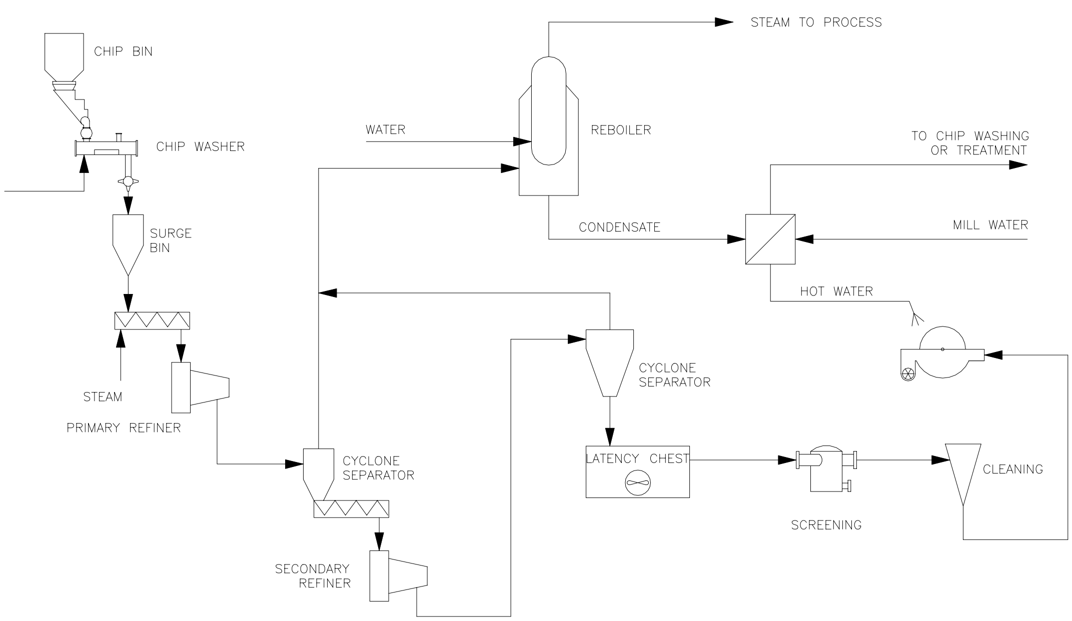

Figure 3.39. Heat Recovery from the TMP Process to Steam and Water

Applicability and Limitations

Recovering heat from the TMP process is applicable to any mill that uses pressurized refining and currently does not use heat recovery. This usually means older mills, because most modern TMP mills are designed with heat recovery systems to improve the economics of the process. The benefits can, however, vary enormously from mill to mill depending upon a variety of factors; for instance, the extent to which such systems are already in place. Maximum heat recovery can be achieved by using pressurized refining in all stages. The end use of recovered heat will depend on the mill's configuration, but most applications that could use this secondary heat will require a reboiler to produce clean steam. Two important variables which should be considered when evaluating this technology are the entering chip temperature and the refining pressure. In addition, heat recovered from TMP operations is typically in the form of low pressure steam (on the order of 30 psig). Therefore a facility considering this technology option should investigate the need for additional low pressure steam.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing systems to utilize secondary heat from the TMP process will reduce energy consumption. The use of secondary heat will replace live steam, which reduces boiler loading. Actual savings will depend on how the secondary heat is utilized.

Impact on CO_2

Recovering heat from the TMP process will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. Using secondary heat will replace the use of live steam. Reducing live steam usage lowers fuel consumption in the boilers. This reduces CO_2 emissions from the boiler.

Impact on Operating Costs

Using secondary heat from the TMP process will reduce operating costs. Secondary heat can be used to replace primary heat, which is more expensive. Primary heat is usually in the form of steam, and reducing the steam load reduces fuel consumption and operating costs.

Capital Costs

Capital costs of installing equipment to recover heat from the TMP process will depend on the end use of the secondary heat. For example, using TMP heat for paper drying or installing a black liquor pre-evaporator system to use exhaust steam will be more expensive than using the steam to heat water in a heat exchanger.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section

2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

- Production — 400 T/d
- Two-stage refining
- Pressurized steam production
- Heat recovery to steam (estimated) — 42% of power
- Power consumption in mainline refiners — 2000 kWh/T
- Power consumption in reject refiners — 800 kWh/T
- Total power to refiners — 2800 kWh/T

Steam generated in mainline refiners:
(2000 kWh/T) x (0.42) x (3.413 kBtu/kWh) x (400 T/d) / (24 hr/d) x (1 MBtu/1000 kBtu)
= 47.8 MBtu/hr

Cost savings from secondary heat:

- Operating hours — 8400 hr/yr
- Steam cost (TG exhaust) — $2.2/MBtu

(47.8 MBtu/hr) x (8400 hr/yr) x ($2.2/MBtu)
= $883,344/yr

CO_2 reduction:

CO_2 reduction from reduced oil use for process steam and back-pressure power generation:
((47.8 MBtu/hr) + (47.8 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (211.8 lb CO_2/MBtu)
= 12,562 lb CO_2/hr *or* 52,760 T CO_2/yr

CO_2 increase due to increased purchased power:
(47.8 MBtu/hr) x (0.0669 MWh/MBtu) x (2009 lb CO_2/MWh)
= 6424 lb CO_2/hr *or* 26,981 T CO_2/yr

Net CO_2 reduction:
12,562 - 6424
= 6138 lb CO_2/hr *or* 25,780 T CO_2/yr

3.3.7.2 *Add third refining stage to the TMP plant*

Description

A conventional TMP plant consists of a two-stage mainline refining system and a reject refining system. In order to intensify refining in the mainline system, a third refining stage has been implemented in some mills (Sabourin, Mackenzie, and Urquhart 1997). The objective of three-stage refining is to achieve a lower freeness level in the mainline refiners. A lower fraction of pulp is sent to the reject refiners. Thus, reject refining can take place in one stage only. Because mainline refiners are typically pressurized and reject refiners are not, adding a third refiner to the mainline enables increased recovery of secondary heat (as steam). The material presented in the subsections below pertains to this method of implementing three-stage refining.

Although not presented in detail in this manual, some mills have added a third, low consistency refiner to the mainline refining system. This configuration enables refining to lower freeness in the primary and secondary refiners (pressurized high consistency), with final refining to target freeness in the low consistency refiner. Total electrical power consumption is reduced, with concurrent reductions in off-site carbon dioxide emissions. Recovery of heat is not increased, and in fact may be decreased by implementing this change. This methodology for implementing three-stage refining is not examined in this resource manual. For more detail on this method, see Musselman, Letarte, and Simard 1997 and Vaughn, Mitchell, and Musselman 1998.

Applicability and Limitations

Three-stage refining was originally developed for pulp quality reasons. According to literature references (for example, Sabourin, Mackenzie, and Urquhart 1997), total power consumption does not change when converting from two-stage to three-stage refining. Energy savings are thus related to improved recovery of energy. Savings are fairly minor compared to capital requirements in an existing plant. The opportunity to convert to three-stage refining should therefore be considered a quality improvement project or an option in the modernization or expansion of a TMP plant.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

According to Sabourin, Mackenzie, and Urquhart (1997), the total electrical energy requirement is the same for two- and three-stage refining. The distribution of power use between mainline refiners and reject refiners is different. About 85% of total energy in Sabourin, Mackenzie, and Urquhart's study was applied in the mainline refiners of the three-stage system, while the corresponding figure for two-stage refining is 70 to 72%. Assuming that all mainline refiners are pressurized and reject refiners are not, three-stage refining, even with the same total power consumption, has an advantage of potentially clean steam production for use in other processes.

Impact on CO_2

Three-stage TMP refining produces a larger amount of clean, pressurized steam. If this replaces steam that is generated with fossil fuel, a reduction in total (considering both direct plus indirect) CO_2 emissions is achieved.

Impact on Costs

Reduced fossil fuel use for steam generation will reduce overall mill operating costs.

Capital Costs

In an existing plant, new refiners and expansion of the heat recovery systems are required. In a new plant, it may be possible to avoid a second stage of reject refining, and the cost difference may not be very high.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil

fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

For an existing TMP plant, assume:

- Production 400 T/d
- Two-stage refining
- Pressurized steam production
- Heat recovery to steam, percent of mainline refiner power 42%
- Hot water supply is sufficient from current sources
- Power consumption in mainline refiners 2000 kWh/T
- Power consumption in reject refiners 800 kWh/T
- Total power to refiners 2800 kWh/T

For three-stage mainline refining, assume:

- Power consumption in mainline refiners 2400 kWh/T
- Power consumption in reject refiners 400 kWh/T
- Total power to refiners 2800 kWh/T
- Clean steam recovery, percent of mainline refiner power 42%

Increased clean steam production:
((2400 - 2000) kWh/T) x (3.413 kBtu/kWh) x 0.42
= 573 kBtu/T

Savings:
(0.573 MBtu/T) x (400 T/d) x ($2.2/MBtu)
= $504/d *or* $176,400/yr

CO_2 reduction from reduced oil burning:
((0.573 MBtu/T) + (0.573 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(400 T/d) / (24 hr/d) x (211.8 lb CO_2/MBtu)
= 2510 lb CO_2/hr *or* 10,542 T CO_2/yr

Increased CO_2 due to increased purchased power:
(0.573 MBtu/T) x (0.0669 MWh/MBtu) x (400 T/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 1284 lb CO_2/hr *or* 5393 T CO_2/yr

Net CO_2 reduction:
2510 - 1284
= 1226 lb CO_2/hr *or* 5149 T CO_2/yr

3.3.7.3 *Replace the conventional groundwood process with pressurized groundwood (PGW) operation*

Description

In the groundwood process short logs are pressed against a grinding stone with a hydraulic ram. The rotating pulp stone creates heat through friction, which softens the lignin and allows the fibers to be pulled free. The stone is washed and cooled with water showers. In the groundwood process grinding is done at atmospheric pressure. The efficiency of the process can be improved by converting to pressurized operation (Figure 3.40). In the pressurized groundwood (PGW) process, grinding is carried out at about three times atmospheric pressure. The elevated pressure is maintained with compressed air and allows higher water temperatures in the showers. The higher temperature promotes softening of the lignin, improving fiber separation and reducing specific energy consumption for production of similar strength pulp. Pulp leaving the grinder is flashed through an expansion valve. The flash steam given off can be recovered as a secondary heat source. The pulp is then thickened in a drum thickener and the hot water filtrate is returned to the grinder. The process can be further enhanced using a pressure disk filter instead of a drum thickener, which allows the use of water temperatures up to 140°C.

Applicability and Limitations

Pressurized groundwood can replace conventional groundwood in most applications. Pulp quality improvements (e.g., fiber length and strength) are normally gained, and as a result consumption of chemical pulp on the wood containing paper grades can be reduced. Alternatively, mechanical pulp with similar properties can be produced at a lower specific energy consumption.

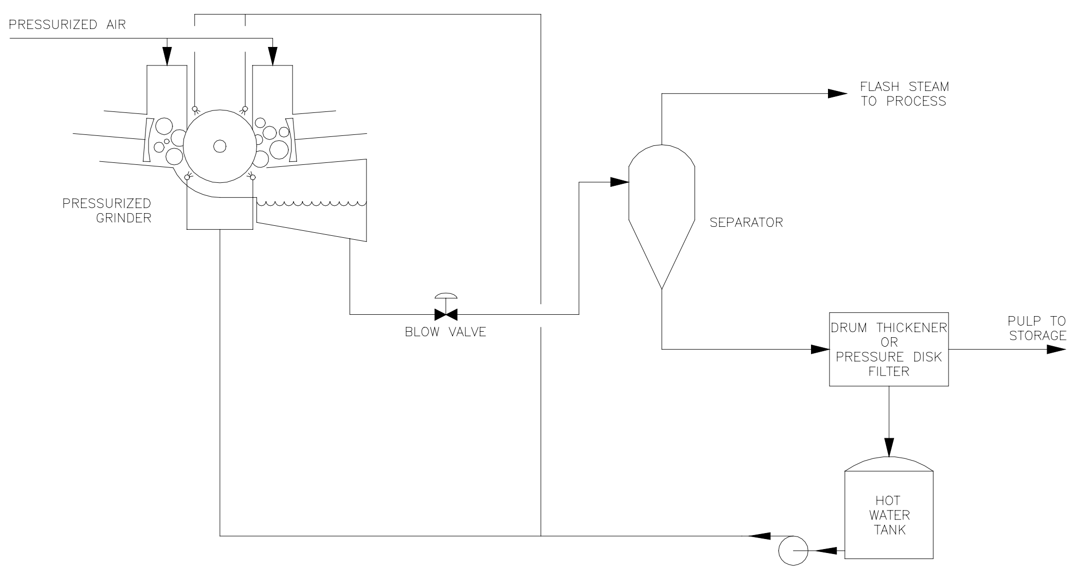

Figure 3.40. Pressurized Groundwood (PGW) Process

Replacement of a conventional groundwood plant with PGW is a major capital project and cannot be justified on an energy savings basis alone. Quality improvements are normally the driving forces behind the replacement.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Converting to pressurized groundwood operation will reduce energy consumption for production of similar quality pulp. The hotter the showers are, the more the lignin is softened, so less mechanical energy is required to separate the fibers. Thus, less electrical energy is consumed by the grinder. Some secondary heat in the form of flash steam can also be recovered.

Impact on CO_2

Conversion to a pressurized groundwood process will reduce off-site CO_2 emissions associated with purchased electrical power. The pressurized process uses less electrical energy per ton of similar quality product because of increased lignin softening. Thus electrical energy demand and fossil fuel usage are reduced, lowering off-site CO_2 emissions. Use of flash steam to eliminate live steam can further reduce CO_2 emissions, assuming that there is a need for steam (e.g., in the paper machine drying section).

Impact on Operating Costs

Using the pressurized groundwood process will reduce operating costs. Because the pressurized process has a lower specific energy usage, operating costs will be reduced accordingly. Recovery of flash steam as secondary heat will also reduce operating costs by replacing live steam.

Capital Costs

Capital costs will include new pressurized grinders and associated equipment such as hot water return piping and pumps and an air pressure system. Installing a pressure disk filter will further increase capital costs.

Sample Calculations

The following sample calculation is based on reduced use of purchased electrical power corresponding to energy conservation/CO_2 reduction measures, and incorporates an emission factor and an assumed price for power. When estimating the impacts of implementing this technology option at a mill, current or projected prices for and emission factors corresponding to purchased electricity should be used (see Section 2.3). Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Groundwood plant capacity 500 T/d
- Power consumption in atmospheric grinding 1800 kWh/T
- Power consumption in PGW grinding 1400 kWh/T
- Same quantity of pulp at similar strength is produced
- Additional heat recovery not implemented (estimated savings due to lower specific energy consumption only)

Energy savings:
((1.8 - 1.4) MWh/T) x (500 T/d) / (24 hr/d) x $35/MWh)
= $292/hr *or* $2.45 million/yr

Reduction in CO_2:
((1.8 - 1.4) MWh/T) x (500 T/d) / (24 hr/d) x (2009 lb CO_2/MWh)
= 16,742 lb CO_2/hr *or* 70,316 CO_2/yr

3.3.7.4 *Countercurrent coupling of paper machine and mechanical pulping white water systems*

Description

Mechanical pulping creates pulp through the use of mechanical energy instead of chemicals. Mechanical pulps can be produced by grinding logs or refining chips. Mechanical pulping processes use water for screening and cleaning and showers on thickeners and grinding stones. The white water systems of the paper machine can be coupled countercurrently to the white water system of the mechanical pulping process, reducing fresh water usage and water heating. Using warm water has other benefits, such as quality and production improvements in the groundwood mill. In a refiner operation the coupled white water could be used for chip washing.

Applicability and Limitations

Countercurrent coupling of the paper machine white water system with the mechanical pulping white water system has great advantages from an energy point of view. The heat generated in mechanical grinding or refining processes can be utilized in the paper mill area. At the same time, however, many undesirable substances contained in natural wood may be transferred to the paper mill. Chemical use for controlling these undesired substances could increase. Efficient washing of pulp may be necessary to avoid increases in chemical costs. Some bleed of white water from mechanical pulping may also be necessary.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Countercurrent coupling of the paper machine and mechanical pulping white water systems will reduce energy consumption. Decreasing fresh water usage lowers water heating requirements. Using warm water for grinding and chip washing helps soften lignin and promotes fiber separation, reducing mechanical energy requirements.

Impact on CO_2

Coupling the paper machine and mechanical pulping white water systems will reduce total (considering both direct plus indirect) CO_2 emissions. Reductions will result from a drop in mill water heating (i.e., lower steam generation and fuel consumption) and increases in process efficiency.

Impact on Operating Costs

Energy savings from countercurrent coupling of the paper machine and mechanical pulping white water systems will reduce operating costs from both steam and electrical power savings. There may be increased costs associated with chemical management in the more tightly closed white water system.

Capital Costs

Capital costs will depend on how the two white water systems are coupled. Additional piping, pumps, and tankage will be required.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

For the sample calculations, assume that a TMP mill recirculates paper machine white water for use in refining and stock handling (screening and cleaning) unit operations. Heat in the white water is used to offset the heating of fresh water with steam.

Assume:

• TMP mill capacity	400 T/d
• Mill fresh water temperature	60°
• White water temperature	100°F
• White water flow rate to pulp mill	1600 gpm

Steam savings:
(1600 gpm) x (100 - 60°F) x (1 Btu/lb/°F) x (60 min/hr) x (8.34 lb/gal) x (1 MBtu/10^6 Btu)
= 32.0 MBtu/hr
(32.0 MBtu/hr) x (24 hr/d) / (400 T/d)
= 1.9 MBtu/T

Total cost savings:
(1.9 MBtu/T) x (\$2.2/MBtu) x (400 T/d) x (350 d/yr)
= \$585,200/yr

Reduction in CO_2 emissions:

Reduction due to reduced oil use:
((1.9 MBtu/T) + (1.9 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (211.8 lb CO_2/MBtu)
= 499 lb CO_2/T

Corresponding annual CO_2 reduction:
(499 lb CO_2/T) x (400 t/d) x (350 d/yr) / (2000 lb/T)
= 34,930 T CO_2/yr

Increase in CO_2 emissions because of increased purchased power:
(1.9 MBtu/T) x (0.0669 MWh/MBtu) x (400 T/d) x (350 d/yr) x (2009 lb CO_2/MWh) / (2000 lb/T)
= 17,875 T CO_2/yr

Net reduction in CO_2 emissions:
34,930 - 17,875
= 17,055 T CO_2/yr

3.3.8 *Deinking Plant*

3.3.8.1 *Supply waste heat from other process areas to deinking plant*

Description

Like the chemical pulping and papermaking processes, deinking requires heat to increase process efficiency. This starts with the repulping process, where the paper is defibered and ink is removed from the fiber surface. Large contaminants are removed through screening and cleaning, and ink particles can then be removed by washing and flotation. Finally, the remaining ink can be dispersed. Waste heat, in the form of hot water, can be supplied to the repulping process. The needed heat can be supplied from secondary heat sources in the recycled fiber plant or from other areas if the recycled mill is integrated with a kraft pulp and paper mill. Water heated with secondary heat can be used in the washing and flotation processes for shower water and dilution. Ink dispersion processes also require high temperatures to soften and disperse the ink. For this process, the stock can be heated in a heat exchanger with hot water or flash vapors from other processes. Live steam could be used for final temperature control if needed.

Applicability and Limitations

Use of secondary heat from other mill areas to provide heat to the deinking process normally implies a facility integrated with a kraft pulp mill or a papermaking process in order to provide sufficient secondary heat. If secondary heat (normally warm or hot water) is available from other mill areas, piping it to the deinking plant is usually feasible.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using secondary heat in the deinking plant will reduce energy consumption. Secondary heat can be used to replace more expensive primary heat, such as steam for water and stock heating. Increasing the stock temperature to certain processes may result in improved operation as well.

Impact on CO_2

Replacing primary heat with secondary heat in the deinking plant will lower total (considering both direct plus indirect) CO_2 emissions. Using waste heat means less steam needs to be generated. This lowers fuel consumption in the boilers, and CO_2 emissions drop.

Impact on Operating Costs

Supplying waste heat to the deinking plant will lower operating costs. Primary heat is more expensive because it must be generated by the combustion of fuel. Replacing primary heat with secondary heat thus saves fuel and reduces operating costs.

Capital Costs

Capital costs will depend on the location of the heat source and the heat user. Piping and pumps will be required, and possibly a heat exchanger.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

• Production of deinked pulp	300 T/d
• Temperature of water currently being used	70ºF
• Temperature of water available from other mill areas	100ºF
• Water use in deinking plant	2500 gal/T of deinked pulp
• Cost of heating pulp suspension for bleaching using low pressure steam	\$2.2/MBtu

Steam savings using 100°F water instead of 70°F water:
((100°F - 70°F) x 1 Btu/°F lb) x (2500 gal/T) x (8.34 lb/gal) x (10^{-6} MBtu/Btu)
= 0.63 MBtu/T of deinked pulp

Total cost savings:
(0.63 MBtu/T) x ($2.2/MBtu) x (300 T/d) x (350 d/yr)
= $145,530/yr

Reduction in CO_2 emissions:

Reduction due to reduced oil use (including loss in back-pressure power generation)
((0.63 MBtu/T) + (0.63 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(211.8 lb CO_2/MBtu)
= 166 lb CO_2/T

Corresponding annual CO_2 reduction:
(166 lb CO_2/T) x (300 T/d) x (350 d/yr) / (2000 lb/T)
= 8715 T CO_2/yr

Increase in CO_2 emissions due to increased purchased power (assume self generated power is decreased):
(0.63 MBtu/T) x (0.0669 MWh/MBtu) x (300 T/d) x (350 d/yr) x (2009 lb CO_2/MWh) / (2000 lb/T)
= 4445 T CO_2/yr

Net reduction:
8715 - 4445
= 4270 T CO_2/yr

3.3.8.2 *Install drum pulpers*

Description

Many deinking plants use vat type pulpers, often with batch operation. Recovered paper and water are charged to the vat, repulped, and then drained from the vat. A batch process consumes more energy. Power demand peaks when the pulper is charged with paper. A batch pulper has a higher down time because it is off-line when being unloaded. Installing continuous drum or dry pulpers will reduce energy consumption, and may also reduce water use and associated water heating requirements.

A continuous drum pulper consists of a rotating inclined drum. The drum is divided into two zones: pulping and screening. The pulping zone operates at high consistency (15 to 20%) and the screening zone operates at a lower consistency (≈5%). Paper, water, and deinking chemicals are fed to the pulping zone at the upper end of the drum. As the drum rotates the paper is picked up and dropped by internal baffles. This action causes the paper to be defibered and the ink to be removed from the fiber surface. The slurry then enters the screening zone where large contaminants are removed and flow out the low end of the drum. The pulp is then processed in a conventional cleaning and deinking stock preparation system. Because of the slow rotation of the drum, contaminants are not reduced in size. This also means that baling wire must be removed and the bales separated before being fed to the drum. Figure 3.41 illustrates the concept for drum pulpers.

Applicability and Limitations

Installing a drum pulper is applicable to any deinking plant that currently uses a vat type pulper and that has the space and production volume to accommodate a drum pulper. Because baling wire must be removed from the paper prior to it entering the drum pulper, bale dewiring and bale breaking equipment may be required in addition to the drum pulper if it does not already exist at the mill.

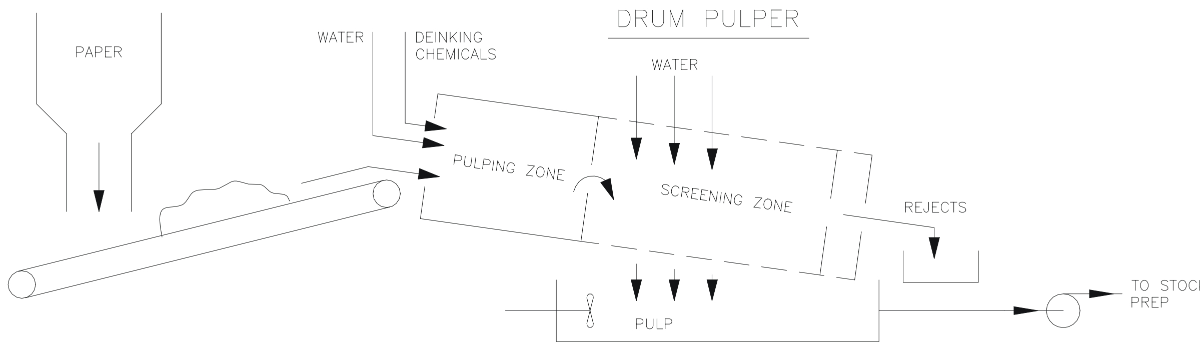

Figure 3.41. Drum Pulper

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing a continuous drum pulper will reduce energy consumption. A continuous repulping process has lower specific energy consumption. Because the power demand is more level, the connected horsepower requirement is also lower.

Impact on CO_2

Installing a drum pulper will reduce CO_2 emissions. Power consumption is lower for the continuous process. This means less electrical power is consumed and less CO_2 is generated.

Impact on Operating Costs

A continuous drum pulper will lower operating costs. Lower specific energy consumption means reduced operating costs.

Capital Costs

Costs of a continuous drum or dry pulper will be higher than those of batch equipment with equivalent capacity.

Sample Calculations

The following sample calculation is based on reduced use of purchased electrical power corresponding to energy conservation/CO_2 reduction measures, and incorporates an emission factor and an assumed price for power. When estimating the impacts of implementing this technology option at a mill, current or projected prices for and emission factors corresponding to purchased electricity should be used (see Section 2.3). Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Production of deinked pulp — 300 T/d
- Specific energy use of continuous drum pulper — 25 kWh/T
- Specific energy use of batch pulper — 35 kWh/T

Energy savings:
(35 kWh/T - 25 kWh/T) x (300 T/d) x (10^{-3} MWh/kWh)
= 3 MWh/d

Cost savings:
(3 MWh/d) x ($35/MWh) x (350 d/yr)
= $36,750/yr

CO_2 reduction due to decreased purchased power:
(3 MWh/d) x (350 d/yr) x (2009 lb CO_2/MWh)
= 2.11 M lb CO_2/yr *or* 1055 T CO_2/yr

3.3.8.3 *Implement closed heat and chemical loop*

Description

The deinking process uses both heat and chemicals to produce deinked paper. Recovering heat and chemicals back to the process reduces energy consumption and operating costs. Heat can be recovered by recycling process water or closing the water loop completely. Recycling process water will reduce water heating requirements and increase water temperature. A closed water loop not only reduces fresh water usage, but also reduces wastewater treatment. During the pulping and deinking process some mechanical energy from pulpers, pumps, etc. is transferred to the process water as heat. A closed water loop allows this energy to be recovered.

In addition to heat recovery, recycling of process water allows recovery of chemicals and fiber. Chemicals are used in the repulping process (e.g., sodium hydroxide) to separate the ink from the fiber, and in the deinking process (e.g., surfactants) to remove ink particles. Recycling water to these processes reduces the amount of new chemicals that must be added. Installing a drum or disk thickener after the stock preparation system and before the paper machine allows alkaline filtrate to be recycled to these processes. It also reduces the amount of acid required on the paper machine for neutralizing incoming stock. Closing the water loop will also maximize recovery of fiber and fines, increasing utilization of raw materials.

Applicability and Limitations

In order to reduce water use in deinking plants, effective washing systems must exist. Low water use may affect the quality of pulp, due partly to accumulation of metals and other non-process elements into the water system of the deinking plant. The feasibility analysis for this technology can be quite complex and must be based on mill-specific process and product quality requirements.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Closing the heat and chemical loop will decrease primary energy consumption. Closing the water loop will decrease water heating and increase water temperature. The increase in water temperature may improve the performance of certain processes, such as the paper machine and dryers. Closing the chemical loop recovers unused chemicals, which means less energy is consumed in the production and transport of makeup chemicals.

Impact on CO_2

Using a closed heat and chemical loop in the deinking plant will lower total (considering both direct plus indirect) CO_2 emissions. Recycling process water will reduce steam usage for water heating and in the paper machine dryers. This drop in steam demand will reduce fossil fuel consumption in the boiler and lower CO_2 emissions.

Impact on Operating Costs

Recovering heat and chemicals in the deinking process will reduce operating costs. Savings will come from reduced steam demand (fuel savings) and decreased chemical consumption. Fiber will be recovered, which will lower raw material costs. The cost of effluent treatment will drop. Some of the savings will be offset if additional equipment, such as thickeners or process water clarifiers, is installed. There may be increased costs associated with chemical management in the more tightly closed water system.

Capital Costs

Capital costs will depend on the degree of heat and chemical loop closure. The higher the degree of closure, the higher capital costs will be. Very low water use may require installation of additional washing equipment, and perhaps a press in order to efficiently separate the deinking plant white water system from the machine white water system.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

• Production of deinked pulp	300 T/d
• Water use in deinking plant	2500 gal/T of deinked pulp
• Water use can be reduced to half the present	1250 gal/T
• Cost of heating pulp suspension using low pressure steam	$2.2/MBtu
• Water temperature to the plant	70ºF
• Stock temperature to paper mill	140ºF

Steam savings from water use reduction correspond to heat required to heat 1250 gal/T from 70°F to 140°F:

((140°F - 70°F) Btu/lb/°F) x (1250 gal/T) x (8.34 lb/gal) x (10^{-6} MBtu/Btu)
= 0.73 MBtu/T of deinked pulp

Total cost savings:
(0.73 MBtu/T) x ($2.2/MBtu) x (300 T/d) x (350 d/yr)
= $168,630/yr

Reduction in CO_2 emissions:

Reduction due to reduced oil use (including loss in back-pressure power generation):
((0.73 MBtu/T) + (0.73 MBtu/T) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x
(211.8 lb CO_2/MBtu)
= 192 lb CO_2/T

Corresponding annual CO_2 reduction:
(192 lb CO_2/T) x (300 T/d) x (350 d/yr) / (2000 lb/T)
= 10,080 T CO_2/yr

Increase in CO_2 emissions because of increased purchased power (assume self generated power production is decreased):
(0.73 MBtu/T) x (0.0669 MWh/MBtu) x (300 T/d) x (350 d/yr) x (2009 lb CO_2/MWh) / (2000 lb/T)
= 5151 T CO_2/yr

Net reduction in CO_2 emission:
10,080 - 5151
= 4929 T CO_2/yr

3.3.9 *Mill General*

The energy and emission impacts of technology options in this section (Section 3.3.9 – Mill General) are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

3.3.9.1 *Optimize integration and utilization of heat recovery systems*

Description

In integrated pulp and paper mills there are opportunities for energy savings through integration of secondary heat recovery and utilization systems between mill departments. The best use of secondary heat is when it can be utilized for steam savings within the same process or department. This is because the operating rates are typically very similar, and thus availability of secondary heat matches demand most of the time. However, there are processes and mill departments that have either surpluses or deficits of hot water. Integration of secondary heat sources and potential users mill wide is thus a potential method to save steam and, in most cases, fossil fuel at the mill.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Optimum secondary heat recovery and utilization is one of the key factors for energy efficient operation of pulp and paper mills. Optimum utilization of secondary heat requires a mill-wide plan.

The benefits can vary enormously from mill to mill depending on a variety of factors; for instance, the extent to which such systems are already in place.

Utilization of secondary heat within the same process areas as it is recovered should be given first priority. Properly sized buffer storage for hot water, for example, is a method that facilitates the maximum benefits of secondary heat recovery and utilization.

Impact on Energy

Integration and optimization of secondary heat sources and potential users mill-wide has a positive impact on the mill's energy efficiency. Using hot water that was previously sewered in other mill areas reduces process steam demand. Recovery of secondary heat, e.g., to the boiler feedwater system, will lower energy required for steam generation.

Impact on CO_2

Increased use of secondary heat will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. These projects will all decrease fuel consumption in the boilers through reduced steam and heat demands. Lower fuel consumption means less CO_2 emissions. Again, savings will be related to projects implemented and conservation measures already achieved.

Impact on Operating Costs

Most of the cost savings will be from reduced steam demand and fuel consumption. Some savings in electrical power from reducing the load on the wastewater treatment aerators are also possible.

Capital Costs

Capital costs will be dependent on which projects are implemented. Most projects will require additional piping and control valves. Pumps, heat exchangers, and extra tankage may also be needed for some projects.

Sample Calculations

Sample calculations for secondary heat recovery and utilization projects have been presented elsewhere in this guide. Sections about measures that have been covered include:

- 3.3.1.3 Preheat demineralized water with secondary heat before steam heating
- 3.3.3.1 Rebuild the mill hot water system to provide for separate production and distribution of warm and hot water
- 3.3.3.2 Install blow heat or flash heat evaporators
- 3.3.3.4 Use flash heat in a continuous digester to preheat chips
- 3.3.3.5 Use evaporator condensates on decker showers
- 3.3.4.2 Preheat ClO_2 before it enters the mixers
- 3.3.5.1 Eliminate steam use in the wire pit by providing hot water from heat recovery and/or pulp mill and by reducing water use on the machine
- 3.3.5.3 Enclose the machine hood and install air-to-air and air-to-water heat recovery
- 3.3.6.7 Integrate condensate stripping to evaporators
- 3.3.7.1 Implement heat recovery from TMP process to steam and water
- 3.3.7.4 Countercurrent coupling of paper machine and mechanical pulping white water systems
- 3.3.8.1 Supply waste heat from other process areas to deinking plant
- 3.3.8.3 Implement closed heat and chemical loop

Integrated pulp and paper mills, especially, have plenty of opportunities to recover and utilize secondary heat. Mill-wide optimization should start by mapping all sources and potential users.

Often only steady state operation is considered. Experience indicates that a significant amount of potential benefit is lost because operating rates between suppliers and users of secondary heat are not synchronized.

3.3.9.2 *Implement preventive maintenance procedures to increase equipment utilization efficiency*

Description

Unplanned shutdowns to repair failed equipment are costly. Excessive downtime means lost production, process upsets, and heat and fiber losses. Excessive downtime can be avoided by implementing preventive maintenance procedures in order to increase equipment utilization efficiency. The process operates more energy efficiently when equipment is operating under load because the energy used by the equipment is transferred to the process. When equipment is operating but not loaded, energy is consumed by the equipment but not transferred to the process. This happens when a piece of equipment fails but the rest of the process is kept on-line while it is repaired. As equipment utilization efficiency increases, specific energy consumption decreases. Also, deterioration and wear of equipment over time results in energy loss. Preventive maintenance programs can help minimize those losses.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

The application of maintenance procedures, including preventive, predictive, and proactive procedures, results in improved mill equipment reliability. One article documents the results of such maintenance (Wheaton 1996). Over a six-year operating period, more than $10 million were saved, with utility costs (energy) around 10% of the savings. Mill-wide equipment availability increased from 82.4% to 89.4% during the same period. The benefits can, however, vary enormously from mill to mill depending on a variety of factors; for instance, the extent to which such systems are already in place.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Implementing preventive maintenance procedures will reduce energy requirements. As equipment utilization increases, production increases incrementally. This reduces specific power consumption. Increasing equipment utilization will also reduce upsets due to equipment failure, which will reduce energy and fiber losses.

Impact on CO_2

Increasing equipment utilization efficiency through preventive maintenance will lower the total (considering both direct plus indirect) CO_2 emissions. The incremental increase in production from increased equipment usage will lower energy consumption. When energy consumption drops, CO_2 emissions decrease because less fuel must be combusted to generate needed energy.

Impact on Operating Costs

Improving preventive maintenance procedures will lower operating costs. Preventive maintenance will extend equipment life and reduce equipment failure. This will increase production and reduce energy consumption, lowering operating costs.

Capital Costs

Most of the costs of this project will be part of the maintenance budget. A program of regular equipment inspection and tracking will be required. Purchase of spare parts will be the major cost.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

One mill documented an improvement in mill-wide equipment availability from 82.4% to 89.4% during six years as a result of reliability maintenance and the use of preventive, predictive, and proactive maintenance procedures. The sample calculation below is based on a reliability improvement of 2% in a bleached kraft mill. Increased reliability increases production correspondingly.

Assume:

- Cost of purchased electrical power — $35/MWh
- Cost of medium pressure steam (Section 2) — $2.5/MBtu
- Cost of low pressure steam (Section 2) — $2.2/MBtu

Basic data:

- Mill production — 1000 ADT/d
- Initial mill-wide reliability — 85%
- Improved reliability — 87%
- Production at improved reliability — 1024 ADT/d
- Initial mill power demand — 35 MW
- Base power load (not dependent on production) — 50%
- Process steam demand (excluding power generation) — 12 MBtu/ADT
- Base steam demand (not dependent on production) — 20%
- MP/LP steam ratio — 30/70%

Power savings:

- Initial power consumption — 0.840 MWh/ADT
- Power consumption at improved reliability — 0.830 MWh/ADT

- Power saving per ton of product 10 kWh/ADT

Steam savings:

- Initial process heat consumption – LP steam 8.40 MBtu/ADT
- Initial process heat consumption – MP steam 3.60 MBtu/ADT
- Process heat consumption at improved reliability – LP steam 8.30 MBtu/ADT
- Process heat consumption at improved reliability – MP steam 3.56 MBtu/ADT
- Steam saving per ton of product – LP steam 0.099 MBtu/ADT
- Steam saving per ton of product – MP steam 0.042 MBtu/ADT

Change in back-pressure power due to reduced steam usage:
(0.099 MBtu/ADT x 66.9 kWh/MBtu) + (0.042 MBtu/ADT x 51.3 kWh/MBtu)
= 8.8 kWh/ADT

Total power savings:
10 - 8.8
= 1.2 kWh/ADT

Change in cost due to steam and power savings:
(0.099 MBtu/ADT × \$2.2/MBtu) + (0.042 MBtu/ADT × \$2.5/MBtu) +
(0.0012 MWh/ADT × \$35/MWh)
= \$0.365/ADT *or* \$128,000/yr

Reduction in CO_2 emission from fossil fuels:

$$\left(\frac{0.099\ \text{MBtu}}{\text{ADT}}+\frac{0.042\ \text{MBtu}}{\text{ADT}}+\left(\frac{8.8\ \text{kWh}}{\text{ADT}}\times\frac{1\ \text{MWh}}{1000\ \text{kWh}}\times\frac{3.6\ \text{MBtu}}{\text{MWh}}\right)\right)\times\frac{211.8\ \text{lb}\ CO_2}{\text{MBtu}}$$

= 36.6 lb CO_2/ADT

Decrease in CO_2 emissions due to reduced power usage:

$$\frac{1.2\ \text{kWh}}{\text{ADT}}\times\frac{1\ \text{MWh}}{1000\ \text{kWh}}\times\frac{3.6\ \text{MBtu}}{\text{MWh}}\times\frac{173.7\ \text{lb}\ CO_2}{\text{MBtu oil}}$$

= 0.75 lb CO_2/ADT

Net reduction in CO_2:
36.6 + 0.75
= 37.35 lb CO_2/ADT
or

$$\frac{37.35\ \text{lb}\ CO_2}{\text{ADT}}\times\frac{1000\ \text{ADT}}{\text{d}}\times\frac{350\ \text{d}}{\text{y}}\times\frac{1\ \text{T}}{2000\ \text{lb}}$$

= 6536 T CO_2/yr

3.3.9.3 *Implement optimum spill management procedures*

Description

In the past, a spill of spent pulping liquor or filtrates in a kraft pulp mill was often sent to the sewer and the wastewater treatment system. This resulted in loss of chemicals and solids and often disrupted the treatment system. Valuable chemicals and solids can be recovered by implementing spill management procedures that optimize chemical and solids recovery while minimizing impacts on the treatment system. The spill management plan should allow spills with solids contents above a pre-determined level to be diverted to a spill collection tank. The minimum solids level of the spill to be reclamed will be determined by the cost of evaporating spilled liquor, the cost of effluent treatment of BOD, the fuel value of the solids in the spilled liquor, and the chemical value of the solids in the spill. Alternatively, the minimum solids content to be reclamed can be determined based on the CO_2 emission implications of fuel used to evaporate the water from the spill, fossil fuel saved related to the (biomass) fuel value of the spill, and electricity used to operate the effluent treatment system. The spill collection system should be equipped with sumps that divert sewer flow automatically based on solids level or conductivity. In spill collection systems that operate infrequently, it is important to set up procedures to ensure that pumps stay clear of debris and that pumps and diversion valves are in good operating condition.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Furthermore, there are several assumed parameters employed in the sample calculations used to demonstrate the determination of the optimum solids content of spills to be collected. These parameters are highlighted in the Sample Calculations section below. The economics and energy/ emission benefits of this option must be addressed mill by mill because the factors that impact the cost effectiveness and greenhouse gas balance are quite mill-specific. Therefore it is crucial that appropriate values of these parameters be used, reflecting the situation at the mill to which the technology may be applied, when assessing the viability of this option.

Applicability and Limitations

The effluent treatment plant may be a bottleneck at some mills. In this case, optimization of spill collection to a minimum operating cost may not be possible. Some effluent quality characteristics, such as color or COD, are not changed in the same proportion as BOD in the effluent treatment plant. If these parameters are critical to the environmental compliance of the mill, optimum spill collection practices have to be assessed taking parameters other than BOD into account.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Implementing optimized spill management procedures will affect the mill energy balance in several ways. Increasing the recovery of spills will place an additional demand on evaporator capacity. The evaporation of spills will require additional steam. However, increased utilization of black liquor solids will generate more steam. More chemicals, such as salt cake, will be recovered, so less makeup chemical will be required. Additional electrical power may be required to pump spills to the collection tank and then to recovery.

Impact on CO_2

An optimized spill management plan will reduce total (considering both direct plus indirect) CO_2 emissions per ton of product. Increased recovery of black liquor solids will allow more steam generation to offset the additional evaporation required.

Impact on Operating Costs

Implementing an optimized spill management plan may improve operating costs. Increased recovery of cooking chemicals will reduce the amount of makeup chemicals required, which will lower chemical costs. Increased recovery of black liquor solids will improve steam costs. Electrical power usage may increase slightly if spill collection and transfer pumps are used frequently.

Capital Costs

Capital costs for this project will depend greatly on the systems currently applied at the mill. Mills with no spill collection systems will have to spend more than mills that have already implemented spill collection. Also, mills that are evaporator limited may have to install additional evaporator capacity. A spill collection system will consist of sumps in the sewer system with automatic diversion based on conductivity, conductivity meters, a collection tank (may include a screening system), pumps, piping, and curbing or diking to direct the flow of spills. Additional process controls may also be required.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Furthermore, several of the assumed parameters can vary widely from facility to facility depending on particular circumstances at the mill site. For example, the following assumed parameters should be examined closely and changed as appropriate to reflect actual values at the mill site: high heating value of dry solids; energy consumption in effluent treatment; cost of makeup chemicals (note that at some kraft mills, sodium sulfate is available as a byproduct of chlorine dioxide production); current amount of water evaporated from spills; and current dissolved solids content criteria used to determine whether or not a spill is reclaimed. As stated, the actual price of and CO_2 emission factor associated with the fuel to be saved at the mill site (in regard to steam generation) should be used in estimating the impacts of this measure at a particular facility. Note that only reductions in fossil fuel use should be counted in estimating on-site reductions in CO_2 emissions.

Assume:

• Pulp production	1000 ADT/d
• Recovery boiler steam generation efficiency	60%
• High heating value of dry solids	6200 Btu/lb
• Liquor dry solids concentration from evaporation	70%
• Energy consumption in effluent treatment (derived from information in Springer 1992)	0.48 kWh/lb of BOD_5
• Cost of makeup chemicals	\$70 /T of Na_2SO_4
• Evaporator steam economy	4.2 lb H_2O/lb steam
• BOD_5 content of liquor dry solids	0.3 lb/lb d.s.
• Current evaporation of spills	0.5 T H_2O/ADT

- Spills down to 1% d.s. concentration are currently returned to evaporation (Amendole, Vice, and McCubbin 1996)
- Sodium content of dry solids — 0.6 lb Na_2SO_4 /lb d.s.
- Heat from steam in evaporation — 1000 Btu/lb stm
- Cost of oil — $3/MBtu
- Efficiency of oil combustion — 82%

In optimizing the solids content of recovered liquor spills, there are four considerations:

- Fuel value of organics in the spill
- Material value of inorganic chemicals in the spill
- Cost of evaporation of water in the spill prior to recovery
- Cost of effluent treatment if the spill is sewered rather than reclaimed

The optimization technique will be used to select from two options: 1) reclaim the spill for energy and chemicals recovery; or 2) send the spill to the effluent treatment plant (sewer). The break-even point, from either an economic cost or a CO_2 emission standpoint, is the solids content of the spill at which the cost or emissions from each option are equivalent. The optimization will be demonstrated for both economic and emission endpoints.

Optimization based on CO_2 emissions:

Emissions impacts associated with reclamation of the spill include emissions corresponding to fuel used to generate steam for use in evaporating water from the spill, and emissions offset due to decreased fossil fuel use corresponding to the biomass fuel value of recovered organics. Mathematically this can be expressed as:

$$\left(\frac{1-\text{x lb H}_2\text{O}}{\text{x lb d.s.}}-\frac{0.3\text{ lb H}_2\text{O}}{0.7\text{ lb d.s.}}\right)\times\left(\frac{1\text{ lb steam}}{4.2\text{ lb H}_2\text{O}}\right)\times\left(\frac{1000\text{Btu}}{1\text{ lb steam}}\right)\times\left(\frac{1\text{ MBtu}}{10^6\text{ Btu}}\right)\times\left(\frac{211.8\text{ lb CO}_2}{\text{MBtu}}\right)-$$
$$(0.6)\times\left(\frac{6200\text{Btu}}{\text{lb d.s.}}\right)\times\left(\frac{1\text{ MBtu}}{10^6\text{ Btu}}\right)\times\left(\frac{211.8\text{ lb CO}_2}{\text{MBtu}}\right)$$
$$=\left(\frac{1-\text{x lb H}_2\text{O}}{\text{x lb d.s.}}-\frac{0.3\text{ lb H}_2\text{O}}{0.7\text{ lb d.s.}}\right)\times 0.0504-0.7879$$

where x is the dry solids concentration of the spill.

Emissions impacts of sewering the spill are those associated with the electrical power required to treat BOD in the spill at the effluent treatment plant. This can be estimated as:

$$\left(\frac{0.48\text{kWh}}{\text{lb BOD}}\right)\times\left(\frac{0.3\text{ lb BOD}}{\text{lb d.s.}}\right)\times\left(\frac{1\text{ MWh}}{1000\text{ kWh}}\right)\times\left(\frac{2009\text{ lb CO}_2}{\text{MWh}}\right)$$
$$=0.2893\text{ lb CO}_2\text{ / lb d.s.}$$

At the break-even point, the emission impacts of reclaiming the spill are equal to those of sewering the spill (emissions from reclaiming spill equal emissions from sewering spill):

$$\left(\frac{1-x\ \text{lb H}_2\text{O}}{x\ \text{lb d.s.}}-\frac{0.3\ \text{lb H}_2\text{O}}{0.7\ \text{lb d.s.}}\right)\times 0.0504-0.7879=0.2893$$

$$\left(\frac{1-x}{x}-\frac{0.3}{0.7}\right)=\frac{0.2893+0.7879}{0.0504}$$

$$\left(\frac{1-x}{x}-\frac{0.3}{0.7}\right)=21.37$$

$$x=0.0439=4.4\%$$

The result of the optimization analysis, based on the criterion of minimizing CO_2 emissions, is that spills with solids contents greater than 4.4% should be reclaimed and those with solids contents less than 4.4% should be sewered. Assuming that the mill currently reclaims all spills at 1% solids or greater, the emission impact of changing the criteria for spill reclamation to 4.4% solids can be estimated. There will be a reduction in evaporation demand if spills with no lower than 4.4% solids are recovered. Assume that 50% of the dissolved solids contained in spills currently recovered at 1% solids will be recovered at the new criterion of 4.4% solids. (An analysis of spills at the actual mill site should be used to determine the amount of spills which would meet the new criterion.)

Current evaporation for spills:
0.5 T H_2O/ADT = 1000 lb H_2O/ADT

Current minimum dry solids recovery rate (assuming that all reclaimed spills are at 1% d.s. concentration, actual dry solids recovery rate will be higher):

$$\frac{\left(\frac{1000\ \text{lb H}_2\text{O}}{\text{ADT}}\right)}{\left(\frac{0.99\ \text{lb H}_2\text{O}}{0.01\ \text{lb d.s.}}-\frac{0.3\ \text{lb H}_2\text{O}}{0.7\ \text{lb d.s.}}\right)}=10.1\ \text{lb d.s./ADT}$$

Dry solids recovery at optimized spill recovery (4.4% d.s. concentration):
0.5 x 10.1 lb/ADT
= 5.05 lb/ADT

Maximum evaporation demand at optimized spill recovery (assuming all reclaimed spills are at 4.4% solids, actual evaporation demand will be less):

$$\frac{1-0.044\ \text{lb H}_2\text{O}}{0.044\ \text{lb d.s.}}-\frac{0.3\ \text{lb H}_2\text{O}}{0.7\ \text{lb d.s.}}=21.3\ \text{lb H}_2\text{O/lb d.s.}$$

21.3 lb H_2O/lb d.s. x 5.05 lb d.s./ADT
= 108 lb H_2O/ADT

Therefore, minimum reduction in evaporation demand:
1000 - 108
= 892 lb H_2O /ADT

Corresponding minimum reduction in steam to evaporation (LP steam):
(892 lb H_2O/ADT) / (4.2 lb H_2O/lb stm)
= 212 lb/ADT *or* as heat ~ 0.212 MBtu/ADT

Reduced spill recovery causes a corresponding loss in recovery boiler steam generation (due to lower quantity of solids recovered):

(10.1 - 5.05 lb d.s./ADT) x (6200 Btu/lb d.s.) x (0.60) x (10^{-6} MBtu/Btu)
= 0.0188 MBtu/ADT

Reduced generation of back-pressure power:
0.212 MBtu/ADT x 66.9 kWh/MBtu
= 14.2 kWh/ADT

Additional BOD load to effluent treatment increases the power demand:
((10.1 - 5.05) lb d.s./ADT) x 0.3 lb BOD/lb d.s. x 0.48 kWh/lb BOD
= 0.73 kWh/ADT

Net reduction in operating cost due to reduced oil use is, therefore:
((0.212 - 0.0188) MBtu/ADT) x ($3/MBtu)
= $0.580/ADT

Net increase in costs for purchased power is:
((0.212 MBtu/ADT x 0.0669 MWh/MBtu) + (0.73 kWh/(1000 kWh/MWh))) x ($35/MWh)
= $0.522/ADT

Therefore, net reduction in operating costs is approximately:
($0.580/ADT - $0.522/ADT) x (1000 ADT/d) x (350 d/yr)
= $20,300/yr

Reduction in on-site CO_2 from reduced use of fossil fuels:
((0.212 MBtu/ADT - 0.0188 MBtu/ADT) + ((0.212 MBtu/ADT) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh))) x 211.8 lb CO_2/MBtu
= 51.7 lb CO_2/ADT

Increase in off-site CO_2 due to increased power generation in utility power plant:
((0.212 MBtu/ADT x 0.0669 MWh/MBtu) + (0.73 kWh/(1000 kWh/MWh)) x 2009 lb CO_2/MWh
= 30.0 lb CO_2/ADT

Net reduction of CO_2:
51.7 - 30.0
= 21.7 lb CO_2/ADT
or
21.7 lb CO_2/ADT x 1000 ADT/d x 350 d/yr x 1 T/2000 lb
= 3798 T CO_2/yr

<u>Optimization based on cost:</u>

Cost considerations associated with reclamation of a spill include: (a) those corresponding to increased fuel use to generate steam to evaporate water from the spill; (b) savings due to the fuel value of organics in the spill (offset use of fossil fuel for steam generation); and (c) savings due to the value of inorganic chemicals in the spill which will be recovered and will offset the need for sodium sulfate makeup chemical. At some mills there is an economical supply of sodium sulfate due to its formation as a byproduct during production of chlorine dioxide. Mathematically this can be expressed as:

$$\left(\frac{1-x\ \text{lb H}_2\text{O}}{x\ \text{lb d.s.}}-\frac{0.3\ \text{lb H}_2\text{O}}{0.7\ \text{lb d.s.}}\right)\times\left(\frac{1\ \text{lb steam}}{4.2\ \text{lb H}_2\text{O}}\right)\times\left(\frac{1000\text{Btu}}{1\ \text{lb steam}}\right)\times\left(\frac{1\ \text{MBtu}}{10^6\ \text{Btu}}\right)\times\left(\frac{\$2.2}{\text{MBtu}}\right)-$$

$$(0.6)\times\left(\frac{6200\text{Btu}}{\text{lb d.s.}}\right)\times\left(\frac{1\ \text{MBtu}}{10^6\ \text{Btu}}\right)\times\frac{1}{0.82}\times\left(\frac{\$3}{\text{MBtu}}\right)-\left(\frac{0.6\ \text{lb Na}_2\text{SO}_4}{\text{lb d.s.}}\right)\times\left(\frac{\$70}{\text{lb Na}_2\text{SO}_4}\right)\times\left(\frac{1\ \text{T}}{2000\ \text{lb}}\right)$$

$$=\left(\frac{1-x\ \text{lb H}_2\text{O}}{x\ \text{lb d.s.}}-\frac{0.3\ \text{lb H}_2\text{O}}{0.7\ \text{lb d.s.}}\right)\times 0.0005238-0.0136-0.021$$

where x is the dry solids concentration of the spill.

The cost impact of sewering the spill is associated with the electrical power required to treat BOD in the spill at the effluent treatment plant. This can be estimated as:

$$\left(\frac{0.48\text{kWh}}{\text{lb BOD}}\right)\times\left(\frac{0.3\ \text{lb BOD}}{\text{lb d.s.}}\right)\times\left(\frac{1\ \text{MWh}}{1000\ \text{kWh}}\right)\times\left(\frac{\$35}{\text{MWh}}\right)$$

$$=\$0.00504\ /\ \text{lb d.s.}$$

At the break even point, the cost of reclaiming the spill is equal to that of sewering the spill (cost of reclaiming spill equals cost of sewering spill):

$$\left(\frac{1-x\ \text{lb H}_2\text{O}}{x\ \text{lb d.s.}}-\frac{0.3\ \text{lb H}_2\text{O}}{0.7\ \text{lb d.s.}}\right)\times 0.0005238-0.0136-0.021=\$0.00504$$

$$\left(\frac{1-x}{x}-\frac{0.3}{0.7}\right)=\frac{0.00504+0.0136+0.021}{0.0005238}$$

$$\left(\frac{1-x}{x}-\frac{0.3}{0.7}\right)=75.68$$

$$x=0.013=1.3\%$$

The result of the optimization analysis based on the criterion of minimizing economic costs is that spills with solids contents greater than 1.3% should be reclaimed and those with solids contents less than 1.3% should be sewered. The cost and emission impacts of changing the mill's spill reclamation criterion from the current value of 1% to the cost-optimized value of 1.3% can be estimated by the same technique presented above for the CO_2 emission-optimized criterion.

3.3.9.4 *Maximize recovery and return of steam condensates*

Description

In most applications the latent heat of steam is utilized for heating and other services. Steam condensates can be recovered and returned for reuse as boiler feedwater. Both steam and chemicals for boiler feedwater treatment can be saved by returning the condensates.

For example, water heating in the paper machine wire pit or hot water tanks is often performed using direct steam. By replacing direct steam heaters with indirect heaters, steam condensates can be recovered and returned to the powerhouse.

Some direct steam use cannot be avoided. Typical examples are:

- Sootblowing steam
- Steam to bleach plant mixers
- Presteaming of chips
- Steam eductors and ejectors

- Boiler blowdown

Although theoretical steam condensate recovery could be over 80%, in practice the recovered condensates are typically only 40 to 60% of the total steam generation in the boilers.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Increased steam condensate recovery is normally possible in all forest industry facilities. Part of the condensates are recoverable without investment; i.e., by improving maintenance procedures.

Steam savings are dependent on the temperature of demineralized water before it enters the deaerator. Therefore the savings for this technology interfere with the savings for technology 1.3 (Section 3.3.1.3), which deals with preheating demineralized water with secondary heat.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Hot steam condensates are normally replaced by demineralized water. The water temperature is typically below 90°F unless it is preheated after the demineralizers. If more steam condensates can be recovered at high temperature, steam consumption in feedwater heating will be reduced.

Impact on CO_2

If the mill uses fossil fuel for steam generation, a reduction in total (considering both direct plus indirect) CO_2 emissions will result from increased steam condensate recovery.

Impact on Operating Costs

In addition to fuel cost savings, cost savings in production of demineralized water will result from increased steam condensate recovery.

Capital Costs

Some steam condensates are lost because of original design; i.e., no condensate recovery and return systems were built into the system. Replacement of direct steam heaters with indirect heaters and installation of condensate return systems (pumps and piping, flash tanks, etc.) would be needed. Other condensates are lost for various reasons, such as:

- Contamination or risk of contamination of boiler feedwater
- Problems with condensate removal from dryer cans
- Problems pumping condensates back to the power house
- Problems maintaining condensate recovery and return systems

Measurement and monitoring of condensate return is an area that most mills should address in order to establish reliable balances.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Assume:

• Mill production	1000 T/d
• Mill steam consumption	20 klb/T
• Steam condensate return (current)	55%
• Demineralized water temperature	100ºF
• Deaerator pressure	50 psig
• Feedwater temperature from deaerator	296ºF

Total steam generation:
(1000 T/d) x (20 klb/T) / (24 hr/d)
= 833 klb/hr

Demineralized water flow:
(1 - 0.55) x (833 klb/hr)
= 375 klb/hr

Steam consumption to heat demineralized water to deaerator temperature:
(375 klb/hr) x (296 - 100°F) x (1 kBtu/klb/°F) x (10^{-3} MBtu/kBtu)
= 73.5 MBtu/hr

Steam consumption to heat returned condensates to deaerator temperature (assume condensates are returned at 200°F):
(833 - 375 klb/hr) x (296 - 200 °F) x (1 kBtu/klb/°F) x (10^{-3} MBtu/kBtu)
= 44.0 MBtu/hr

Total steam to deaerator:
73.5 + 44.0
= 117.5 MBtu/hr

Steam savings (if condensate return can be increased from 55% to 65%):
(117.5 MBtu/hr) - ((1 - 0.65) x (833 klb/hr) x (296 - 100°F) + 0.65 x (833 klb/hr) x (296 - 200°F)) x (1 kBtu/klb/°F) x (10^{-3} MBtu/kBtu)
= 8.4 MBtu/hr

Energy cost savings:
(8.4 MBtu/hr) x ($2.2/MBtu)
= $18.5/hr *or* $155,400/yr

Some additional savings will result from reduced demineralized water treatment cost.

CO_2 impact of oil burning (including reduced back-pressure power generation):
((8.4 MBtu/hr) + (8.4 MBtu/hr) x (0.0669 MWh/MBtu) x (3.6 MBtu/MWh)) x (211.8 lb CO_2/hr)
= 2208 lb CO_2/hr *or* 9274 T CO_2/yr

CO_2 impact of increased purchased power (assume decreased self generated power production):
(8.4 MBtu/hr) x (0.0669 MWh/MBtu) x (2009 lb CO_2/MWh)
= 1129 lb CO_2/hr *or* 4742 T CO_2/yr

Net CO_2 reduction by 10% increase in steam condensate return:
2208 - 1129
= 1079 lb CO_2/hr *or* 4532 T CO_2/yr

3.3.9.5 *Recover wood waste that is going to landfill*

Description

A significant amount of bark and wood material is normally spilled in woodyards. Because this material often comes into contact with dirt and rocks, it is not usable as raw material for forest products. However, it could often be recovered and used as fuel instead of being sent to the landfill.

To be able to segregate wood material more accurately, the wood yard and hog fuel handling areas can be paved with concrete. This way wood material can be kept separate from dirt and can be more easily recovered and classified as needed.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Most forest product industry facilities have recently completed studies on how to reduce solid waste to the landfill. In some cases, a significant amount of wood debris has been identified in the solid waste stream. Recovery and utilization of this organic material would reduce fossil fuel usage and decrease the amount of solid waste sent to the landfill. This measure is applicable to nearly every facility that receives and uses wood as a raw material. The benefits can, however, vary enormously from mill to mill depending upon a variety of factors; for instance, the extent to which such systems are already in place.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Facilities that have enough hog fuel burning capacity can use recovered wood refuse as a fuel for steam generation. Plants that have an excess of hog fuel available can sell wood waste as fuel.

Impact on CO_2

It is assumed that recovered wood refuse can be used as fuel to replace fossil fuel either in the plant where generated or in some other facility. Accordingly, recovery and utilization of this refuse material will reduce fossil CO_2 emissions.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Rough lumber production	120,000 MBF/yr
• Timber consumption	15 Mft^3/yr
• Amount of nonutilized, recoverable wood material (% of incoming wood)	2%
• Heating value of wood debris	8750 Btu/lb d.s.
• Wood residues (2% of incoming wood)	300,000 ft^3/yr
• Wood residues	3000 units/yr
• Wood residues	8100 T/yr
• Moisture content of wood residues	50%

Savings:

Value of reasonable wood residue (assume supplier gets $5/T for hog fuel):
(8100 T/yr) x ($5/T)
= $40,500/yr

CO_2 impact:

Reduction in CO_2 (assume hog fuel recovered will be used to replace oil for steam generation, hog fuel boiler efficiency is estimated to be 63%):
(2000 lb/T) x (8100 T/yr) x (50% d.s.) x (8750 Btu/lb d.s.) x (10^{-6} MBtu/Btu) x
((63% eff.) x 211.8 lb CO_2/MBtu)
= 9.5 M lb CO_2/yr *or* 4750 T CO_2/yr

3.3.9.6 *Install energy measurement, monitoring, reporting, and follow-up systems*

Description

Providing current and reliable information about energy usage and costs at a mill allows more efficient use of available resources, and less energy is wasted. Installing energy measurement, monitoring, reporting, and follow-up systems will reduce operating expenses. Production units that could benefit from energy management systems include the boilers, evaporators, brownstock washers, lime kiln, paper machines, and wastewater treatment. The energy management system should be tied into the DCS and the operator control system to allow operators access to trend charts. The energy management system should allow for on-line reporting and accounting of energy usage in the unit, including steam, condensate return, fuel consumption, and other important process variables specific to each unit. New process instruments, such as flow meters, may need to be added.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Nearly every pulp and paper mill could benefit from more efficient energy measurement, monitoring, reporting, and follow-up systems. The benefits can, however, vary enormously from mill to mill depending on a variety of factors; for instance, the extent to which such systems are already in place. This measure would be especially applicable for older mills that do not normally measure the steam to each major user or steam condensate flows from all major steam users.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing an energy management system will help the mill reduce energy consumption. Less energy will be wasted. Steam consumption should drop and condensate return should improve.

Impact on CO_2

An energy management system will reduce steam consumption and fuel usage. This will reduce total (considering both direct plus indirect) CO_2 emissions.

Impact on Operating Costs

Using an energy management system will lower operating costs. More efficient use of steam and process equipment will lower fuel consumption, resulting in cost savings.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3). The sample calculations incorporate a "CO_2 penalty" associated with process steam savings due to reduced on-site power generation capacity, which may not be appropriate for all mills (see Section 2.2 for additional information).

Some energy may be lost because information on actual consumptions and achievable target consumptions is unavailable. By having access to current information on-line, operating personnel can react promptly to any unusual situation where energy utilization efficiency is not at the target. No firm numbers for savings can be calculated. The estimates from mills that have implemented energy management systems typically vary from 1 to 10% of total energy saved. The achievable results, of course, depend on the mill-specific situation.

Assume:

• Market pulp mill production	1000 ADT/d
• Steam consumption	20 MBtu/ADT
• Savings from improved energy management procedures	1%
• Average price of steam (HP, MP, and LP)	\$2.7/MBtu

Savings (1% steam savings):
(20 MBtu/ADT) x (1/100) x (1000 ADT/d) / (24 hr/d) x (\$2.7/MBtu)
= \$22.5/hr *or* \$189,000/yr

CO_2 reduction from oil burning (1% savings):
(20 MBtu/ADT) x (0.01) x (1000 ADT/d) / (24 hr/d) x (211.8 lb CO_2/MBtu)
= 1765 lb CO_2/hr *or* 7413 T CO_2/yr

Increased CO_2 emissions because of increased purchased power (assume average back-pressure power yield for saved steam is 0.0513 MWh/MBtu):
(20 MBtu/ADT) x (0.01) x (1000 ADT/d) / (24 hr/d) x (0.0513 MWh/MBtu) x (2009 lb CO_2/MWh)
= 859 lb CO_2/hr *or* 3608 T CO_2/yr

Net reduction in CO_2:
1765 - 859
= 906 lb CO_2/hr *or* 3805 T CO_2/yr

3.3.9.7 *Convert pump and fan drives to variable speed drives*

Description

Pumps and fans are used throughout the forest products industry. These devices generally operate at one speed. By converting pumps and fans to variable speed drives (VSD) or variable frequency drives (VFD), pumping speed can be reduced to match the required flow. Such applications include stock, liquor, filtrate, and paper machine pumps in pulp and paper mills, kiln and dryer fans in wood products facilities, boiler air fans, and any other pumps or fans with variable flows. Lumber kilns may also benefit from fans with variable pitch blades to maintain maximum air flow.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Forest products facilities have a large number of pump and fan applications where pumping duties vary because of different operating rates, different requirements at different grades, and so on.

The most common method to control flows is to throttle using valves or similar flow control devices. A more energy efficient method of controlling flows would be to control the speed of the motor that is driving the pumps or fans. There are normally hundreds of potential applications for variable speed controls in complex forest products facilities. The limitation is the high payback time, typically from five to ten years. Therefore, it is most likely that implementation will be limited to situations where equipment must be replaced due to failure or when initiating other projects requiring pump or fan replacement.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing variable speed drives on fans and pumps will reduce electrical power consumption, because power is a function of impeller or fan speed. Actual savings will depend on the pump or fan application and the number of VSDs installed.

Impact on CO_2

Installing variable speed drives on fans and pumps will reduce electrical power consumption. This will reduce either on-site or off-site (purchased power) power generation requirements. Reducing power generation translates into fuel savings and a reduction in CO_2 emissions. Again, actual power savings, and thus CO_2 reduction, will depend on pump or fan applications and the number of VSDs installed.

Impact on Operating Costs

Using variable speed drives on pumps and fans will reduce operating costs. VSDs reduce the electrical power used by pumps and fans. Electrical power savings will lower operating costs.

Capital Costs

Capital costs for variable speed drives include equipment (VSD, wiring, control, etc.), installation, and engineering. The cost for a VSD may be large compared to annual savings. Therefore, these projects may only be feasible if there are mitigating circumstances, such as subsidies from the utility company.

Sample Calculations for Variable Speed Fan

When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of purchased electricity should be used in estimating cost and off-site emission impacts at a mill (see Section 2.3).

An analysis of 15 lumber drying batch kilns was performed. Each kiln had 8 to 18 circulation fans driven by individual motors with 5 to 10 hp connected power. In batch operations air circulation and ventilation must be high in the beginning of the drying schedule, and decreases as the schedule progresses. Typical drying schedules vary from two to five days.

A detailed analysis indicated that about 3000 MWh/yr of power could be saved by installing frequency converters common for motors in each individual kiln; i.e., one converter (100 hp) for each kiln.

Cost savings:
($35/MWh) x (3000 MWh/yr)
= $105,000/yr

CO_2 reduction due to decreased purchased power:
(3000 MWh/yr) x (2009 lb CO_2/MWh)
= 6.0 M lb CO_2/yr *or* 3000 T CO_2/yr

Sample Calculations for Variable Speed Pump

Assume:

• Washer vat filtrate pump	500 hp
• Operating hours per year	8400 hr/yr
• Average power consumption before installing VSD	90% of rating
• Average power consumption after installing VSD	60% of rating
• Cost of purchased electricity	\$35/MWh

Power savings:
(500 hp) x (1 kW/1.34 hp) x (8400 hr/yr) x (0.9 - 0.6) x (1 MW/10^3 kW)
= 940 MWh/yr

Cost savings:
(\$35/MWh) x (940 MWh/yr)
= \$32,900/yr

CO_2 reduction due to decreased purchased power:
(940 MWh/yr) x (2009 lb CO_2/MWh)
= 1.9 M lb CO_2/yr *or* 950 T CO_2/yr

3.3.9.8 *Install advanced process controls*

Description

Modern forest products facilities are complex, with many different interrelated processes. Optimizing one process may come at the expense of another. By installing advanced process controls, process operation becomes smoother and operators can be freed to focus on process optimization. Advanced controls can be used to optimize steam generation and use, electrical power generation, steam condensate return, water usage, chemical production and usage, raw material usage, equipment loading, and production scheduling. Most processes will benefit from advanced controls which reduce variability and upset conditions.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Energy savings through advanced process controls are essentially available to mills that have not yet installed DCS systems, and/or to mills which do not yet utilize the process control features that advanced controls allow. Pulp and paper processes are very complicated from an operational point of view. Installation of advanced controls usually results in energy savings, such as improvements in boiler efficiencies. The benefits can, however, vary enormously from mill to mill depending on a variety of factors; for instance, the extent to which such systems are already in place.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing advanced process controls will reduce energy consumption. Advanced process controls will reduce process variability and energy misuse by alerting operators to increases in steam consumption and decreases in condensate return, increases in water usage, and changes in optimal equipment loading.

Impact on CO_2

Using advanced process controls will lower total (considering both direct plus indirect) CO_2 emissions. Optimizing the use of secondary heat, steam generation, and condensate return will minimize fuel usage in the boiler.

Impact on Operating Costs

Installing advanced process controls will lower operating costs by minimizing fuel usage, chemical consumption, water usage, and raw material consumption, and maximizing power generation and equipment utilization.

Capital Costs

Costs of advanced process controls will depend on the process to which they are being applied. The system may include process instruments, wiring, control systems, and operator interfaces.

Sample Calculations

The following sample calculation is based on reduced use of residual fuel oil (No. 6 oil – assumed to be the marginal fuel for pulp and paper mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Benefits from advanced recovery boiler controls include a 1 to 3% improvement in the thermal efficiency of the boiler (Gullichsen and Fogelholm 1999). Assume that the thermal efficiency calculated from the High Heating Value (HHV) and without advanced controls is 61% and is improved to 63% with the use of advanced controls.

Assume:

• Pulp production	1000 ADT/d
• Dry solids	3400 lb/ADT
• High Heating Value (HHV)	6200 Btu/lb
• Fuel cost for oil	\$3/MBtu
• Boiler efficiency with oil	82%

Heat to steam without advanced controls:
(0.61) x (3400 lb/ADT) x (1000 ADT/d) x (6200 Btu/lb) x (10^{-6} MBtu/Btu) / (24 hr/d)
= 535.8 MBtu/hr

Heat to steam with advanced controls:
(0.63) x (3400 lb/ADT) x (1000 ADT/d) x (6200 Btu/lb) x (10^{-6} MBtu/Btu) / (24 hr/d)
= 553.4 MBtu/hr

Oil savings (assume oil is replaced with increased heat from liquor):
(553.4 MBtu/hr - 535.8 MBtu/hr) / 0.82
= 21.5 MBtu/hr

Cost savings:
($3/MBtu) x (21.5 MBtu/hr) x (8400 hr/yr)
= $541,800/yr

Reduction in CO_2 emissions from oil burning:
(21.5 MBtu/hr) x (173.7 lb CO_2/MBtu)
= 3735 lb CO_2/hr *or* 15,687 T CO_2/yr

3.3.9.9 *Replace oversized electric motors*

Description

Many pieces of process equipment in the forest products industry are powered by electric motors, including pumps, compressors, conveyors, stock agitators, refiners, pressure screens, and other equipment. In many of these applications, demand on the motors is not constant. Peaks result from batch operations, temporary increases in production, and process upset conditions. In anticipation of potential peaks in demand, electric motors are often oversized compared to actual process demand. An oversized motor is inefficient because power is wasted. Although some applications will require an oversized motor to respond to process surges, avoiding all unnecessary oversizing of electric motors will save energy. Energy can also be saved by using high efficiency motors, especially on small equipment.

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

This technology is applicable to all mills where electrical motors have been conservatively designed or where process conditions (e.g., due to operation at higher consistencies) have changed process flows and pump throughputs. Many older mills have, however, increased production by equipment overloading and may thus operate equipment at a higher load than designed. Consequently, savings are very mill-specific and require detailed checking of pump and fan characteristics in relation to actual operating points.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Avoiding oversized electric motors will reduce energy consumption. Reducing the connected horsepower means electrical power usage will drop. Electrical power can also be saved by using high efficiency motors.

Impact on CO_2

CO_2 emissions will be lower if oversizing of electrical motors is avoided. Less connected horsepower means less electrical energy is consumed. As generating requirements decrease, so do boiler fuel consumption and CO_2 emissions.

Impact on Operating Costs

If oversizing of electric motors is avoided, operating costs will decrease due to reduced electricity usage. This will lower purchased power cost or on-site generating costs.

Capital Costs

For an existing facility, this project will probably be part of the maintenance budget. As motors need to be replaced, an assessment should be made as to whether a smaller motor could be used for each application. High efficiency motors should be used when replacing old motors.

Sample Calculations

When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of purchased electricity should be used in estimating cost and off-site emission impacts at a mill (see Section 2.3).

Assume:

• Old motor	40 hp, 85% efficiency
• New motor	25 hp, 95% efficiency
• Operating hours per year	8400 hr/yr
• Cost of purchased power	$35/MWh

Power consumption of old motor:
(40 hp) x (746 W/hp) x (8400 hr/yr) / ((10^6 W/MW) x (0.85))
= 295 MWh/yr

Power consumption of new motor:
(25 hp) x (746 W/hp) x (8400 hr/yr) / ((10^6 W/MW) x (0.95))
= 165 MWh/yr

Power savings from replacing the motor:
295 - 165
= 130 MWh/yr

Cost savings:
(130 MWh/yr) x ($35/MWh)
= $4550/yr

CO_2 reduction due to decreased purchased power:
(130 MWh) x (2009 lb CO_2/MWh)
= 261,170 lb CO_2/yr *or* 131 T CO_2/yr

3.3.9.10 *Use high efficiency lighting*

Description

Power consumption for lighting interior and exterior areas of forest products facilities is rarely measured separately. However, in large facilities the total load for lighting can be several hundreds of kilowatts. In one study of six lumber mills, for example, the power consumption for lighting was assessed to vary from 50 kW to 150 kW. Although power consumption for lighting may represent only around 1% of the total plant power consumption, savings opportunities may still be significant.

The savings opportunities in power consumption include:

- Installation of photocells to switch lights on and off based on daylight intensity
- Optimum placement of lights
- Use of high efficiency lights
- Elimination of unnecessary lights

The energy and emission impacts of technology options in this section are less certain than those associated with many of the technology options presented in other sections of this manual. The sample calculations are presented as examples of what may be attainable as a result of implementing the technology options, based on experience at mills. The impacts at any specific mill must be estimated based on the equipment and procedures in place at that mill, and may vary widely from facility to facility.

Applicability and Limitations

Use of high efficiency lighting is applicable in all forest products facilities that have not already implemented power savings programs for lighting.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Facilities that have not already optimized power consumption for lighting may find that 10 to 30% savings in the lighting power consumption are possible. Depending on the facility type and size, this could mean 10 to 100 kW savings, or savings of 80 to 800 MWh annually.

Impact on CO_2

In nearly all facilities, savings in power consumption would reduce demand for purchased power. According to this assumption, savings in purchased power would reduce condensing power generation. The purchased power reduction of 80 to 800 MWh/yr would reduce CO_2 emissions accordingly by 100 to 1000 T CO_2/yr.

Sample Calculations

When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of purchased electricity should be used in estimating cost and off-site emission impacts at a mill (see Section 2.3).

Sample calculations are based on the Illuminating Engineering Society's (IES) method for prescribing illumination (see Kaufman and Haynes 1981 for more information). Assume that lighting in a paper machine building is being upgraded to high pressure sodium vapor lamps.

Assume:

• Paper machine building	500 ft (L) x 100 ft (W) x 50 ft (H)
• Ceiling reflection	50%
• Wall reflection	50%
• Type of illumination	direct

• Recommended level of illumination (IES handbook)	50 footcandles
• Old lamps (fluorescent)	165 watts and 11,000 lumens
• New lamps (high pressure sodium vapor)	400 watts and 47,000 lumens
• Operating hours per year	8400 hr/yr
• Cost of purchased power	\$35/MWh

$$\text{Room ratio} = \frac{W \times L}{H \times (W + L)} = \frac{100 \times 500}{50 \times (100 + 500)} = 1.67$$

From IES handbook, based on room ratio of 1.67:
Room index = F

From IES handbook, based on luminaire type, ceiling and wall reflection factors:
Coefficient of utilization (CU) = 0.57

From IES handbook lamp maintenance factor (MF) = 0.60

Number of lamps required (assume lamp per luminaire):

$$\text{Number of lamps} = \frac{(\text{ft} - \text{c required}) \times (\text{floor area, sq ft})}{(\text{lumens per lamp}) \times (\text{Cu}) \times (\text{MF})}$$

$$\text{for the old lamps} = \frac{(50\ \text{ft} - \text{c}) \times (500 \times 100\ \text{ft}^2)}{(11{,}000\ \text{lumens}) \times (0.57) \times (0.60)} = 665\ \text{lamps}$$

$$\text{for the new lamps} = \frac{(50\text{ft} - \text{c}) \times (500 \times 100\ \text{ft}^2)}{(47{,}000\ \text{lumens}) \times (0.57) \times (0.60)} = 156\ \text{lamps}$$

Power consumption:

For the old lamps:
(665 lamps) x (165 W/lamp) x (8400 hr/yr) / (10^6 W/MW)
= 922 MWh/yr

For the new lamps:
(156 lamps) x (400 W/lamp) x (8400 hr/yr) / (10^6 W/MW)
= 524 MWh/yr

Power saving for switching to new lamps:
922 - 524
= 398 MWh/yr

Cost savings:
(398 MWh/yr) x (\$35/MWh)
= \$13,930/yr

CO_2 reduction due to decreased purchased power:
(398 MWh/yr) x (2009 lb CO_2/MWh)
= 799,582 lb CO_2/yr *or* 400 T CO_2/yr

3.3.10 *Sawmills*

3.3.10.1 *Use advanced controls to control the drying process*

Description

Drying lumber in a kiln is a complex process. The drying rate involves many factors, such as wood species, moisture content, lumber thickness, and so on. Older kilns may use manual or semi-automatic controls. Switching to automatic computer controls will shorten drying schedules and reduce energy consumption. Automatic controls can be used to control the drying rates of different parts of the kiln for multizone operation. This reduces over- or under-drying. The control package can be used to calculate the lumber moisture content based on wet and dry bulb temperatures in the kiln, which eliminates the need for manual moisture checks near the end of the drying schedule. Using wet and dry bulb temperatures, automatic controls can regulate heating and humidity in the kiln and open and close kiln vents. Finally, automatic controls can be used to control the circulating fan speed. Once lumber is below the fiber saturation point, the circulating fan speed can be reduced without affecting drying time.

Applicability and Limitations

Advanced controls provide an opportunity for energy and other savings for every lumber mill that does not already have them in operation. However, the benefits can vary enormously from facility to facility depending on a variety of factors; for instance, the extent to which such systems have already been put in place. Controls may not be justifiable based on energy savings alone. Improved quality and potential savings of labor as well as increased production may offer the main justifications for advanced controls.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using advanced controls for the lumber drying process in the kiln will reduce energy consumption. Automatic controls will reduce steam consumption by creating more uniform drying throughout the kiln. Automated controls will also reduce electricity usage by reducing fan speed once the lumber is below the fiber saturation point. This, of course, assumes that the fans are equipped with variable speed control devices.

Impact on CO_2

Automated control of the drying kiln will lower CO_2 emissions. Steam and power savings mean less fuel will be burned in the boilers, and CO_2 emissions will drop.

Impact on Operating Costs

Using advanced controls on the drying kiln will reduce operating costs. Decreases in steam and power consumption will lower boiler fuel and purchased power costs. Reduced drying time means increased throughput.

Capital Costs

Advanced controls for the kiln will include wet and dry bulb sensors, control valves for steam heating and humidity spray, mechanical and pneumatic controls for kiln vents, and a computer control system. The controls will require air and water hookups.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Lumber mill capacity 120 MBF/yr
- All product dried
- Heat consumption in drying 3.0 MBtu/kBF
- Total heat consumption 360 x 103 MBtu/yr, 43 MBtu/hr (average)
- No back-pressure power generation

Assume that with computer control, 10% of the heat can be saved. This involves:

- Exhaust moisture control
- Control of air circulation (including variable speed drives)

Assume that mill-generated hog fuel is sufficient and:

- Sales value of hog fuel (at 50% moisture) $5/T
- Moisture content 50%
- Heating value 8750 Btu/lb d.s.
- Boiler efficiency 64%

Steam generated with 1 T of hog fuel:
(2000 lb/T) x (0.5 lb d.s./lb total) x (8750 Btu/lb d.s.) x (0.64 eff.) x (10^{-6} MBtu/Btu)
= 5.6 MBtu/T

Cost of steam:
($5/T) / (5.6 MBtu/T)
= $0.89/MBtu

Savings when hog fuel is saved:
(0.1) x (360,000 MBtu/yr) x ($0.89/MBtu)
= $32,040/yr

Savings if natural gas is marginal fuel (boiler efficiency assumed to be 80%):
(0.1) x (360,000 MBtu/yr) x ($3/MBtu) / (0.8 eff.)
= $135,000/yr
Note: Savings are from reduced fuel use only, and do not include savings of electricity due to variable speed drives for fans (Section 3.3.9.7).

Reduction in CO_2 emissions (assume either savings in natural gas at the plant or savings of gas in some other forest products facility):
(0.1) x (360,000 MBtu/yr) x (146.3 lb CO_2/MBtu) x (1 T/2000 lb)
= 2633 T CO_2/yr

This reduction in CO_2 does not include possible reductions in purchased power, such as power consumption by fans.

3.3.10.2 *Install heat recovery systems on the drying kiln exhaust*

Description

In a sawmill, large amounts of heat energy are used to dry lumber in the drying kiln. Exhaust from the kiln contains moisture evaporated from the lumber and unused heat. This heat can be recovered by recovery equipment placed on the dryer exhaust, then used in the kiln. Heat recovery can be air-to-air or air-to-water.

Air-to-air heat exchangers are used to preheat incoming kiln ventilation air (Figure 3.42). These exchangers can have either countercurrent or crosscurrent air flow. Air-to-water heat recovery is accomplished using a spray scrubber in which water is sprayed into a chamber with kiln exhaust flowing in the opposite direction. The warm water generated by the scrubber can then be used for other mill processes such as heating boiler feedwater. Both types of heat recovery equipment can be used at the same time. For batch kilns, one heat recovery unit may serve several kilns to make heat recovery more feasible.

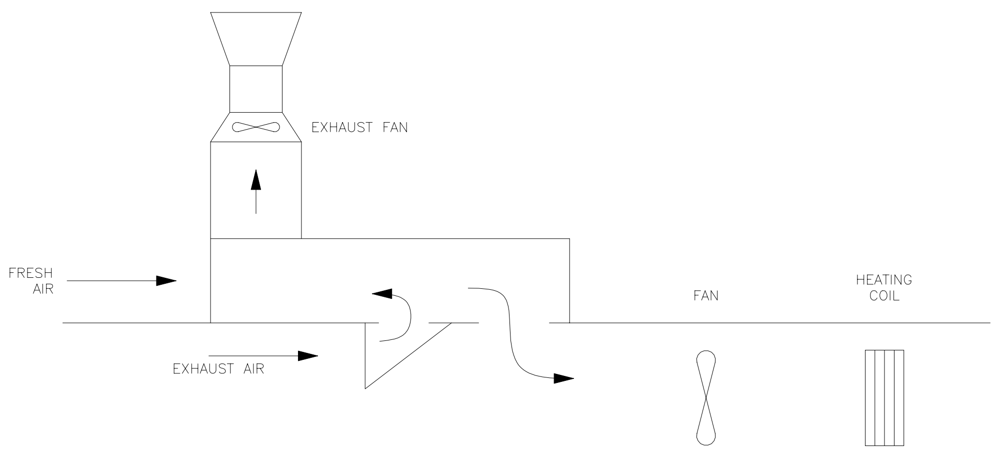

Figure 3.42. Heat Recovery Systems on the Drying Kiln Exhaust (air-to-air recovery)

Applicability and Limitations

Heat recovery from kiln exhaust means that the temperature of the exhaust has to be reduced, normally below the dew point. Many softwoods have high contents of volatiles that deposit at lower temperatures. This may prevent use of heat recovery equipment.

Heat recovery from batch kilns is complicated and expensive because exhaust flow and heat content vary according to the drying schedule. A common heat recovery system can be installed for several kilns in order to level out the variability and reduce costs.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Recovering heat from drying kiln exhaust will reduce energy consumption at the mill. Preheating ventilation air will reduce energy demand (in the form of steam or hot water) of the drying kiln. This will reduce fuel consumption in the boiler. Some additional electrical power may be used if additional fans or pumps must be installed.

Impact on CO_2

Energy savings from recovering heat from drying kiln exhaust will reduce the steam load in the boiler, and fuel savings will result. These fuel savings will reduce CO_2 emissions per product unit.

Impact on Operating Costs

Steam and related fuel savings will reduce operating costs. Savings will depend on the price of marginal fuel. Electrical costs may increase if fans or pumps are required.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Heat savings of up to 25% are achievable by recovering dryer exhaust heat to the fresh air entering the kiln. These high savings are only possible in progressive kilns which are applicable for drying softwood lumber. Heat savings in batch kilns are estimated to be 10 to 15%.

Assume:

- Lumber mill capacity (green lumber) 120 MBF/yr
- All product dried in batch kilns
- Heat consumption in drying 3.0 MBtu/kBF
- No back-pressure power generation

Savings if hog fuel is saved (assume savings in heat are 10%) (hog fuel data from Section 3.3.10.1):
(0.1) x (3 MBtu/kBF) x (120,000 kBF/yr) x ($0.89/MBtu)
= $32,040/yr

Savings if natural gas is saved (boiler efficiency assumed to be 80%):
(0.1) x (3 MBtu/kBF) x (120,000 kBF/yr) x ($3/MBtu) / (0.8 eff.)
= $135,000/yr

Reduction in CO_2 emissions from reduced natural gas use either at this site or another facility:
(0.1) x (3 MBtu/kBF) x (120,000 kBF/yr) x (146.3 lb CO_2/MBtu) x (1 T/2000 lb)
= 2633 T CO_2/yr

3.3.10.3 *Insulate the kiln and eliminate heat leaks*

Description

After the lumber is rough cut in a sawmill it is sent to kilns to be dried. Dried lumber may be planed before being sold. Drying kilns use large amounts of heat in the form of steam or hot water to dry the lumber. Improving the thermal efficiency of the kiln will reduce energy consumption. One way to do this is to insulate the kiln and eliminate heat leaks. The kiln may need insulation for several reasons: it was never insulated, the original insulation is in poor condition, or additional insulation is desired. Insulating the kiln reduces heat loss from radiation.

Heat leaks can occur in several locations. They can form around kiln doors due to deterioration or lack of seals, or in the kiln roof and walls from corrosion or cracks. Leaks can be fixed by replacing door seals, fixing cracks and holes, and adding insulation to prevent cold spots. Air and heat leaks into and out of the kiln increase the energy required to dry lumber because the heat lost to the ambient air is not available to dry the lumber.

Applicability and Limitations

Modern kilns are typically well insulated, with leaks minimized. This project may be an attractive improvement opportunity for an older kiln with leaks and insufficient insulation.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Insulating the kiln and eliminating heat leaks will reduce energy used for lumber drying. More heat will be available for drying and less will be wasted. The increase in available heat for drying means less steam or hot water will be used by the kiln to dry the lumber.

Impact on CO_2

Improving the performance of the drying kiln by adding or replacing insulation and eliminating heat leaks will reduce CO_2 emissions. Because more energy will be available for drying, less steam will be required. This means less steam must be generated in the boiler and fuel consumption will drop. This reduction in fuel usage will reduce CO_2 emissions.

Impact on Operating Costs

This energy conservation project will reduce the operating costs of the kiln. Improvements in kiln thermal efficiency will result in a reduction in fuel usage, which will reduce costs.

Capital Costs

Costs of insulation and eliminating heat leaks will depend on the number of kilns and their size and condition (door seals, walls, etc.).

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Radiation and leaks can be responsible for a very significant portion of the energy consumption in lumber drying. Heat losses through leaks and radiation of 3 to 30% of kiln heat consumption have been measured or estimated (consultant's data from energy audits of individual sawmills).

Assume:

- Lumber mill capacity 120 MBF/yr
- All product kiln dried

- Heat consumption in drying 3 MBtu/kBF
- Heat losses due to leakage and radiation 0.5 MBtu/kBF
- Heat losses after insulation and fixing leakage 0.2 MBtu/kBF
- Assume indirect heating (steam from natural gas at 80% efficiency)

Natural gas savings:
(120,000 kBF/yr) x ((0.5 - 0.2) MBtu/kBF) / 0.80
= 45,000 MBtu/yr

Savings:
(45,000 MBtu/yr) x ($3/MBtu)
= $135,000/yr

Reduction in CO_2 emissions:
(45,000 MBtu/yr) x (117 lb CO_2/MBtu)
= 2633 T CO_2/yr

3.3.10.4 *Use heat pump for lumber drying*

Description

Most sawmill drying kilns in the US are the batch kiln type. A batch kiln has a high energy consumption compared to a progressive kiln. If conversion to a progressive kiln is not feasible due to drying schedule variability, a batch kiln using dehumidification can be used. A dehumidification kiln works like a heat pump. Heat from condensation is recovered; therefore energy consumption is low. Dehumidification kilns operate at lower temperatures than conventional batch kilns, so drying rates are slower.

Applicability and Limitations

Dehumidification techniques are applicable to small lumber mill operations. Because of the high extractives content of softwood species, dehumidification techniques may not be suitable for drying softwood lumber.

Dehumidification may not be economically viable if the mill has a sufficient amount of hog fuel available for steam drying.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

A dehumidification or heat pump kiln has low energy consumption. Electrical energy is consumed by the kiln. Therefore use of heat energy in the form of steam will decrease, while use of electrical energy will increase.

Impact on CO_2

Using a dehumidification or heat pump kiln will reduce steam demand but increase electrical power demand. This affects both on-site and off-site (purchased power) CO_2 generation.

Impact on Operating Costs

A dehumidification drying kiln will reduce steam demand, and fuel savings will result. However, the kiln will consume more electrical power, and will only be feasible if fuel savings exceed the electrical power increase. A source of inexpensive electricity will be required, especially if the fuel for the steam supply is hog fuel generated at the plant.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail). Similarly, current or projected prices for and emission factors corresponding to purchased electricity should be used when estimating cost and off-site emission impacts at a mill (see Section 2.3).

Assume:

- Lumber mill capacity (hardwood) 50 MBF/yr
- All production dried in batch kilns
- Heat consumption in drying 3.0 MBtu/kBF
- No back-pressure power generation

For savings calculations from dehumidification drying, it is assumed that the heat consumption of the heat pump is 0.5 MBtu/kBF, or in power consumption:
(0.5 MBtu/kBF) / (3.6 MBtu/MWh)
= 0.139 MWh/kBF

Cost of drying with steam from hog fuel (hog fuel data from Section 3.3.10.1):
(50,000 kBF/yr) x (3.0 MBtu/kBF) x ($0.89/MBtu)
= $133,500/yr

Cost of drying with steam from natural gas (boiler efficiency assumed to be 80%):
(50,000 kBF/yr) x (3.0 MBtu/kBF) x ($3/MBtu) / (0.8 eff.)
= $562,500/yr

CO_2 contribution of drying with natural gas:
(50,000 kBF/yr) x (3.0 MBtu/kBF) x (146.3 lb CO_2/MBtu) / (2000 lb/T)
= 10,973 T CO_2/yr

Cost of power for dehumidification drying (assume purchased power $35/MWh):
(50,000 kBF/yr) x (0.139 MWh/kBF) x ($35/MWh)
= $243,250/yr

As can be seen, the dehumidification kiln is not cost effective if hog fuel is available at a cost of $5/T. Additionally, since combustion of hog fuel represents a net zero contribution to "greenhouse" CO_2, there are no emission reduction advantages associated with replacing hog fuel fired heating with a dehumidification kiln.

Savings from dehumidification drying if natural gas is marginal fuel for drying:
562,500 - 243,250
= $319,250/yr

CO_2 emissions from purchased power:
(50,000 kBF/yr) x (0.139 MWh/kBF) x (2009 lb/MWh) / (2000 lb/T)
= 6981 T CO_2/yr

Reduction of CO_2 emissions from dehumidification drying (converting from natural gas):
10,973 - 6981
= 3992 T CO_2/yr

3.3.10.5 *Convert batch kiln to progressive kiln*

Description

Lumber from a sawmill is conditioned, or dried, before being sold. The most common method of drying lumber in the US is in a batch or compartment drying kiln. A batch kiln is loaded with wet lumber and heated to dry the lumber, then the dry lumber is unloaded. Batch kilns have high operating and energy costs. Energy requirements are high due to heating and cooling of the kiln. The heat load is uneven because more heat is required at the start of the cycle when the wood has a higher moisture content. Extra boiler capacity may be required to meet peaks in energy demand. Heat recovery is also more difficult on batch kilns. Improvements in energy and operating costs can be achieved by replacing batch kilns with progressive kilns.

Progressive kilns are continuous drying kilns with long drying chambers (Figure 3.43). A load of wet lumber is loaded into one end of the kiln, while a load of dry lumber is simultaneously discharged at the opposite end. Intermediate stacks of lumber are at various stages of drying, and all stacks progress through the kiln in a stepwise fashion. Airflow in a progressive kiln is longitudinal from the dry end to the wet end. A progressive kiln requires large amounts of the same thickness of lumber to maintain the drying schedule. Different lumber thicknesses are dried in different kiln channels. Therefore, progressive kilns are suitable only for large sawmills. The heat load in a progressive kiln is much more even, so less boiler capacity may be required.

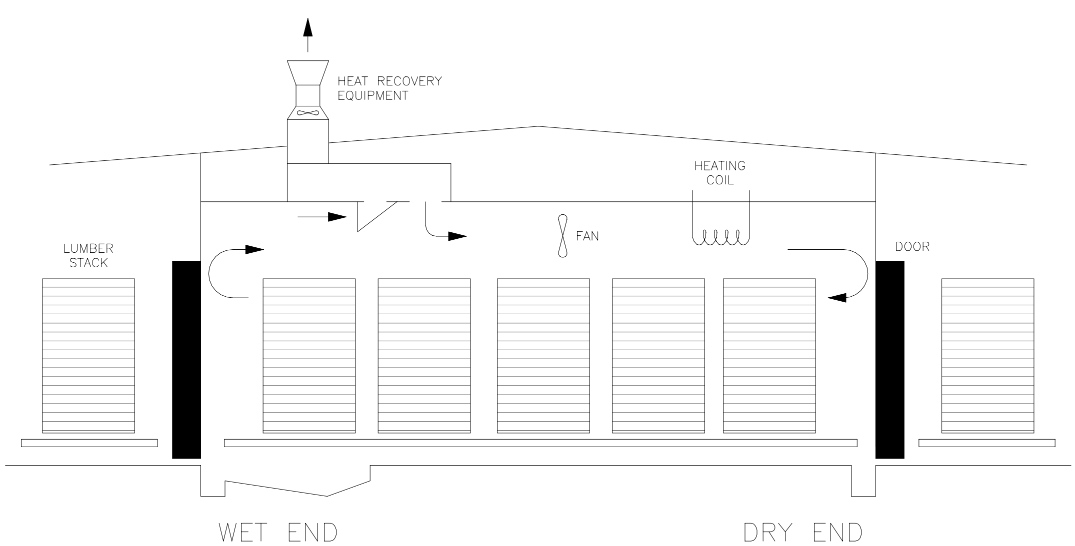

Figure 3.43. Principle of Progressive Lumber Drying Kiln

Applicability and Limitations

The feasibility of progressive kiln operations requires that production of lumber with the same dimensions be fairly high. Thus, progressive kiln techniques are applicable only for reasonably large softwood lumber mills.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Progressive kilns are more energy efficient than batch kilns. The heat load in a progressive kiln is stable and little energy is lost from heating up and cooling down the kiln (as with batch kilns). The constant heat load allows more efficient heat recovery from kiln exhaust. Progressive kilns can use hot water for heating the kiln, which is more efficient than steaming, where most of the enthalpy of the steam is lost. Progressive kilns require proportionately smaller volumes of exhaust air because the exhaust air is near the saturation point. Some electrical power may be saved due to the proportionately lower exhaust flow.

Impact on CO_2

Due to improved energy efficiency and better heat recovery, progressive kilns consume less energy than batch kilns. These improvements translate into reduced CO_2 emissions. Reductions occur from fuel savings in the boiler. Leveling the heating requirements of the kiln may also reduce fuel usage and CO_2 emissions.

Impact on Operating Costs

Replacing batch drying kilns with progressive drying kilns will reduce operating costs of the sawmill. Savings will be due to improved energy efficiency in the kiln and reduced fuel consumption in the boilers.

Capital Costs

Capital costs for installing a progressive drying kiln will be large. However, one progressive kiln will replace many batch kilns. This project is only feasible for plants with a large enough lumber throughput of the same thickness to support a progressive kiln.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Typical heat consumptions for progressive and compartment (batch) kilns are:

- Progressive kiln with heat recovery — 1.8 - 2.1 MBtu/kBF
- Compartment kiln without heat recovery — 2.1 - 3.2 MBtu/kBF

Assume:

- Lumber mill production — 120 MBF/yr
- All production dried in compartment kilns
- Heat consumption in drying — 2.7 MBtu/kBF
- No back-pressure power generation
- Heat consumption of a progressive kiln — 2.0 MBtu/kBF

Savings from converting to progressive kiln when hog fuel is used as fuel (hog fuel data from Section 3.3.10.1):
((2.7 - 2.0) MBtu/kBF) x (120,000 kBF/yr) x ($0.89/MBtu)
= $74,760/yr

Savings when natural gas is marginal fuel:
((2.7 - 2.0) MBtu/kBF) x (120,000 kBF/yr) x ($3/MBtu) x (1/0.8 eff.)
= $315,000/yr

Reduction in CO_2 when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
((2.7 - 2.0) MBtu/kBF) x (120,000 kBF/yr) x (146.3 lb CO_2/MBtu) / (2000 lb/T)
= 6145 T CO_2/yr

3.3.10.6 *Implement steam load management system*

Description

Steam consumption in a batch lumber dryer varies widely. Consumption is at its highest immediately after the start of the drying cycle. At the end of the drying cycle, steam consumption is nearly zero.

There are typically 10 to 20 drying kilns in a lumber mill. Different kilns may have different drying schedules. Starting several kilns simultaneously or nearly simultaneously will cause a high peak in steam demand. Boiler or steam piping capacity may limit the steam supply to the dryers. Sometimes oil or natural gas has to be used in the boilers in order to boost capacity. By planning drying schedules to eliminate simultaneous startups of several dryers, boiler loads can be leveled out.

Better scheduling of kilns is one way to manage the boiler steam load. This may, however, have a negative impact on plant capacity. Another option would be to use a steam accumulator to level out steam demand variations. The principle of the steam accumulator is described in Section 3.3.1.5.

Applicability and Limitations

Steam load management can be applied in any lumber mill with steam heated batch drying kiln operations. The benefits can, however, vary enormously from mill to mill depending on a variety of factors; for instance, the extent to which such systems are already in place. Scheduling kiln starts for steam load management may cause a reduction in drying capacity unless additional kiln capacity is installed.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Boilers normally operate most efficiently at steady loads; high variations reduce efficiency. In some cases, swing boilers may need to be started up in order to meet high steam demand. Shutting down or idling boilers during low steam demand situations will increase fuel consumption for a given steam demand. Leveling out demand will reduce fuel consumption.

Impact on CO_2

If fossil fuels have to be used in order to generate steam to meet demand peaks, steam load management would reduce CO_2 emissions.

Impact on Operating Costs

Steam load management would save fuel and thus result in reduced fuel costs. With steadier loads, boiler maintenance costs should also go down.

Capital Costs

Steam load management itself does not require any major capital. However, scheduling drying kiln operations based on steam load may affect plant capacity. This may create a need for installation of additional kilns in some cases.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Number of kilns	15
• Operating hours	2 shifts, 5 d/wk
• Average drying time	70 h

Frequency of dryer starts:

• Time available for loading the kilns	(5 d/wk x 16 hr/d) = 80 hr/wk
• Average number of loads per week	(15 x 168/70) = 36 loads/wk
• Average start frequency	(36 loads/wk) / (80 hr/wk) = 0.45 loads/hr

The average interval between kiln starts during regular working hours is thus about 2.2 hours.

The start of one kiln may cause a peak of 2000 to 5000 lb/hr in steam demand. If more than one kiln starts simultaneously, the steam peak can be a significant, sudden load change.

Figure 3.44 illustrates the steam storage capacity of a steam accumulator as a function of its water volume. If, for example, a peak of 5000 lb/hr is desired to be leveled out over two hours, an accumulator capacity of about 10,000 lb of steam or a water volume of about 2000 ft^3 would be needed. The actual size determination would require evaluation of the existing load swing.

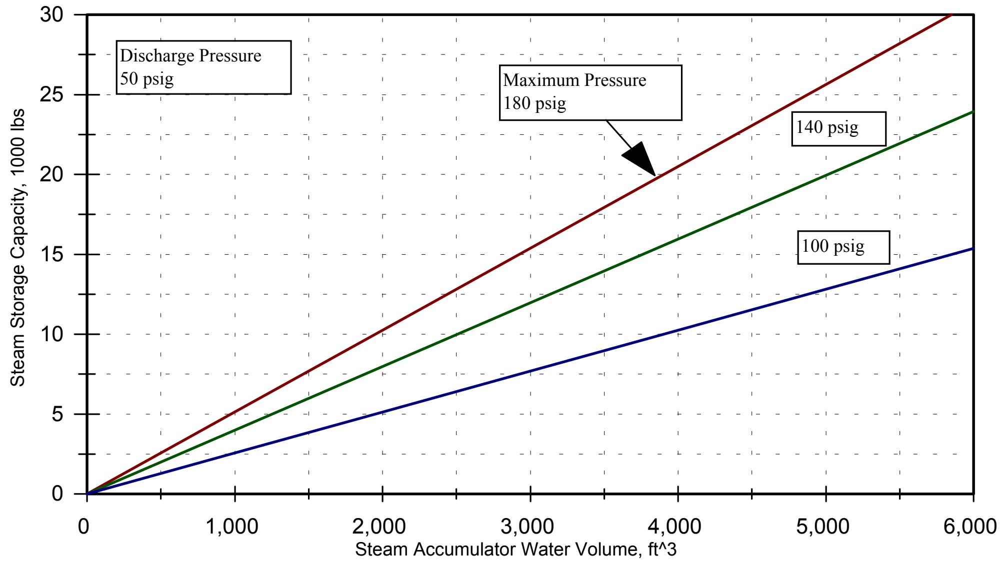

Figure 3.44. Steam Storage Capacity of a Steam Accumulator

Assume that, on average, 5 MBtu/hr of steam has to be made using natural gas in order to be able to comply with rapid swings.

Savings in natural gas corresponding to eliminating demand swings:
(5 MBtu/hr) / (0.8) x ($3/MBtu)
= $18.75/hr *or* $157,500/yr

CO_2 reduction:
(5 MBtu/hr) x (146.3 lb CO_2/MBtu) x (8400 hr/yr) / (2000 lb/T)
= 3072 T CO_2/yr

3.3.11 *Plywood Mills*

3.3.11.1 *Use advanced controls to control the drying process*

Description

The drying of plywood is accomplished by evaporating water from the veneer and removing it by exhausting wet air. Heat used for evaporation is supplied either by steam or by firing natural gas in the dryer. The control system measures wet and dry bulb temperatures and adjusts the exhaust fan speed to set the moisture content of the exhaust air near saturation.

Applicability and Limitations

Advanced controls are normally applicable for any plywood dryer that has not yet been equipped with such controls. Control of exhaust airflow at too low a level may cause hot air leaks from the dryer to the ambient air and may deteriorate working conditions. Any leakage point, especially on the upper parts of the hood, should be eliminated in order to allow operation at higher exhaust moisture content.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using advanced controls on the plywood drying process will reduce energy consumption. Exhausting air near its saturation point means more energy is used for drying and less is wasted on heating the air. This means less energy will need to be supplied from steam. Controlling the moisture content of exhaust air will also reduce electrical power consumption in the exhaust fan because fan speed can be reduced.

Impact on CO_2

Automated control of the plywood drying process will reduce CO_2 emissions. Maintaining the exhaust air near saturation by optimizing exhaust airflow means more energy will be available for the drying process. This means less fuel must be combusted to provide heat, and CO_2 emissions will drop.

Impact on Operating Costs

Optimizing the drying process through advanced controls will lower operating costs. Cost savings will come from a drop in fuel consumption. Savings will also come from a reduction in electrical power usage, especially if the exhaust fan has a speed control system.

Capital Costs

Costs of this project will include sensors and a computer control system. A variable speed drive may be justified on the exhaust fan.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

One of the important factors that affects plywood dryer heat consumption is the moisture content of exhaust air. Figure 3.45 illustrates the relationship based on a study in Finland (Usenius 1982). Control of the moisture content of exhaust air would be one important task for an advanced control system.

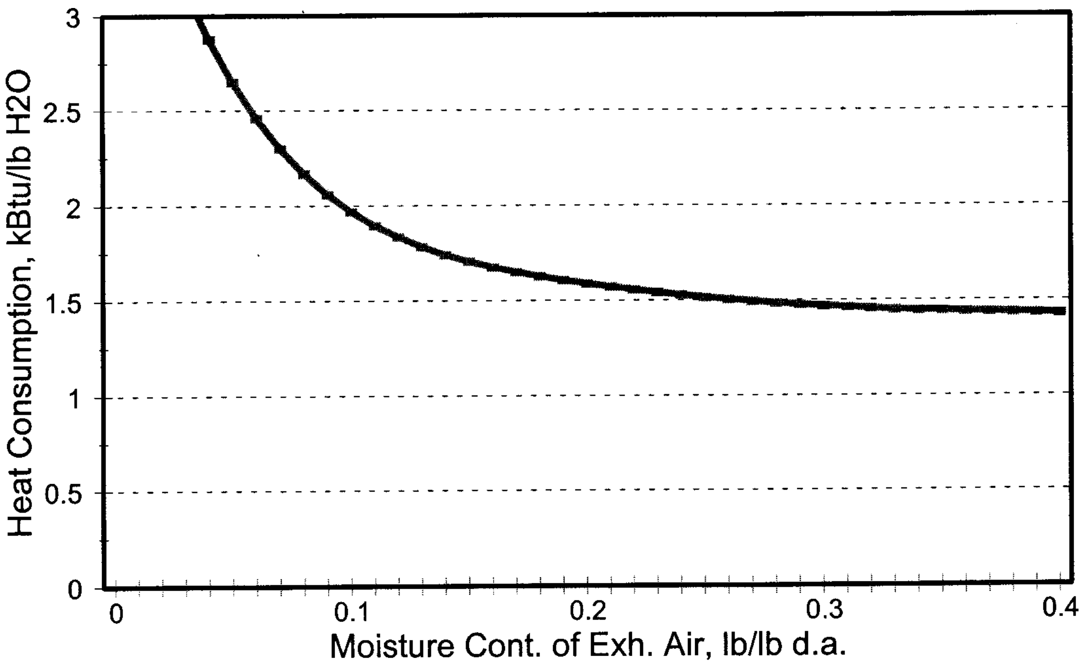

Figure 3.45. Impact of Moisture Content of Dryer Exhaust Air on Heat Consumption

Assume:

• Plywood plant production (3/8" basis)	150 Mft^2/yr
• Steam consumption in dryer	2.1 $MBtu/kft^2$

Advanced controls can typically save 10 to 15% of heat for drying.

Savings (assume 10% savings and hog fuel ($0.89/MBtu from Section 3.3.10.1) for steam generation):
(0.1) x (2.1 $MBtu/kft^2$) x (150,000 kft^2/yr) x ($0.89/MBtu)
= $28,035/yr

Savings if natural gas is used to produce steam:
(0.1) x (2.1 $MBtu/kft^2$) x (150,000 kft^2/yr) x ($3/MBtu) / (0.80)
= $118,125/yr

CO_2 reduction when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
(0.1) x (2.1 $MBtu/kft^2$) x (150,000 kft^2/yr) x (146.3 lb $CO_2/MBtu$) / (2000 lb/T)
= 2304 T CO_2/yr

3.3.11.2 *Insulate the dryer and eliminate air and heat leaks*

Description

In a plywood plant wet veneers are dried before being glued and pressed into sheets of plywood. The dryer has a high temperature and large internal air flow. Thermal efficiency can be improved by insulating the dryer and eliminating air and heat leaks. Insulating the dryer will reduce radiation losses from its surface. Reducing air leaks to and from the dryer will reduce heat consumption. Cold air leaking into the dryer reduces its internal temperature, which causes more heat to be consumed to dry the veneer. Air leaks into the dryer also increase exhaust gas flow, which increases fan power consumption. Hot air leaking out the ends of the dryer also increases dryer heat demand. Seals at the ends of the dryer help reduce the escape of hot air.

Applicability and Limitations

Insulating and eliminating leaks from the dryer is applicable for old dryers with insufficient insulation and excessive air leaks.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Insulating the dryer and eliminating air and heat leaks to and from it will reduce heat consumption in the dryer. More heat will be available to dry the veneer and less fuel will be required to provide needed heat. Reduced exhaust airflow will save electrical power.

Impact on CO_2

These energy conservation measures will reduce CO_2 emissions. The reduction will be primarily due to reductions in fuel usage because more heat will be available for veneer drying.

Impact on Operating Costs

Insulating the veneer dryer and reducing air and heat leaks to and from it will reduce the dryer's operating costs. The improvement in thermal efficiency will reduce fuel consumption, resulting in operating cost savings.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Plywood production (3/8" basis) — 150 Mft^2/yr
- No back-pressure power generation at the plant
- Steam consumption in dryer — 2.1 MBtu/kft^2
- Current losses through leaks and radiation — 0.2 MBtu/kft^2
- Reduction of losses with elimination of leaks and improved insulation — 0.1 MBtu/kft^2

Savings with hog fuel steam (hog fuel data from Section 3.3.10.1):
(0.1 MBtu/kft^2) x (150,000 kft^2/yr) x ($0.89/MBtu)
= $13,350/yr

Savings with oil as fuel (assume boiler efficiency of 82%):
(0.1 MBtu/kft^2) x (150,000 kft^2/yr) x ($3/MBtu) / (0.82)
= $54,878

CO_2 reduction when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
$(0.1\ MBtu/kft^2) \times (150{,}000\ kft^2/yr) \times (211.8\ lb\ CO_2/MBtu) / (2000\ lb/T)$
$=\quad 1589\ T\ CO_2/yr$

3.3.11.3 *Install heat recovery systems on the dryer exhaust*

Description

In the plywood manufacturing process, logs are heated in vats with steam or hot condensates from other processes. Heated and softened logs are then turned on a lathe to create veneers. These veneer sheets are dried before being glued and pressed into plywood. Veneer dryers consume large amounts of heat and can be either heated with steam or direct fired with natural gas. Large amounts of air are circulated in the dryer to remove water evaporated from the veneer. This exhaust air contains heat energy that can be recovered.

Heat can be recovered using several methods. Two possible methods are air-to-air and air-to-water. Hot, moist exhaust air can be passed through a heat exchanger to preheat incoming air. This would reduce heat consumption in the dryer. The second method of heat recovery is air-to-water. This method usually involves a spray scrubber. Water is sprayed into a chamber with hot dryer exhaust gases flowing in the opposite direction. The hot water that is produced can be used to replace live steam in the ply block conditioning vats.

Applicability and Limitations

Heat recovery from dryer hood exhaust is best suited for plants that use hot water for block conditioning. Some heat could also be used for heating boiler feedwater before it enters the deaerator. The temperature increase would not be very great, especially in the summer, because the water temperature from heat recovery could be at a maximum of 140 to 150°F and an indirect heater would be required to transfer heat to the boiler makeup water.

For a softwood veneer dryer, air-to-water heat recovery may cause pitch problems (cooling veneer dryer exhaust can cause volatile organics to condense).

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Installing heat recovery systems on the veneer dryer exhaust will reduce the mill's energy consumption. Using exhaust to preheat dryer air will reduce steam or fuel usage in the dryer. Using dryer exhaust to make hot water can reduce steam usage elsewhere, such as in the conditioning vats or debarking shotguns.

Impact on CO_2

Installing heat recovery equipment on the veneer dryer exhaust will allow reductions in CO_2 emissions. Preheating dryer air will reduce dryer steam or fuel consumption, which will reduce CO_2 emissions. Generating hot water will reduce steam consumption in other areas of the plant, which will result in fuel savings and CO_2 emission reduction in the boiler.

Impact on Operating Costs

Recovering heat from veneer dryer exhaust will improve the mill's operating costs. Savings will come from reductions in fuel usage, either from the dryer or from other mill processes.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Up to one-third of the heat used in veneer drying can potentially be recovered. However, the temperature level of the recovered heat is low. Furthermore, there is normally no controlled air makeup to the plywood dryers. Preheating of drying air is thus not easily arranged.

If the plant uses hot water vats or hot water sprays for block conditioning, dryer exhaust would be a natural place to get heat for it.

Assume:

- Plywood production (3/8" basis) 150 Mft^2/yr
- No back-pressure power generation at the plant
- Steam consumption in dryer 2.1 MBtu/kft^2
- 20% of dryer heat is recovered for production of water at 120°F
- Hot water is further heated with steam to 150°F

Savings with hog fuel steam (hog fuel data from Section 3.3.10.1):
(0.2) x (2.1 MBtu/kft^2) x (150,000 kft^2/yr) x ($0.89/MBtu)
= $56,070/yr

Savings with gas as fuel (assume boiler efficiency of 80%):
(0.2) x (2.1 MBtu/kft^2) x (150,000 kft^2/yr) x ($3/MBtu) / (0.8)
= $236,250/yr

CO_2 reduction based on gas use:
(0.2) x (2.1 MBtu/kft^2) x (150,000 kft^2/yr) x (146.3 lb CO_2/MBtu) / (2000 lb/T)
= 4608 T CO_2/yr

3.3.11.4 *Use boiler blowdown in the log vat*

Description

Boiler blowdown is normally sewered. Heat contained in blowdown liquid is recovered in some plants by flashing blowdown to a low pressure steam header and, perhaps, by preheating boiler feedwater. Water going to the sewer is normally still at a high temperature (boiling) and reasonably clean. Reuse of boiler blowdown, for example in block conditioning, would save steam heat in most plants.

Applicability and Limitations

If the plant can justify the piping and pumping and if a use for boiler blowdown water exists, recovery of boiler blowdown is applicable. Many plants sewer blowdown at even higher temperatures. Recovered heat above the boiling point, however, may be most effectively used for boiler feedwater heating.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy and CO_2

Steam would normally be saved if boiler blowdown heat was utilized instead of sewered. This would affect plant fuel consumption as well as CO_2 emissions.

Capital Costs

Blowdown water is clean enough for use, for example, in a log vat. No heat exchangers are needed, just a pump and piping to the point of use.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Plywood production 150 Mft^2/yr
- No back-pressure power generation
- Total steam consumption 90 klb/hr
- Boiler blowdown flow 5% of steam flow
- Boiler blowdown is sewered at 212°F
- Mill water temperature 70°F

Heat recovered (reference mill water, 70°F):
(0.05) x (90 klb/hr) x ((212 - 70)°F) x (1 kBtu/klb/°F) x (10^{-3} MBtu/kBtu)
= 0.64 MBtu/hr

Savings with hog fuel steam (hog fuel data from Section 3.3.10.1):
(0.64 MBtu/hr) x ($0.89/MBtu) x (8400 hr/yr)
= $4785/yr

Savings with natural gas as fuel:
(0.64 MBtu/hr) x ($3/MBtu) / (0.8) x (8400 hr/yr)
= $20,160/yr

Reduction in CO_2 emissions when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
(0.64 MBtu/hr) x (146.3 lb CO_2/MBtu) x (8400 hr/yr)/ (2000 lb/T)
= 393 T CO_2/yr

3.3.12 *Particleboard Mills*

3.3.12.1 *Measure and control the dryer exhaust moisture content to minimize air heating*

Description

This project is similar to Section 3.3.11.1 for plywood plants. By controlling dryer exhaust moisture content near the saturation point, less energy is wasted on air heating. This is accomplished by measuring the exhaust air moisture content using wet and dry bulb temperatures and adjusting exhaust air and makeup air flow rates to maintain the set point.

Applicability and Limitations

Advanced controls can be applied in any particleboard dryer that does not already apply such controls. The benefits can, however, vary enormously between applications depending on a variety of factors; for instance, the extent to which such systems are already in place. Estimated savings were based on 5% reduction in fuel consumption. This may be a very conservative estimate for an old dryer with no advanced controls currently applied.

A significant portion of particleboard is made from dried furnish. The technology described is not suitable for facilities with low drying demand.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Controlling the dryer exhaust moisture content will reduce energy consumption. Savings will come from reduced dryer heat demand and lower power consumption in the ventilation fans.

Impact on CO_2

Using automated controls on dryer exhaust will reduce CO_2 emissions. The drop in dryer heat demand means less fuel will be combusted to supply needed heat, and CO_2 emissions will drop. Lower power consumption by fans also means reduced consumption of purchased electricity, and off-site CO_2 emissions will drop accordingly.

Impact on Operating Costs

Controlling the moisture content of dryer exhaust will lower operating costs. Savings will come from reduced dryer heat demand and lower power consumption in ventilating fans.

Capital Costs

Costs of this project will include sensors, computer controls, and variable speed drives for the ventilation fans if they are not already installed.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Figure 3.46 illustrates the specific heat consumption of a particleboard dryer as a function of the moisture content of dryer exhaust air. As shown, heat consumption decreases from about 2.3 kBtu/lb H_2O evaporated to about 1.8 kBtu/lb H_2O when the moisture content of exhaust gases is increased from 0.1 lb H_2O/lb d.a. to 0.2 lb/lb d.a. Control of the exhaust air moisture content is the key element in an advanced control system. Of course, control of the final moisture content is still the key objective of the drying process.

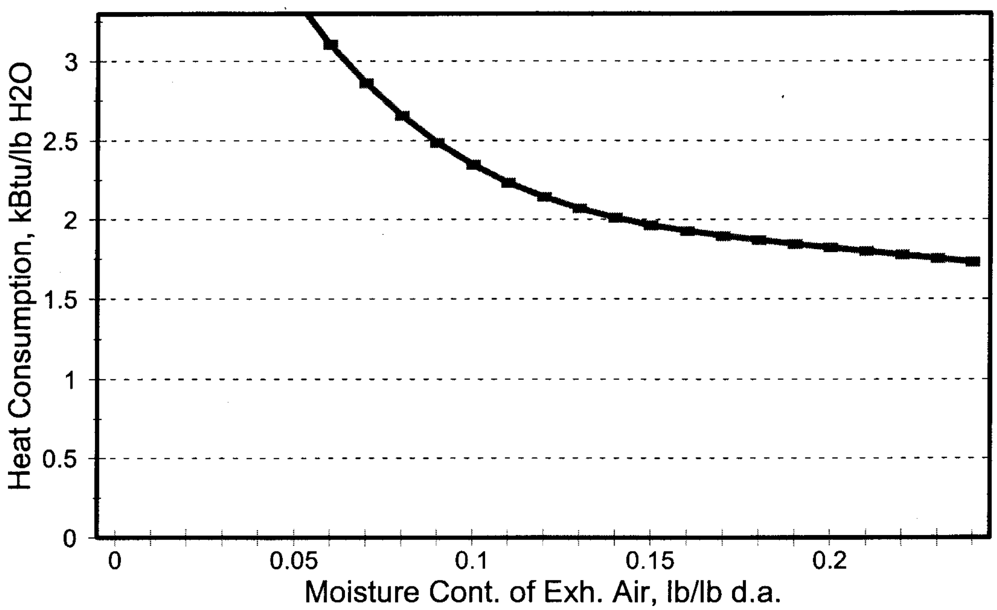

Figure 3.46. Impact of Dryer Exhaust Moisture Content on Heat Consumption in Drying

Assume:

• Production of particleboard (3/4" basis)	130 Mft^2/yr
or	8.1 Mft^3/yr
• Specific weight of board	45 lb/ft^3
• Initial moisture content of particles (green)	45%
• Moisture content of dried particles	5%
• Heat consumption in drying	2 kBtu/lb H_2O
• Operating time	8400 hr/yr
• Indirect heating (heating air with steam)	

Evaporation in the dryer:

$$\left(\frac{8{,}100{,}000\ \text{ft}^3/\text{yr}}{8400\ \text{hr/yr}}\right) \text{x} \left(45\ \text{lb/ft}^3\right) \text{x} \left(\frac{0.45\ \text{lb H}_2\text{O}}{0.55\ \text{lb d.s. to dryer}} - \frac{0.05\ \text{lb H}_2\text{O}}{0.95\ \text{lb d.s. from dryer}}\right) \times \left(0.95\ \text{lb d.s./lb product}\right)$$

= 31,600 lb H_2O/h

Heat consumption:
(31.6 klb/hr) x (2 MBtu/klb H_2O)
= 63.2 MBtu/hr

Savings (assume savings of 5% in heat consumption due to advanced controls):

With wood residues as fuel (hog fuel data from Section 3.3.10.1):
(0.05) x (63.2 MBtu/hr) x ($0.89/MBtu)
= $2.8/hr *or* $23,520/yr

With natural gas as fuel:
(0.05) x (63.2 MBtu/hr) x ($3/MBtu)
= $9.5/hr *or* $79,800/yr

CO_2 reduction when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
(0.05) x (63.2 MBtu/hr) x (146.3 lb CO_2/MBtu)
= 462 lb CO_2/hr *or* 1940 T CO_2/yr

3.3.12.2 *Recover heat from dryer exhaust*

Description

To produce the final particleboard product, the particles must be dried. The dryer is normally operated by direct fired fuel, hog fuel, oil, or gas. Large amounts of air must be heated and circulated to evaporate water from the particles. The exhaust air from the dryer contains heat that can be recovered. This heat can be used to preheat combustion air, especially in dryers with no exhaust air recirculation. Another option is to use the heat for hot water production.

Applicability and Limitations

Heat recovery in an air-to-air heat exchanger may be difficult because of extractives in the exhaust gases. A more attractive option may be conversion or replacement of the dryer with a “closed” dryer with recirculation of exhaust air.

The drying calculation is based on green furnish. If pre-dried furnish is used, the potential for savings and CO_2 reductions is very small.

Heat recovery to water may not be feasible because of limited demand for water and tight regulations for effluent water.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Recovering heat from dryer exhaust to combustion air will reduce energy consumption in the dryer. If exhaust air is partially recycled, recovery of exhaust air for some other purpose, such as hot water production, may be more attractive.

Impact on CO_2

Using heat recovery equipment to preheat dryer combustion air will reduce heating demand and lower fuel consumption. This lowers CO_2 emissions. If exhaust heat is recovered to water, site-specific conditions will determine whether the heat can be utilized to reduce fuel consumption.

Impact on Operating Costs

The use of heat recovery equipment on dryer exhaust will reduce operating costs. Energy savings from using preheated air will reduce fuel usage, and this will lower operating costs. There may be a small increase in electrical power consumption due to additional fans that are needed.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• Production of particleboard	130 Mft^2/yr
• "Open" dryers; i.e., no exhaust is recirculated to feed dryer	
• Heat consumption in the dryer	2.0 kBtu/lb H_2O
• Evaporation (see Section 3.3.12.1)	31.6 klb/hr
• Temperature of combustion air	70ºF
• Heat recovery will increase temperature to	150ºF

In these conditions, heat consumption in drying is estimated to be reduced by 10% due to higher combustion air temperature. The savings are:

Hog fuel basis (hog fuel data from Section 3.3.10.1):
(0.1) x (31.6 klb/hr) x (2.0 MBtu/klb) x ($0.89/MBtu)
= $5.6/hr *or* $47,040/yr

Natural gas as fuel:
(0.1) x (31.6 klb/hr) x (2.0 MBtu/klb) x ($3/MBtu) / (0.8)
= $23.7/hr *or* $199,080/yr

Reduction in CO_2 emissions when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
(0.1) x (31.6 klb/hr) x (2.0 MBtu/klb) x (146.3 lb CO_2/MBtu)
= 925 lb CO_2/hr *or* 3885 T CO_2/yr

3.3.12.3 *Use wood waste as fuel for drying (suspension burning)*

Description

Particleboard dryers are sometimes directly fired with natural gas to provide heat for the drying process. An alternative is to use wood waste to supply heat for drying. This will reduce consumption of natural gas and increase use of on-site generated biofuels. Wood waste would be combusted in suspension burners and hot combustion gases would supply heat for the drying process.

Applicability and Limitations

Suspension burning of hog fuel in a particleboard dryer is proven technology and is applicable to plants using fossil fuel as the heat supply to the dryer. Special attention must be paid to fire protection when designing hog fuel handling, feeding, and burning systems.

Air emissions regulations may limit the feasibility of wood residues as fuel for particleboard dryers.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Using wood waste to replace fossil fuels for particleboard drying will result in better energy recovery. The energy required for drying will not change. Wood waste generated at the facility is a valuable heat source, and recovering it to the drying process improves the mill's energy recovery. Wood waste is also a renewable resource, while fossil fuels are not.

Impact on CO_2

Using wood waste as fuel for drying will reduce fossil CO_2 emissions. The same amount of heat energy will be required in the drying process. The difference will be that this energy will come from combustion of wood waste and not from fossil fuels.

Impact on Operating Costs

Replacing fossil fuels with wood waste as fuel for direct drying will reduce operating costs. Wood waste is a cheaper fuel because it is generated on-site. There will be a cost associated with processing, transporting, and storing the fuel before burning. If wood waste was previously disposed of, the cost of transporting and landfilling it will be eliminated.

Capital Costs

Costs of the project will include the cost of the wood waste suspension burners plus any processing, conveying, and storage equipment needed to deliver the fuel to the burners.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Particleboard production — 130 Mft^2/yr
- Heat consumption in drying — 2.0 kBtu/lb H_2O
- Evaporation in drying (Section 3.3.12.1) — 31.6 klb/hr
- All fossil fuel can be replaced with hog fuel

Savings from conversion from natural gas to hog fuel (hog fuel data from Section 3.3.10.1):

Cost of direct wood fired heat:

$$\frac{\$5}{\text{T}} \times \frac{1\,\text{T}}{2000\,\text{lb}} \times \frac{1\,\text{lb wood}}{0.5\,\text{lb d.s.}} \times \frac{1\,\text{lb d.s.}}{8750\,\text{Btu}} \times \frac{10^6\ \text{Btu}}{\text{MBtu}}$$

= $0.57/MBtu

(31.6 klb/hr) x (2.0 MBtu/klb) x ($3 - $0.57/MBtu)

= $153.6/hr *or* $1,290,038/yr

CO_2 reduction:

(31.6 klb/hr) x (2.0 MBtu/klb) x (146.3 lb CO_2/MBtu)

= 9246 lb CO_2/hr *or* 38,833 T CO_2/yr

3.3.13 *Hardboard Mills*

3.3.13.1 *Install heat recovery*

Description

The hardboard dryer for this example is assumed to operate similarly to plywood dryers. After pressing, the wet formed board is loaded into the dryer. The dryer usually has multiple decks and is divided into several zones. The hardboard progresses from the wet end of the dryer to the dry end on conveyor chains. The ends of the dryer are usually equipped with seals to prevent loss of hot gases. The dryer is heated with steam or natural gas and individual zones have separate heating and ventilating systems. Large amounts of air must be heated and circulated to evaporate water from wet fiberboard. Dryer exhaust air can be used to preheat incoming air. An air-to-air heat exchanger with cross flow or countercurrent flow can be used.

Applicability and Limitations

Heat recovery can be applied on dryers that do not yet have heat recovery installed. On direct fired dryers, heat can be used for preheating combustion air and space heating. Heat recovery to water would also be a possibility if there is a need for hot water.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Preheating dryer air will reduce energy used for air heating, leaving more energy available for drying. Thus, less fuel will have to be fired to dry the same amount of product.

Impact on CO_2

Preheating dryer air by installing heat recovery equipment on dryer exhaust will reduce CO_2 emissions. The increase in energy available for drying will reduce fuel requirements. Reducing the amount of fuel burned will decrease CO_2 emissions.

Impact on Operating Costs

Using heat recovery equipment to preheat dryer air will reduce operating costs. Fuel usage will be reduced as a result of air preheating. This will lower the amount spent on fuel.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Hardboard mill production (1/8" basis) 250 Mft^2/yr
- Hardboard density 65 lb/ft^3
- Operating time 8400 hr/yr

- Moisture content of board to dryer 60%
- Moisture content of board from dryer 5%
- Steam enthalpy 1220 Btu/lb
- Enthalpy of returned condensates 180 Btu/lb
- Hardboard production 10.6 T/hr
- Dryer operated with steam

Evaporation in dryer:

$$(10.6\ \text{T/h}) \times (2000\ \text{lb/T}) \times (0.95\ \text{lb d.s./lb product}) \times \left(\frac{0.6\ \text{lb}\ H_2O}{0.4\ \text{lb d.s. to dryer}} - \frac{0.05\ \text{lb}\ H_2O}{0.95\ \text{lb d.s. from dryer}}\right)$$

= 29,150 lb/hr

Assume steam consumption is 1.45 lb/lb H_2O.

Heat consumption in drying:
(1.45 lb/lb H_2O) x (29,150 lb H_2O/hr) x (1220 Btu/lb - 180 Btu/lb) x (10^{-6} MBtu/Btu)
= 44.0 MBtu/hr

Most of the heat used for drying will escape the system with dryer exhaust. Assume that 15% of the heat is recovered to heat dryer makeup air and room air. Savings are:

Hog fuel as fuel for steam generation (hog fuel data from Section 3.3.10.1):
(0.15) x (44 MBtu/hr) x ($0.89/MBtu)
= $5.9/hr *or* $49,560/yr

Natural gas as fuel:
(0.15) x (44 MBtu/hr) x ($3/MBtu) / (0.80)
= $24.8/hr *or* $208,320/yr

CO_2 reduction (based on reducing gas use):
(0.15) x (44 MBtu/hr) x (146.3 lb CO_2/MBtu)
= 966 lb CO_2/hr *or* 4057 T CO_2/yr

3.3.13.2 *Preheat drying air with steam*

Description

Many hardboard (wet process) dryers are operated by heating drying air in natural gas or oil burners. If hog fuel and steam boiler capacity exists, preheating drying air with steam would reduce the costs of drying. Conversion to 100% steam heating would normally reduce dryer capacity, because drying air temperature levels would be decreased from levels that can be reached by gas or oil fired burners.

Applicability and Limitations

Replacement of oil or natural gas with hog fuel may be possible on hardboard dryers that use direct fired dryers. Replacing all drying with steam drying may not be possible because the capacity of the dryer may decrease. Preheating drying air can be technically feasible. Space available for steam heaters may limit the applicability of this technology. Also, if boiler capacity has to be added in order to allow increased steam usage, the payback time of steam usage in drying will be very long.

<u>Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change</u>. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Total heat consumption in energy would not change. However, if steam generated with hog fuel is available, a significant portion of gas or oil use for drying could be replaced with hog fuel, and thus the cost of drying would be reduced.

Impact on CO_2

Partial replacement of gas or oil with hog fuel would reduce CO_2 emissions.

Impact on Operating Costs

Hog fuel is normally a low cost fuel compared to oil or natural gas. Replacing steam generated by oil or gas with steam generated by hog fuel would thus reduce operating costs.

Capital Costs

Costs of converting part of the drying to steam drying are very site-specific. Minimum equipment requirements would include steam coil heaters and steam piping. If steam generation capacity is not sufficient, additional boiler capacity may be needed.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

- Hardboard production (1/8" basis) — 250 Mft^2/yr
- Hardboard production — 2.6 Mft^3/yr
- Operating time — 8400 hr/yr
- Hardboard density — 65 lb/ft^3
- Hardboard production — 84,500 T/yr
- Board moisture content before dryer — 60%
- Board moisture content after dryer — 5%
- Dryer operated with natural gas
- Heat consumption in drying (Section 3.3.13.1): — 44.0 MBtu/hr

The portion of heat that can be replaced with steam depends on drying air temperatures at different zones and steam pressures.

Steam consumption (assume 40% of air heating can be done with steam):
(0.4) x (44 MBtu/hr)
= 17.6 MBtu/hr

Cost savings using steam generated from burning hog fuel rather than direct firing with gas (hog fuel data from Section 3.3.10.1):
(17.6 MBtu/hr) x ($3 - $0.89/MBtu)
= $37.1/hr *or* $311,640/yr

CO_2 reduction:
(17.6 MBtu/hr) x (117.0 lb CO_2/MBtu)
= 2059 lb CO_2/hr *or* 8649 T CO_2/yr

3.3.14 *Oriented Strand Board (OSB) Plants*

3.3.14.1 *Screen flakes before drying; dry fines separately*

Description

The required drying time for flakes depends on their particle size and initial moisture content. If all particles, independent of size, are dried in the same dryer, small particles have to be overdried in order to dry larger flakes to the required dryness level. By separating small particles and drying them in a separate dryer, over drying can be avoided and control of the drying process can be performed more efficiently.

Especially in pneumatic type dryers where flakes are transported with drying air, a certain minimum air flow velocity is required to move the flakes to avoid the risk of fire. Maintaining a high enough air velocity may imply that the moisture content of dryer exhaust air cannot be controlled to an economical level from the energy consumption point of view, particularly if the dryer does not have air recirculation. Classification of material for drying based on particle size and also, if possible, on initial moisture content, will help control the drying process.

Applicability and Limitations

Screening fines out of the rest of the material before drying is applicable in all OSB plants. Economic feasibility will be site-specific.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Having more homogeneous material going through each dryer will allow optimization of drying conditions for each type of flake. This will save heat in drying.

Impact on CO_2

CO_2 emissions will be reduced because of reduced heat consumption in drying.

Capital Costs

In an existing plant, screening out fines and drying them separately may require installation of a screening and conveying system for fines. There are typically several drying lines installed in a modern OSB plant. One of the existing dryers can be designated as the fines dryer, so no additional dryers are needed.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• OSB production (3/8" basis)	400 Mft^2/yr
• OSB production	12.5 Mft^3/yr
• Operating time	8400 hr/yr
• Board density	40 lb/ft^3
• OSB production	250,000 T/yr
• Chip moisture content before dryer	50%
• Chip moisture content after dryer	5%
• BD wood in the final product	88%

Evaporation in drying:

$$\left(\frac{250{,}000\ \text{T/yr}}{8400\ \text{hr/yr}}\right) \text{x (0.88 BDT/T) x (2000 lb/T) x} \left(\frac{0.5\ \text{lb H}_2\text{O}}{0.5\ \text{lb d.s. to dryer}} - \frac{0.05\ \text{lb H}_2\text{O}}{0.95\ \text{lb d.s. from dryer}}\right)$$

= 49,624 lb H_2O/hr

As discussed in Section 3.3.12.1, heat consumption in drying is highly dependent on the moisture content of dryer exhaust air. If feed to the dryer is inhomogeneous, exhaust moisture content is estimated to be 0.12 lb H_2O/lb d.a. Heat consumption by the dryer is about 2.2 kBtu/lb H_2O evaporated (Figure 3.46).

Total heat consumption in drying:
(49,624 lb H_2O/hr) x (2.2 x 10^{-3} MBtu/lb H_2O)
= 109.2 MBtu/hr

Assume that with more homogeneous material to the dryer, average exhaust moisture content can be increased to 0.15 lb H_2O/lb d.a. Heat consumption in drying will drop by about 0.2 kBtu/lb H_2O (Figure 3.46). The savings would be as follows.

Savings with hog fuel (hog fuel data from Section 3.3.10.1), direct fired (Section 3.3.12.3):
(49,624 lb H_2O/hr) x (0.2 x 10^{-3} MBtu/lb H_2O) x ($0.57/MBtu)
= $5.66/hr *or* $47,519/yr

Savings with natural gas as fuel (direct fired):
(49,624 lb H_2O/hr) x (0.2 x 10^{-3} MBtu/lb H_2O) x ($3/MBtu)
= $29.8/hr *or* $250,320/yr

Reduction in CO_2 emissions (only if gas use is reduced):
(49,624 lb H_2O/hr) x (0.2 x 10^{-3} MBtu/lb H_2O) x (146.3 CO_2/MBtu)
= 1452 lb CO_2/hr *or* 6098 T CO_2/yr

3.3.14.2 *Use advanced controls to optimize the drying process*

Description

This project is similar to Section 3.3.12.1 for particleboard plants. By controlling dryer exhaust moisture content to near the saturation point, less energy is wasted on air heating. This is accomplished by measuring the exhaust air moisture content using wet and dry bulb temperatures and adjusting exhaust air and makeup airflow rates to maintain the set point.

Applicability and Limitations

Advanced controls can be applied in any OSB dryer that does not already apply such controls. The benefits can, however, vary enormously between applications depending on a variety of factors; for instance, the extent to which such systems are already in place. Estimated savings are based on a 5% reduction in fuel consumption. This may be a conservative estimate, especially for an old dryer without advanced controls.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

Controlling the dryer exhaust moisture content will reduce energy consumption. Savings will come from reduced dryer heat demand and lower power consumption in the ventilation fans.

Impact on CO_2

Using automated controls on dryer exhaust will reduce CO_2 emissions. The drop in dryer heat demand means less fuel will be combusted to supply needed heat, and CO_2 emissions will drop. Lower power consumption by fans also means less fuel will be used to generate electricity, and off-site CO_2 emissions will drop.

Impact on Operating Costs

Controlling the moisture content of dryer exhaust will lower operating costs. Savings will come from reduced dryer heat demand and lower power consumption in ventilating fans.

Capital Costs

Costs of this project will include sensors, computer controls, and variable speed drives for ventilation fans if they are not already installed.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Specific heat consumption of a particleboard dryer is described in Section 3.3.12.1. As discussed, heat consumption decreases from about 2.3 kBtu/lb H_2O evaporated to about 1.8 kBtu/lb H_2O when the moisture content of the exhaust gases is increased from 0.1 lb H_2O/lb d.a. to 0.2 lb/lb d.a. Control of exhaust air moisture content is the key element in an advanced control system. Control of the final moisture content is still the key objective of the drying process.

Assume:

• Production of OSB (3/8" basis)	400 Mft^2/yr
or	12.5 Mft^3/yr
• Specific weight of board	40 lb/ft^3
• Initial moisture content of particles	50%

- Moisture content of dried particles 5%
- Heat consumption in drying 2.2 kBtu/lb H_2O
- Operating time 8400 hr/yr
- Indirect heating (heating dryer air with steam)

Evaporation in dryer (Section 3.3.14.1):
= 49,624 lb H_2O/hr

Heat consumption in drying (Section 3.3.14.1):
= 109.2 MBtu/hr

Savings (assume savings of 5% in heat consumption due to advanced controls):

With wood residues as fuel to generate steam (Section 3.3.10.1):
(0.05) x (109.2 MBtu/hr) x ($0.89/MBtu)
= $4.9/hr *or* $41,160/yr

With natural gas as fuel to generate steam:
(0.05) x (109.2 MBtu/hr) x ($3/MBtu) / (0.8)
= $20.5/hr *or* $171,990/yr

CO_2 reduction when natural gas is the fuel (there are no emission reductions associated with hog fuel savings):
(0.05) x (109.2 MBtu/hr) x (146.3 lb CO_2/MBtu)
= 799 lb CO_2/hr *or* 3356 T CO_2/yr

3.3.14.3 *Use powdered resins*

Description

Use of powdered resins would reduce the drying demand of the flakes. If a constant amount of water is assumed to go to the hot presses, higher water content of flakes can be allowed from the dryer if powdered rather than liquid resins are used.

Applicability and Limitations

Use of powdered resins may require modifications to the manufacturing process. The potential impact on board quality must be addressed as well as the cost of powdered resins compared to liquid resins.

The impact of powdered resin use on indirect CO_2 emissions depends on the processes and fuels that are being applied in manufacturing.

Before making this or any other process change, companies need to understand the environmental permitting requirements that might be triggered by the change. Costs associated with permitting issues are not addressed in this manual.

Impact on Energy

If less drying is required for materials going to the presses, less energy for drying is required.

Impact on CO_2

Less fuel for drying will result in lower CO_2 emissions. The overall impact of the use of powdered resins on CO_2 emissions depends on the method that is used by the resin manufacturer to dry the resin. If fossil fuel is used by the resin manufacturer to dry the resins and hog fuel is used for drying flakes, the net impact of the use of powdered resins could be an increase in CO_2 emissions.

Impact on Operating Costs

Using dry, powdered resins will require less fuel for drying the wood furnish, with corresponding savings in fuel consumption and associated costs. However, the cost of powdered resins must be compared to that of liquid resins, and any cost differential should be considered.

Capital Costs

The transportation, storage, and blending systems may need to be changed when converting from liquid resins to powdered resins.

Sample Calculations

The following sample calculation is based on reduced use of natural gas (assumed to be the marginal fuel for wood products mills) corresponding to energy conservation/CO_2 reduction measures, and incorporates the emission factor and an assumed price for this fuel. When estimating the impacts of implementing this technology option at a mill, the emission factor and current or projected price of the actual fuel likely to be saved should be used. Note that only reductions in fossil fuel consumption should be considered when estimating on-site CO_2 emission reductions, as biomass derived fuels are considered to be net zero greenhouse gas contributors (see Section 2.1 for additional detail).

Assume:

• OSB production (3/8" basis)	400 Mft^2/yr
• OSB production	12.5 M ft^3/yr
• Operating time	8400 hr/yr
• Board density	40 lb/ft^3
• OSB production	250,000 T/yr
• Chip moisture before dryer	50%
• Chip moisture after dryer	5%
• Bone dry wood in final product	88%
• Direct heating of flakes	

Assume:

• The amount of resins (dry basis)	5% on BD wood
• Dry solids contents of resins	65%

Resin usage:
(250,000 T/yr) / (8400 hr/yr) x (2000 lb/T) x (0.88 lb BD wood/lb product) x
(0.05 lb resin/lb BD wood)
= 2619 lb/hr

Water introduced with resin:
(100 / 65 - 1) x (2619 lb/hr)
= 1410 lb H_2O/hr

Assume that this additional amount of water can be left with the flakes if powdered rather than liquid resins are used. Assume further that the heat consumption in drying is 2.0 kBtu/lb H_2O.

Heat savings:
(1410 lb H_2O/hr) x (2 x 10^{-3} MBtu/lb/H_2O)
= 2.8 MBtu/hr

Savings if hog fuel is used (Section 3.3.10.1; cost of direct fired heat from Section 3.3.12.3):
(2.8 MBtu/hr) x ($0.57/MBtu)
= $1.6/hr *or* $13,406/yr

Savings if natural gas is the fuel:
(2.8 MBtu/hr) x ($3/MBtu)
= $8.4/hr *or* $70,560/yr

Reduction in "site" CO_2 emissions (based on direct fired gas):
(2.8 MBtu/hr) x (117.0 lb CO_2/MBtu)
= 328 lb/hr *or* 1378 T CO_2/yr

4.0 CAPITAL COST ESTIMATES

4.1 Estimate Preparation Method

Capital cost estimates developed for this study were compiled by the equipment factoring method. In using this method the major pieces of engineered equipment are costed either by quotations, similar recent experience and proposals, or other known values, then ratio factors are applied for the other areas of work in order to arrive at a complete facility cost. In this manner, civil structural costs, piping costs, electrical and instrumentation costs, and typical indirect costs such as engineering, overhead, temporary facility, taxes, and so on, are estimated without having to prepare detailed design drawings. This is a very common method of preparing feasibility grade and comparative cost estimates. The actual ratio factors used are shown on the capital cost estimation sheets, which are provided for most of the technology options in Appendix C.

Some of the technologies do not lend themselves to this method of factored estimates, such as those which involve only instrumentation and controls. Direct costs for those estimates were developed based on results of EKONO's recent experience, with indirect costs estimated by applying ratio factors to arrive at total installed costs.

Estimations of equipment costs were based predominately on data from recent projects. Costs were adjusted for size or capacity differences using capacity scaling factors. In this way, estimates more closely reflect the potential costs to an "average" mill.

An execution and design contingency of 15% was added to each cost estimate to account for items which typically are included in a project but which cannot be identified at this point. The accuracy range of these estimates can be assumed to be in the ±40% range, meaning that the actual cost, should one of these projects be built, would be between 60% and 140% of the estimated cost.

An attempt was made to include "average" indirect costs, recognizing that special conditions and requirements at a specific mill may significantly affect the magnitude of these costs. For example, the amount of taxes and mill support costs will be site-specific. Whether the mill is enclosed in a building or not may also affect indirect costs. These kinds of issues make it impossible to accurately predict costs, but the cost variability associated with most of these issues should be covered within the accuracy range stated above.

4.2 Cost Estimates

Cost estimates developed for most of the technologies selected for evaluation are provided in Appendix C. Table 4.1 summarizes the cost estimates and provides a brief description of the sizing basis for each estimate. For estimating capital costs associated with applying a technology at a different equipment size or capacity, costs can be adjusted using capacity scaling factors (e.g., the six-tenths factor rule).

Table 4.1. Cost Estimates and Bases for Energy Conservation Technologies

	Technology Option	Capacity or Size Factor	Cost ($million)
1 STEAM AND POWER SUPPLY			
1.1	Replace low pressure boilers and install turbogenerator capacity	Boiler sized at 300,000 lbs/hr steam generation; turbine generator sized at 18 MW	61.3
1.2	Switch power boiler from fossil fuel to wood (or build new wood boiler to utilize available biofuel)	New boiler sized at 200,000 lbs/hr steam generation	33.3
1.3	Preheat demineralized water with secondary heat before steam heating	System sized for 10,000 ft^2 heat exchanger	1.8
1.4	Rebuild or replace low efficiency boilers	Boiler sized at 300,000 lbs/hr steam generation	12.4
1.5	Install a steam accumulator to facilitate efficient control of steam header pressures	Accumulator sized at 10,000 ft^3 corresponding to steam storage capacity of 40,000 to 50,000 lbs	2.6
1.6	Install an ash reinjection system in the hog fuel boiler	System sized at 300,000 lbs/hr steam boiler capacity	0.5
1.7	Install a bark press or bark dryer to increase utilization of biofuels	System sized at 300,000 lbs/hr steam boiler capacity (bark press/bark dryer)	4.2/7.0
1.8	Install additional heat recovery systems to boilers to lower losses with flue gases	System sized at 300,000 lbs/hr steam boiler capacity	7.2
1.9	Implement energy management program to provide current and reliable information on energy use	System contains measurement loops and necessary software	1.5
1.10	Switch power boiler fuel from coal or oil to natural gas	Variable, see Section 3.3.1.10	
1.11	Install gas turbine cogeneration system for electrical power and steam generation	Variable, see Section 3.3.1.11	
2 WOOD SUPPLY			
2.1	Replace pneumatic chip conveyors with belt conveyors	System sized to supply 1000 ADT/d pulp mill	2.0
2.2	Use secondary heat instead of steam in debarking	Sized to bring hot water from pulp mill to wood room	0.5

(Continued on next page.)

Table 4.1. Continued

	Technology Option	Capacity or Size Factor	Cost ($million)
3 KRAFT PULPING			
3.1	Rebuild mill hot water system to provide for separate production and distribution of warm and hot water	Based on 1000 ADT/d pulp mill	1.7
3.2	Install blow heat (batch digesters) or flash heat (continuous digester) evaporators	Based on 1000 ADT/d pulp mill	9.3
3.3	Replace conventional batch digesters with cold blow systems	Based on 1000 ADT/d pulp mill	60.5
3.4	Use flash heat in a continuous digester to preheat chips	Based on 1000 ADT/d pulp mill	2.0
3.5	Use evaporator condensates on decker showers	Based on 1000 ADT/d pulp mill	0.7
3.6	Use two pressure level steaming of batch digesters to maximize back-pressure power generation	Based on six batch digesters and mill producing 1000 ADT/d	1.5
3.7	Optimize the dilution factor control	System estimated to support six control loops and control software	0.5
4 KRAFT BLEACHING			
4.1	Optimize the filtrate recycling concept for optimum chemical and energy use	Based on 1000 ADT/d pulp mill	1.5
4.2	Preheat ClO_2 before it enters the mixer	Based on 1000 ADT/d pulp mill	0.7
4.3	Use oxygen based chemicals to reduce use of ClO_2 (O_2 or O_3 delignification, EP, EOP, etc.)	Based on new oxygen delignification system for 1000 ADT/d pulp mill	25.0
5 PULP DRYER AND PAPER MACHINE			
5.1	Eliminate steam use in the wire pit by providing hot water from heat recovery and/or pulp mill and by reducing water use on the machine	Based on heat exchanger surface area of 8000 ft^2 and piping to supply hot water to 500 to 800 ADT/d machine	1.5
5.2	Upgrade press section to enhance water removal	Based on double felting press section of dryer (500 to 800 ADT/d machine)	3.6

(Continued on next page.)

Table 4.1. Continued

	Technology Option	Capacity or Size Factor	Cost ($million)
5.3	Enclose the machine hood (if applicable) and install air-to-air and air-to-water heat recovery	Includes mechanical enclosure and heat recovery (500 to 800 ADT/d paper machine)	3.0
5.4	Install properly sized white water and broke systems to minimize white water losses during upset conditions	Sized for adding up to 50,000 gallons to existing tankage and related piping	1.4
5.5	Implement hood exhaust moisture controls to minimize air heating and maximize heat recovery	Includes new variable speed drives for exhaust fans, and moisture sensing and control instruments (500 to 1100 ADT/d machine)	0.5
5.6	Implement efficient control systems for the machine steam and condensate systems to eliminate excessive blowthrough and steam venting during machine breaks	Includes piping modifications to dryer sections for flow control instead of pressure difference control	1.0
6 KRAFT RECOVERY			
6.1	Convert recovery boiler to non-direct contact and implement high solids firing	Assumes one high solids concentrator and economizer for 1000 ADT/d mill	22.7
6.2	Perform evaporator boilout with weak black liquor	Based on piping modifications, 3-way valves, and automatic switching for 800 klb/hr evaporation plant	0.5
6.3	Convert evaporation to seven-effect operation (install additional evaporator effect)	Based on additional two bodies to evaporator plant	8.0
6.4	Install high solids concentrator to maximize steam generation with black liquor	Assumes boiler is low odor design and black liquor solids from 1000 ADT/d mill concentrated to 75% instead of 67%	10.8
6.5	Implement an energy efficient lime kiln (lime mud dryer, mud filter, product coolers, etc.)	Kiln capacity 300 ADT/d product lime	10.0
6.6	Replace lime kiln scrubber with an electrostatic precipitator	Kiln capacity 300 ADT/d product lime	3.0
6.7	Integrate condensate stripping to evaporation	Stripping column capacity 500 gpm feed	1.7

(Continued on next page.)

Table 4.1. Continued

	Technology Option	Capacity or Size Factor	Cost ($million)
6.8	Install a methanol rectification and liquefaction system	Stripping system capacity 500 gpm condensates to stripping	1.0
6.9	Install a biofuel gasifier, use low Btu gas for lime reburning	Kiln capacity 300 ADT/d product lime	16.0
7 MECHANICAL PULPING			
7.1	Implement heat recovery from TMP process to steam and water	Reboiler heat exchanger surface 18,000 ft^2 (one TMP line)	3.8
7.2	Add third refining stage to the TMP plant	Refiner and installation for 400 ADT/d line	5.0
7.3	Replace the conventional groundwood process with pressurized groundwood (PGW) operation	Replace eight grinders and associated equipment (500 ADT/d facility)	76.5
7.4	Countercurrent coupling of paper machine and mechanical pulping white water systems	Includes 150,000 gallon white water tank, two 1000 gpm pumps, filtering equipment, and related piping (≈400 ADT/d facility)	1.4
8 DEINKING PLANT			
8.1	Supply waste heat from other process areas to deinking plant	Includes 150,000 gallon white water tank and two 1000 gpm pumps	0.6
8.2	Install drum pulpers	Install pulper and associated equipment (300 ADT/d facility)	3.0
8.3	Implement closed heat and chemical loop	Includes 120,000 gallon tank, two 800 gpm pumps, filtering equipment, and related piping (≈300 ADT/d plant)	1.2
9 MILL GENERAL			
9.1	Optimize integration and utilization of heat recovery systems	Includes heat exchangers, tanks, pumps, piping, etc., for 1000 ADT/d pulp mill	6.0
9.2	Implement preventive maintenance procedures to increase equipment utilization efficiency	Estimate to purchase PM system from vendor	0.5

(Continued on next page.)

Table 4.1. Continued

	Technology Option	Capacity or Size Factor	Cost ($million)
9.3	Implement optimum spill management procedures	Spill tank and six sewer pumps included	1.2
9.4	Maximize recovery and return of steam condensates	Includes flow and other meters for measurements and software for monitoring and follow-up	0.4
9.5	Recover wood waste that is going to landfill	Assumes concrete pavement in wood yard area and minor modifications to hog fuel boiler (grate)	3.0
9.6	Install energy measurement, monitoring, reporting, and follow-up systems	Includes flow and other meters and power house monitoring and management systems	1.6
9.7	Convert pump and fan drives to variable speed drives	Includes 15 pumps/fans, average size 150 hp	1.5
9.8	Install advanced process controls	Allowance for mill-wide advanced controls system	1.6
9.9	Replace oversized electric motors	Replace 100 motors, buy 25 new ones	0.5
9.10	Use high efficiency lighting	No associated capital costs	N/A
10 SAWMILLS			
10.1	Use advanced controls to control the drying process	Based on ten moisture control loops and variable speed control of fans	1.0
10.2	Install heat recovery systems on the drying kiln exhaust	Based on an air-to-air heat exchanger of 10,000 ft^2	1.1
10.3	Insulate the kiln and eliminate heat leaks	Based on insulating surface of 15,000 ft^2	0.2
10.4	Use heat pump for lumber drying	Based on 20 MBtu/hr heat pump (to dry 50 MBF/yr lumber)	5.0
10.5	Convert batch kiln to progressive kiln	Kiln to dry 150 MBF/yr lumber	12.3
10.6	Implement steam load management system	Based on steam accumulator, 2000 ft^3	1.2
11 PLYWOOD MILLS			
11.1	Use advanced controls to control the drying process	Includes ten field loops, DCS system for control, and variable speed control of fans	1.2

(Continued on next page.)

Table 4.1. Continued

	Technology Option	Capacity or Size Factor	Cost ($million)
11.2	Insulate the dryer and eliminate air and heat leaks	Based on insulating a surface of 15,000 ft^2	0.2
11.3	Install heat recovery systems on the dryer exhaust	Based on air-to-air heat exchanger of 10,000 ft^2	1.1
11.4	Use boiler blowdown in the log vat	Includes piping ≈100 gpm hot water to log vat	0.1
12 PARTICLEBOARD MILLS			
12.1	Measure and control the dryer exhaust moisture content to minimize air heating	Includes seven field loops, DCS system for moisture control, and fan speed control	0.8
12.2	Recover heat from dryer exhaust	Based on air-to-air heat exchanger of 10,000 ft^2	1.1
12.3	Use wood waste as fuel for drying (suspension burning)	Based on 70 MBtu/hr dryer and associated equipment to support 130 Mft^3/yr production	7.0
13 HARDBOARD MILLS			
13.1	Install heat recovery	Includes new hood for machine and air-to-water recovery heat exchanger of 1200 ft^2	1.6
13.2	Preheat drying air with steam	Includes new ducting and steam coil heaters with heat transfer capacity of ≈20 MBtu/hr, and steam piping from boiler to dryer	0.6
14 ORIENTED STRAND BOARD (OSB) PLANTS			
14.1	Screen flakes before drying; dry fines separately	Screening system for 60 T/hr chips and fines (wet basis)	0.6
14.2	Use advanced controls to optimize the drying process	Based on seven control loops using DCS controls and variable speed drives	0.9
14.3	Use powdered resins	Based on facility producing 400 Mft^2/yr OSB	0.1

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APPENDIX A

STEAM COST CALCULATIONS

The cost of steam is based on the assumption that all low (50 psig) and intermediate pressure (150 psig) steam comes through a back-pressure turbine. The calculations and results are shown in Table A1. The calculations on each line of the table are explained in Sections 1 through 12 of this appendix. Figure 2.1 from Section 2 has been reproduced here to aid in understanding the steam flows used to perform the calculations.

Table A1. Cost of Process Steam for 1 klb Change in Process Steam Consumption [a]

Item	Units	Boiler Steam	Extraction Steam	Exhaust Steam
1. Incremental change in process steam consumption	klb	1.0	1.0	1.0
2. Change in process steam to desuperheaters	klb	0.88	0.96	0.98
3. Change in process heat consumption	MBtu	1.18	1.11	1.08
4. Change in deaerator steam consumption	klb	0.16	0.16	0.16
5. Total change in steam flow to turbogenerator	klb	0.16	1.12	1.15
6. Change in heat to back-pressure power generation	kBtu	37.3	204.8	259.9
7. Change in back-pressure power generation	kWh	10.4	57.0	72.3
8. Change in purchased power cost	$	-0.36	-2.00	-2.53
9. Change in total fuel consumption	MBtu	1.49	1.61	1.64
10. Change in total fuel cost	$	4.46	4.82	4.91
11. Change in purchased energy cost	$/klb	4.1	2.8	2.4
12. Change in purchased energy cost	$/MBtu	3.5	2.5	2.2

[a] For calculations in this table, the following assumptions are made:
condensate return to power house = 50%
temperature of returned condensates = 210ºF

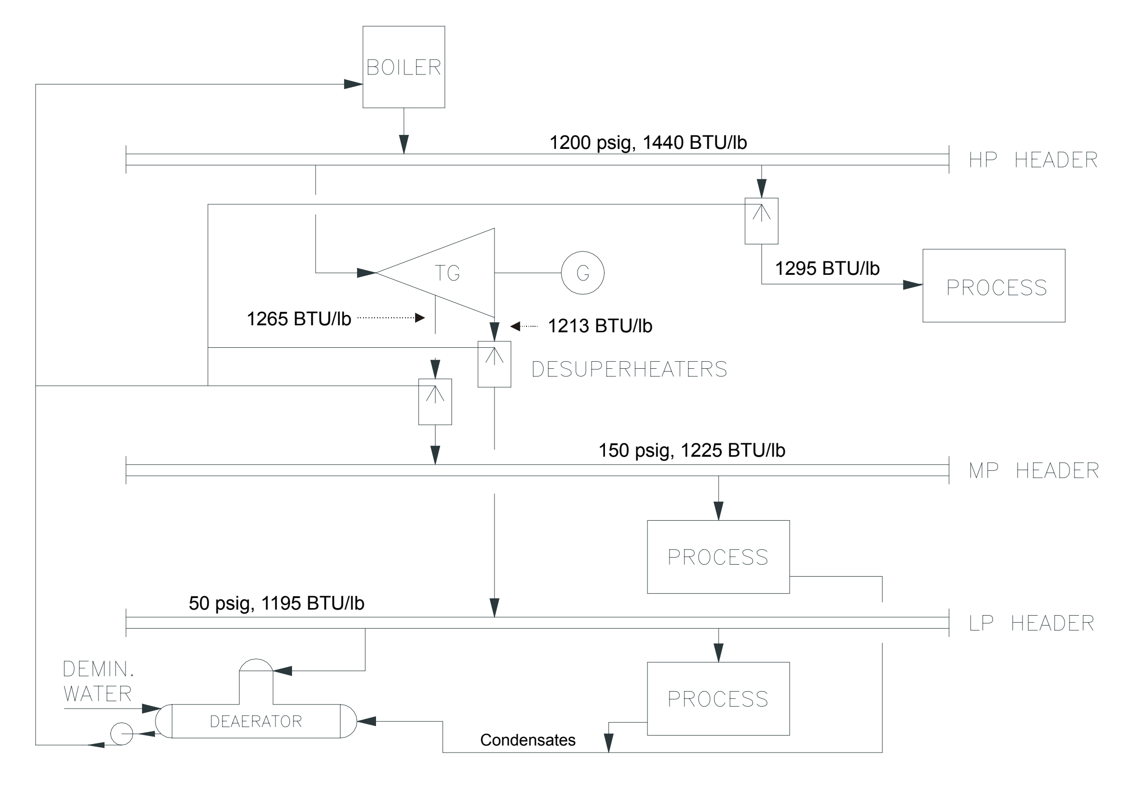

Figure 2.1. Typical Steam and Power Generation Concept (from Chapter 2)

1. Incremental Change in Process Steam Consumption

The incremental change is assumed to be 1 klb (1000 lb).

2. Change in Process Steam to Desuperheaters

For each klb of process steam, the amount of steam to the desuperheaters (from the turbogenerator) can be computed as follows:

Mass balance:
Fst = F1 + F2

Energy balance:

$F_{st} \times h_{st} = F_1 \times h_1 + F_2 \times h_2$

$= F_1 \times h_1 + (F_{st} - F_1) \times h_2$

$F_1 \times (h_1 - h_2) = F_{st} \times (h_{st} - h_2)$

$$F_1 = F_{st} \times \frac{h_{st} - h_2}{h_1 - h_2}$$

if F_{st} = 1 klb steam: $$F_1 = \frac{h_{st} - h_2}{h_1 - h_2}$$

where:

F_1 = steam flow from the turbogenerator (TG) to the desuperheater (klb)
F_2 = water flow to the desuperheater (klb)

F_{st} = the steam flow to the process (klb)
h_{st} = enthalpy of steam to the process (Btu/lb)
h_1 = enthalpy of steam to the desuperheater (Btu/lb)
h_2 = enthalpy of desuperheater water (Btu/lb, in calculation assumed to be the same as deaerator water)

The amount of water to the desuperheater is correspondingly:

$$F_2 = F_{st} - F_1 = F_{st} \times \left[1 - \frac{h_{st} - h_2}{h_1 - h_2}\right]$$

$$= F_{st} \times \left[\frac{h_1 - h_2 - h_{st} + h_2}{h_1 - h_2}\right]$$

$$= F_{st} \times \left[\frac{h_1 - h_{st}}{h_1 - h_2}\right] = \frac{h_1 - h_{st}}{h_1 - h_2}$$

3. Change in Process Heat Consumption

The change in process heat consumption is calculated to be the difference between steam heat and the sum of heat returned with condensates and heat brought with demineralized water (before heating with steam); i.e.,

$$\text{process heat} = \left[F_{st} \times h_{st} - F_{cond} \times h_{cond} - \left(F_{st} - F_{cond}\right) \times h_{FW}\right] \times 1000\ \text{lb/klb}$$

where:

F_{st} = steam flow to the process (klb)
h_{st} = steam enthalpy to the process (Btu/lb)
F_{cond} = condensates flow to the power house (klb)
h_{cond} = enthalpy of condensates to the power house (Btu/lb)
h_{FW} = enthalpy of demineralized water before steam heating in the deaerator (Btu/lb)

For example, the change in process heat consumption corresponding to a 1000 lb increase in low pressure process steam consumption is:
[(1 klb) × (1195 Btu/lb) – (0.5 klb) × (178 Btu/lb) – (1 – 0.5 klb) × (48 Btu/lb)]×1000
= 1,080,000 Btu *or* 1.08 MBtu

4. Change in Deaerator Steam Consumption

Steam to the deaerator is needed to:

- Increase the demineralized water temperature to the deaerator temperature
- Increase the temperature of returned condensates to the deaerator temperature
- Compensate for vent and other losses

The losses are ignored in these calculations. The change in exhaust (50 psi) steam demand in the deaerator (DA) is calculated as follows:

Change in DA steam:

$$\frac{F_{st} \times \{(T_{DA} - T_{FW}) \times (100 - R_{cond}) \div 100 + (T_{DA} - T_{RC}) \times R_{cond} \div 100\} \times 1 \text{ Btu/lb °F}}{(h_{est} - h_{DA})}$$

where:

F_{st} = change in process steam flow (lb)
T_{DA} = deaerator temperature (°F)
T_{FW} = temperature of demineralized water (°F)
R_{cond} = condensate return, % of steam use
T_{RC} = temperature of returned steam condensates (°F)
h_{est} = enthalpy of exhaust steam (Btu/lb)
h_{DA} = enthalpy of water in the deaerator (Btu/lb, at T_{DA})

For example:

$$\frac{1 \text{ klb} \times \{(297.7 - 80^{\circ}\text{F}) \times (100\text{-}50) \div 100 + (297.7 - 210^{\circ}\text{F}) \times (50 \div 100)\} \times 1 \text{Btu/lb}^{\circ}\text{F}}{(1195 \text{ Btu/lb} - 265.7 \text{ Btu/lb})}$$

= 0.164 klb of steam to deaerator

5. Total Change in Steam Flow to Turbogenerator

The total change in steam to the turbogenerator is the sum, in pounds, of the change in steam to the desuperheater(s) [line 2][1] and the change in steam to the deaerator [line 4]. Only changes in steam consumption to the deaerator are considered for changes in high pressure steam consumption (1200 psi), because steam to the desuperheater does not first pass through the turbogenerator. Note that for changes in medium pressure process steam consumption (extraction steam, 150 psi) this sum corresponds to changes in exhaust steam to the deaerator (50 psi) plus changes in extraction steam to the appropriate desuperheater (150 psi), in pounds of steam (it cannot be directly converted to heat in Btus due to summing steam flows which are at differing pressures).

6. Change in Heat to Back-Pressure Power Generation

Heat to back-pressure power consists of two components:

- Contribution of low pressure steam to the deaerator
- Contribution of process steam from the turbine and desuperheaters

Note that steam to the deaerator is low pressure (turbogenerator exhaust) steam. Only deaerator steam contributes to back-pressure power for the process use of boiler steam (high pressure).

The change in heat to back-pressure power is:
(Change in steam to turbogenerator (lb)) x (Isentropic enthalpy drop (Btu/lb)) x
(Isentropic efficiency (%))

The isentropic enthalpy drop across the turbogenerator is estimated from the steam tables. In the sample cases they are:

- from 1200 psig and 900°F to 150 psig 224 Btu/lb
- from 1200 psig and 900°F to 50 psig 299 Btu/lb

[1] Line number references in this appendix refer to lines in Table A1.

The isentropic efficiencies vary based on turbine design, condition, and loading. The following values are assumed:

- Extraction steam 78%
- Exhaust steam 76%

For an increase of 1000 lb in high pressure steam consumption, the change in heat to power generation is:
(164 lb) x (299 Btu/lb) x (0.76)
= 37,267 Btu

For an increase of 1000 lb in medium pressure (extraction) steam consumption, the change in heat to power generation is:
(960 lb) x (224 Btu/lb) x (0.78) + (164 lb) x (299 Btu/lb) x (0.76)
= 204,998 Btu

For an increase of 1000 lb in low pressure (exhaust) steam consumption, the change in heat to power generation is:
(980 lb + 164 lb) x (299 Btu/lb) x (0.76)
= 259,962 Btu

7. Change in Back-Pressure Power Generation

Heat to power generation [line 6] is converted to power. Some losses occur in the turbogenerator itself. The theoretical conversion is 1 kWh = 3413 Btu. The heat, mechanical, and electrical losses are assumed to be 5% in this case. Accordingly, each Wh of power generation consumes 3.59 Btu of steam energy.

For example, the change in power generation corresponding to a 1000 lb increase in medium pressure process steam consumption would be:
(204,998 Btu) ÷ (3.59 Btu/Wh)
= 57,103 Wh or 57.1 kWh

8. Change in Purchased Power Cost

It is assumed that an incremented change in back-pressure power generation directly affects purchased power demand. If process steam consumption increases by 1 klb, the reduction in purchased power cost can be calculated by multiplying increased back-pressure power [line 7] by the purchased power price, which is assumed to be $35/MWh in this case. Obviously, if process steam consumption goes down, purchased power cost will go up correspondingly.

9. Change in Total Fuel Consumption

Change in fuel consumption is:
(Change in process heat [line 3] + Change in heat to B-P power [line 6]) ÷ Θ_{Boiler}
Where:
Θ_{Boiler} = Boiler efficiency

For example, given a 1000 lb increase in medium pressure process steam consumption, when the marginal fuel is oil (i.e., $\Theta = 0.82$):
(1.112 MBtu + 0.2048 MBtu) ÷ (0.82)
= 1.61 MBtu in oil

10. Change in Total Fuel Cost

The change in purchased fuel cost is the fuel cost multiplied by the change in fuel consumption [line 9].

11. Change in Purchased Energy Cost ($/klb)

The change in purchased energy cost is the sum of the change in fuel cost and the change in purchased power cost. This is given for 1 klb change in process steam consumption.

12. Change in Purchased Energy Cost ($/MBtu)

The change in purchased energy cost per MBtu is the change in purchased energy cost per thousand pounds of process steam consumption [line 11] divided by the change in process energy consumption associated with the thousand pounds of process steam [line 3].

APPENDIX B

BOILER BALANCE CALCULATIONS FOR TECHNOLOGY 1.4 SAMPLE CALCULATIONS

Heating Value/Flue Gas Calculations

Fuel:	**#6 Oil**
Excess Air:	42%

6.5% O_2 Content of dry Flue Gases

Uncombustible material (sand, rocks, etc.; dry basis)	0.0%	
Fuel moisture content	0.1%	
Combustible fuel elementary analysis (dry basis)		
Carbon	85.5%	
Hydrogen	11.2%	
Oxygen	0.7%	
Nitrogen	0.0%	
Sulfur	2.5%	
Ash/other	0.1%	
Total	100.0%	
Higher heating value (type "+ HHV" to have it estimated)	18,520	Btu/lb d.s.

Wet fuel composition		
Carbon	85.5	lb/100 lb dry fuel
Hydrogen	11.2	lb/100 lb dry fuel
Oxygen	0.8	lb/100 lb dry fuel
Nitrogen	0.0	lb/100 lb dry fuel
Sulfur	2.5	lb/100 lb dry fuel
Other	0.1	lb/100 lb dry fuel
	100.1	lb/100 lb dry fuel
Theoretical air		
Ambient air moisture content	0.006	lb/lb dry air
Oxygen	319.4	lb/100 lb dry fuel
Nitrogen	1051.4	lb/100 lb dry fuel
Moisture	8.2	lb/100 lb dry fuel
TOTAL	1379.0	lb/100 lb dry fuel

Flue gas	lb/100lb	lbmol/100lb	vol%	vol% (dry basis)
Carbon dioxide	313.5	7.13	10.0%	11.0%
Oxygen	134.1	4.19	5.9%	6.5%
Nitrogen	1,492.9	53.32	75.1%	82.4%
Sulfur dioxide	5.0	0.08	0.1%	0.1%
TOTAL DRY	1,945.6	64.71	91.2%	100.0%
Water	112.6	6.25	8.8%	
TOTAL WET	2,058.2	70.97	100.0%	

Dry flue gas		
Molecular weight	30.1	lb/lbmol
Volume @ 68 °F, 1 atm	24,915	cu.ft./100 lb
Estimated Higher Heating Value (HHV)	18,590	Btu/lb dry fuel
Lower Heating Value (LHV)	17,338	Btu/lb dry fuel

Stack test parameters

Flue gas oxygen content	6.48%	(by volume, dry basis)
Flue gas moisture	8.81%	(by volume)
Flue gas SO2	1207.2	ppmdv
Flue gas flowrate	16.31	m^3/sec (dry basis, 20 °C)
Flue gas SO2 . . .	188.8	kg/hr
. . . at fuel consumption of	100.0	T/d (actual)

Adiabatic flame temperature

Assume all feeds enter at 77 °F

	Mean Cp Btu/lb°F	Mass flow lb/lb dry fuel	Heat content Btu/lb dry fuel	
Carbon dioxide	0.2843	3.135	2,564.2	
Oxygen	0.2558	1.341	987.3	
Nitrogen	0.2784	14.929	11,958.6	
Sulfur dioxide	0.1996	0.050	28.7	
Water	0.5555	1.126	1,799.1	
TOTAL	0.2928	20.582	17,337.9	= LHV

Adiabatic flame temperature 2,953.8 °F

Boiler heat balance

Ambient air temperature, °F	80
Flue gas temperature, °F	500
Feedwater temperature, °F	282
FW temperature before heating, °F	80
Steam enthalpy, Btu/lb	1440
Unburned combustible (%)	0.4%
Unaccounted loss (%)	2.1%
Radiation loss (%)	0.8%

Heat inputs	Btu/lb dry fuel		
Fuel heating value	18,520	99.3%	
Combustion air	137	0.7%	
TOTAL	18,657	100.0%	
Heat outputs			
Flue gases, sensible heat	2,267	12.2%	
Flue gases, latent heat	1,182	6.3%	
Unburned combustible	74	0.4%	
Unaccounted loss	392	2.1%	
Radiation loss	149	0.8%	
Heat to steam	14,593	78.2%	78.8%
TOTAL	18,657	100.0%	

CO2 discharges	214.8	lb CO2/MBtu in Steam
SO2 discharges	3.4	lb SO2/MBtu in Steam

Steam generation	**lb/lb dry fuel**
Steam generated	12.28
LP steam needed in feedwater heater	0.72

Heating Value/Flue Gas Calculations

Fuel:	**#6 Oil**
Excess Air:	20%
	3.7% O2 Content of dry Flue Gases

Uncombustible material (sand, rocks, etc.; dry basis)	0.0%	
Fuel moisture content	0.1%	
Combustible fuel elementary analysis (dry basis)		
Carbon	85.5%	
Hydrogen	11.2%	
Oxygen	0.7%	
Nitrogen	0.0%	
Sulfur	2.5%	
Ash/other	0.1%	
Total	100.0%	
Higher heating value (type "+HHV" to have it estimated)	18,520	Btu/lb d.s.

Wet fuel composition		
Carbon	85.5	lb/100 lb dry fuel
Hydrogen	11.2	lb/100 lb dry fuel
Oxygen	0.8	lb/100 lb dry fuel
Nitrogen	0.0	lb/100 lb dry fuel
Sulfur	2.5	lb/100 lb dry fuel
Other	0.1	lb/100 lb dry fuel
	100.1	lb/100 lb dry fuel
Theoretical air		
Ambient air moisture content	0.006	lb/lb dry air
Oxygen	319.4	lb/100 lb dry fuel
Nitrogen	1051.4	lb/100 lb dry fuel
Moisture	8.2	lb/100 lb dry fuel
TOTAL	1379.0	lb/100 lb dry fuel

Flue gas	lb/100lb	lbmol/100lb	vol%	vol% (dry basis)
Carbon dioxide	313.5	7.13	11.8%	13.1%
Oxygen	63.9	2.00	3.3%	3.7%
Nitrogen	1,261.6	45.06	74.6%	83.0%
Sulfur dioxide	5.0	0.08	0.1%	0.1%
TOTAL DRY	1,644.0	54.26	89.8%	100.0%
Water	110.8	6.15	10.2%	
TOTAL WET	1,754.8	60.41	100.0%	

Dry flue gas		
Molecular weight	30.3	lb/lbmol
Volume @ 68 °F, 1 atm	20,889	cu.ft./100 lb
Estimated Higher Heating Value (HHV)	18,590	Btu/lb dry fuel
Lower Heating Value (LHV)	17,357	Btu/lb dry fuel

Stack test parameters

Flue gas oxygen content	3.68%	(by volume, dry basis)
Flue gas moisture	10.19%	(by volume)
Flue gas SO_2	1439.9	ppmdv
Flue gas flowrate	13.68	m^3/sec (dry basis, 20 °C)
Flue gas SO_2 . . .	188.8	kg/hr
. . . at fuel consumption of	100.0	T/d (actual)

Adiabatic flame temperature

Assume all feeds enter at 77 °F

	Mean Cp Btu/lb°F	Mass flow lb/lb dry fuel	Heat content Btu/lb dry fuel	
Carbon dioxide	0.2906	3.135	2,995.3	
Oxygen	0.2596	0.639	545.2	
Nitrogen	0.2822	12.616	11,703.4	
Sulfur dioxide	0.2035	0.050	33.5	
Water	0.5711	1.108	2,079.6	
TOTAL	0.3009	17.548	17,356.9	= LHV

Adiabatic flame temperature 3,364.3 °F

Boiler heat balance

Ambient air temperature, °F	80
Flue gas temperature, °F	350
Feedwater temperature, °F	282
FW temperature before heating, °F	80
Steam enthalpy, Btu/ lb	1440
Unburned combustible (%)	0.4%
Unaccounted loss (%)	2.1%
Radiation loss (%)	0.8%

Heat inputs	Btu/lb dry fuel		
Fuel heating value	18,520	99.4%	
Combustion air	116	0.6%	
TOTAL	18,636	100.0%	
Heat outputs			
Flue gases, sensible heat	1,241	6.7%	
Flue gases, latent heat	1,163	6.2%	
Unburned combustible	74	0.4%	
Unaccounted loss	391	2.1%	
Radiation loss	149	0.8%	
Heat to steam	15,617	83.8%	84.3%
TOTAL	18,636	100.0%	

CO_2 discharges	200.7	lb CO_2/MBtu in Steam
SO_2 discharges	3.2	lb SO_2/MBtu in Steam

Steam generation	**lb/lb dry fuel**
Steam generated	13.15
LP steam needed in feedwater heater	0.73

APPENDIX C

CAPITAL COST ESTIMATE TABLES FOR TECHNOLOGIES

This appendix contains cost estimates for most of the technologies discussed in the main body of this document and listed in Sections 3 and 4. The capital investments required for technologies 1.10 and 1.11 are discussed in detail in Sections 3.3.1.10 and 3.3.1.11, respectively, and are not addressed in this appendix. Implementation of technology 9.10 requires little or no capital investment and is not addressed in this appendix.

Table C1. Technology 1.1

Technology 1.1: Replace low pressure boilers and install turbogenerator capacity												
	Includes: Boiler, fuel feed system, turb/gen, ESP, and stack											
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						1,200,000
	Sub-Total Civil/Structural Account	8 to 35%				30.0%						7,200,000
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				24,000,000		24,480,000
	Sub-Total Piping Account	25 to 90%				10.0%						2,400,000
	Sub-Total Instrumentation Account	20 to 40%				7.0%						1,680,000
	Sub-Total Electrical Account	20 to 40%				15.0%						3,600,000
	Sub-Total Miscellaneous Account	15 to 30%				8.0%						1,920,000
	Sub-Total Directs	194 to 365%				177.0%				24,000,000		42,480,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						4,248,000
	Mill Administration and Temp Facilities at 5%											2,124,000
	Sales Tax on Material and Equipment at 5%											2,124,000
	Training Cost Materials at 1%											424,800
	Freight at 1.5%											637,200
	Capital Spare Parts at 2%											849,600
	Start up Services at 1%											424,800
	Sub-Total Indirects					45.1%						10,832,400
	Sub-Total Directs Plus Indirects											53,312,400
	Contingency at 15%											7,996,900
	Grand Total Capital					255.5%						61,309,300
	Equipment Costs											
	Fuel Feed System	1,000,000										
	ESP	3,100,000										
	Boiler	14,000,000										
	Turbine Generator	5,900,000										
		24,000,000										

Table C2. Technology 1.2

Technology 1.2: Switch power boiler from fossil fuel to wood (or build new wood boiler to utilize available biofuel)

Includes: Boiler and fuel feed system

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						740,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						2,960,000
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				14,800,000		15,096,000
	Sub-Total Piping Account	25 to 90%				10.0%						1,480,000
	Sub-Total Instrumentation Account	20 to 40%				7.0%						1,036,000
	Sub-Total Electrical Account	20 to 40%				7.0%						1,036,000
	Sub-Total Miscellaneous Account	15 to 30%				5.0%						740,000
	Sub-Total Directs	194 to 365%				156.0%				14,800,000		23,088,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						2,308,800
	Mill Administration and Temp Facilities at 5%											1,154,400
	Sales Tax on Material and Equipment at 5%											1,154,400
	Training Cost Materials at 1%											230,900
	Freight at 1.5%											346,300
	Capital Spare Parts at 2%											461,800
	Start up Services at 1%											230,900
	Sub-Total Indirects					39.8%						5,887,500
	Sub-Total Directs Plus Indirects											28,975,500
	Contingency at 15%											4,346,300
	Grand Total Capital					225.1%						33,321,800
	Equipment Costs											
	Boiler/Boiler Rebuild	11,000,000										
	Fuel Feed System	1,500,000										
	ESP Modifications	2,300,000										
		14,800,000										

Table C3. Technology 1.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 1.3: Preheat demineralized water with secondary heat before steam heating											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						18,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						45,000
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				450,000		472,500
	Sub-Total Piping Account	25 to 90%				70.0%						315,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						90,000
	Sub-Total Electrical Account	20 to 40%				20.0%						90,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						90,000
	Sub-Total Directs	194 to 365%				249.0%				450,000		1,120,500
	Indirect Costs											
	Design Engineering	10 to 20%				20%						224,100
	Mill Administration and Temp Facilities at 5%											56,025
	Sales Tax on Material and Equipment at 5%											56,000
	Training Cost Materials at 1%											11,200
	Freight at 1.5%											16,800
	Capital Spare Parts at 2%											22,400
	Start up Services at 1%											11,200
	Sub-Total Indirects					88.4%						397,725
	Sub-Total Directs Plus Indirects											1,518,225
	Contingency at 15%											227,700
	Grand Total Capital					388.0%						1,745,925
	Equipment Costs											
	Shell and Tube Heat Exchanger	400,000										
	Pumps	50,000										
		450,000										

Table C4. Technology 1.4

Technology 1.4: Rebuild or replace low efficiency boilers												
	Includes: Boiler and fuel feed system											
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						275,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						1,100,000
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				5,500,000		5,610,000
	Sub-Total Piping Account	25 to 90%				10.0%						550,000
	Sub-Total Instrumentation Account	20 to 40%				7.0%						385,000
	Sub-Total Electrical Account	20 to 40%				7.0%						385,000
	Sub-Total Miscellaneous Account	15 to 30%				5.0%						275,000
	Sub-Total Directs	194 to 365%				156.0%				5,500,000		8,580,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						858,000
	Mill Administration and Temp Facilities at 5%											429,000
	Sales Tax on Material and Equipment at 5%											429,000
	Training Cost Materials at 1%											85,800
	Freight at 1.5%											128,700
	Capital Spare Parts at 2%											171,600
	Start up Services at 1%											85,800
	Sub-Total Indirects					39.8%						2,187,900
	Sub-Total Directs Plus Indirects											10,767,900
	Contingency at 15%											1,615,200
	Grand Total Capital					225.1%						12,383,100
	Equipment Costs											
	Boiler/Boiler Rebuild	5,000,000										
	Fuel Feed System	500,000										
		5,500,000										

Table C5. Technology 1.5

Technology 1.5: Install a steam accumulator to facilitate efficient control of steam header pressures												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						40,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						80,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				800,000		848,000
	Sub-Total Piping Account	25 to 90%				40.0%						320,000
	Sub-Total Instrumentation Account	20 to 40%				30.0%						240,000
	Sub-Total Electrical Account	20 to 40%				5.0%						40,000
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						80,000
	Sub-Total Directs	194 to 365%				206.0%				800,000		1,648,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						329,600
	Mill Administration and Temp Facilities at 5%											82,400
	Sales Tax on Material and Equipment at 5%											82,400
	Training Cost Materials at 1%											16,500
	Freight at 1.5%											24,700
	Capital Spare Parts at 2%											33,000
	Start up Services at 1%											16,500
	Sub-Total Indirects					73.1%						585,100
	Sub-Total Directs Plus Indirects											2,233,100
	Contingency at 15%											335,000
	Grand Total Capital					321.0%						2,568,100
	Equipment Costs											
	Steam Pressure Accumulator 10,000 CF	800,000		200k	lbs							

Table C6. Technology 1.6

Technology 1.6: Install an ash reinjection system in the hog fuel boiler												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				15.0%						22,500
	Sub-Total Civil/Structural Account	8 to 35%				25.0%						37,500
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				150,000		165,000
	Sub-Total Piping Account	25 to 90%				15.0%						22,500
	Sub-Total Instrumentation Account	20 to 40%				15.0%						22,500
	Sub-Total Electrical Account	20 to 40%				20.0%						30,000
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						15,000
	Sub-Total Directs	194 to 365%				210.0%				150,000		315,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						47,300
	Mill Administration and Temp Facilities at 5%											15,750
	Sales Tax on Material and Equipment at 5%											15,800
	Training Cost Materials at 1%											3,200
	Freight at 1.5%											4,700
	Capital Spare Parts at 2%											6,300
	Start up Services at 1%											3,200
	Sub-Total Indirects					64.2%						96,250
	Sub-Total Directs Plus Indirects											411,250
	Contingency at 15%											61,700
	Grand Total Capital					315.3%						472,950
	Equipment Cost											
	Ash Collection Conveyors	50000										
	Ash Hopper	50000										
	Re Feed Conveyor	50000										
	Total Equipment Cost	150000										

Table C7. Technology 1.7a

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 1.7a: Install a bark press to increase utilization of biofuels											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						86,800
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						217,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				2,170,000		2,256,800
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				0.0%						0
	Sub-Total Electrical Account	20 to 40%				10.0%						217,000
	Sub-Total Miscellaneous Account	15 to 30%				5.0%						108,500
	Sub-Total Directs	194 to 365%				133.0%				2,170,000		2,886,100
	Indirect Costs											
	Design Engineering	10 to 20%				10%						288,600
	Mill Administration and Temp Facilities at 5%											144,305
	Sales Tax on Material and Equipment at 5%											144,300
	Training Cost Materials at 1%											28,900
	Freight at 1.5%											43,300
	Capital Spare Parts at 2%											57,700
	Start up Services at 1%											28,900
	Sub-Total Indirects					33.9%						736,005
	Sub-Total Directs Plus Indirects											3,622,105
	Contingency at 15%											543,300
	Grand Total Capital					192.0%						4,165,405
	Equipment Cost											
	Bark Press x 3	2010000										
	Conveyor Modifications for In & Out	160000										
	Total Equipment Cost	2170000										

Table C8. Technology 1.7b

Technology 1.7b: Install a bark dryer to increase utilization of biofuels												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						146,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						365,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				3,650,000		3,796,000
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				0.0%						0
	Sub-Total Electrical Account	20 to 40%				10.0%						365,000
	Sub-Total Miscellaneous Account	15 to 30%				5.0%						182,500
	Sub-Total Directs	194 to 365%				133.0%				3,650,000		4,854,500
	Indirect Costs											
	Design Engineering	10 to 20%				10%						485,500
	Mill Administration and Temp Facilities at 5%											242,725
	Sales Tax on Material and Equipment at 5%											242,700
	Training Cost Materials at 1%											48,500
	Freight at 1.5%											72,800
	Capital Spare Parts at 2%											97,100
	Start up Services at 1%											48,500
	Sub-Total Indirects					33.9%						1,237,825
	Sub-Total Directs Plus Indirects											6,092,325
	Contingency at 15%											913,800
	Grand Total Capital					191.9%						7,006,125
	Equipment Cost											
	Bark Dryer	3500000										
	Conveyor Modifications for In & Out	150000										
	Total Equipment Cost	3650000										

Table C9. Technology 1.8

Technology 1.8: Install additional heat recovery systems to boilers to lower losses with flue gases												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				7.0%						182,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						260,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				2,600,000		2,704,000
	Sub-Total Piping Account	25 to 90%				25.0%						650,000
	Sub-Total Instrumentation Account	20 to 40%				15.0%						390,000
	Sub-Total Electrical Account	20 to 40%				15.0%						390,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						390,000
	Sub-Total Directs	194 to 365%				191.0%				2,600,000		4,966,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						496,600
	Mill Administration and Temp Facilities at 5%											248,300
	Sales Tax on Material and Equipment at 5%											248,300
	Training Cost Materials at 1%											49,700
	Freight at 1.5%											74,500
	Capital Spare Parts at 2%											99,300
	Start up Services at 1%											49,700
	Sub-Total Indirects					48.7%						1,266,400
	Sub-Total Directs Plus Indirects											6,232,400
	Contingency at 15%											934,900
	Grand Total Capital					275.7%						7,167,300
	Equipment Cost											
	Flue Gas Heat Exchanger	2500000										
	Pumps or Fans	100000										
	Total Equipment Cost	2600000										

Table C10. Technology 1.9

Subject:	Provide Controls for Energy Management System											
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Sub-Total Demolition and Sitework Account											15,000
	Sub-Total Civil/Structural Account											0
	Sub-Total Engineered Equipment Account											0
	Sub-Total Piping Account											100,000
	Sub-Total Instrumentation Account	80	lps					10000				800,000
	Sub-Total Electrical Account											0
	Sub-Total Miscellaneous Account											30,000
	Sub-Total Directs	194 to 365%				0.0%						945,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						189,000
	Mill Administration and Temp Facilities at 5%											47,250
	Sales Tax on Material and Equipment at 5%											47,300
	Training Cost Materials at 1%											9,500
	Freight at 1.5%											14,200
	Capital Spare Parts at 2%											18,900
	Start up Services at 1%											9,500
	Sub-Total Indirects											335,650
	Sub-Total Directs Plus Indirects											1,280,650
	Contingency at 15%											192,100
	Grand Total Capital											1,472,750
	Equipment Cost											
		100										
	Total Equipment Cost	100										

Table C11. Technology 2.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 2.1: Replace pneumatic chip conveyors with belt conveyors												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				15.0%						105,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						140,000
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				700,000		735,000
	Sub-Total Piping and Conveyors Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				10.0%						70,000
	Sub-Total Electrical Account	20 to 40%				20.0%						140,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						105,000
	Sub-Total Directs	194 to 365%				185.0%				700,000		1,295,000
	Indirect Costs											
	Design Engineering	10 to 20%				18%						233,100
	Mill Administration and Temp Facilities at 5%											64,750
	Sales Tax on Material and Equipment at 5%											64,800
	Training Cost Materials at 1%											13,000
	Freight at 1.5%											19,400
	Capital Spare Parts at 2%											25,900
	Start up Services at 1%											13,000
	Sub-Total Indirects					62.0%						433,950
	Sub-Total Directs Plus Indirects											1,728,950
	Contingency at 15%											259,300
	Grand Total Capital					284.0%						1,988,250
	Equipment Cost											
	Conveyors	700000										
	Total Equipment Cost	700,000										

Table C12. Technology 2.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 2.2: Use secondary heat instead of steam in debarking												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						5,500
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						16,500
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				110,000		116,600
	Sub-Total Piping and Conveyors Account	25 to 90%				90.0%						99,000
	Sub-Total Instrumentation Account	20 to 40%				25.0%						27,500
	Sub-Total Electrical Account	20 to 40%				20.0%						22,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						33,000
	Sub-Total Directs	194 to 365%				291.0%				110,000		320,100
	Indirect Costs											
	Design Engineering	10 to 20%				20%						64,000
	Mill Administration and Temp Facilities at 5%											16,005
	Sales Tax on Material and Equipment at 5%											16,000
	Training Cost Materials at 1%											3,200
	Freight at 1.5%											4,800
	Capital Spare Parts at 2%											6,400
	Start up Services at 1%											3,200
	Sub-Total Indirects					103.3%						113,605
	Sub-Total Directs Plus Indirects											433,705
	Contingency at 15%											65,100
	Grand Total Capital					453.5%						498,805
	Equipment Cost											
	Heat Exchangers	90000										
	Pumps	10,000										
	Tank Warm or Hot	10,000										
	Total Equipment Cost	110,000										

Table C13. Technology 3.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 3.1: Rebuild the mill hot water system to provide for separate production and distribution of warm (120°F) and hot (160°F) water												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						19,000
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						57,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				380,000		402,800
	Sub-Total Piping Account	25 to 90%				90.0%						342,000
	Sub-Total Instrumentation Account	20 to 40%				25.0%						95,000
	Sub-Total Electrical Account	20 to 40%				20.0%						76,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						114,000
	Sub-Total Directs	194 to 365%				291.0%				380,000		1,105,800
	Indirect Costs											
	Design Engineering	10 to 20%				20%						221,200
	Mill Administration and Temp Facilities at 5%											55,290
	Sales Tax on Material and Equipment at 5%											55,300
	Training Cost Materials at 1%											11,100
	Freight at 1.5%											16,600
	Capital Spare Parts at 2%											22,100
	Start up Services at 1%											11,100
	Sub-Total Indirects					103.3%						392,690
	Sub-Total Directs Plus Indirects											1,498,490
	Contingency at 15%											224,800
	Grand Total Capital					453.5%						1,723,290
	Equipment Cost											
	Heat Exchangers	200000										
	Pumps	80000										
	Tank Warm or Hot	100000										
	Total Equipment Cost	380000										

Table C14. Technology 3.2

Technology 3.2: Install blow heat (batch digesters) or flash heat (continuous digester) evaporators												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						90,800
	Sub-Total Civil/Structural Account	8 to 35%				25.0%						567,500
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				2,270,000		2,497,000
	Sub-Total Piping Account	25 to 90%				40.0%						908,000
	Sub-Total Instrumentation Account	20 to 40%				30.0%						681,000
	Sub-Total Electrical Account	20 to 40%				35.0%						794,500
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						454,000
	Sub-Total Directs	194 to 365%				264.0%				2,270,000		5,992,800
	Indirect Costs											
	Design Engineering	10 to 20%				20%						1,198,600
	Mill Administration and Temp Facilities at 5%											299,640
	Sales Tax on Material and Equipment at 5%											299,600
	Training Cost Materials at 1%											59,900
	Freight at 1.5%											89,900
	Capital Spare Parts at 2%											119,900
	Start up Services at 1%											59,900
	Sub-Total Indirects					93.7%						2,127,440
	Sub-Total Directs Plus Indirects											8,120,240
	Contingency at 15%											1,218,000
	Grand Total Capital					411.4%						9,338,240
	Equipment Cost											
	Flash Tanks	180000										
	Pre Evaporator Bodies	1300000										
	Surface Condensor, Hoggers, Hot Well	420000										
	Vapor Ducting	100000										
	Condensate Pumps	70000										
	Liquor Pumps	150000										
	Cooling Water Upgrade	50000										
	Total Equipment Cost	2270000										

Table C15. Technology 3.3

Technology 3.3: Replace conventional batch digesters with cold blow systems												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						720,000
	Sub-Total Civil/Structural Account	8 to 35%				30.0%						5,400,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				18,000,000		19,080,000
	Sub-Total Piping Account	25 to 90%				30.0%						5,400,000
	Sub-Total Instrumentation Account	20 to 40%				25.0%						4,500,000
	Sub-Total Electrical Account	20 to 40%				20.0%						3,600,000
	Sub-Total Miscellaneous Account	15 to 30%				18.0%						3,240,000
	Sub-Total Directs	194 to 365%				233.0%				18,000,000		41,940,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						4,194,000
	Mill Administration and Temp Facilities at 5%											2,097,000
	Sales Tax on Material and Equipment at 5%											2,097,000
	Training Cost Materials at 1%											419,400
	Freight at 1.5%											629,100
	Capital Spare Parts at 2%											838,800
	Start up Services at 1%											419,400
	Sub-Total Indirects					59.4%						10,694,700
	Sub-Total Directs Plus Indirects											52,634,700
	Contingency at 15%											7,895,200
	Grand Total Capital					336.3%						60,529,900
	Equipment Cost											
	Cold Blow Modifications and Equipment	18000000										
	Total Equipment Cost	18000000										

Table C16. Technology 3.4

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 3.4: Use flash heat in a continuous digester to preheat chips											
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						31,500
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						63,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				630,000		667,800
	Sub-Total Piping Account	25 to 90%				30.0%						189,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						126,000
	Sub-Total Electrical Account	20 to 40%				10.0%						63,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						126,000
	Sub-Total Directs	194 to 365%				201.0%				630,000		1,266,300
	Indirect Costs											
	Design Engineering	10 to 20%				20%						253,300
	Mill Administration and Temp Facilities at 5%											63,315
	Sales Tax on Material and Equipment at 5%											63,300
	Training Cost Materials at 1%											12,700
	Freight at 1.5%											19,000
	Capital Spare Parts at 2%											25,300
	Start up Services at 1%											12,700
	Sub-Total Indirects					71.4%						449,615
	Sub-Total Directs Plus Indirects											1,715,915
	Contingency at 15%											257,400
	Grand Total Capital					313.2%						1,973,315
	Equipment Cost											
	Flash Steam/Water Reboiler	400000										
	Feedwater Pump	30000										
	Air Lock to Chip Bin	200000										
	Total Equipment Cost	630000										

Table C17. Technology 3.5

Technology 3.5: Use evaporator condensates on decker showers												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						5,600
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						21,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				140,000		148,400
	Sub-Total Piping Account	25 to 90%				75.0%						105,000
	Sub-Total Instrumentation Account	20 to 40%				45.0%						63,000
	Sub-Total Electrical Account	20 to 40%				35.0%						49,000
	Sub-Total Miscellaneous Account	15 to 30%				25.0%						35,000
	Sub-Total Directs	194 to 365%				305.0%				140,000		427,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						85,400
	Mill Administration and Temp Facilities at 5%											21,350
	Sales Tax on Material and Equipment at 5%											21,400
	Training Cost Materials at 1%											4,300
	Freight at 1.5%											6,400
	Capital Spare Parts at 2%											8,500
	Start up Services at 1%											4,300
	Sub-Total Indirects					108.3%						151,650
	Sub-Total Directs Plus Indirects											578,650
	Contingency at 15%											86,800
	Grand Total Capital					475.3%						665,450
	Equipment Cost											
	Tanks	70000										
	Pumps	60000										
	Segregate Showers on Decker	10000										
	Total Equipment Cost	140000										

Table C18. Technology 3.6

Technology 3.6: Use two pressure level steaming of batch digesters to maximize back-pressure power generation												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										50,000
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										500,000
	Sub-Total Instrumentation Account	20 to 40%										200,000
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%										200,000
	Sub-Total Directs	194 to 365%								0		950,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						190,000
	Mill Administration and Temp Facilities at 5%											47,500
	Sales Tax on Material and Equipment at 5%											47,500
	Training Cost Materials at 1%											9,500
	Freight at 1.5%											14,300
	Capital Spare Parts at 2%											19,000
	Start up Services at 1%											9,500
	Sub-Total Indirects											337,300
	Sub-Total Directs Plus Indirects											1,287,300
	Contingency at 15%											193,100
	Grand Total Capital											1,480,400
	Equipment Cost											
	No Equipment Estimated											

Table C19. Technology 3.7

Technology 3.7: Optimize the dilution factor control												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										50,000
	Sub-Total Instrumentation Account	6	lps					15000				90,000
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%										180,000
	Sub-Total Directs	194 to 365%				0.0%						320,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						64,000
	Mill Administration and Temp Facilities at 5%											16,000
	Sales Tax on Material and Equipment at 5%											16,000
	Training Cost Materials at 1%											3,200
	Freight at 1.5%											4,800
	Capital Spare Parts at 2%											6,400
	Start up Services at 1%											3,200
	Sub-Total Indirects											113,600
	Sub-Total Directs Plus Indirects											433,600
	Contingency at 15%											65,000
	Grand Total Capital											498,600
	Equipment Cost											
	No Equipment Needed											

Table C20. Technology 4.1

Technology 4.1: Optimize the filtrate recycling concept for optimum chemical and energy use												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%						31,000
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						46,500
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				310,000		341,000
	Sub-Total Piping Account	25 to 90%				60.0%						186,000
	Sub-Total Instrumentation Account	20 to 40%				40.0%						124,000
	Sub-Total Electrical Account	20 to 40%				50.0%						155,000
	Sub-Total Miscellaneous Account	15 to 30%				25.0%						77,500
	Sub-Total Directs	194 to 365%				310.0%				310,000		961,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						192,200
	Mill Administration and Temp Facilities at 5%											48,050
	Sales Tax on Material and Equipment at 5%											48,100
	Training Cost Materials at 1%											9,600
	Freight at 1.5%											14,400
	Capital Spare Parts at 2%											19,200
	Start up Services at 1%											9,600
	Sub-Total Indirects					110.0%						341,150
	Sub-Total Directs Plus Indirects											1,302,150
	Contingency at 15%											195,300
	Grand Total Capital					483.0%						1,497,450
	Equipment Cost											
	Booster Pumps 4 ea 25 Hp	60000										
	Fiber Filters 2 ea	50000										
	Filtrate Tanks	200000										
	Total Equipment Cost	310000										

Table C21. Technology 4.2

Technology 4.2: Preheat ClO_2 before it enters the mixer												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						13,500
	Sub-Total Civil/Structural Account	8 to 35%				8.0%						21,600
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				270,000		275,400
	Sub-Total Piping Account	25 to 90%				20.0%						54,000
	Sub-Total Instrumentation Account	20 to 40%				15.0%						40,500
	Sub-Total Electrical Account	20 to 40%				0.0%						0
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						40,500
	Sub-Total Directs	194 to 365%				165.0%				270,000		445,500
	Indirect Costs											
	Design Engineering	10 to 20%				15%						66,800
	Mill Administration and Temp Facilities at 5%											22,275
	Sales Tax on Material and Equipment at 5%											22,300
	Training Cost Materials at 1%											4,500
	Freight at 1.5%											6,700
	Capital Spare Parts at 2%											8,900
	Start up Services at 1%											4,500
	Sub-Total Indirects					50.4%						135,975
	Sub-Total Directs Plus Indirects											581,475
	Contingency at 15%											87,200
	Grand Total Capital					247.7%						668,675
	Equipment Cost											
	ClO2 Heat Exchanger Titanium	270000				pipe at 60/lf						
	Total Equipment Cost	270000										

Table C22. Technology 4.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 4.3: Use oxygen-based chemicals to reduce the use of ClO_2 (O_2 or O_3 delignification, EP, EOP, etc.)											
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				8.0%						584,800
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						1,096,500
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				7,310,000		7,748,600
	Sub-Total Piping Account	25 to 90%				35.0%						2,558,500
	Sub-Total Instrumentation Account	20 to 40%				20.0%						1,462,000
	Sub-Total Electrical Account	20 to 40%				20.0%						1,462,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						1,096,500
	Sub-Total Directs	194 to 365%				219.0%				7,310,000		16,008,900
	Indirect Costs											
	Design Engineering	10 to 20%				20%						3,201,800
	Mill Administration and Temp Facilities at 5%											800,445
	Sales Tax on Material and Equipment at 5%											800,400
	Training Cost Materials at 1%											160,100
	Freight at 1.5%											240,100
	Capital Spare Parts at 2%											320,200
	Start up Services at 1%											160,100
	Sub-Total Indirects					77.7%						5,683,145
	Sub-Total Directs Plus Indirects											21,692,045
	Contingency at 15%											3,253,800
	Grand Total Capital					341.3%						24,945,845
	Equipment Cost											
	Oxygen Reactor	1100000										
	Wash Presses/Deckers	3500000										
	Blow Tank	1600000										
	Filtrate/Stock Tanks	300000										
	Heat Exchangers/Mixers	360000										
	Pumps	450000										
	Total Equipment Cost	7310000										

Table C23. Technology 5.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 5.1: Eliminate steam use in the wire pit by providing hot water from heat recovery and/or pulp mill and by reducing water use on the machine												
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						18,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						36,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				360,000		381,600
	Sub-Total Piping Account	25 to 90%				80.0%						288,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						72,000
	Sub-Total Electrical Account	20 to 40%				15.0%						54,000
	Sub-Total Miscellaneous Account	15 to 30%				25.0%						90,000
	Sub-Total Directs	194 to 365%				261.0%				360,000		939,600
	Indirect Costs											
	Design Engineering	10 to 20%				20%						187,900
	Mill Administration and Temp Facilities at 5%											46,980
	Sales Tax on Material and Equipment at 5%											47,000
	Training Cost Materials at 1%											9,400
	Freight at 1.5%											14,100
	Capital Spare Parts at 2%											18,800
	Start up Services at 1%											9,400
	Sub-Total Indirects					92.7%						333,580
	Sub-Total Directs Plus Indirects											1,273,180
	Contingency at 15%											191,000
	Grand Total Capital					406.7%						1,464,180
	Equipment Cost											
	Heat Exchangers 2 ea Use 8000 sf	300000										
	Pumps 3 ea	60000										
	Total Equipment Cost	360000										

Table C24. Technology 5.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 5.2: Upgrade press section to enhance water removal												
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						90,000
	Sub-Total Civil/Structural Account	8 to 35%				0.0%						0
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				2,250,000		2,295,000
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				0.0%						0
	Sub-Total Electrical Account	20 to 40%				5.0%						112,500
	Sub-Total Miscellaneous Account	15 to 30%				0.0%						0
	Sub-Total Directs	194 to 365%				111.0%				2,250,000		2,497,500
	Indirect Costs											
	Design Engineering	10 to 20%				10%						249,800
	Mill Administration and Temp Facilities at 5%											124,875
	Sales Tax on Material and Equipment at 5%											124,900
	Training Cost Materials at 1%											25,000
	Freight at 1.5%											37,500
	Capital Spare Parts at 2%											50,000
	Start up Services at 1%											25,000
	Sub-Total Indirects					28.3%						637,075
	Sub-Total Directs Plus Indirects											3,134,575
	Contingency at 15%											470,200
	Grand Total Capital					160.2%						3,604,775
	Equipment Cost											
	Double Felt Existing Press	2250000					2226500					
	Total Equipment Cost	2250000										

Table C25. Technology 5.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 5.3: Enclose the machine hood (if applicable) and install air-to-air and air-to-water heat recovery											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						55,000
	Sub-Total Civil/Structural Account	8 to 35%				8.0%						88,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				1,100,000		1,166,000
	Sub-Total Piping Account	25 to 90%				25.0%						275,000
	Sub-Total Instrumentation Account	20 to 40%				10.0%						110,000
	Sub-Total Electrical Account	20 to 40%				15.0%						165,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						220,000
	Sub-Total Directs	194 to 365%				189.0%				1,100,000		2,079,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						207,900
	Mill Administration and Temp Facilities at 5%											103,950
	Sales Tax on Material and Equipment at 5%											104,000
	Training Cost Materials at 1%											20,800
	Freight at 1.5%											31,200
	Capital Spare Parts at 2%											41,600
	Start up Services at 1%											20,800
	Sub-Total Indirects					48.2%						530,250
	Sub-Total Directs Plus Indirects											2,609,250
	Contingency at 15%											391,400
	Grand Total Capital					272.8%						3,000,650
	Equipment Cost											
	Dryer Enclosure	400000										
	Pocket Ventilation Changes	200000										
	Hood Fans	70000										
	Spray Scrubber and Pumps	200000										
	Discharge Pump	30000										
	Heat Exchangers	200000										
	Total Equipment Cost	1100000										

Table C26. Technology 5.4

Technology 5.4: Install properly sized white water and broke systems to minimize white water losses during upset conditions												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%						44,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						88,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				440,000		457,600
	Sub-Total Piping Account	25 to 90%				30.0%						132,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						88,000
	Sub-Total Electrical Account	20 to 40%				20.0%						88,000
	Sub-Total Miscellaneous Account	15 to 30%				5.0%						22,000
	Sub-Total Directs	194 to 365%				209.0%				440,000		919,600
	Indirect Costs											
	Design Engineering	10 to 20%				20%						183,900
	Mill Administration and Temp Facilities at 5%											45,980
	Sales Tax on Material and Equipment at 5%											46,000
	Training Cost Materials at 1%											9,200
	Freight at 1.5%											13,800
	Capital Spare Parts at 2%											18,400
	Start up Services at 1%											9,200
	Sub-Total Indirects					74.2%						326,480
	Sub-Total Directs Plus Indirects											1,246,080
	Contingency at 15%											186,900
	Grand Total Capital					325.7%						1,432,980
	Equipment Cost											
	New White Water Chest for Added Capacity	150000										
	Broke Chest	150000										
	Pumps 2ea	40000										
	Agitators 2 ea	100000										
	Total Equipment Cost	440000										

Table C27. Technology 5.5

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 5.5: Implement hood exhaust moisture controls to minimize air heating and maximize heat recovery												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%										100,000
	(Moisture Control Instruments)											
	Sub-Total Electrical Account	20 to 40%										150,000
	(Variable Speed Drives)											
	Sub-Total Miscellaneous Account	15 to 30%										70,000
	Sub-Total Directs	194 to 365%				0.0%				0		320,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						64,000
	Mill Administration and Temp Facilities at 5%											16,000
	Sales Tax on Material and Equipment at 5%											16,000
	Training Cost Materials at 1%											3,200
	Freight at 1.5%											4,800
	Capital Spare Parts at 2%											6,400
	Start up Services at 1%											3,200
	Sub-Total Indirects											113,600
	Sub-Total Directs Plus Indirects											433,600
	Contingency at 15%											65,000
	Grand Total Capital											498,600
	Equipment Cost											
	Variable Speed Drives	150000										
	Total Equipment Cost	150000										

Table C28. Technology 5.6

Technology 5.6: Implement efficient control systems for the machine steam and condensate systems to eliminate excessive blow through and steam venting during machine breaks

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%						30,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						30,000
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				300,000		306,000
	Sub-Total Piping Account	25 to 90%				20.0%						60,000
	Sub-Total Instrumentation Account	20 to 40%				40.0%						120,000
	Sub-Total Electrical Account	20 to 40%				10.0%						30,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						90,000
	Sub-Total Directs	194 to 365%				222.0%				300,000		666,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						99,900
	Mill Administration and Temp Facilities at 5%											33,300
	Sales Tax on Material and Equipment at 5%											33,300
	Training Cost Materials at 1%											6,700
	Freight at 1.5%											10,000
	Capital Spare Parts at 2%											13,300
	Start up Services at 1%											6,700
	Sub-Total Indirects					67.7%						203,200
	Sub-Total Directs Plus Indirects											869,200
	Contingency at 15%											130,400
	Grand Total Capital					333.2%						999,600
	Equipment Cost											
	Thermocompressors 5 ea	100000										
	Reconfigure Machine Piping 5 lots	200000										
	Total Equipment Cost	300000										

Table C29. Technology 6.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 6.1: Convert recovery boiler to non-direct contact and implement high solids firing												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						292,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						1,460,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				7,300,000		7,738,000
	Sub-Total Piping Account	25 to 90%				40.0%						2,920,000
	Sub-Total Instrumentation Account	20 to 40%				10.0%						730,000
	Sub-Total Electrical Account	20 to 40%				15.0%						1,095,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						1,460,000
	Sub-Total Directs	194 to 365%				215.0%				7,300,000		15,695,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						1,569,500
	Mill Administration and Temp Facilities at 5%											784,750
	Sales Tax on Material and Equipment at 5%											784,800
	Training Cost Materials at 1%											157,000
	Freight at 1.5%											235,400
	Capital Spare Parts at 2%											313,900
	Start up Services at 1%											157,000
	Sub-Total Indirects					54.8%						4,002,350
	Sub-Total Directs Plus Indirects											19,697,350
	Contingency at 15%											2,954,600
	Grand Total Capital					310.3%						22,651,950
	Equipment Cost											
	Install Economizer Section	5000000										
	Crystallizer Equipment and Pumps	1700000										
	Black Liquor Tank	600000										
	Total Equipment Cost	7300000										

Table C30. Technology 6.2

Technology 6.2: Perform evaporator boilout with weak black liquor												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				6.0%						7,500
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						18,750
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				125,000		132,500
	Sub-Total Piping Account	25 to 90%				60.0%						75,000
	Sub-Total Instrumentation Account	20 to 40%				25.0%						31,250
	Sub-Total Electrical Account	20 to 40%				20.0%						25,000
	Sub-Total Miscellaneous Account	15 to 30%				25.0%						31,250
	Sub-Total Directs	194 to 365%				257.0%				125,000		321,300
	Indirect Costs											
	Design Engineering	10 to 20%				20%						64,300
	Mill Administration and Temp Facilities at 5%											16,065
	Sales Tax on Material and Equipment at 5%											16,100
	Training Cost Materials at 1%											3,200
	Freight at 1.5%											4,800
	Capital Spare Parts at 2%											6,400
	Start up Services at 1%											3,200
	Sub-Total Indirects					91.3%						114,065
	Sub-Total Directs Plus Indirects											435,365
	Contingency at 15%											65,300
	Grand Total Capital					400.5%						500,665
	Equipment Cost											
	Boilout Liquor Tank	100000										
	Pumps	25000										
	Total Equipment Cost	125000										

Table C31. Technology 6.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 6.3: Convert evaporation to seven-effect operation (install additional evaporator effect)											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				6.0%						151,200
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						252,000
	Sub-Total Engineered Equipment Account	102 to 110%				108.0%				2,520,000		2,721,600
	Sub-Total Piping Account	25 to 90%				40.0%						1,008,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						504,000
	Sub-Total Electrical Account	20 to 40%				10.0%						252,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						504,000
	Sub-Total Directs	194 to 365%				214.0%				2,520,000		5,392,800
	Indirect Costs											
	Design Engineering	10 to 20%				15%						808,900
	Mill Administration and Temp Facilities at 5%											269,640
	Sales Tax on Material and Equipment at 5%											269,600
	Training Cost Materials at 1%											53,900
	Freight at 1.5%											80,900
	Capital Spare Parts at 2%											107,900
	Start up Services at 1%											53,900
	Sub-Total Indirects					65.3%						1,644,740
	Sub-Total Directs Plus Indirects											7,037,540
	Contingency at 15%											1,055,600
	Grand Total Capital					321.2%						8,093,140
	Equipment Cost											
	Evaporator Bodies	2000000										
	Pumps	120000										
	Vapor Ducting	100000										
	Surface Condenser Modifications	300000										
	Total Equipment Cost	2520000										

Table C32. Technology 6.4

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 6.4: Install high solids concentrator to maximize steam generation with black liquor											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				6.0%						138,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						460,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				2,300,000		2,438,000
	Sub-Total Piping Account	25 to 90%				80.0%						1,840,000
	Sub-Total Instrumentation Account	20 to 40%				30.0%						690,000
	Sub-Total Electrical Account	20 to 40%				40.0%						920,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						690,000
	Sub-Total Directs	194 to 365%				312.0%				2,300,000		7,176,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						1,076,400
	Mill Administration and Temp Facilities at 5%											358,800
	Sales Tax on Material and Equipment at 5%											358,800
	Training Cost Materials at 1%											71,800
	Freight at 1.5%											107,600
	Capital Spare Parts at 2%											143,500
	Start up Services at 1%											71,800
	Sub-Total Indirects					95.2%						2,188,700
	Sub-Total Directs Plus Indirects											9,364,700
	Contingency at 15%											1,404,700
	Grand Total Capital					468.2%						10,769,400
	Equipment Cost											
	Crystallizer Equipment and Pumps	1700000										
	Black Liquor Tank and Pumps	600000										
	Total Equipment Cost	2300000										

Table C33. Technology 6.5a

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 6.5a: Implement an energy efficient lime kiln (product coolers, etc.)												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%						48,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						96,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				480,000		508,800
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				0.0%						0
	Sub-Total Electrical Account	20 to 40%				0.0%						0
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						48,000
	Sub-Total Directs	194 to 365%				146.0%				480,000		700,800
	Indirect Costs											
	Design Engineering	10 to 20%				10%						70,100
	Mill Administration and Temp Facilities at 5%											35,040
	Sales Tax on Material and Equipment at 5%											35,000
	Training Cost Materials at 1%											7,000
	Freight at 1.5%											10,500
	Capital Spare Parts at 2%											14,000
	Start up Services at 1%											7,000
	Sub-Total Indirects					37.2%						178,640
	Sub-Total Directs Plus Indirects											879,440
	Contingency at 15%											131,900
	Grand Total Capital					210.7%						1,011,340
	Equipment Cost											
	Kiln Product Coolers 6 ea	360000										
	Hot Lime Conveyor	120000										
	Total Equipment Cost	480000										

Table C34. Technology 6.5b

Technology 6.5b: Implement an energy efficient lime kiln (mud filter, etc.)												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				8.0%						64,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						80,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				800,000		848,000
	Sub-Total Piping Account	25 to 90%				50.0%						400,000
	Sub-Total Instrumentation Account	20 to 40%				25.0%						200,000
	Sub-Total Electrical Account	20 to 40%				25.0%						200,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						160,000
	Sub-Total Directs	194 to 365%				244.0%				800,000		1,952,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						390,400
	Mill Administration and Temp Facilities at 5%											97,600
	Sales Tax on Material and Equipment at 5%											97,600
	Training Cost Materials at 1%											19,500
	Freight at 1.5%											29,300
	Capital Spare Parts at 2%											39,000
	Start up Services at 1%											19,500
	Sub-Total Indirects					86.6%						692,900
	Sub-Total Directs Plus Indirects											2,644,900
	Contingency at 15%											396,700
	Grand Total Capital					380.2%						3,041,600
	Equipment Cost											
	Lime Mud Filter and Pumps	700000										
	Chutes and Conveyors	100000										
	Total Equipment Cost	800000										

Table C35. Technology 6.5c

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 6.5c: Implement an energy efficient lime kiln (lime mud dryer, etc.)												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%						200,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						400,000
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				2,000,000		2,200,000
	Sub-Total Piping Account	25 to 90%				15.0%						300,000
	Sub-Total Instrumentation Account	20 to 40%				10.0%						200,000
	Sub-Total Electrical Account	20 to 40%				15.0%						300,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						400,000
	Sub-Total Directs	194 to 365%				200.0%				2,000,000		4,000,000
	Indirect Costs								592			
	Design Engineering	10 to 20%				15%						600,000
	Mill Administration and Temp Facilities at 5%											200,000
	Sales Tax on Material and Equipment at 5%											200,000
	Training Cost Materials at 1%											40,000
	Freight at 1.5%											60,000
	Capital Spare Parts at 2%											80,000
	Start up Services at 1%											40,000
	Sub-Total Indirects					61.0%						1,220,000
	Sub-Total Directs Plus Indirects											5,220,000
	Contingency at 15%											783,000
	Grand Total Capital					300.2%						6,003,000
	Equipment Cost											
	Lime Mud Dryer Equipment	2000000										
	Total Equipment Cost	2000000										

Table C36. Technology 6.6

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 6.6: Replace lime kiln scrubber with an electrostatic precipitator											
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%						80,000
	Sub-Total Civil/Structural Account	8 to 35%				25.0%						200,000
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				800,000		880,000
	Sub-Total Piping Account	25 to 90%				35.0%						280,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						160,000
	Sub-Total Electrical Account	20 to 40%				30.0%						240,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						160,000
	Sub-Total Directs	194 to 365%				250.0%				800,000		2,000,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						300,000
	Mill Administration and Temp Facilities at 5%											100,000
	Sales Tax on Material and Equipment at 5%											100,000
	Training Cost Materials at 1%											20,000
	Freight at 1.5%											30,000
	Capital Spare Parts at 2%											40,000
	Start up Services at 1%											20,000
	Sub-Total Indirects					76.3%						610,000
	Sub-Total Directs Plus Indirects											2,610,000
	Contingency at 15%											391,500
	Grand Total Capital					375.2%						3,001,500
	Equipment Cost											
	Electrostatic Precipitator	$ 800,000										
	Total Equipment	$ 800,000										

Table C37. Technology 6.7

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 6.7: Integrate condensate stripping to evaporation												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				8.0%						43,200
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						81,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				540,000		572,400
	Sub-Total Piping Account	25 to 90%				30.0%						162,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						108,000
	Sub-Total Electrical Account	20 to 40%				10.0%						54,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						81,000
	Sub-Total Directs	194 to 365%				204.0%				540,000		1,101,600
	Indirect Costs											
	Design Engineering	10 to 20%				15%						165,200
	Mill Administration and Temp Facilities at 5%											55,080
	Sales Tax on Material and Equipment at 5%											55,100
	Training Cost Materials at 1%											11,000
	Freight at 1.5%											16,500
	Capital Spare Parts at 2%											22,000
	Start up Services at 1%											11,000
	Sub-Total Indirects					62.2%						335,880
	Sub-Total Directs Plus Indirects											1,437,480
	Contingency at 15%											215,600
	Grand Total Capital					306.1%						1,653,080
	Equipment Cost											
	Evaporator Body (Stainless)	500000										
	Condensate Pump	20000										
	Liquor Pump	20000										
	Total Equipment Cost	540000										

Table C38. Technology 6.8

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 6.8: Install a methanol rectification and liquefaction system											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						13,200
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						49,500
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				330,000		349,800
	Sub-Total Piping Account	25 to 90%				25.0%						82,500
	Sub-Total Instrumentation Account	20 to 40%				20.0%						66,000
	Sub-Total Electrical Account	20 to 40%				20.0%						66,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						49,500
	Sub-Total Directs	194 to 365%				205.0%				330,000		676,500
	Indirect Costs											
	Design Engineering	10 to 20%				15%						101,500
	Mill Administration and Temp Facilities at 5%											33,825
	Sales Tax on Material and Equipment at 5%											33,800
	Training Cost Materials at 1%											6,800
	Freight at 1.5%											10,100
	Capital Spare Parts at 2%											13,500
	Start up Services at 1%											6,800
	Sub-Total Indirects					62.5%						206,325
	Sub-Total Directs Plus Indirects											882,825
	Contingency at 15%											132,400
	Grand Total Capital					307.6%						1,015,225
	Equipment Cost											
	Methanol rectification & condensing system	$ 330,000										
	Total Equipment	$ 330,000										

Table C39. Technology 6.9

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 6.9: Install a biofuel gasifier, use low Btu gas for lime reburning											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						208,000
	Sub-Total Civil/Structural Account	8 to 35%				15.0%						780,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				5,200,000		5,512,000
	Sub-Total Piping Account	25 to 90%				25.0%						1,300,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						1,040,000
	Sub-Total Electrical Account	20 to 40%				20.0%						1,040,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						780,000
	Sub-Total Directs	194 to 365%				205.0%				5,200,000		10,660,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						1,599,000
	Mill Administration and Temp Facilities at 5%											533,000
	Sales Tax on Material and Equipment at 5%											533,000
	Training Cost Materials at 1%											106,600
	Freight at 1.5%											159,900
	Capital Spare Parts at 2%											213,200
	Start up Services at 1%											106,600
	Sub-Total Indirects					62.5%						3,251,300
	Sub-Total Directs Plus Indirects											13,911,300
	Contingency at 15%											2,086,700
	Grand Total Capital					307.7%						15,998,000
	Equipment Cost											
	Fuel Dryer and Gasifier System	5200000										
	Total Equipment Cost	5200000										

Table C40. Technology 7.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 7.1: Implement heat recovery from TMP process to steam and water												
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						49,600
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						124,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				1,240,000		1,289,600
	Sub-Total Piping Account	25 to 90%				35.0%						434,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						248,000
	Sub-Total Electrical Account	20 to 40%				15.0%						186,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						186,000
	Sub-Total Directs	194 to 365%				203.0%				1,240,000		2,517,200
	Indirect Costs											
	Design Engineering	10 to 20%				15%						377,600
	Mill Administration and Temp Facilities at 5%											125,860
	Sales Tax on Material and Equipment at 5%											125,900
	Training Cost Materials at 1%											25,200
	Freight at 1.5%											37,800
	Capital Spare Parts at 2%											50,300
	Start up Services at 1%											25,200
	Sub-Total Indirects					61.9%						767,860
	Sub-Total Directs Plus Indirects											3,285,060
	Contingency at 15%											492,800
	Grand Total Capital					304.7%						3,777,860
	Equipment Cost											
	Fibre Collector/Scrubber	300000										
	Steam Reboiler	900000										
	Pumps	40000										
	Total Equipment Cost	1240000										

Table C41. Technology 7.2

Technology 7.2: Add third refining stage to the TMP plant

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						68,000
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						170,000
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				1,700,000		1,870,000
	Sub-Total Piping Account	25 to 90%				25.0%						425,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						340,000
	Sub-Total Electrical Account	20 to 40%				20.0%						340,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						255,000
	Sub-Total Directs	194 to 365%				204.0%				1,700,000		3,468,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						346,800
	Mill Administration and Temp Facilities at 5%											173,400
	Sales Tax on Material and Equipment at 5%											173,400
	Training Cost Materials at 1%											34,700
	Freight at 1.5%											52,000
	Capital Spare Parts at 2%											69,400
	Start up Services at 1%											34,700
	Sub-Total Indirects					52.0%						884,400
	Sub-Total Directs Plus Indirects											4,352,400
	Contingency at 15%											652,900
	Grand Total Capital					294.4%						5,005,300
	Equipment Cost											
	Refiner	1700000										
	Total Equipment Cost	1700000										

Table C42. Technology 7.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 7.3: Replace the conventional groundwood process with pressurized groundwood (PGW) operation												
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						1,205,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						4,820,000
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				24,100,000		25,305,000
	Sub-Total Piping Account	25 to 90%				25.0%						6,025,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						4,820,000
	Sub-Total Electrical Account	20 to 40%				30.0%						7,230,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%						3,615,000
	Sub-Total Directs	194 to 365%				220.0%				24,100,000		53,020,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						5,302,000
	Mill Administration and Temp Facilities at 5%											2,651,000
	Sales Tax on Material and Equipment at 5%											2,651,000
	Training Cost Materials at 1%											530,200
	Freight at 1.5%											795,300
	Capital Spare Parts at 2%											1,060,400
	Start up Services at 1%											530,200
	Sub-Total Indirects					56.1%						13,520,100
	Sub-Total Directs Plus Indirects											66,540,100
	Contingency at 15%											9,981,000
	Grand Total Capital					317.5%						76,521,100
	Equipment Cost											
	Grinders (8 total), $2.7 million a piece	$21,600,000										
	Screens & Misc Equipment	$2,500,000										
	Total Equipment Cost	$24,100,000										

Table C43. Technology 7.4

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 7.4: Countercurrent coupling of paper machine and mechanical pulping white water systems											
		Range as % of Engrd										
	Sub-Total Demolition and Sitework	4 to 20%				4.0%						18,000
	Sub-Total Civil/Structural	8 to 35%				20.0%						90,000
	Sub-Total Engineered Equipment	102 to 110%				105.0%				450,000		472,500
	Sub-Total Piping	25 to 90%				25.0%						112,500
	Sub-Total Instrumentation	20 to 40%				15.0%						67,500
	Sub-Total Electrical	20 to 40%				15.0%						67,500
	Sub-Total Miscellaneous	15 to 30%				10.0%						45,000
	Sub-Total Directs	194 to 365%				194.0%				450,000		873,000
	Indirect Costs											
	Design	10 to 20%				20%						174,600
	Mill Administration and Temp Facilities at											43,650
	Sales Tax on Material and Equipment at											43,700
	Training Cost Materials at											8,700
	Freight at 1.5%											13,100
	Capital Spare Parts at 2%											17,500
	Start up Services at											8,700
	Sub-Total					68.9%						309,950
	Sub-Total Directs Plus											1,182,950
	Contingency at 15%											177,400
	Grand Total					302.3%						1,360,350
	Equipment Cost											
	Pumps 2 at 1000	20000										
	White Water Tank 20000	120000										
	Filter	60000										
	Air Floatation	250000										
	Total Equipment	450000										

Table C44. Technology 8.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 8,1: Supply waste heat from other process areas to deinking plant												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						8,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						40,000
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				200,000		210,000
	Sub-Total Piping Account	25 to 90%				25.0%						50,000
	Sub-Total Instrumentation Account	20 to 40%				15.0%						30,000
	Sub-Total Electrical Account	20 to 40%				15.0%						30,000
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						20,000
	Sub-Total Directs	194 to 365%				194.0%				200,000		388,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						77,600
	Mill Administration and Temp Facilities at 5%											19,400
	Sales Tax on Material and Equipment at 5%											19,400
	Training Cost Materials at 1%											3,900
	Freight at 1.5%											5,800
	Capital Spare Parts at 2%											7,800
	Start up Services at 1%											3,900
	Sub-Total Indirects					68.9%						137,800
	Sub-Total Directs Plus Indirects											525,800
	Contingency at 15%											78,900
	Grand Total Capital					302.4%						604,700
	Equipment Cost											
	Pumps 2 at 1000 GPM	20000										
	White Water Tank 20000 cf	120000										
	Filter	60000										
	Total Equipment Cost	200000										

Table C45. Technology 8.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 8.2: Install drum pulpers												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				15.0%						150,000
	Sub-Total Civil/Structural Account	8 to 35%				30.0%						300,000
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				1,000,000		1,050,000
	Sub-Total Piping Account	25 to 90%				15.0%						150,000
	Sub-Total Instrumentation Account	20 to 40%				15.0%						150,000
	Sub-Total Electrical Account	20 to 40%				15.0%						150,000
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						100,000
	Sub-Total Directs	194 to 365%				205.0%				1,000,000		2,050,000
	Indirect Costs											
	Design Engineering	10 to 20%				12%						246,000
	Mill Administration and Temp Facilities at 5%											102,500
	Sales Tax on Material and Equipment at 5%											102,500
	Training Cost Materials at 1%											20,500
	Freight at 1.5%											30,800
	Capital Spare Parts at 2%											41,000
	Start up Services at 1%											20,500
	Sub-Total Indirects					56.4%						563,800
	Sub-Total Directs Plus Indirects											2,613,800
	Contingency at 15%											392,100
	Grand Total Capital					300.6%						3,005,900
	Equipment Cost											
	Drum Pulper with drives, etc.	1000000										
	Total Equipment Cost	1000000										

Table C46. Technology 8.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 8.3: Implement closed heat and chemical loop											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						15,920
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						79,600
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				398,000		417,900
	Sub-Total Piping Account	25 to 90%				25.0%						99,500
	Sub-Total Instrumentation Account	20 to 40%				15.0%						59,700
	Sub-Total Electrical Account	20 to 40%				15.0%						59,700
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						39,800
	Sub-Total Directs	194 to 365%				194.0%				398,000		772,100
	Indirect Costs											
	Design Engineering	10 to 20%				20%						154,400
	Mill Administration and Temp Facilities at 5%											38,605
	Sales Tax on Material and Equipment at 5%											38,600
	Training Cost Materials at 1%											7,700
	Freight at 1.5%											11,600
	Capital Spare Parts at 2%											15,400
	Start up Services at 1%											7,700
	Sub-Total Indirects					68.8%						274,005
	Sub-Total Directs Plus Indirects											1,046,105
	Contingency at 15%											156,900
	Grand Total Capital					302.3%						1,203,005
	Equipment Cost											
	Pumps 2 at 800 GPM	18000										
	White Water Tank 16000 cf	120000										
	Filter	40000										
	Air Flotation Unit	220000										
	Total Equipment Cost	398000										

Table C47. Technology 9.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 9.1: Optimize integration and utilization of heat recovery systems												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						67,500
	Sub-Total Civil/Structural Account	8 to 35%				30.0%						405,000
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				1,350,000		1,485,000
						No Capital Cost Estimate Required						
	Sub-Total Piping Account	25 to 90%				90.0%						1,215,000
	Sub-Total Instrumentation Account	20 to 40%				40.0%						540,000
	Sub-Total Electrical Account	20 to 40%				30.0%						405,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						405,000
	Sub-Total Directs	194 to 365%				335.0%						4,522,500
	Indirect Costs											
	Design Engineering	10 to 20%										0
	Mill Administration and Temp Facilities at 5%											226,125
	Sales Tax on Material and Equipment at 5%											226,100
	Training Cost Materials at 1%											45,200
	Freight at 1.5%											67,800
	Capital Spare Parts at 2%											90,500
	Start up Services at 1%											45,200
	Sub-Total Indirects											700,925
	Sub-Total Directs Plus Indirects											5,223,425
	Contingency at 15%											783,500
	Grand Total Capital											6,006,925
	Equipment Cost											
	Water Tanks 3 ea	600000										
	Pumps 7 ea	150000										
	Exchangers 4 ea	600000										
	Total Equipment Cost	1350000										

Table C48. Technology 9.2

Technology 9.2: Implement preventive maintenance procedures to increase equipment utilization efficiency

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%										0
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%		Purchase Preventative Maintenance Software						Allowance		250,000
	Sub-Total Directs	194 to 365%										250,000
	Indirect Costs											
	Design Engineering	10 to 20%										250,000
	Mill Administration and Temp Facilities at 5%											
	Sales Tax on Material and Equipment at 5%											
	Training Cost Materials at 1%											
	Freight at 1.5%											
	Capital Spare Parts at 2%											
	Start up Services at 1%											
	Sub-Total Indirects											250,000
	Sub-Total Directs Plus Indirects											
	Contingency at 15%											
	Grand Total Capital											500,000

Table C49. Technology 9.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 9.3: Implement optimum spill management procedures												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						17,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						68,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				340,000		353,600
	Sub-Total Piping Account	25 to 90%				60.0%						204,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						68,000
	Sub-Total Electrical Account	20 to 40%				20.0%						68,000
	Sub-Total Miscellaneous Account	15 to 30%				5.0%						17,000
	Sub-Total Directs	194 to 365%				234.0%				340,000		795,600
	Indirect Costs											
	Design Engineering	10 to 20%				20%						159,100
	Mill Administration and Temp Facilities at 5%											39,780
	Sales Tax on Material and Equipment at 5%											39,800
	Training Cost Materials at 1%											8,000
	Freight at 1.5%											11,900
	Capital Spare Parts at 2%											15,900
	Start up Services at 1%											8,000
	Sub-Total Indirects					83.1%						282,480
	Sub-Total Directs Plus Indirects											1,078,080
	Contingency at 15%											161,700
	Grand Total Capital					364.6%						1,239,780
	Equipment Cost											
	Spill Tank	280000										
	Sewer Pumps 6 ea	60000										
	Total Equipment Cost	340000										

Table C50. Technology 9.4

Technology 9.4: Maximize recovery and return of steam condensates

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										40,000
	Sub-Total Instrumentation Account	20 to 40%										228,000
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%										0
	Sub-Total Directs	194 to 365%				0.0%				0		268,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						53,600
	Mill Administration and Temp Facilities at 5%											13,400
	Sales Tax on Material and Equipment at 5%											13,400
	Training Cost Materials at 1%											2,700
	Freight at 1.5%											4,000
	Capital Spare Parts at 2%											5,400
	Start up Services at 1%											2,700
	Sub-Total Indirects											95,200
	Sub-Total Directs Plus Indirects											363,200
	Contingency at 15%											54,500
	Grand Total Capital											417,700
	Instruments											
	Steam Flow Loops 4 ea	48000										
	Condensate Return Loops 4 ea	40000										
	Temperature Loops 4 ea	40000										
	Supervisory Data System	100000										
	Total Equipment Cost	228000										

Table C51. Technology 9.5

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 9.5: Recover wood waste that is going to landfill												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										1,800,000
	Sub-Total Engineered Equipment Account	102 to 110%										300,000
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%										0
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%										0
	Sub-Total Directs	194 to 365%										2,100,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						210,000
	Mill Administration and Temp Facilities at 5%											105,000
	Sales Tax on Material and Equipment at 5%											105,000
	Training Cost Materials at 1%											21,000
	Freight at 1.5%											31,500
	Capital Spare Parts at 2%											42,000
	Start up Services at 1%											21,000
	Sub-Total Indirects											535,500
	Sub-Total Directs Plus Indirects											2,635,500
	Contingency at 15%											395,300
	Grand Total Capital											3,030,800
	Civil Structural Scope											
	Pave 600' x 600' Wood Handling Yard	1800000										
	Modify Waste Boiler Grate	300000										

Table C52. Technology 9.6

Technology 9.6: Install energy measurement, monitoring, reporting, and follow-up systems

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										100,000
	Sub-Total Instrumentation Account	20 to 40%										925,000
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%										0
	Sub-Total Directs	194 to 365%				0.0%				0		1,025,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						205,000
	Mill Administration and Temp Facilities at 5%											51,250
	Sales Tax on Material and Equipment at 5%											51,300
	Training Cost Materials at 1%											10,300
	Freight at 1.5%											15,400
	Capital Spare Parts at 2%											20,500
	Start up Services at 1%											10,300
	Sub-Total Indirects											364,050
	Sub-Total Directs Plus Indirects											1,389,050
	Contingency at 15%											208,400
	Grand Total Capital											1,597,450
	Instruments											
	Steam Flow Loops 10 ea	125000										
	Condensate Return Loops 10 ea	100000										
	Valve Position Indicator Loops 20 ea	80000										
	Temperature Loops 10 ea	120000										
	Boiler Monitoring	200000										
	Supervisory Data System	300000										
	Total Equipment Cost	925000										

Table C53. Technology 9.7

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 9.7: Convert pump and fan drives to variable speed drives												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				20.0%						92,000
	Sub-Total Civil/Structural Account	8 to 35%				12.0%						55,200
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				460,000		506,000
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				20.0%						92,000
	Sub-Total Electrical Account	20 to 40%				20.0%						92,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						92,000
	Sub-Total Directs	194 to 365%				202.0%				460,000		929,200
	Indirect Costs											
	Design Engineering	10 to 20%				25%						232,300
	Mill Administration and Temp Facilities at 5%											46,460
	Sales Tax on Material and Equipment at 5%											46,500
	Training Cost Materials at 1%											9,300
	Freight at 1.5%											13,900
	Capital Spare Parts at 2%											18,600
	Start up Services at 1%											9,300
	Sub-Total Indirects					81.8%						376,360
	Sub-Total Directs Plus Indirects											1,305,560
	Contingency at 15%											195,800
	Grand Total Capital					326.4%						1,501,360
	Equipment Cost											
	Motor Cost	160000										
	Variable Speed Drive Units	300000										
	Total Equipment Cost	460000										

Table C54. Technology 9.8

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 9.8: Install advanced process controls												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%								1,000,000		1,000,000
	Sub-Total Electrical Account	20 to 40%										0
	Sub-Total Miscellaneous Account	15 to 30%										0
	Sub-Total Directs	194 to 365%								1,000,000		1,000,000
	Indirect Costs											
	Engineering	10 to 20%				20%						200,000
	Mill Administration and Temp Facilities at 5%											50,000
	Sales Tax on Material and Equipment at 5%											50,000
	Training Cost Materials at 1%											10,000
	Freight at 1.5%											15,000
	Capital Spare Parts at 2%											20,000
	Start up Services at 1%											10,000
	Sub-Total Indirects					35.5%						355,000
	Sub-Total Directs Plus Indirects											1,355,000
	Contingency at 15%											203,300
	Grand Total Capital					155.8%						1,558,300
	Instrument and Control Costs											
	Upper Level Management System Mill Wide allowance	1000000										
	Total Equipment Cost	1000000										

Table C55. Technology 9.9

Technology 9.9: Replace oversized electric motors												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										300,000
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%										0
	Sub-Total Electrical Account	20 to 40%										17,000
	Sub-Total Miscellaneous Account	15 to 30%										0
	Sub-Total Directs	194 to 365%										317,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						63,400
	Mill Administration and Temp Facilities at 5%											15,850
	Sales Tax on Material and Equipment at 5%											15,900
	Training Cost Materials at 1%											3,200
	Freight at 1.5%											4,800
	Capital Spare Parts at 2%											6,300
	Start up Services at 1%											3,200
	Sub-Total Indirects											112,650
	Sub-Total Directs Plus Indirects											429,650
	Contingency at 15%											64,400
	Grand Total Capital											494,050
	Equipment Costs											
	New Motors 25 ea	150000										
	Install/Replace Motors 100 ea	150000										
	Reset MCC Heaters 100 ea	17000										
	Total Equipment Cost	317000										

Table C56. Technology 10.1

Technology 10.1: Use advanced controls to control the drying process												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%				110.0%				300,000		330,000
	Sub-Total Electrical Account	20 to 40%										300,000
	Sub-Total Miscellaneous Account	15 to 30%										0
	Sub-Total Directs	194 to 365%				110.0%				300,000		630,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						126,000
	Mill Administration and Temp Facilities at 5%											31,500
	Sales Tax on Material and Equipment at 5%											31,500
	Training Cost Materials at 1%											6,300
	Freight at 1.5%											9,500
	Capital Spare Parts at 2%											12,600
	Start up Services at 1%											6,300
	Sub-Total Indirects					74.6%						223,700
	Sub-Total Directs Plus Indirects											853,700
	Contingency at 15%											128,100
	Grand Total Capital					327.3%						981,800
	Instrumentation Costs											
	Field Loops for Measurement 10 ea	100000										
	DCS Equipment	150000										
	Programming Costs	50000										
	Total Instrument Costs	300000										
	Electrical Costs VSD Units 10 ea	300000										

Table C57. Technology 10.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 10.2: Install heat recovery systems on the drying kiln exhaust											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						15,800
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						39,500
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				395,000		418,700
	Sub-Total Piping/Ducting Account	25 to 90%				30.0%						118,500
	Sub-Total Instrumentation Account	20 to 40%				10.0%						39,500
	Sub-Total Electrical Account	20 to 40%				10.0%						39,500
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						39,500
	Sub-Total Directs	194 to 365%				180.0%				395,000		711,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						106,700
	Mill Administration and Temp Facilities at 5%											35,550
	Sales Tax on Material and Equipment at 5%											35,600
	Training Cost Materials at 1%											7,100
	Freight at 1.5%											10,700
	Capital Spare Parts at 2%											14,200
	Start up Services at 1%											7,100
	Sub-Total Indirects					54.9%						216,950
	Sub-Total Directs Plus Indirects											927,950
	Contingency at 15%											139,200
	Grand Total Capital					270.2%						1,067,150
	Equipment Cost											
	Air to Air Heat Exchanger	350000										
	Fan	45000										
	Total Equipment Cost	395000										

Table C58. Technology 10.3

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 10.3: Insulate the kiln and eliminate heat leaks												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				0.0%						0
	Sub-Total Civil/Structural Account	8 to 35%				0.0%						0
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				100,000		110,000
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				0.0%						0
	Sub-Total Electrical Account	20 to 40%				0.0%						0
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						30,000
	Sub-Total Directs	194 to 365%				140.0%				100,000		140,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						14,000
	Mill Administration and Temp Facilities at 5%											7,000
	Sales Tax on Material and Equipment at 5%											7,000
	Training Cost Materials at 1%											1,400
	Freight at 1.5%											2,100
	Capital Spare Parts at 2%											2,800
	Start up Services at 1%											1,400
	Sub-Total Indirects					35.7%						35,700
	Sub-Total Directs Plus Indirects											175,700
	Contingency at 15%											26,400
	Grand Total Capital					202.1%						202,100
	Equipment Cost											
	Insulate and Seal Drying Kiln 15000 sf	100000										
	Total Equipment Cost	100000										

Table C59. Technology 10.4

Technology 10.4: Use heat pump for lumber drying												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				7.0%						98,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						280,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				1,400,000		1,484,000
	Sub-Total Piping Account	25 to 90%				40.0%						560,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						280,000
	Sub-Total Electrical Account	20 to 40%				20.0%						280,000
	Sub-Total Miscellaneous Account	15 to 30%				25.0%						350,000
	Sub-Total Directs	194 to 365%				238.0%				1,400,000		3,332,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						499,800
	Mill Administration and Temp Facilities at 5%											166,600
	Sales Tax on Material and Equipment at 5%											166,600
	Training Cost Materials at 1%											33,300
	Freight at 1.5%											50,000
	Capital Spare Parts at 2%											66,600
	Start up Services at 1%											33,300
	Sub-Total Indirects					72.6%						1,016,200
	Sub-Total Directs Plus Indirects											4,348,200
	Contingency at 15%											652,200
	Grand Total Capital					357.2%						5,000,400
	Equipment Cost											
	Heat exchangers, Compressors, etc. for a	1400000										
	50 MBF/a Dryer System (Heat supply 20MBTu/h)											
	Total Equipment Cost	1400000										

Table C60. Technology 10.5

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 10.5: Convert batch kiln to progressive kiln												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				7.0%						210,000
	Sub-Total Civil/Structural Account	8 to 35%				35.0%						1,050,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				3,000,000		3,180,000
	Sub-Total Piping Account	25 to 90%				25.0%						750,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						600,000
	Sub-Total Electrical Account	20 to 40%				40.0%						1,200,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						900,000
	Sub-Total Directs	194 to 365%				263.0%				3,000,000		7,890,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						1,578,000
	Mill Administration and Temp Facilities at 5%											394,500
	Sales Tax on Material and Equipment at 5%											394,500
	Training Cost Materials at 1%											78,900
	Freight at 1.5%											118,400
	Capital Spare Parts at 2%											157,800
	Start up Services at 1%											78,900
	Sub-Total Indirects					93.4%						2,801,000
	Sub-Total Directs Plus Indirects											10,691,000
	Contingency at 15%											1,603,700
	Grand Total Capital					409.8%						12,294,700
	Equipment Cost											
	Progressive dry kiln for drying of 150 MBF/a	3000000										
	of lumber											
	Total Equipment Cost	3000000										

Table C61. Technology 10.6

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 10.6: Implement steam load management system												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				10.0%			40			22,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%			80			44,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				220,000		233,200
	Sub-Total Piping Account	25 to 90%				75.0%			320			165,000
	Sub-Total Instrumentation Account	20 to 40%				100.0%			240			220,000
	Sub-Total Electrical Account	20 to 40%				15.0%			40			33,000
	Sub-Total Miscellaneous Account	15 to 30%				15.0%			80			33,000
	Sub-Total Directs	194 to 365%				341.0%				220,000		750,200
	Indirect Costs											
	Design Engineering	10 to 20%				20%						150,000
	Mill Administration and Temp Facilities at 5%											37,510
	Sales Tax on Material and Equipment at 5%											37,500
	Training Cost Materials at 1%											7,500
	Freight at 1.5%											11,300
	Capital Spare Parts at 2%											15,000
	Start up Services at 1%											7,500
	Sub-Total Indirects					121.1%						266,310
	Sub-Total Directs Plus Indirects											1,016,510
	Contingency at 15%											152,500
	Grand Total Capital					531.4%						1,169,010
	Equipment Cost											
	Steam Pressure Accumulator 2,000 CF	220000		50k	lbs							
	Total Equipment Cost	220000										

Table C62. Technology 11.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 11.1: Use advanced controls to control the drying process											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%				110.0%				420,000		462,000
	Sub-Total Electrical Account	20 to 40%										200,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						126,000
	Sub-Total Directs	194 to 365%				140.0%				420,000		788,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						157,600
	Mill Administration and Temp Facilities at 5%											39,400
	Sales Tax on Material and Equipment at 5%											39,400
	Training Cost Materials at 1%											7,900
	Freight at 1.5%											11,800
	Capital Spare Parts at 2%											15,800
	Start up Services at 1%											7,900
	Sub-Total Indirects					66.6%						279,800
	Sub-Total Directs Plus Indirects											1,067,800
	Contingency at 15%											160,200
	Grand Total Capital					292.4%						1,228,000
	Instrumentation Costs											
	Field Loops for Measurement 10 ea	120000										
	DCS Equipment	200000										
	Programming Costs	100000										
	Total Instrument Costs	420000										
	Electrical Work VSD Drives 4 ea	200000										

Table C63. Technology 11.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
Technology 11.2: Insulate the dryer and eliminate air and heat leaks												
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				0.0%						0
	Sub-Total Civil/Structural Account	8 to 35%				0.0%						0
	Sub-Total Engineered Equipment Account	102 to 110%				102.0%				110,000		112,200
	Sub-Total Piping Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				0.0%						0
	Sub-Total Electrical Account	20 to 40%				0.0%						0
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						33,000
	Sub-Total Directs	194 to 365%				132.0%				110,000		145,200
	Indirect Costs											
	Design Engineering	10 to 20%				5%						7,300
	Mill Administration and Temp Facilities at 5%											7,260
	Sales Tax on Material and Equipment at 5%											7,300
	Training Cost Materials at 1%											1,500
	Freight at 1.5%											2,200
	Capital Spare Parts at 2%											2,900
	Start up Services at 1%											1,500
	Sub-Total Indirects					27.2%						29,960
	Sub-Total Directs Plus Indirects											175,160
	Contingency at 15%											26,300
	Grand Total Capital					183.1%						201,460
	Equipment Cost											
	Insulate and Seal Drying Kiln 15000 sf	110000										
	Total Equipment Cost	110000										

Table C64. Technology 11.3

Technology 11.3: Install heat recovery systems on the dryer exhaust												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						15,800
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						39,500
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				395,000		418,700
	Sub-Total Piping/Ducting Account	25 to 90%				30.0%						118,500
	Sub-Total Instrumentation Account	20 to 40%				10.0%						39,500
	Sub-Total Electrical Account	20 to 40%				10.0%						39,500
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						39,500
	Sub-Total Directs	194 to 365%				180.0%				395,000		711,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						106,700
	Mill Administration and Temp Facilities at 5%											35,550
	Sales Tax on Material and Equipment at 5%											35,600
	Training Cost Materials at 1%											7,100
	Freight at 1.5%											10,700
	Capital Spare Parts at 2%											14,200
	Start up Services at 1%											7,100
	Sub-Total Indirects					54.9%						216,950
	Sub-Total Directs Plus Indirects											927,950
	Contingency at 15%											139,200
	Grand Total Capital					270.2%						1,067,150
	Equipment Cost											
	Air to Air Heat Exchanger	350000										
	Fan	45000										
	Total Equipment Cost	395000										

Table C65. Technology 11.4

Technology 11.4: Use boiler blowdown in the log vat												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				15.0%						3,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						4,000
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				20,000		22,000
	Sub-Total Piping/Ducting Account	25 to 90%				90.0%						18,000
	Sub-Total Instrumentation Account	20 to 40%				40.0%						8,000
	Sub-Total Electrical Account	20 to 40%				25.0%						5,000
	Sub-Total Miscellaneous Account	15 to 30%				30.0%						6,000
	Sub-Total Directs	194 to 365%				330.0%				20,000		66,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						9,900
	Mill Administration and Temp Facilities at 5%											3,300
	Sales Tax on Material and Equipment at 5%											3,300
	Training Cost Materials at 1%											700
	Freight at 1.5%											1,000
	Capital Spare Parts at 2%											1,300
	Start up Services at 1%											700
	Sub-Total Indirects					101.0%						20,200
	Sub-Total Directs Plus Indirects											86,200
	Contingency at 15%											12,900
	Grand Total Capital					495.5%						99,100
	Equipment Cost											
	Pump 100 GPM	15000										
	Tank Modifications	5000										
	Total Equipment Cost	20000										

Table C66. Technology 12.1

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 12.1: Measure and control the dryer exhaust moisture content to minimize air heating											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%				110.0%				340,000		374,000
	Sub-Total Electrical Account	20 to 40%				20.0%						100,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						68,000
	Sub-Total Directs	194 to 365%				150.0%				340,000		542,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						108,400
	Mill Administration and Temp Facilities at 5%											27,100
	Sales Tax on Material and Equipment at 5%											27,100
	Training Cost Materials at 1%											5,400
	Freight at 1.5%											8,100
	Capital Spare Parts at 2%											10,800
	Start up Services at 1%											5,400
	Sub-Total Indirects					56.6%						192,300
	Sub-Total Directs Plus Indirects											734,300
	Contingency at 15%											110,100
	Grand Total Capital					248.4%						844,400
	Instrumentation Costs											
	Field Loops for Measurement 7 ea	90000										
	DCS Equipment	150000										
	Programming Costs	100000										
	Total Instrument Costs	340000										
	Electrical Costs VSD Units 4 ea	100000										

Table C67. Technology 12.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 12.2: Recover heat from dryer exhaust											
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						15,800
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						39,500
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				395,000		418,700
	Sub-Total Piping/Ducting Account	25 to 90%				30.0%						118,500
	Sub-Total Instrumentation Account	20 to 40%				10.0%						39,500
	Sub-Total Electrical Account	20 to 40%				10.0%						39,500
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						39,500
	Sub-Total Directs	194 to 365%				180.0%				395,000		711,000
	Indirect Costs											
	Design Engineering	10 to 20%				15%						106,700
	Mill Administration and Temp Facilities at 5%											35,550
	Sales Tax on Material and Equipment at 5%											35,600
	Training Cost Materials at 1%											7,100
	Freight at 1.5%											10,700
	Capital Spare Parts at 2%											14,200
	Start up Services at 1%											7,100
	Sub-Total Indirects					54.9%						216,950
	Sub-Total Directs Plus Indirects											927,950
	Contingency at 15%											139,200
	Grand Total Capital					270.2%						1,067,150
	Equipment Cost											
	Air to Air Heat Exchanger	350000										
	Fan	45000										
	Total Equipment Cost	395000										

Table C68. Technology 12.3

Technology 12.3: Use wood waste as fuel for drying (suspension burning)												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				20.0%						440,000
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						440,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				2,200,000		2,332,000
	Sub-Total Piping Account	25 to 90%				15.0%						330,000
	Sub-Total Instrumentation Account	20 to 40%				20.0%						440,000
	Sub-Total Electrical Account	20 to 40%				20.0%						440,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						440,000
	Sub-Total Directs	194 to 365%				221.0%				2,200,000		4,862,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						486,200
	Mill Administration and Temp Facilities at 5%											243,100
	Sales Tax on Material and Equipment at 5%											243,100
	Training Cost Materials at 1%											48,600
	Freight at 1.5%											72,900
	Capital Spare Parts at 2%											97,200
	Start up Services at 1%											48,600
	Sub-Total Indirects					56.4%						1,239,700
	Sub-Total Directs Plus Indirects											6,101,700
	Contingency at 15%											915,300
	Grand Total Capital					319.0%						7,017,000
	Equipment Cost											
	Fuel handling, storage bin, feed and burner system	2200000										
	for 130 Mft^3/a particleboard dryer (70 MBTu/h)											
	Total Equipment Cost	2200000										

Table C69. Technology 13.1

Technology 13.1: Install heat recovery												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				5.0%						30,000
	Sub-Total Civil/Structural Account	8 to 35%				8.0%						48,000
	Sub-Total Engineered Equipment Account	102 to 110%				106.0%				600,000		636,000
	Sub-Total Piping Account	25 to 90%				25.0%						150,000
	Sub-Total Instrumentation Account	20 to 40%				10.0%						60,000
	Sub-Total Electrical Account	20 to 40%				15.0%						90,000
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						60,000
	Sub-Total Directs	194 to 365%				179.0%				600,000		1,074,000
	Indirect Costs											
	Design Engineering	10 to 20%				10%						107,400
	Mill Administration and Temp Facilities at 5%											53,700
	Sales Tax on Material and Equipment at 5%											53,700
	Training Cost Materials at 1%											10,700
	Freight at 1.5%											16,100
	Capital Spare Parts at 2%											21,500
	Start up Services at 1%											10,700
	Sub-Total Indirects					45.6%						273,800
	Sub-Total Directs Plus Indirects											1,347,800
	Contingency at 15%											202,200
	Grand Total Capital					258.3%						1,550,000
	Equipment Cost											
	Dryer Enclosure	300000										
	Hood Fans	70000										
	Spray Scrubber and Pumps	200000										
	Discharge Pump	30000										
	Total Equipment Cost	600000										

Table C70. Technology 13.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 13.2: Preheat drying air with steam											
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						9,200
	Sub-Total Civil/Structural Account	8 to 35%				8.0%						18,400
	Sub-Total Engineered Equipment Account	102 to 110%				105.0%				230,000		241,500
	Sub-Total Piping Account	25 to 90%				20.0%						46,000
	Sub-Total Instrumentation Account	20 to 40%				10.0%						23,000
	Sub-Total Electrical Account	20 to 40%				0.0%						0
	Sub-Total Miscellaneous Account	15 to 30%				10.0%						23,000
	Sub-Total Directs	194 to 365%				157.0%				230,000		361,100
	Indirect Costs											
	Design Engineering	10 to 20%				20%						72,200
	Mill Administration and Temp Facilities at 5%											18,055
	Sales Tax on Material and Equipment at 5%											18,100
	Training Cost Materials at 1%											3,600
	Freight at 1.5%											5,400
	Capital Spare Parts at 2%											7,200
	Start up Services at 1%											3,600
	Sub-Total Indirects					55.7%						128,155
	Sub-Total Directs Plus Indirects											489,255
	Contingency at 15%											73,400
	Grand Total Capital					244.6%						562,655
	Equipment Cost											
	Insulate Steam/Air Heating Coils 30000#/Hr	200000										
	Modify Existing Air Heater Unit	30000										
	Total Equipment Cost	230000										

Table C71. Technology 14.1

Technology 14.1: Screen flakes before drying; dry fines separately												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Range as % of Engrd Equip											
	Sub-Total Demolition and Sitework Account	4 to 20%				4.0%						10,400
	Sub-Total Civil/Structural Account	8 to 35%				10.0%						26,000
	Sub-Total Engineered Equipment Account	102 to 110%				110.0%				260,000		286,000
	Sub-Total Piping/Ducting Account	25 to 90%				0.0%						0
	Sub-Total Instrumentation Account	20 to 40%				10.0%						26,000
	Sub-Total Electrical Account	20 to 40%				15.0%						39,000
	Sub-Total Miscellaneous Account	15 to 30%				0.0%						0
	Sub-Total Directs	194 to 365%				149.0%				260,000		387,400
	Indirect Costs											
	Design Engineering	10 to 20%				15%						58,100
	Mill Administration and Temp Facilities at 5%											19,370
	Sales Tax on Material and Equipment at 5%											19,400
	Training Cost Materials at 1%											3,900
	Freight at 1.5%											5,800
	Capital Spare Parts at 2%											7,700
	Start up Services at 1%											3,900
	Sub-Total Indirects					45.5%						118,170
	Sub-Total Directs Plus Indirects											505,570
	Contingency at 15%											75,800
	Grand Total Capital					223.6%						581,370
	Equipment Cost											
	60 tons/hr Fines Screen System	140000										
	Conveyors 3 ea	120000										
	Total Equipment Cost	260000										

Table C72. Technology 14.2

Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
	Technology 14.2: Use advanced controls to optimize the drying process											
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%										0
	Sub-Total Civil/Structural Account	8 to 35%										0
	Sub-Total Engineered Equipment Account	102 to 110%										0
	Sub-Total Piping/Ducting Account	25 to 90%										0
	Sub-Total Instrumentation Account	20 to 40%				110.0%				340,000		374,000
	Sub-Total Electrical Account	20 to 40%										150,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						68,000
	Sub-Total Directs	194 to 365%				130.0%				340,000		592,000
	Indirect Costs											
	Design Engineering	10 to 20%				20%						118,400
	Mill Administration and Temp Facilities at 5%											29,600
	Sales Tax on Material and Equipment at 5%											29,600
	Training Cost Materials at 1%											5,900
	Freight at 1.5%											8,900
	Capital Spare Parts at 2%											11,800
	Start up Services at 1%											5,900
	Sub-Total Indirects					61.8%						210,100
	Sub-Total Directs Plus Indirects											802,100
	Contingency at 15%											120,300
	Grand Total Capital					271.3%						922,400
	Equipment Cost											
	Field Loops for Measurement 7 ea	90000										
	DCS Equiptment	150000										
	Programming Costs	100000										
	Total Instrument Costs	340000										
	Electrical Costs VSD Units	150000										

Table C73. Technology 14.3

Technology 14.3: Use powdered resins												
Act #	Description	Factor	Unit	MH/U	TMH	Rate	Mtl $/U	Sub $/U	Labor $	Material $	SubCon $	Total Cost
		Range as % of Engrd Equip										
	Sub-Total Demolition and Sitework Account	4 to 20%				8.0%						2,400
	Sub-Total Civil/Structural Account	8 to 35%				20.0%						6,000
	Sub-Total Engineered Equipment Account	102 to 110%				104.0%				30,000		31,200
	Sub-Total Piping Account	25 to 90%				25.0%						7,500
	Sub-Total Instrumentation Account	20 to 40%				30.0%						9,000
	Sub-Total Electrical Account	20 to 40%				20.0%						6,000
	Sub-Total Miscellaneous Account	15 to 30%				20.0%						6,000
	Sub-Total Directs	194 to 365%				227.0%				30,000		68,100
	Indirect Costs											
	Design Engineering	10 to 20%				13%						8,900
	Mill Administration and Temp Facilities at 5%											3,405
	Sales Tax on Material and Equipment at 5%											3,400
	Training Cost Materials at 1%											700
	Freight at 1.5%											1,000
	Capital Spare Parts at 2%											1,400
	Start up Services at 1%											700
	Sub-Total Indirects					65.0%						19,505
	Sub-Total Directs Plus Indirects											87,605
	Contingency at 15%											13,100
	Grand Total Capital					335.7%						100,705
	Equipment Cost											
	Misc. Blowers, etc.	30000										
	Total Equipment	30000										