A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry

FINAL REPORT

8 October 2003

Princeton University

POLITECNICO MILANO

NAVIGANT CONSULTING

A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry

FINAL REPORT

Eric D. Larson
Princeton Environmental Institute
Princeton University
Princeton, NJ
elarson@princeton.edu

Stefano Consonni
Dipartimento di Energetica
Politecnico di Milano
Milan, Italy
stefano.consonni@polimi.it

Ryan E. Katofsky
Navigant Consulting, Inc.*
Burlington, MA
rkatofsky@navigantconsulting.com

8 October 2003

Abstract

The U.S. pulp and paper industry, with its substantial capacity for producing and using renewable biomass energy – 1.6 quads in 2002 – has the potential to contribute significantly to addressing global warming and U.S. energy security concerns, while potentially also improving its own global competitiveness. A key requirement for substantially enhancing renewable energy use in this industry to achieve these goals is the commercialization of breakthrough technologies, especially gasification. Gasification of biomass produces a fuel gas ("syngas") consisting largely of hydrogen (H_2) and carbon monoxide (CO) that can be cleanly converted into electricity in a gas turbine combined cycle or, in the longer term, into transportation fuels such as Fischer-Tropsch liquids or hydrogen.

The predominant form of biomass energy available at pulp mills today is black liquor, the lignin-rich byproduct of fiber extraction from wood. Black liquor contains about half the energy of the wood input to a kraft pulp mill, along with all of the spent pulping chemicals (Na_2S and NaOH) used in the kraft process, the predominant process for pulp production. At pulp mills today, black liquor is burned in so-called Tomlinson recovery boilers to generate steam and recover pulping chemicals for re-use. The steam is expanded through a turbine to make electricity that meets a portion of the process electricity needs. Some steam is extracted from the turbine to provide all of the process steam needs of the mill.

The majority of Tomlinson boilers now operating in the United States will reach the end of their 30-40 year lifetimes over the next 10 to 20 years. Thus, there is intense interest in the pulp and paper industry in having improved black liquor processing technology commercially available in the 2010 time frame. At the same time, there are growing public interests in expanding the role of clean renewable energy to address environmental and energy security concerns. These private and public interests can potentially both be met by commercial implementation of black liquor gasification.

This study examines in greater depth and breadth than previous studies the prospective costs and benefits of commercializing black liquor gasification combined cycle (BLGCC) cogeneration systems. The analysis was carried out with guidance from an industry-government Steering Committee, with review by a board of independent experts, and with inputs from many other individuals.

The underlying basis for results obtained in this study are detailed engineering designs, capital costs, and operating costs for "Nth plant" BLGCC and Tomlinson cogeneration systems the authors developed in consultation with equipment developers, industrial design engineers, pulp and paper industry experts, and a variety of others. Prospective characteristics of two black liquor gasification technologies under commercial development (one high-temperature design and one low-temperature design) are used in the BLGCC designs.

With these inputs, energy, environmental, financial, and economic evaluations of alternative cogeneration systems were made in the context of a reference mill having process characteristics representative of expected typical mills in the 2010 time frame in the Southeastern U.S., where 2/3 of kraft mill capacity is located. The reference mill produces uncoated freesheet paper from a mix of hardwood and softwood. The nominal scale of the mill is 6 million lbs/day of black liquor

solids (BLS) – 1,495 million Btu/h or 438 MW_{fuel} – corresponding to 1,900 machine dry short tons per day of paper production (1,725 metric tonnes). Pulp mills processing more than 6 million lbs/day BLS account for about 1/3 of all U.S. capacity today, and this fraction will grow over time as mill consolidations continue.

Three BLGCC designs were developed incorporating different gasification technologies and design philosophies: two "mill-scale" cases (each with a different gasifier design), wherein the BLGCC system is sized to the flow of black liquor available at the reference mill, and one "utility-scale" case employing a larger gas turbine co-firing natural gas with black liquor syngas to achieve higher electricity output. Detailed mass and energy balances were calculated for each of the BLGCC designs, along with a conventional Tomlinson design for comparison. Due to the inherently higher thermodynamic efficiency of gas turbine-based cogeneration compared to steam-turbine cogeneration (as reflected in a higher electricity-to-steam production capability), BLGCC systems are able to produce more electricity than needed by the mill, while meeting the same steam demand as a Tomlinson system. A consequence of this is that for the same process steam demand, a BLGCC requires additional fuel to be consumed (e.g., purchased wood residues and/or natural gas) to maximize electricity production.

This study confirms results of earlier studies showing BLGCC systems offer the prospect for significant improvements in energy efficiency compared to Tomlinson systems. In particular, at the reference mill a Tomlinson system would need to import 36 MW_e to meet its onsite electricity needs – about 1/3 of the total process electricity demand. In contrast, the mill-scale and utility-scale BLGCC systems would have available for export 15-22 MW_e and 126 MW_e, respectively. Importantly, the efficiency with which purchased fuels are converted into electricity in the BLGCC cases ranges from 50% to 96%, which compares favorably with the efficiency of making electricity from stand-alone power plants that might be displaced by the excess BLGCC power.

Aside from efficiency benefits, a distinctive and intrinsic feature of BLGCC technology is the expected low relative emissions of most pollutants compared to a modern Tomlinson system employing sophisticated pollution controls. Per unit of black liquor processed, BLGCC systems would provide considerable improvements in air emissions, some improvements in water pollution, and a similar solid waste emissions profile as Tomlinson technology. When environmental emissions are considered on a per-unit-of-electricity-generated basis, BLGCC systems would exhibit improved environmental characteristics across the board relative to Tomlinson technology. Moreover, if the difference in the power generated between a BLGCC system and the Tomlinson system is assumed to displace power generation on the grid, there would be additional reductions in environmental impacts associated with the displaced grid emissions in most regions of the United States.

Prospective internal rates of return (IRR) on incremental investments in BLGCCs in place of Tomlinson systems were calculated assuming commercially-mature cost levels for both systems. IRRs up to 20% were calculated without considering the value of any environmental or renewable energy benefits of BLGCC. If economic values for environmental and renewable energy benefits are factored into the analysis, e.g., considering values for renewable energy attributes similar to those that currently benefit wind power and closed loop biomass systems, IRRs of 35% are possible.

Beyond the energy, environmental, and economic benefits at the mill level, widespread implementation of BLGCC systems would produce regional and national benefits. These were estimated for both the Southeast region and for the United States under different technology market penetration assumptions.

In the Southeast, where total electricity demand is projected to double by 2030, BLGCC technology has the potential to contribute up to 4,000 MW (mill-scale configuration) to more than 11,000 MW (utility-scale configuration) of generating capacity beyond that needed to meet process demands at the mills. Moreover since BLGCC plants would be smaller than typical central station power plants, they would be more numerous and dispersed, which may allow capital investments in the transmission and distribution system to be deferred while improving overall grid reliability.

At such levels of penetration, BLGCC systems would contribute importantly to meeting any future mandated renewable electricity requirements in the Southeast (Renewable portfolio standards – RPS – are already in place in 12 states across the nation, although not yet in the Southeast.). Under a future scenario in which 5% of all new electricity supply in the Southeast region is mandated to be renewable, aggressive deployment of BLGCC systems could meet nearly half of the required renewable electricity supply in 2020.

Nationally, BLGCC technology (particularly in “utility-scale” configurations) could provide a host of economic, environmental, and energy security benefits, including the potential to displace more than 360 trillion Btu per year of fossil fuel use within 25 years of introduction, with a corresponding reduction of more than 35 million tons per year of CO_2 emissions. The following table summarizes potential national benefits identified in this study.

The attractive IRRs on Nth plant BLGCC investments, together with the substantial public benefits that could result from such investments, suggest a public-private partnership as an appropriate approach to addressing research, development, and demonstration (RD&D) issues (identified in this study) during the next few years to bring BLGCC systems to commercial readiness. Delaying commercial deployment of BLGCC technology could carry with it an opportunity cost that is estimated here to be up to $9 billion.

It may be noted that this study considered only electricity as the energy export from gasification-based systems. In this regard, commercializing BLGCC could be a first step in the evolution to future biorefineries that would take fuller advantage of the characteristics of gasification as a “breakthrough” technology platform. Conversion of black liquor to high-value chemicals and/or transportation fuels, e.g., F-T middle distillates or hydrogen, should be a focus of future analysis to better understand the possibilities. Moreover, such studies should also examine the potential for gasifying forest residues collected sustainably from the vicinity of the mills. Estimates suggest that the energy contained in potential supplies of such residues could match the amount of energy in black liquor. In time, a gasification-based biorefinery industry might extend beyond the pulp and paper industry, whereby biomass crops would be grown for conversion to heat, electricity, fuels, chemicals, animal feed, and other commodity products.

Prospective National Benefits of BLGCC Commercialization

Economic Benefits	• Higher pulp yields (due to pulping modifications enabled by BLGCC) reduce pulpwood requirements by approximately 7% per unit paper output. • Up to $6.5 billion (constant 2002 dollars) in cumulative energy cost savings over 25 years. • Additional potential cumulative (over 25 years) emissions credit values in the range of $450 million for SO_2, $3.2 billion for NO_x, and $3.1 billion for CO_2. • Job preservation and growth in the pulp & paper industry.
Environmental Benefits	• Higher pulp yields reduce pulpwood requirements by approximately 7% per unit output. • Potential for reduced cooling water and makeup water requirements, for the mill-scale BLGCC. All BLGCC options also result in reduced cooling water and makeup water requirements for the grid power displaced, and reduce solid waste production at grid power plants. • Up to 35 million tons net CO_2, 160,000 tons net SO_2 and 100,000 tons net NO_x displaced annually within 25 years of introduction. Additional reductions of particulates, VOCs and TRS. • Additional benefits could accrue if BLGCC helps catalyze a new biomass-based energy industry, resulting in the development and use of sustainable biomass supplies for additional energy and chemicals production.
Security Benefits	• Up to 156 billion kWh more electricity produced compared with continued use of Tomlinson technology within 25 years of introduction. Of this, as much as 62 billion kWh would be renewable. • Up to 360 trillion Btu/year of fossil energy savings within 25 years of introduction. • Potential for fuels and chemicals production from black liquor and other biomass feedstocks directly displacing petroleum.
Knowledge Benefits	• Advances in materials science, syngas cleanup technology, alternative pulping chemistries, and other areas.

*****

Acknowledgments

The authors thank the U.S. Department of Energy Office of Biomass Programs, the American Forest & Paper Association and its member companies, the Southern Company, the Tennessee Valley Authority, and the William and Flora Hewlett Foundation for financial support of the research described in this report.

The authors also thank the members of the Steering Committee, the Review Board, and other members of the Analytical Team (see Figure 5) for their many constructive inputs. For additional inputs, the authors also thank Niklas Berglin (STFI), Richard Campbell (AFPA), Ravi Chandran (ThermoChem), Gerard Closet (consultant), Elmer Fleischmann (Idaho National Engineering Lab), Jim Frederick (Chalmers University), Hassan Jameel (North Carolina State Univ.), Jarmo Kaila (Andritz), Ingvar Landalv (Chemrec), John Lewis (Fluor), Reid Miner (NCASI), King Ng (Nexant), Tervo Olavi (Andritz), John Pinkerton (NCASI), Lee Rockvam (ThermoChem), Michael Ryan (consultant), Scott Sinquefield (IPST), and Adriaan van Heiningen (University of Maine).

Table of Contents

List of Figures

List of Tables

Preface

by
Delmar Raymond, Weyerhaeuser Company
Ben Thorp, Georgia-Pacific Company

According to the recently completed U.S. Department of Energy's vision for Bioenergy and Biobased Products in the United States:

The United States is approaching a biobased revolution that will fundamentally change the way in which we produce and consume energy and industrial products. From biological resources we can derive products as diverse as fuels and lubricants, heat and electricity, chemicals, food, feed, building materials, paper, clothing, and much more.

The U.S. imports 11 barrels of oil for every 10 produced domestically. Imported petroleum supplies transportation fuels, heating oil, chemical feedstocks, and many other products used throughout our economy. A primary goal of the National Energy Policy is to increase our energy supplies by using a more diverse mix of domestic resources and to reduce our dependence on imported oil. Biomass technologies—some currently in use or in the early stages of development, and others not yet imagined—can contribute to the new mix of resources for energy and value-added chemicals and materials.

Bioenergy and biobased products—produced from resources such as crops, trees, and agricultural, industrial, municipal, and forestry wastes—hold great promise for our economy. We can harness the molecular building blocks and components of plants to heat our homes, run our cars, light our buildings, and provide industrial and consumer products for everyday use. Efficient use of biomass can help the U.S. to utilize its domestic energy resources more wisely.

One of the largest sources of indigenous, renewable and sustainable raw material in the United States is represented by the 278 million dry tons of wood that are processed each year by U.S. Pulp and Wood Products facilities, coupled with likely an additional 100 million dry tons or more of residuals within the vicinity of these mills.

Pulp and paper mills have existing infrastructure to receive, store, and handle woody biomass residuals. It is logical and desirable to utilize the existing infrastructure at pulp and paper mills to explore innovative ways to integrate gasification of wood residuals and black liquor with recovery of pulping chemicals.

In his 2003 State of the Union address, President Bush emphasized that the administration's goal is to promote energy independence for the United States while dramatically improving the environment. He indicated that he had sent Congress plans to: a) promote energy efficiency and conservation; b) develop cleaner technology; c) produce more energy at home; and d) significantly reduce air pollution from power plants. The President also proposed a specific challenge to move the automobile industry toward cars powered with fuel cells.

The forest products industry gasification initiative addresses all of these points head on. It more than doubles the ability to generate electric power from renewable, sustainable forest residuals and spent pulping liquors—or alternatively, it can produce significant amounts of liquid fuels and/or bio-based chemicals. In moving forward with this initiative, the new technology, if deployed, will replace existing technology first introduced in the early 1900's. In so doing, it could make a significant contribution to the President's objectives.

Once gasification technology is implemented, pulp and paper mills will have choices of how best to utilize and convert their spent pulping liquors and residual materials. Among those choices will be the production of:

- Clean, renewable and sustainable electric power – Black liquor gasification (BLG) in an integrated combined cycle (BLGCC) has the potential of producing more than twice the current output of electricity per ton. In many cases, power in excess of a pulp mill's needs could be produced and exported.
- Clean, renewable and sustainable liquid fuels – When gasified, black liquor converts to a high quality synthetic gas. It is similar to syngas produced from fossil residual oil. Conventional processes can then be used to convert the gas to liquid fuels or hydrogen. Preliminary studies have shown that the economics of this choice may be equal to, or in some cases even better, than using the gas to generate electric power.
- Clean, renewable and sustainable chemical and carbon products – Most of the chemical and carbon products currently made from oil and natural gas can, and in many cases have in the past, been made from biomass.

It is estimated that full implementation of the BLG initiative could achieve the following energy benefits by 2020:

- BLG only – The production of up to 8 gigawatts of electricity from sustainable, renewable raw materials by the year 2020.
- BLG and wood residual gasification combined – The production of 16 gigawatts or more of electric power for the application of BLG in conjunction with wood residual gasification by the year 2020.
- Alternatively, if applied to syngas production to be used for liquid fuels, these technologies could displace over 282 million barrels of oil per year.

Widespread use of the technology would also have significant implications with respect to jobs—both from the viewpoint of sustaining jobs in manufacturing facilities that otherwise might become uneconomical and close, as well as adding jobs for those involved in supplying the raw material for processing and the operation of new facilities. Even though this opportunity seems compelling, the driving force to implement this technology is small for the first few installations and the initial risk is high. As a result, unless the high risk of these first units is significantly lowered, the substantial benefits to the industry and the Nation will not be achieved for decades—or possibly not at all. Once the aging fleet of recovery furnaces has been replaced in kind, the economics will dictate that they remain in operation for 30 years or more in spite of their low energy efficiency.

There are likely a number of ways to reduce the time to deployment of gasification technology and to gain benefits early. One way is to take advantage of the synergy and economics of scale by combining the compelling business needs of the pulp and paper industry with those of the utility industry. This concept is analyzed in the material presented here by examining the use of a "utility scale" gas turbine at a pulp mill site fired by a combination of natural gas and syngas from gasified black liquor to generate electricity for use by the mill and export to the grid.

The study also addresses the question of how to generate sufficient economics to accelerate commercialization, including the impact of possible incentives. An explicit goal of the study was to understand quantitatively the magnitude of benefits that could be attained in the long term for the Nation and the industry with black liquor gasification technology. A remaining task for the industry and partners is to put into effect practical steps to attain these benefits at an accelerated pace.

Although this study assumes that gasification technology is utilized to transform spent pulping liquors and residuals to electric power, it should be recognized as discussed above that gasification provides a base for other products that may be even more desirable. An even higher national priority may be to use gasification for generating syngas for conversion to liquid fuels, chemicals and/or hydrogen for fuel cells. This could be done with or without the co-production of electricity. The study presented here examines only the conversion to power and heat. The possibility of even more attractive applications of gasification should be kept in mind, as should the fact that its successful commercial-scale demonstration is fundamental to securing any of the potential benefits discussed.

Summary

Background for this Study

The U.S. pulp and paper industry is among the largest producers and users of renewable energy in the United States today. The total of these biomass energy sources consumed at pulp mills in 2002 was an estimated 1.6 quads (one quad is 10^{15} BTU). For comparison, all energy sources consumed in 2001 in the U.S. totaled 97 quads. With substantial renewable energy resources at its disposal, the U.S. pulp and paper industry has the potential to contribute significantly to addressing global warming and U.S. energy security concerns, while potentially also improving its global competitiveness. A key requirement for achieving these goals is the commercialization of breakthrough technologies, including gasification, that will enable the clean and efficient conversion of biomass to useful energy forms, including electricity and transportation fuels.

Gasification technology enables solid fuels like biomass to be converted with low pollution into a fuel gas ("syngas") consisting largely of hydrogen (H_2) and carbon monoxide (CO). This gas can be burned cleanly and efficiently in a gas turbine to generate electricity. It can be passed over appropriate catalysts to synthesize clean transportation fuels or chemicals. It can be converted efficiently into pure H_2 for use in fuel cells, whose only air emissions are water vapor. While pulp and paper manufacturing facilities do not produce transportation fuels from biomass today, the infrastructure they have in place for collecting and processing biomass resources provides an established foundation for future gasification-based "biorefineries" that might produce a variety of renewable fuels, electricity, and chemicals in conjunction with pulp and paper products (Figure S1).

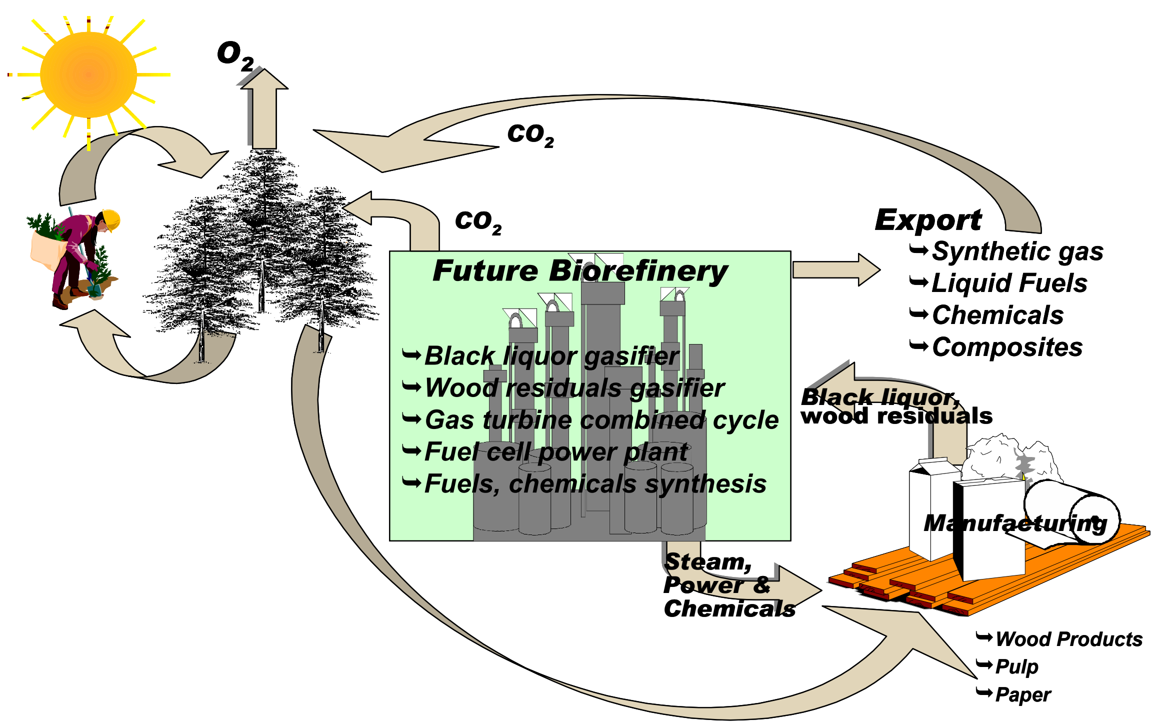


Figure S1. Future "biorefinery" concept based at a pulp and paper manufacturing facility.

If pulp and paper facilities do evolve into such "biorefineries," the first likely feedstock to be used for gasification is black liquor, given that its generation and processing are integral to the manufacturing process and that its contained energy is about six times the energy contained in the other biomass by-products (bark and wood wastes) generated at a typical mill. Adoption of woody-biomass gasification would likely follow, once black liquor gasification is successfully introduced. This would then facilitate the collection and use of additional sustainable biomass resources, such as purpose-grown energy crops.

This study examines the prospective technical and financial feasibility of black liquor gasification-based systems at kraft pulp mills for steam/power cogeneration and recovery of pulping chemicals as full replacements for Tomlinson recovery boiler systems, the current state-of-the-art technology in the industry. (More advanced gasification-based "biorefinery" designs, e.g., including transportation fuels production, are not examined in this study.)

The majority of Tomlinson boilers operating in the United States were built beginning in the late 1960s through the 1970s. With lifetimes of 30 to 40 years, many of these units are approaching the time at which they will need to be rebuilt or replaced. Thus, over the next 10 to 20 years, there will be strong demand for replacement black liquor energy and chemical recovery systems.

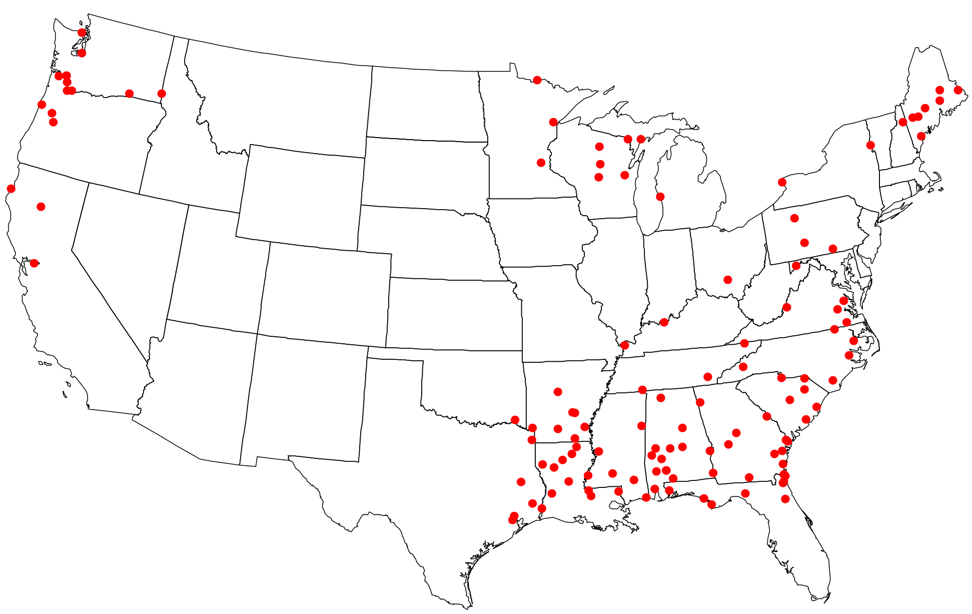


Figure S2. Location of U.S. pulp mills, 2/3 of which are in the Southeast.

This study aims to inform technology decision makers in the pulp and paper industry, in the utility and independent power generating industries, and in the U.S. Department of Energy and other government agencies regarding the prospective costs and benefits of black liquor gasification systems. The analysis has been carried out with guidance from an industry-government Steering Committee, review by a board of independent experts, and with inputs from many other individuals.

In addition to mill-level cost-benefit assessments, this study includes an assessment of potential regional and national energy and environmental impacts of the implementation of black liquor gasification technology under different future market penetration scenarios. The regional analysis focuses on the Southeastern United States, where two-thirds of kraft pulp mills are located (Figure S2). Particular attention is given to the possibility of electricity export from kraft pulp mills in this region contributing substantial, largely renewable, electricity to the electricity supply from the grid.

Conventional Kraft Pulp Production

Production of pulp and paper from wood by the kraft process, the dominant pulp-making process in the United States, is illustrated in Figure S3. Logs are debarked and chipped, with the clean chips sent to the digester for cellulose extraction. The bark and waste wood (called "hog fuel") are used as a boiler fuel. The wood chips undergo cellulose extraction in the digester in a solution of sodium sulfide (Na_2S) and sodium hydroxide (NaOH) called white liquor. A subsequent washing step separates the cellulose fibers from the remaining solution containing the spent pulping chemicals and the lignin and hemicellulose from the wood. This solution is called black liquor. The cellulose fibers are processed into a final pulp product (at a stand-alone pulp mill) or into paper (at an integrated pulp and paper mill).

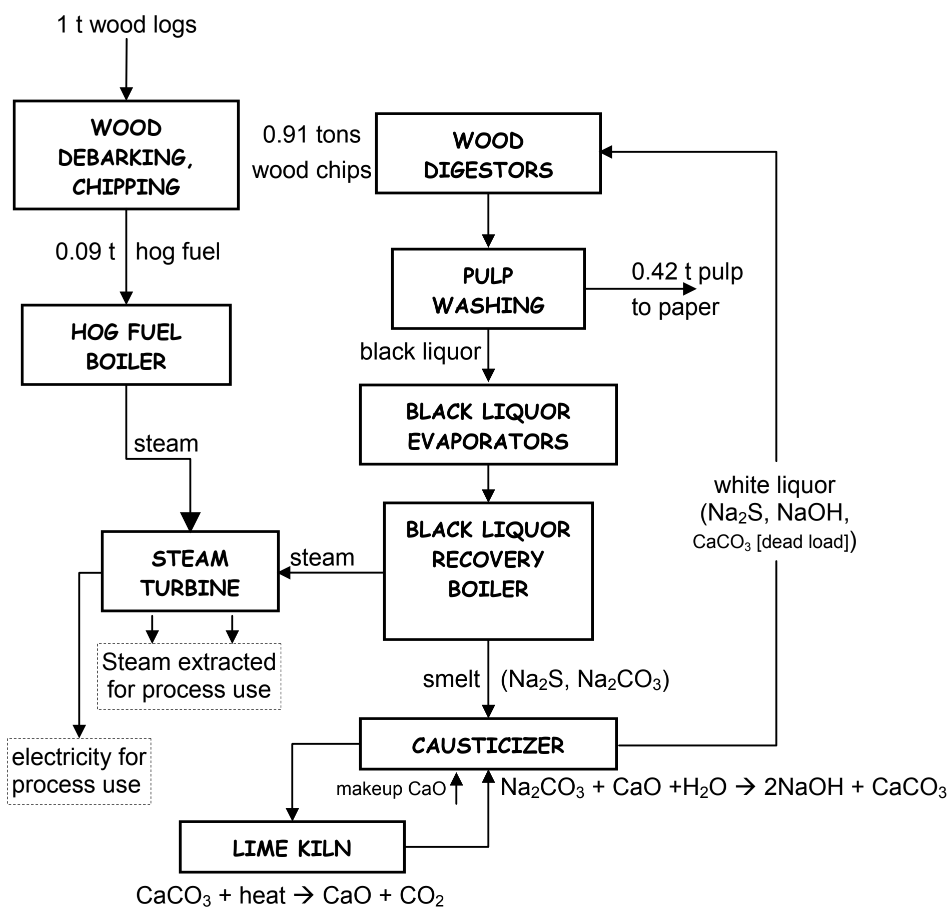


Figure S3. Simplified representation of kraft pulping and the associated chemical recovery cycle. Indicated mass balance is on a dry-matter basis and intended only to be illustrative.

The black liquor solids (BLS) carry about half the energy in the original wood chips sent to the digester, and thus represent a considerable energy resource. At pulp mills today, the black liquor is burned in Tomlinson recovery boilers. Steam from the Tomlinson boiler, together with steam from the hog fuel boilers, provides all of the steam needed to run the pulp (or integrated pulp and paper) mill. The steam is expanded through a steam turbine before being used at the mill, resulting in some electricity generation. Most U.S. mills must also purchase some electricity, since the amount generated from black liquor and hog fuel is not sufficient to meet all of the mill's electricity needs with power generating technology in use today.

In addition to energy generation, a critical task of the Tomlinson boiler is to begin the process of recovering sulfur and sodium for re-use in pulp production. The inorganic fraction of the black liquor leaves a Tomlinson reactor as a molten smelt containing largely sodium sulfide (Na_2S) and sodium carbonate (Na_2CO_3). The smelt is dissolved in water to form green liquor that is sent to a causticizer, where lime (CaO) is added to convert the Na_2CO_3 in the green liquor back to the desired caustic pulping chemical, sodium hydroxide ($NaOH$). The lime is converted to calcium carbonate ($CaCO_3$) in the causticizer and must be converted back to CaO by heating in a kiln. Typically, fuel oil or natural gas is burned in the kiln to generate the needed heat.

Black Liquor Gasification Technologies

Black liquor gasifiers are being developed as replacements for Tomlinson boilers, and a number of concepts have been proposed over the past two decades. Serious commercialization efforts are ongoing for two of these concepts in joint initiatives between industry and government. The two concepts can be distinguished by their operating temperatures.

A high-temperature gasification process is under development by Chemrec, a Swedish company. Similar to an entrained-flow coal gasifier, the Chemrec design operates under elevated pressure with oxygen used to partially oxidize the black liquor. The raw product gas ("syngas") contains carbon monoxide and hydrogen as its principal combustible components. Because of the high operating temperature (950-1000^oC), the inorganic material in the black liquor leaves the reactor as a liquid smelt. The relatively large oxygen requirement for gasification justifies a dedicated air separation unit (ASU) as part of the overall design. Other uses of oxygen at the mill, e.g., for oxygen bleaching, effluent treatment, and lime kiln capacity enhancement (discussed below), which might be cost-prohibitive on their own due to the small scales of use, may become feasible with a dedicated ASU on site.

A pilot plant Chemrec gasifier was first started up in 1994 at a pulp mill near Karlstad, Sweden. This unit used air rather than oxygen, operating at 15 bar pressure and 975^oC. After successful testing, the pilot plant was modified in 1997 to use oxygen, resulting in an increase in capacity to 10 t/day of black liquor solids. The unit was shut down in 2000, having provided significant data for further development of the technology. Weyerhaeuser installed a Chemrec atmospheric-pressure air-blown reactor (365 t/d BLS) at a mill in North Carolina in the late 1990s to augment the chemical recovery capacity provided by the existing Tomlinson boiler. That gasifier operated for three years before being shut down to repair an unanticipated problem with the pressure vessel. The unit was restarted in June 2003. Meanwhile, construction of a new Chemrec pilot plant has begun at a mill in Pitea, Sweden. The unit is designed to provide data for scale-up to full-scale Tomlinson boiler replacement applications. The unit will operate at 30 bar pressure with oxygen and have a capacity of 20 t/day of black liquor solids.

A low-temperature, near-atmospheric-pressure black liquor gasification process is under development by Thermochem Recovery International (TRI), an American company. The design utilizes indirect-heating of the black liquor via pulse-combustor heat exchange tubes immersed in a fluidized bed. Steam is used to fluidize the bed in which the black liquor is gasified. The raw gas produced with this "steam reformer" design is richer in hydrogen than gas from the high-temperature gasifier and also is undiluted with partial oxidation products, resulting in a relatively higher gas heating value than for the high-temperature design. With the moderate temperature maintained in the reactor (~600^oC), the condensed-phase material leaves as a dry solid rather than as a smelt.

This technology has been under development since the mid-1980s with support from the U.S. Department of Energy. TRI (or MTCI at the time) carried out gasification studies of spent pulping liquor in a 1,000 lbs/day BLS pilot unit starting in the early 1990s. A nominal 50-ton per day BLS pilot plant completed a 500-hour continuous test at a Weyerhaeuser kraft pulp mill in North Carolina in 1994/1995. A commercial-scale (200 tpd BLS) unit is now under construction at a Georgia Pacific pulp mill in Big Island, Virginia. The Big Island mill utilizes a non-sulfur pulping process. (This report considers gasification of sulfur-laden black liquor generated by the kraft process, the dominant pulp-making process in the United States and the world.)

With gasification, the process for recovering pulping chemicals is modified from the conventional process used with a Tomlinson boiler. Essentially all of the sodium and sulfur leaves a Tomlinson boiler in the smelt. During gasification, there is a natural partitioning of sulfur (mainly as hydrogen sulfide, H_2S) to the gas phase and sodium to the condensed phase. The lower the gasification temperature, the more complete is the partitioning of sulfur and sodium. With the low-temperature process described above, over 90% of the sulfur in the black liquor will leave the gasifier as H_2S in the product gas. With the high-temperature process described above, somewhat more than half of the sulfur goes to the gas phase.

The sulfur-sodium split with gasification offers the opportunity for use of new pulping chemistries, such as polysulfide pulping, that can improve pulp yield. When elemental sulfur is dissolved in a solution containing Na_2S at moderate temperature (<100^oF), polysulfide forms, for example, $3S + Na_2S \rightarrow Na_2\text{-}S_3\text{-}S$. The higher digester yield with polysulfide pulping enables a mill to decrease wood input costs compared to conventional pulping (for a fixed pulp production). (Wood cost savings amount to over $4 million per year at the case study mill in this study.)

To take advantage of the polysulfide pulping opportunity, H_2S must be recovered from the syngas in a form suitable for preparing modified pulping liquors. Capture of acid gases like H_2S is routinely practiced in other industries (e.g., petroleum refining) using patented processes. It is also possible to capture H_2S using a solution of Na_2CO_3 (e.g., green liquor) or NaOH (e.g., white liquor) as a scrubbing medium.

One negative consequence of the natural sulfur-sodium split with gasification is a higher causticizer and lime kiln load compared to processing in a Tomlinson boiler. One cause of this increased load is the larger amount of carbonate (Na_2CO_3) that leaves the gasifier in the condensed phase (due to less sulfur being available in the condensed phase to form sodium sulfide, Na_2S). The added carbonate must be converted to hydroxide (NaOH) through the causticizing cycle (Figure S3), an important consequence of which is a larger required lime kiln capacity and an associated increase in lime kiln fuel consumption. This negative impact is more pronounced with the low-temperature gasification technology than the high-temperature technology due to the greater fraction of sulfur going to the syngas with the former.

A second source of added causticizing load will appear if green or white liquor scrubbing is used to capture H_2S from the syngas, since CO_2 in the syngas will be co-absorbed and form additional Na_2CO_3 in the liquor, which must eventually be converted back to NaOH. The second source of causticizing load comes into play with the low-temperature gasification technology, since the Na_2S formed in the white liquor during H_2S stripping is necessary to provide a sufficient sulfide base in the white liquor to form polysulfide when dissolving the elemental sulfur. With high-temperature gasification, the H_2S in the syngas can be converted completely to elemental sulfur (which involves no co-absorption of CO_2) since there is sufficient Na_2S leaving the gasifier with the smelt (and subsequently appearing in the white liquor) to provide the needed base for polysulfide formation.

Considering all of the above details regarding chemicals recovery with gasification, the low-temperature gasification system in the case study analysis in this study requires an estimated 44% more causticizing/lime kiln capacity than a conventional Tomlinson system. For the high-temperature gasification system, the estimated increment is 16%. These estimates take account of both the higher kiln load per unit of black liquor solids processed through the recovery area, as well as the reduction in black liquor flow to the recovery area with gasification when polysulfide pulping is use (which decreases the wood feed to the digester for a fixed pulp production rate).

The high incremental lime kiln load with the low-temperature technology would require installation of an additional causticizer and lime kiln. In this study it is assumed that the modest lime kiln load increment with the high-temperature system can be accommodated by firing the kiln with oxygen-enriched air. A small increase in the size of the air separation unit (needed to supply oxygen to the gasifier) provides a low-cost source of oxygen for this purpose.

Characteristics of the Reference Mill

To assess the prospective commercial competitiveness of black liquor gasification relative to Tomlinson recovery boiler systems, a case study approach is used. Comparisons of different power/recovery systems are made in the context of an existing reference mill where the power/recovery system is to be replaced by a new system. The reference mill has process characteristics representative of expected typical mills in the Southeastern U.S. in the 2010 time frame. It is an integrated pulp and paper mill producing uncoated freesheet paper from a 65/35 mix of hardwood and softwood. Consistent with the forward-looking nature of this study and the continual improvements in process energy efficiency historically achieved by U.S. pulp and paper makers, the process steam demands at the mill are taken to be about 10% below current "best-practice" levels. The nominal scale of the case study mill is 6 million lbs/day of black liquor solids (BLS). Pulp mills processing 6 million lbs/day BLS or more account for about 1/3 of all U.S. capacity today, and this fraction is expected to grow over time as industry consolidation continues.

Key input mill parameter assumptions are shown in Table S1 for both conventional pulping (used with Tomlinson technology) and polysulfide pulping (used with gasification). The

Tomlinson BASE case represents a state-of-the art power/recovery system assumed as the "business-as-usual" choice of technology when considering replacement of the existing power/recovery system at the reference mill. As a variant on the Tomlinson BASE system, the potential impact of a number of marginal improvements, not all of which have been proven commercially, are examined in the Tomlinson high-efficiency recovery boiler (HERB) case.

Table S1. Reference case study mill parameter assumptions.

POWER/RECOVERY SYSTEM →		**Tomlinson**		**Gasification**
		BASE	**HERB**	
PULPING CHEMISTRY →		**Conventional**		**Polysulfide**
Product Flow (paper)	Machine-dry metric tons/day	1,725		
Unbleached Pulp Rate	Bone dry short tons/day	1,580		
Mill Hardwood/Softwood Mix	% HW, % SW	65% HW, 35% SW		
Digester Yield	% for softwood	45.50%		48.75%
	% for hardwood	46.50%		49.75%
Wood To Process (91% of total)		3,434		3,208
Hog Fuel (9% of total)	Bone dry short tons/day	340		317
Total Wood Used		3,774		3,525
Black Liquor Solids Concentration	% solids	80%	85%	80%
BL Solids Flow Rate	lb BLS per day	6,000,000		5,419,646
	kg BLS per day	2,721,555		2,458,311
BL Energy Content	kJ per kg of BLS (HHV)	13,892		13,874
	Btu per lb of BLS (HHV)	5,974		5,966
	MW, HHV	437.6		394.7
BL Solids Composition, mass%	C	33.46%		32.97%
	H	3.75%		3.70%
	O	37.35%		36.88%
	S	4.10%		4.27%
	Na	19.27%		20.03%
	K	1.86%		1.93%
	Ash/chlorides	0.21%		0.22%
Hog Fuel Energy Content	MJ / kg of hog fuel (HHV)	10		10
(50% moisture content)	Btu / lb of hog fuel (HHV)	4,300		4,300
	MWth, HHV	71.3		66.6
Mill Steam Use, 55 psig Steam	kg / kg of paper	3.384	3.362	3.207
(including evaporators, but excluding	MWth	142.8	141.8	135.3
power/recovery area)	MJ / mt of paper	7,149	7,100	6,774
Mill Steam Use, 175 psig Steam	kg / kg of paper	1.760	1.817	1.648
(including evaporators, but excluding	MWth	69.3	71.5	64.8
power/recovery area)	MJ / mt of paper	3,469	3,581	3,247
Total Mill Steam Use	MWth	212.1	213.3	200.1
Mill Electricity Use (excluding power/recovery)	kWh / mt of paper	1,407	1,406	1,407

Detailed mass and energy balances were calculated for each power/recovery system integrated into the reference mill. A process design and simulation tool previously applied extensively to analysis of combustion and gasification-based power systems (including black liquor-based systems) was used. The design of each power/recovery system was developed in consultation with equipment developers, industrial design engineers, and a variety of other experts.

The process configuration for the Tomlinson BASE (Figure S4) features steam conditions of 1,250 psig (87.2 bar abs.) and temperature of 480°C (896°F), with the hog fuel boilers existing at the mill contributing additional steam generation. Steam expands through the existing back-pressure steam turbine, with two extractions for steam sent to the process. Because of the process-steam efficiency gains assumed for the reference mill (compared to most actual existing mills today), the amount of exhaust steam is more than needed for the process. A small condensing steam turbine is added to enable increased electricity generation. The Tomlinson BASE power/recovery system produces 64 MW_e of net electricity. Considering both the black liquor and hog fuel inputs, the electricity generating efficiency is 12.6%. Since the mill requires 100 MW_e for the process, the mill must purchase 36 MW_e to meet its needs.

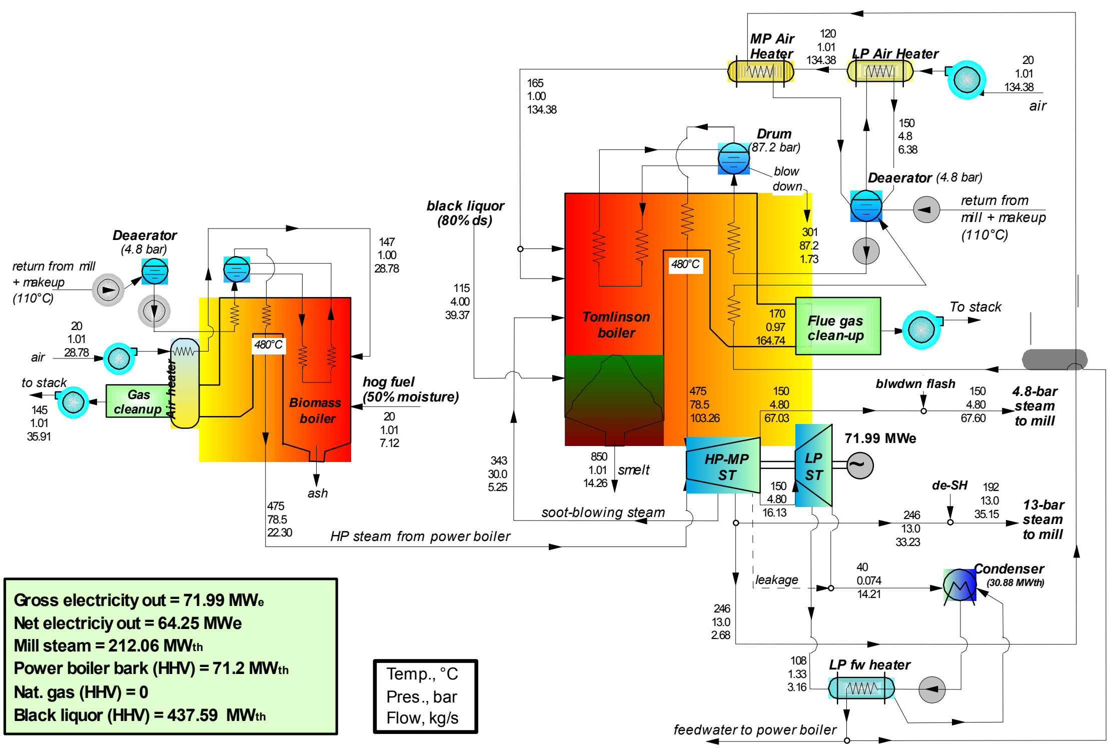


Figure S4. Energy/mass balance for Base Tomlinson recovery boiler.

The most significant improvements incorporated in the Tomlinson HERB design are an increase in steam conditions to 1,500 psig, 968°F (104.5 bar abs., 520°C) and an increase in black liquor dry solids concentration to 85%. Experts in the pulp industry have expressed serious concern over the feasibility in practice of a Tomlinson system operating under these conditions. Of particular concern are boiler-tube corrosion effects (and attendant increased risk of recovery boiler explosions), as well as the difficulty and added cost of firing 85% solids black liquor due to the properties of black liquor at these high solids concentrations. Nevertheless, the HERB analysis is included here to see what impact maximizing incremental Tomlinson improvements might have in the long term. Net electricity output and electric generating efficiency increase to

87 MW_e and 16.3%, respectively. The mill still requires 100 MW_e of process electricity, so 12 MW_e must be purchased.

Black Liquor Gasification Combined Cycles Integrated in the Reference Mill

Three black liquor gasifier/combined cycle (BLGCC) plant designs were developed incorporating different technologies and design philosophies. One key objective of this study was to assess the commercial viability of gasification technology in the long term. For this reason, the analysis assumes that black liquor gasification systems are at a comparable level of technological maturity as Tomlinson systems. The implicit assumption is that in the years between the present and the post-2010 time period, research, development, and demonstration needs (discussed below) are met for black liquor gasification technology, enabling it to be a reliable replacement for Tomlinson technology.

The analysis here considers full replacement of an existing Tomlinson boiler at the reference mill. An important additional market for black liquor gasification technology that was beyond the scope of consideration here is for incremental black liquor processing capacity. Such applications would arise when an existing Tomlinson boiler does not yet require replacing, but represents a mill's bottleneck to increased pulp/paper production. Such applications will involve considerably smaller black liquor processing requirements than considered in this study.

Figure S5 gives a simplified representation of the basic design of the black liquor gasification/combined cycle (BLGCC) power/recovery systems considered here. The black liquor is first gasified to produce syngas, which is then cooled, cleaned, stripped of H_2S (in a Selexol® unit), and burned in a gas turbine. The gas turbine exhaust passes to a heat recovery steam generator (HRSG). In the process designs considered here, the exhaust passes first through a "duct burner," wherein some syngas or natural gas is burned to generate additional heat for steam raising in the HRSG. The steam drives a condensing steam turbine, from which process steam for the mill is extracted at two pressures.

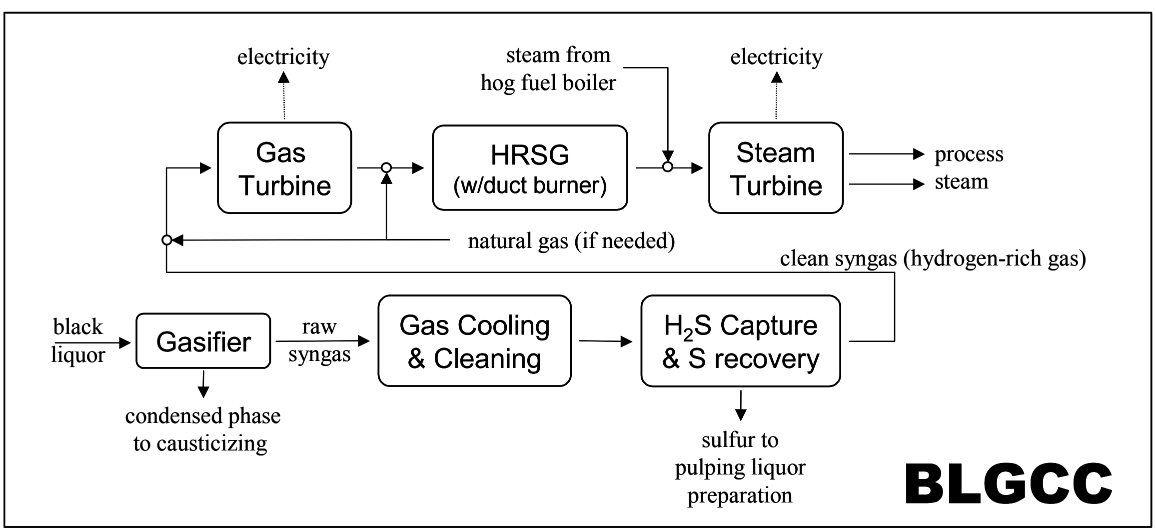


Figure S5. Simplified representation of power/recovery systems simulated in this study.

Since commercial gas turbines are available in only a relatively few specific sizes (unlike steam turbines, which can be built to any desired size), the design of the BLGCC system is tied largely to the specific choice of gas turbine. For two of the BLGCC systems (one using a low-temperature gasifier and the other using a high-temperature gasifier), a "mill-scale" gas turbine was selected to match as closely as possible the syngas available from the black liquor gasifier. For the third case, a "utility-scale" gas turbine was selected having the same technological sophistication as the "mill-scale" turbine, but with a larger output capacity that requires co-firing natural gas and syngas in the turbine. The motivations for examining a "utility-scale" case include: *(i)* the relatively modest incremental capital cost that would be involved in stepping up to a larger gas turbine would enable incremental electricity production at low added cost, *(ii)* the economics of electricity generation overall would be still more favorable if renewable-energy credits were available for the fraction of the power generated from biomass, and *(iii)* the larger electricity output may be of greater interest to an electric utility that might partner with a paper company in the development of BLGCC projects. Key technical features for all three BLGCC systems (Table S2) include:

- Black liquor solids concentration of 80% in all three cases. This is the same solids concentration as in the Tomlinson BASE analysis.
- Higher steam pressure and temperature (representing current state-of-the-art) are used for the steam cycle (than with Tomlinson systems) since clean combustion products pass over the boiler tubes in the heat recovery steam generator. A steam pressure of 1870 psia is assumed in all cases. The larger combined cycle in the utility-scale case justifies a slightly higher steam temperature than in the other two cases.
- Back-pressure steam turbines are used in the bottoming cycle in the mill-scale cases. In the utility-scale case, more steam can be produced than needed for the process, so a condensing steam turbine is used to increase electricity production.
- Due to higher thermodynamic efficiencies, gas turbine-based cogeneration systems are characterized by a ratio of electricity-to-steam production that is inherently higher than steam turbine-based systems. A consequence of this is that for the same process steam demand, a BLGCC requires additional fuel to be consumed (purchased wood residues and/or natural gas) in order to produce sufficient process steam for the mill. (The efficiency with which the incremental fuel is used is typically high.)
    - In the mill-scale BLGCCs, hog fuel is burned in the existing hog fuel boilers to supplement steam raising. Additionally, purchased wood wastes are burned up to the capacity of the existing hog fuel boilers at the mill. Finally, some natural gas is burned in the HRSG duct burner (Figure S5) to provide remaining heat for steam raising.
    - In the utility-scale case, the heat in the gas turbine exhaust flow is sufficient to raise all process steam needed by the mill, but since some hog fuel is nevertheless available on-site, it is used to raise steam to generate additional electricity in the condensing turbine.
- The final row in Table S2 indicates that the BLGCC systems will require fuel consumption at the lime kiln (assumed to be fuel oil in this study) in excess of that required with Tomlinson technology.

Table S2. Summary of BLGCC power/recovery systems case studies.

	Low-Temp Gasifier Mill-scale GT	High-Temp Gasifier Mill-scale GT	High-Temp Gasifier Utility-scale GT
Gas turbine performance based on	General Electric 6FA		GE 7FA
Black liquor solids fraction (% dry)	80	80	80
Co-fire natural gas with syngas in turbine?	No	No	Yes
Steam cycle pressure, psia	1,870	1,870	1,870
Steam cycle temperature, ^{o}F	1,004	1,004	1,049
Steam turbine type	back pressure	back pressure	condensing
Use on-site hog fuel for steam raising?	Yes	Yes	Yes
Purchase wood wastes to raise more steam?	Yes	Yes	No
Natural gas used for supplemental steam?	Yes	Yes	No
Supplemental fuel needed for lime kiln?	Yes	Yes	Yes

Energy and mass balances calculated for the BLGCC systems are shown in Figure S6, Figure S7, and Figure S8. Table S3 summarizes performance results for all systems, including the Tomlinson cases. Key points to note from this table include the following:

- The process steam demands at the mill are met in all cases.
- Total fuel inputs to the power/recovery area are higher for the BLGCC systems than for the Tomlinson systems. This arises from the choice of gas turbine size, together with the characteristically higher electricity production efficiency for a gas turbine combined cycle compared to a steam cycle (when both systems deliver the same amount of process steam). An additional factor is the higher lime-kiln load with the BLGCC systems, giving an increased requirement for lime kiln fuel.
- The added lime kiln load is higher for the low-temperature BLGCC than for the high-temperature BLGCC. The high load in the low-temperature case leads to the requirement for capital investment for an additional lime kiln and causticizer in this case. The added load with the high-temperature case is modest enough that oxygen-enrichment of the combustion air to the existing lime kiln is sufficient to provide the needed increase in capacity.
- The high efficiency of the BLGCC systems contributes to an excess of electricity after meeting mill electricity needs. By contrast, mills utilizing Tomlinson systems, including the advanced HERB design, must purchase some electricity to meet mill demands.
- The efficiency with which purchased fuel is utilized by the BLGCC systems is very high, ranging from 50% to 96% for the cases with mill-scale gas turbine and exceeding 60% for the system employing a utility-scale gas turbine.

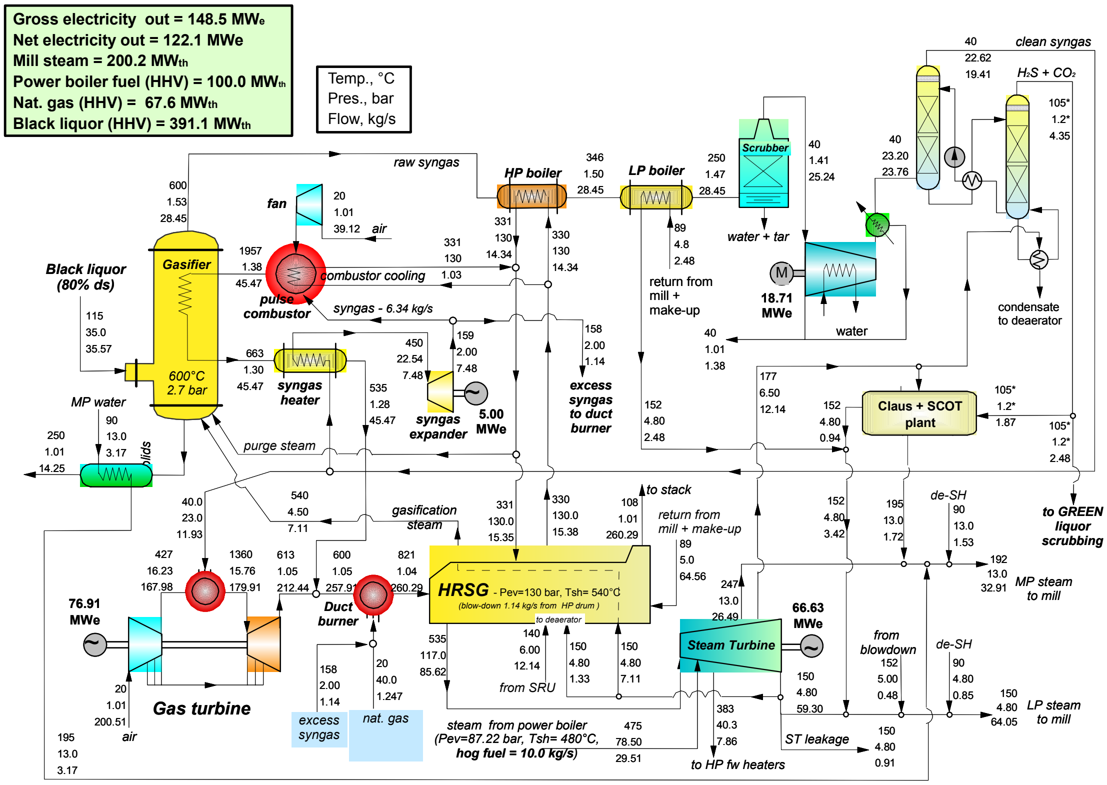


Figure S6. Energy/mass balance for BLGCC with low-temperature gasifier and mill-scale gas turbine.

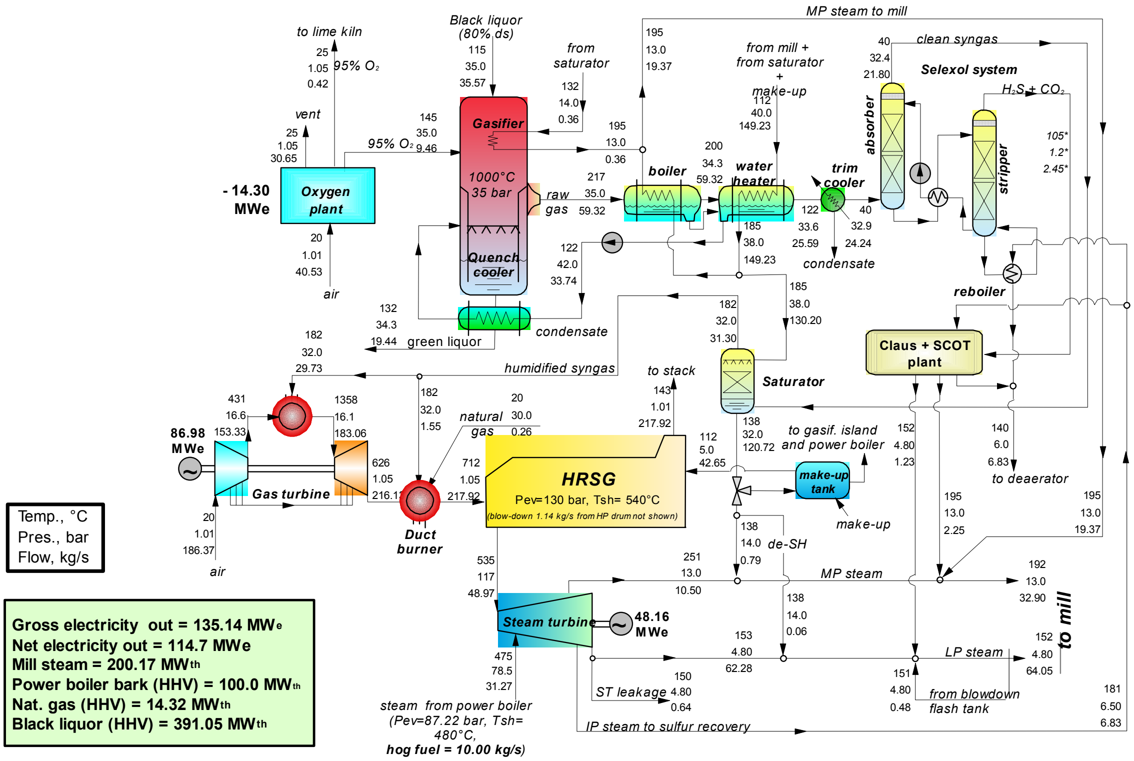


Figure S7. Energy/mass balance for BLGCC with high-temperature gasifier and mill-scale gas turbine.

Table S3. Summary of performance estimates for all power/recovery system simulations.

	Tomlinson		BLGCC		
	BASE	**HERB**	**Low-Temp Gasifier, Mill-scale GT**	**High-Temp Gasifier, Mill-scale GT**	**High-Temp Gasifier, Utility-scale GT**
FUEL INPUTS, MW (HHV)					
Mill by-product fuels	**508.8**	**508.8**	**457.7**	**457.7**	**457.7**
Black liquor to gasifier	437.6	437.6	391.1	391.1	391.1
Hog fuel	71.2	71.2	66.6	66.6	66.6
Purchased fuels	**33.1**	**33.1**	**148.7**	**85.9**	**301.2**
Wood wastes (MW, HHV)	0	0	33.4	33.4	0.0
Natural gas to gas turbine (MW, HHV)	--	--	0.0	0.0	263.0
Natural gas to duct burner (MW, HHV)	--	--	67.6	14.3	--
Lime kiln #6 fuel oil (MW, HHV)	33.1	33.1	47.7	38.2	38.2
TOTAL FUEL INPUTS, MW (HHV)	**541.9**	**541.9**	**606.4**	**543.6**	**758.9**
STEAM TO PROCESS[a]					
LP (55 psig) steam to process	142.8	141.8	135.3	135.3	135.3
MP (175 psig) steam to process	69.3	71.5	64.9	64.9	64.9
Total process steam, MW	**212.1**	**213.3**	**200.2**	**200.2**	**200.2**
ELECTRICITY (MW)					
Gas turbine gross output	--	--	76.9	87.0	175.8
Steam turbine gross output	72.0	96.5	65.1	48.2	71.5
Syngas expander output	--	--	5.0	0.0	0.0
Total gross production	*72.0*	*96.5*	*147.0*	*135.1*	*247.4*
Air separation unit power use	--	--	--	14.3	14.3
Syngas compressor power use	--	--	18.7	--	--
Auxiliaries for steam cycle	6.7	6.8	1.9	1.2	2.6
Auxiliaries for gasification island	--	--	2.7	2.7	2.7
Auxiliaries for sulfur recovery unit	--	--	2.1	1.1	1.1
Auxiliaries for hog fuel boiler	1.0	1.0	1.2	1.2	1.0
Total recovery area use	*7.7*	*7.8*	*26.6*	*20.5*	*21.6*
NET POWER PRODUCTION, MW	**64.3**	**88.6**	**122.1**	**114.7**	**225.8**
Power in excess of Tomlinson BASE	--	24.3	57.8	50.4	161.5
Process use (excluding recovery area)	100.1	100.1	100.1	100.1	100.1
Excess power available for grid	- 35.8	- 11.5	22.0	14.6	125.7
EFFICIENCIES (HHV basis)					
(Steam + Electricity)/(Total fuel input)	0.510	0.557	0.531	0.579	0.561
(Net Electricity Output)/(Total fuel input)	0.119	0.163	0.201	0.211	0.298
Efficiency of purchased fuel use[b] (%)	--	--	0.500	0.955	0.602

(a) Excluding steam used in the power/recovery area.

(b) Net electricity in excess of Tomlinson BASE divided by difference in total purchased fuel between BLGCC and BASE.

Environmental Considerations

Per unit of black liquor processed through the power/recovery area, BLGCC provides considerable improvements in air emissions, some improvements in water pollution (mainly an issue of cooling water discharge temperature and evaporative loss), and a similar solid waste emissions profile as Tomlinson technology (Table S4). When considered on a per-unit-of-electricity-generated basis, BLGCC systems will show improved environmental characteristics across the board. Moreover, if the difference in power generated between a BLGCC system and the Tomlinson BASE system is assumed to displace power generation on the grid, there will be reductions in environmental impacts associated with the displaced grid emissions in most regions of the United States.

Since the most significant effluent differences between BLGCC and Tomlinson systems are in expected air emissions, detailed quantitative estimates were made in this study based on actual data for Tomlinson furnaces and on extrapolation of gas turbine emissions and other relevant data for BLGCC systems. Estimates are made for emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM), and total reduced sulfur (TRS). Hazardous air pollutants (HAPs) and other emissions issues are discussed qualitatively.

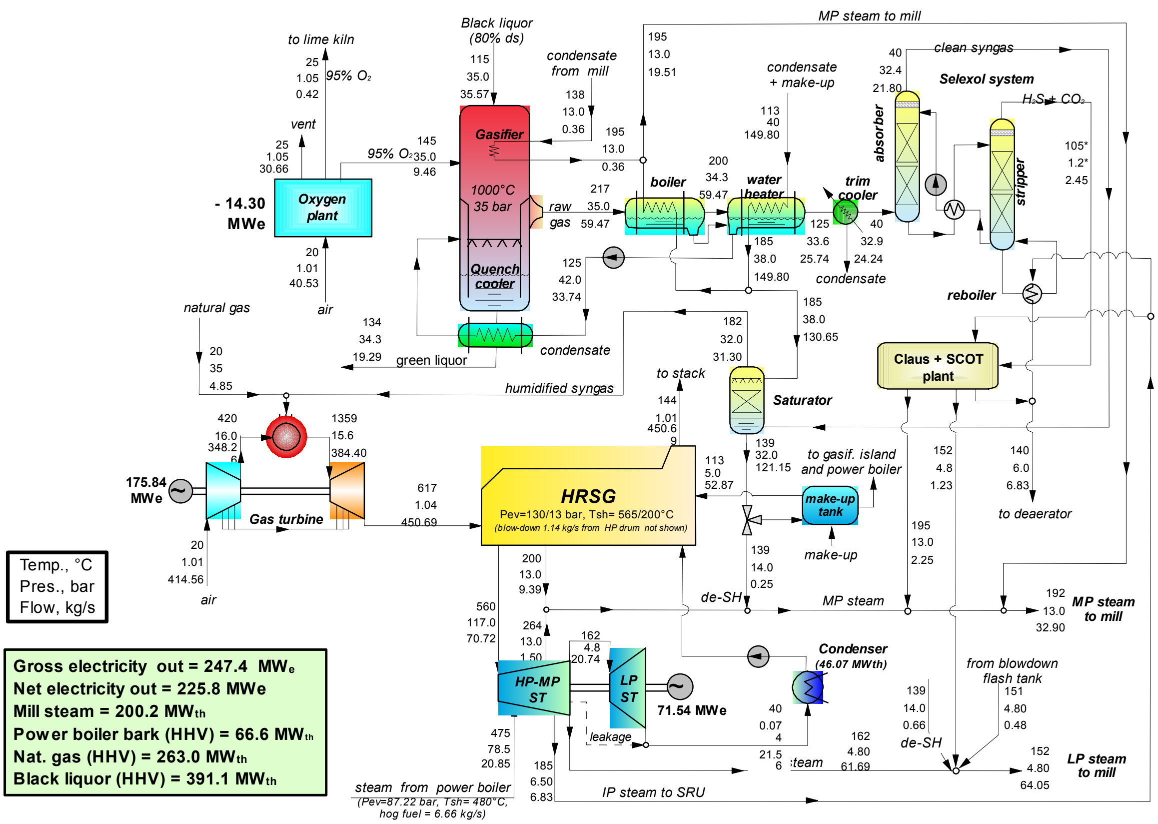


Figure S8. Energy/mass balance for BLGCC with high-temperature gasifier and utility-scale gas turbine.

Quantitative estimates are also made for carbon dioxide (CO_2), the major greenhouse gas. If the CO_2 emitted in using biomass for energy is photosynthetically removed from the atmosphere by replacement biomass growth, then there are no net emissions of CO_2 to the atmosphere. The estimates of total emissions of CO_2 in this study assume wood-derived fuels produce no net CO_2 emissions. However, actual emissions of CO_2 associated with the wood-derived fuels (in addition to the net emissions) are also reported. Biomass combustion also generates small amounts of non-CO_2 greenhouse gases - specifically, methane and nitrous oxide. However, even after considering the potency of methane and nitrous oxide as greenhouse gases, these emissions are small. As a result, they have not been included in the analysis.

A distinctive feature of BLGCC technology is the expected low relative emissions for most of these pollutants compared to a modern Tomlinson system employing sophisticated pollution controls (Table S4). Low emissions are an intrinsic characteristic of BLGCC technology: considerable upstream removal of contaminants in the raw syngas is required to protect the gas turbine from damage, as well as to recover pulping chemicals from the gas. Also, gas turbine combustion is inherently efficient and complete due to high overall air-fuel ratios.

Table S4. Qualitative indication of relative environmental impact of different emissions, together with relative emission rates for controlled and uncontrolled Tomlinson furnaces and with BLGCC technology (VL = very low, L = low, M = moderate, H = high).

Pollutant/ Discharge	Relative Environmental Impact of Pollutant[a]	Relative Emissions Rates from Tomlinson Furnaces (uncontrolled)	Relative Emissions Rates with Controls on Tomlinson	Relative Emissions Rates with BLGCC Technology
SO_2	H	L	L (not required)	VL
NOx	H	M	M[d]	VL
CO	L	M (can be highly variable)	M[d]	VL
VOCs	H	L	L[d]	VL
PM[b]	H	H[c]	L-M	VL
CH_4	L-M	L	L[d]	VL
HAPs	M-H	L[c]	L[c]	VL
TRS[e]	L	L	L[d]	VL
Waste Water[f]	M-H	L	L	VL-L
Solids	L	L	L	L

a) General importance, not specifically for the P&P industry.
b) PM = particulate matter. Of greatest concern with PM emissions are fine particulates smaller than 10 and 2.5 microns in diameter (PM_{10} and $PM_{2.5}$ respectively).
c) Current MACTII rules are expected to result in about a 10% reduction of HAPs and a modest reduction in PM.
d) Not generally practiced other than by maintaining good combustion efficiency.
e) Total reduced sulfur.
f) For power systems, the issue is mainly one of the cooling water (quantity and discharge temperature).
Note: Emissions per lb BLS may increase with BLGCC because total fuel use increases, especially in the utility-scale case.

Economic Analysis

To assess the prospective economics of BLGCC technology at the mill level, a cash flow analysis was carried out assuming that an investment would be made in a new power/recovery system to replace an existing Tomlinson system (characterized by the Tomlinson BASE system described earlier) that had reached the end of its working life. The internal rate of return (IRR) and net present value (NPV) of the incremental investment required for a BLGCC over a new Tomlinson system were calculated. Calculations were done both without and with consideration of the potential economic value of environmental benefits of the advanced recovery systems.

Key inputs to the financial analysis include the mass/energy balances and engineering cost estimates for each power/recovery system. Two engineering firms were engaged to estimate capital, maintenance, operating labor, and consumables costs based on the process flow diagrams shown earlier. Fluor, Inc. was selected to estimate costs for the BLGCC system based on low-temperature gasification largely because of their involvement in the design and construction of the commercial demonstration of the MTCI gasifier at Georgia Pacific's Big Island mill. Nexant, Inc., an affiliate of the Bechtel Corporation, was selected to estimate costs for the Tomlinson cases and the BLGCC cases based on high-temperature gasification. Capital costs by major plant area are estimated to be ±30% accuracy. In order to make the cost estimates among technologies and between firms as consistent as possible, the two engineering firms discussed and agreed on the percentage values to be used for construction indirects, engineering, contingencies, spare parts, and owner's costs.

Table S5. Installed capital costs (million 2002$) and non-fuel operating and maintenance costs (million 2002$ per year) estimated for Tomlinson and BLGCC power/recovery systems.

	Tomlinson		BLGCC System		
	BASE	HERB	Low-Temp Mill-Scale	High-Temp Mill-Scale	High-Temp Utility-Scale
Recovery boiler	87.479	90.748	0	0	0
Steam system modifications	7.792	32.798	0	0	0
Air separation unit	0	0	0	31.202	31.202
Gasifier island & green liquor filter	0	0	40.815	46.640	46.640
Process gas handling	0	0	27.514	0	0
Gas cleanup and sulfur recovery	0	0	39.920	13.138	13.138
Combined cycle power island	0	0	62.861	61.441	99.803
Hog fuel boiler	0	0	0	0	0
Auxiliaries	0	0	5.194	0	0
Subtotal, Direct Costs (materials & labor)	**95.271**	**123.546**	**176.303**	**152.421**	**190.783**
Premium labor	0	0	1.043	0	0
Construction indirects	5.443	9.932	21.006	7.160	8.486
Sales tax, customs, duties	0	0	0	0.527	0.529
Engineering	8.309	9.640	23.043	7.124	10.962
Contingency	3.931	7.862	14.228	9.927	11.855
Escalation	1.274	1.295	0	0	0
Spare parts	1.797	1.989	5.107	4.872	4.631
Licensing fee	0	0	0.318	0	0
Owner's costs	5.704	6.525	11.460	9.888	12.389
Subtotal, Non-Direct Costs	**26.458**	**37.244**	**76.207**	**39.497**	**48.850**
TIC BEFORE ADJUSTMENTS	**121.729**	**160.790**	**252.510**	**191.918**	**239.633**
Causticizing area adjustment, TIC	--	--	- 18.365	+ 1.000	+1.000
Polysulfide tank adjustment, TIC	--	--	Incl. Above	+ 1.050	+ 1.050
TOTAL INSTALLED CAPITAL COST	**121.729**	**160.790**	**234.145**	**194.418**	**242.133**
Annual non-fuel O&M cost	**6.940**	**10.611**	**10.611**	**10.611**	**11.151**

Table S5 summarizes the capital and operating cost estimates based on the work of the engineering companies. The capital estimates assume "Nth plant" levels of technology maturity and operational reliability, including 98% overall plant availability during 8500 hours per year of operation. Each of the BLGCC cost estimates include two gasifier vessels, each with 50% of the needed total capacity. This represents a level of gasifier reliability that has not often been reached in existing gasification projects with other feedstocks (coal, pet coke, etc.). However, given that at most large pulp mills today the Tomlinson recovery boiler is typically a single unit handling 100% of the black liquor recovery duty, it was judged feasible that a black liquor gasifier could reliably operate with no spare capacity in an "N^{th} plant" implementation. For the BLGCC cases, the cost estimates include the impact of increased lime kiln capacity and a polysulfide dissolving tank. In all cases (Tomlinson and BLGCC), the hog fuel boilers pre-existing at the mill are assumed to continue to be used once the new power/recovery system has been installed.

The economic analysis focused on the power/recovery area, but the operating-cost analysis also considered in the BLGCC cases the reduced wood costs due to higher digester yield with polysulfide pulping, the increased use of #6 fuel oil in the lime kiln, and (in the two BLGCC cases with the mill-scale gas turbine) the cost of purchased wood residues. Table S6 summarizes the annual material and energy flows used in the analyses.

Additional key input assumptions included expected future prices for natural gas, fuel oil, purchased wood fuel, electricity purchased by the mill and electricity sold to the grid, and financial parameter assumptions (Table S7).

The calculated IRR and NPV results are presented for all cases in Table S8, which shows three sets of values: "stand-alone" values are calculated assuming all avoided electricity purchases as positive cash flows and all O&M costs as negative cash flows; "relative to Tomlinson BASE" values are calculated based on incremental cash flows relative to those for an investment in a new Tomlinson BASE system, and; "Relative to Tomlinson HERB" values are calculated based on incremental cash flows relative to an investment in a new Tomlinson HERB system.

The incremental IRRs for the mill-scale high-temperature BLGCC cases relative to investments in either a new Tomlinson BASE or new HERB system are reasonably attractive (18.5% to 21.1%) for the baseline assumptions. The IRRs for the utility-scale BLGCC are higher still. The lower financial performance of the low-temperature BLGCC is due largely to the high incremental lime kiln requirement. If the lime kiln requirement were eliminated (for example as at a pulp mill using a non-sulfur pulping process), the incremental IRR for this case relative to the Tomlinson BASE system would increase from 9% to an estimated 13%. This suggests that this technology may be preferable for use with non-sulfur black liquors, e.g., those found at pulp mills using the soda process. For kraft black liquor applications, the use of the low-temperature BLGCC presents the possibility of completely eliminating the lime kiln, e.g., using direct causticization. Without accounting for added costs with direct causticizing, but eliminating all costs associated with the lime kiln, the IRR would nearly double to 17%. This result highlights the importance of proving the commercial feasibility of ways to reduce or eliminate the lime kiln at kraft pulp mills.

Because the low-temperature system considered here operates at close to atmospheric-pressure and is inherently modular in design, it may also be an especially suitable technology for applications where relatively small amounts of incremental black liquor recovery capacity are required to augment existing Tomlinson recovery boiler capacity. Analysis of this application was beyond the scope of the present study.

An important aspect of BLGCC economics will be the ability to convert environmental and renewable energy benefits of the technology into monetary value, e.g., by selling excess NO_x

allowances or garnering a premium for renewable electricity sold to meet a renewable portfolio standard. In the longer term, carbon trading or some other scheme to reduce emissions of greenhouse gases may also come into play. Other factors affecting the economics of BLGCC include existing and potential Federal and state incentives (tax exemptions and production tax credits) designed to promote the development of renewable energy resources.

Table S6. Annual material and energy flows for the alternative power/recovery systems.

Parameter	Units per year	Tomlinson		BLGCC		
		BASE	HERB	Low-Temp Gasifier, Mill-Scale GT	High-Temp Gasifier, Mill-Scale GT	High-Temp Gasifier, Utility-Scale GT
Annual Material Flows						
Mill Operating Hours	Hours	8,330				
Total Pulp Production	Bone dry short tons	548,277				
Total Wood to Mill	Bone dry short tons	1,309,943	1,309,943	1,223,482	1,223,482	1,223,482
Hog Fuel Production	Bone dry short tons	117,895	117,895	110,113	110,113	110,113
Hog Fuel Purchases	Bone dry short tons	---	---	55,158	55,158	---
Avoided Pulpwood Purchases	Bone dry short tons	---	---	86,461	86,461	86,461
Black Liquor Production	Short tons BLS	1,041,250	1,041,250	940,534	940,534	940,534
Annual Energy Flows						
Mill Electricity Use	MWh	833,800				
Net Electricity Production	MWh	535,203	738,188	1,017,260	955,309	1,880,622
Net Electricity Purchased	MWh	298,597	95,612	---	---	---
Net Electricity Exported	MWh	---	---	183,460	121,510	1,046,823
Incremental Total Electricity Production						
Production relative to Base Tomlinson	MWh	---	202,985	482,057	420,107	1,345,420
Production relative to HERB Tomlinson	MWh	---	---	279,072	217,121	1,142,435
Incremental Renewable Electricity Production						
Production relative to Base Tomlinson	MWh		202,985	326,368	386,401	549,521
Production relative to HERB Tomlinson	MWh	---	---	123,101	183,415	346,536
Natural Gas Purchased	MMBtu per year	---	---	1,922,376	406,974	7,473,725
Total Lime Kiln Fuel	MMBtu per year	939,437	939,437	1,353,729	1,086,928	1,086,928
Incremental Lime Kiln Fuel	MMBtu per year	---	---	414,292	147,492	147,492
Hog Fuel + Wood Residuals Consumption	MMBtu per year	2,027,792	2,027,792	2,842,675	2,842,675	1,893,950
Purchased Wood Residuals	MMBtu per year	---	---	948,725	948,725	---

Table S7. Summary of key input assumptions for the financial analysis.

Financial Parameters[a]	
Inflation Rate	2.1%
Debt Fraction	50%
Equity Fraction	50%
Interest Rate on Debt	8%
Return on Equity	15%
Resulting Discount Rate used for NPV calculations	9.9% (after tax)
Income Tax Rate (combined Federal & State)	40%
Property Tax & Insurance	2%
Economic Life (years)	25
Depreciation Method	20-year MACRS rate schedule
Construction time for Tomlinson systems	24 months
Construction time for BLGCC systems	30 months
Baseline Levelized Fuel and Feedstock Prices (2002$)	
Utility Natural Gas ($/MCF) [$/MMBtu]	$3.86 [$3.76]
Industrial #6 Oil ($/gallon) [$/MMBtu]	$0.59 [$3.96]
Industrial Retail Electricity ($/MWh)	$43.16
Exported Electricity ($/MWh)	$40.44
Hog Fuel/Bark ($/MMBtu)	$1.50
Pulpwood ($/dry ton)	$51.26
P&P Industry/Mill Assumptions	
O&M cost inflator (% per year, current $)	2.7%
Annual Operating Hours	8,330
Average Annual Industry Growth Rate	1.2%
Start-up Assumptions (% of full output)	
Year 1 of Operation	80%
Year 2 of Operation	100%

(a) The resulting annual capital charge rate is 17.9%.

The impact on IRR and NPV of environmental improvements arising from the application of advanced power/recovery systems was examined by applying a range of monetary values to environmental impacts based on existing types of incentives and programs, assuming similar incentives might apply to advanced black liquor power/recovery systems. When such environmental values are explicitly included in the analysis, financial performance improves considerably. Table S9 shows results when a renewable electricity premium and a renewable production tax credit are applied at levels available in some states today for wind power. The financial performance for the high-temperature BLGCC cases are overwhelmingly attractive for both mill-scale and utility-scale systems.

It may be noted that this study considered only electricity as the energy export from gasification-based power/recovery systems. In this regard, the characteristics of black liquor gasification as a ‘breakthrough” technology have not been fully investigated. In particular, conversion of black liquor to high-value chemicals and/or transportation fuels, e.g., F-T middle distillates or hydrogen, may give considerably different economic results. Systems studies of the type presented here, but for different product slates, should be a focus of future analysis to better understand the possibilities. Moreover, such studies should also examine the potential for gasifying hog fuel and wood wastes alongside black liquor in the power/recovery area. This configuration would result in additional high value products and could reduce or eliminate the need for fossil fuels to be used in the lime kiln and power cycles.

Table S8. Baseline financial results. Values shown are for stand-alone analysis[a] and incremental analysis (relative to Tomlinson BASE[b] or Tomlinson HERB[c]).

	TOTAL NET CASH FLOW					
	Stand-alone[a]		Relative to Tomlinson BASE[b]		Relative to Tomlinson HERB[c]	
	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)
Tomlinson – BASE	14.2%	28.0	N/A	N/A	N/A	N/A
Tomlinson – HERB	14.2%	37.0	14.2%	9.0	N/A	N/A
BLGCC – Low T Gasifier - Mill Scale	11.6%	21.9	8.9%	-6.0	6.1%	-15.0
BLGCC – High T Gasifier - Mill Scale	16.1%	72.8	18.5%	44.9	21.1%	35.8
BLGCC – High T Gasifier - Utility Scale	17.5%	111.1	20.1%	83.1	22.0%	74.1

(a) This is the total net cash flow of the option on a stand-alone basis, treating all avoided electricity purchases as positive cash flows and all O&M costs as negative cash flows.

(b) This is the difference between the total net cash flow of that option and the total net cash flow of the Tomlinson BASE option, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

(c) This is the difference between the total net cash flow of that option and the total net cash flow of the HERB option, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

Table S9. Financial results assuming a renewable electricity premium of 2.5¢/kWh, together with a renewable electricity production tax credit equivalent to 1.8¢/kWh for ten years, applied to all incremental renewable generation above Tomlinson BASE.[a]

	TOTAL NET CASH FLOW					
	Stand-alone[b]		Relative to Tomlinson BASE[c]		Relative to Tomlinson HERB[d]	
	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)
Tomlinson – BASE	14.2%	28.0	N/A	N/A	N/A	N/A
Tomlinson – HERB	20.1%	86.2	37.8%	58.2	N/A	N/A
BLGCC – Low T Gasifier - Mill Scale	17.7%	100.9	20.9%	73.0	13.4%	14.8
BLGCC – High T Gasifier - Mill Scale	24.2%	166.4	34.8%	138.5	33.2%	80.3
BLGCC – High T Gasifier - Utility Scale	26.6%	244.2	35.1%	216.2	34.4%	158.0

(a) Assumes the credits are available whether the renewable energy is sold or used onsite, consistent with the use of renewable energy certificates, whereby the attributes of the electricity can be unbundled and sold separately (e.g., to meet a renewable portfolio standard). Assumes the production tax credit (PTC) is available for the first ten years of operation and is indexed to inflation, similar to current Federal PTC for wind power and closed loop biomass.

(b) This is the total net cash flow of the option on a stand-alone basis, treating all avoided electricity purchases as positive cash flows and all O&M costs as negative cash flows.

(c) This is the difference between the total net cash flow of that option to the total net cash flow of the Tomlinson BASE, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

(d) This is the difference between the total net cash flow of that option to the total net cash flow of the Tomlinson HERB, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

Regional and National Impacts of BLGCC Implementation

In addition to the mill-level cost-benefit assessment, an analysis of potential impacts in the Southeast region of the United States and for the entire United States were also carried out. Given the importance of the forest products industries in the Southeast, this region was a focus for this study. Moreover, some benefits, such as electricity supply and demand, are less relevant in a national context compared to a regional context. Conversely, other benefits, such as fossil fuel savings, are largely of strategic national concern, and hence more appropriate for analysis at the national level. Potential BLGCC impacts, divided into seven categories, are discussed below:

- National Fossil Energy Savings
- Southeast Regional Energy Supply & Demand
- Renewable Energy Markets
- Emissions Reductions
- Fuel Diversity, Energy Security and the Hydrogen Economy
- Economic Development
- Reaping the Benefits of Government RD&D

Some benefits can be quantified, whereas others are by nature more qualitative. Where possible, this study has made quantitative estimates of these benefits using alternative market penetration scenarios developed for this study from the technical market potential. The latter was developed using a detailed industry database of existing recovery boilers and took the form of a year-by-year estimate of the annual and cumulative boiler capacity eligible for replacement by BLGCC.

To cover a range of possible market deployment scenarios, three market penetration scenarios were developed. The "High" market penetration scenario assumed a 25-year saturation time (i.e., time to reach 90% of technical market potential) and relatively shorter replacement/rebuild cycles for Tomlinson boilers. The "Low" scenario assumed a 30-year saturation time and longer replacement/rebuild cycles. The "Aggressive" scenario assumed the same replacement/rebuild cycle as the High scenario, but a 10-year saturation time. While this saturation time is more typical of rapid-payback, discretionary-spending investments, it was used here to illustrate what might be possible given some of the unique drivers facing the pulp & paper industry.

National Fossil Energy Savings

The benefits of fossil fuel displacement include the associated emissions reductions, the conservation of finite resources, the positive effects on fossil fuel price volatility, and in the case of petroleum, the reduction of imports, which enhances energy supply security. Generally, an economy that is less dependent on fossil fuels is less susceptible to the negative impacts of fuel price volatility, which has increased in recent years.

Figure S9 shows that BLGCC (in the configuration with utility-scale gas turbine) relative to Tomlinson BASE technology has the potential to offset more than 360 trillion Btu/year within 25 years of introduction (*Aggressive* scenario). The utility-scale case produces the largest impacts due to the large amount of grid power displaced, despite using by far the largest quantity of natural gas at the mill. The two mill-scale cases produce less net fossil fuel savings despite using less natural gas onsite. They differ from one another in the amount of natural gas used and the lime kiln load, both of which are higher in the low-temperature case. This illustrates the potential importance of the development of direct causticizing, which would eliminate the lime kiln altogether.

Cumulative net fossil fuel savings over a 25-year period with BLGCC relative to continued use of Tomlinson BASE technology range from 0.75 to 2.5 quads (*Low* scenario) up to 2.3 to 5.5 quads (*Aggressive* scenario). This assumes constant energy efficiency in pulp and paper manufacturing, which may be conservative. Reductions in manufacturing energy intensities would lead to higher energy savings than estimated here.

Regional Energy Supply & Demand

The Southeast is one of the fastest growing regions in the United States in terms of population and electricity demand. Based on current projections and extrapolations of demand and supply growth, total electricity demand in the Southeast region could double by 2030. In that same timeframe, there will be the need for a certain amount of replacement capacity, making it clear that the Southeast will require significant new electric generating capacity in the coming decades.

Based on the market penetration scenarios described above, BLGCC technology has the potential to contribute in a meaningful way to the overall supply of electricity in the Southeast region. Specifically, BLGCC in the configurations with the mill-scale gas turbine could provide from 2,500-3,000 MW within 25 years of introduction in the *Low* scenario to nearly 3,500 MW in the *High* scenario, to more than 4,000 MW in the *Aggressive* scenario. In the configuration with a utility-scale gas turbine, because of the much larger unit size, total capacity contributions would exceed 11,000 MW within 25 years of introduction (*Aggressive* scenario). While far short of the total expected requirements for new capacity, these amounts are not insignificant, making BLGCC a potentially important resource in a diversified Southeast capacity mix (and even more important in regions within the Southeast with higher concentrations of mills).

A key additional impact to address when exporting large amounts of power into the grid is the ease and cost with which the interconnection can be made. Studying any particular site in detail was beyond the scope of this report, but a high level review of the issues along with some preliminary specific site analyses were conducted with cooperation from Southern Company.

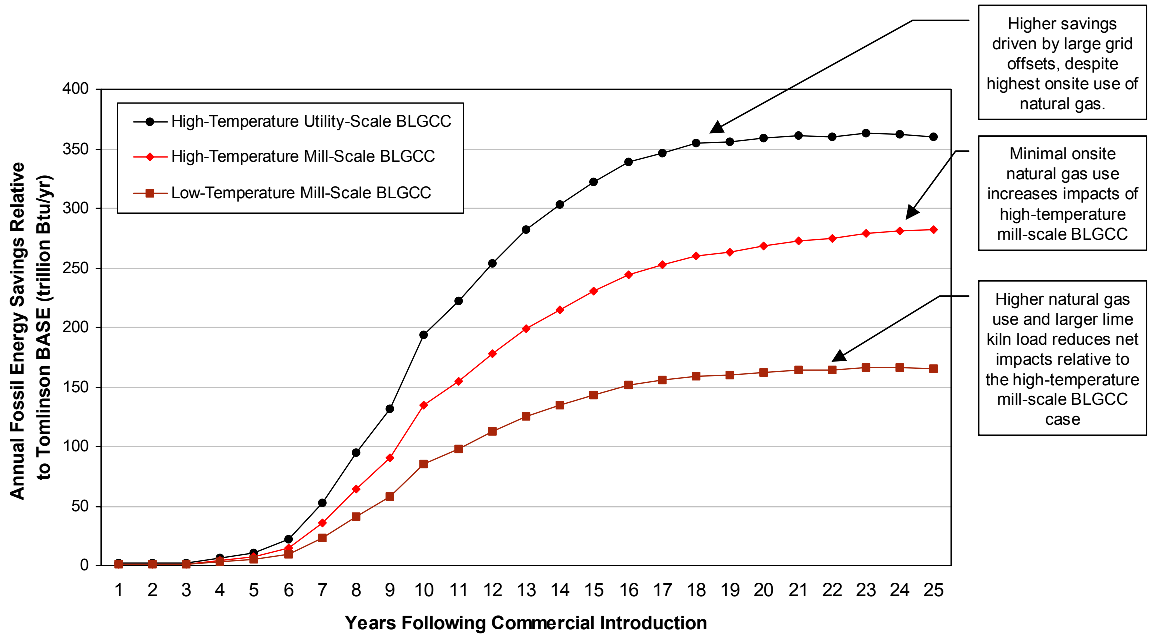


Figure S9. Net fossil fuel savings with BLGCC relative to Tomlinson BASE, Total U.S. Market, *Aggressive* market penetration scenario.

Three factors are expected to make the interconnection of BLGCC projects relatively simple in comparison to other new generation projects:

- Many pulp and paper mills currently have existing "behind the fence" generators and a substation that supplies electricity to the mill. Upgrading the existing substation is generally a simpler process than tapping into an existing circuit, acquiring necessary rights of way, and other issues normally associated with interconnection of a new (greenfield or brownfield) generator.
- The current grid interconnections and mill substations are sized to meet the full load of the mill and often have excess capacity (e.g., if the existing onsite generation were offline, the mill could continue to operate by purchasing all of its electricity). For all the BLGCC cases, the net power flows should be within the limits of the existing equipment
- Many mills in the Southeast are relatively close to the "backbone" of the transmission system, so that if line upgrades are necessary, the distances involved are not large, which would help control costs.

Given these considerations, the expected interconnection costs for many BLGCC power plants are between $0.5 and $4 million per facility, based on estimates made for several pulp mills in the Southern Company service territory. These costs are relatively minor, especially compared to a $150-250 million investment in the BLGCC system.

It is worth noting that the installation of BLGCC systems will increase the reserve margin and likely aid in overall system reliability. Adding generation at strategic locations on the transmission grid may actually defer capital investments to upgrade the transmission and distribution system, if those upgrades are being primarily driven by load growth. Thus, even modest deferrals in other transmission investments as a result of adding BLGCC at key locations, could more than cover BLGCC interconnection costs.

Renewable Electricity Markets

Distinct markets for renewable energy and its associated attributes are developing in the United States and elsewhere. Aside from applications where renewables are cost competitive with conventional power, these markets are being driven by Renewable Portfolio Standards (RPS), voluntary green power programs offered through utilities and retail power marketers, and emissions trading markets. These various programs effectively create markets for the attributes of renewable energy that are separate from energy markets, adding a second revenue stream for renewable generators. These markets may be regional, national or even international (e.g., with carbon trading).

BLGCC could be of major importance in meeting future renewable energy requirements in the Southeast. RPS is emerging in the United States as the dominant driver for renewable electricity capacity growth – twelve states already have renewable portfolio standards and three others have renewable electricity "best effort" goals/targets (essentially a voluntary RPS). To illustrate the value of BLGCC in this context, consider a hypothetical RPS for the Southeast region, in which 5% of all electricity sales in 2020 must come from new renewable resources. The effects of this RPS and the potential contribution of the pulp & paper industry are shown in Table S10, assuming all black liquor generated in the industry comes from renewable biomass and all of it is used exclusively in Tomlinson boilers or exclusively in BLGCC systems (i.e., independent of market penetration assumptions). If the pulp & paper industry continued to use Tomlinson BASE technology, organic growth of the industry would only produce up to 4.4 billion kWh/yr of new renewable generation by 2020, or about 5% of the RPS requirement. In comparison, HERB technology would produce about four times this amount or 20% of the RPS requirement. BLGCC technology, with its much higher electricity efficiency, would generate in excess of 36 billion kWh/yr of incremental renewable generation (based on the average of the three cases), or nearly 45% of the 5% RPS requirement.

The total incremental investment (above the replacement cost of the Tomlinson systems) required to achieve this amount of generation from BLGCC would be approximately \$6.3 billion. If this amount of renewable energy were to be produced from new wind power, about 12,000 MW of wind turbines would need to be installed at a capital investment of \$8.3-9.4 billion.

Table S10. Incremental Renewable Energy Generation Potential (billion kWh/yr) from black liquor in the pulp and paper industry in the Southeastern United States.[a]

	Electricity Generated from all Renewable Sources in 2002	Projected Renewable Generation in 2020, with 5% RPS	Added RPS Electricity in 2020 versus 2002	Incremental BL Potential by 2020	
				Billion kWh/yr	% of RPS
Tomlinson BASE[b]	65.2 billion kWh/yr	147.9 billion kWh/yr	82.7 billion kWh/yr	4.4	5.3%
Tomlinson HERB[c]				16.7	20.2%
BLGCC[c]				36.2	43.8%

(a) Incremental potential assumes industry capacity is same in 2008 as today and grows 1.2% per year after that. All figures are relative to the potential generation in 2008 from black liquor using BASE Tomlinson technology. Baseline data and future requirements developed from the DOE/EIA *Annual Energy Outlook 2002.*

(b) Represents organic growth of the entire industry in the SE at 1.2%/year, assuming continued use of BASE technology.

(c) Incremental capacity relative to current generation assuming all mills that have been repowered (with HERB or BLGCC), including the effects of industry growth at 1.2% per year. *BLGCC* case is based on the average for the three BLGCC technology cases.

If a national RPS were to be put in place such that renewable energy certificates (RECs) could be traded across the United States, BLGCC and other biomass gasification technologies could clearly play an important role in meeting the overall targets and would also ensure that many of the benefits of renewable energy (e.g., reduced emissions) would be more evenly distributed around the country. Using the same approach as that outlined above, BLGCC has the potential to provide up to 53 billion kWh/yr of incremental renewable generation in 2020 compared to current production with Tomlinson technology. If the industry continued to use Tomlinson BASE technology, the amount of incremental renewable electricity generation due to organic growth of the industry, would only be 6.5 billion kWh/yr. The equivalent wind power capacity required to produce 53 billion kWh with moderate (Class 4) wind resources would be about 17,000 MW, requiring a capital investment of approximately $12-14 billion. In comparison, the incremental investment in BLGCC relative to replacement with Tomlinson BASE technology would be approximately $9.2 billion.

In order for biomass to play this role, however, it must be considered an eligible resource. A review of existing state RPS rules shows that unlike wind power, biomass is not always considered to be RPS-eligible today, or if it is, there are often additional restrictions on the types of biomass resources or conversion technologies that can be used to meet an RPS. However, as an advanced technology, gasification-based systems are more likely to eligible than those relying on conventional combustion.

Emissions Reductions

Relative to Tomlinson BASE technology, BLGCC has the potential to offset more than 25 million tons of CO_2 per year in the Southeast United States (Figure S10). It also has the potential to significantly reduce SO_2 and NO_x emissions, even as the grid emissions rates (lb/MWh) of these pollutants continue to fall as a result of fuel mix changes and compliance with the 1990 Clean Air Act Amendments. Other emissions would also be reduced, but to a lesser extent, mainly because the total tonnages of these emissions are smaller to begin with. With the rapid market penetration assumed in the *Aggressive* scenario, the cumulative CO_2 offsets would amount to roughly 7.5% of the expected increase in total CO_2 emissions from the grid in the Southeast in the 2008-2035 timeframe (absent the introduction of BLGCC technology).

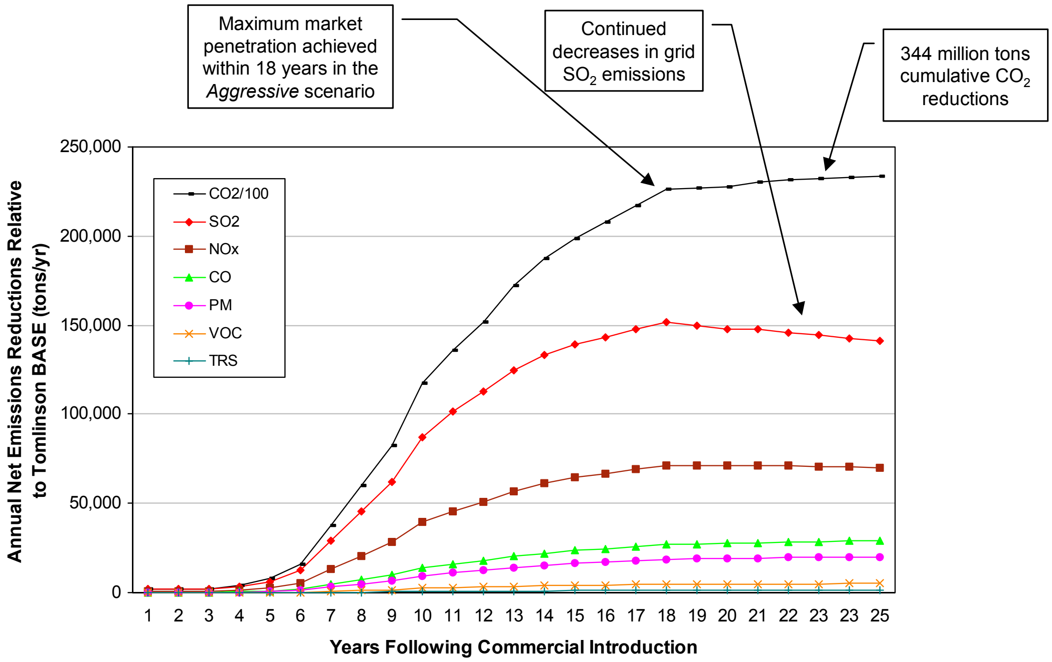


Figure S10. Net emissions reduction from Utility-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Aggressive* market penetration scenario.

Figure S11 illustrates the corresponding emissions impacts of BLGCC in the whole of the United States. BLGCC technology, relative to Tomlinson BASE technology, has the potential to offset more than 35 million tons of CO_2 per year in the United States by 2020. It could also significantly reduce SO_2 and NO_x emissions. Other emissions would also be reduced, but to a lesser extent, mainly because their total emissions are smaller to begin with. With the rapid market penetration assumed in the *Aggressive* scenario, the cumulative CO_2 offsets would amount to roughly 4% of the expected increase in total CO_2 emissions from the grid in the United States in the 2008-2035 time frame (absent the introduction of BLGCC systems).

It is noteworthy that SO_2 and NO_x have economic value today, because of existing emissions trading regimes. At \$160/ton (the current price for SO_2 allowances), and assuming prices remain at this level in real terms, the SO_2 reductions have a market value of nearly \$400 million for the 25-year forecast period. NO_x, if conservatively valued at \$2,000/ton over the same period, would have a market value of \$2.2 billion. If a system for trading CO_2 is put in place, the CO_2 value could be \$2.1 billion at a price of \$25/metric ton of carbon (a mid-range value of various estimates). The corresponding values at the national level are SO_2: \$450 million; NO_x: \$3.2 billion; and CO_2: \$3.1 billion.

These illustrative results suggest that BLGCC technology has the potential to provide significant environmental benefits. As in the case with energy savings, this emissions analysis assumed constant energy efficiency in pulp and paper manufacturing. Continued improvements in manufacturing energy efficiency would lead to greater emissions reductions than estimated here.

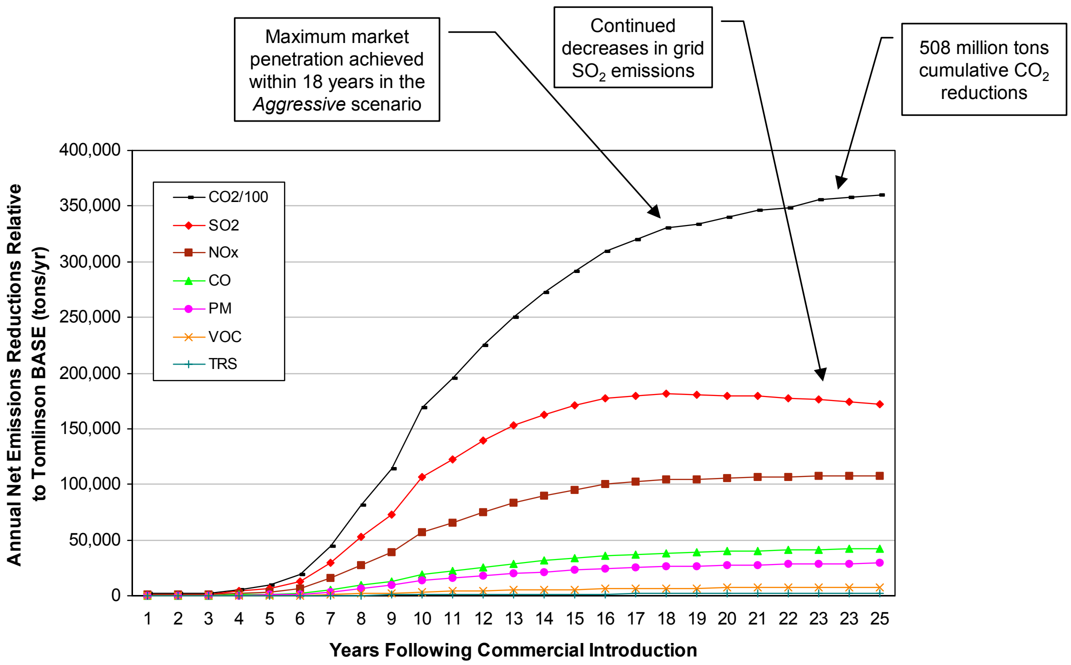


Figure S11. Net emissions reduction from Utility-Scale BLGCC relative to Tomlinson BASE, Total United States, *Aggressive* market penetration scenario.

Fuel Diversity and Energy Security

The nation's power sector remains heavily dependent on fossil fuels and is becoming increasingly dependent on gas-fired combined cycle technology for new power generation capacity, and the Southeast is no exception. This increasing reliance on natural gas has some important energy cost, fuel diversity and energy security implications:

- Natural-gas fired power plants will increasingly set the marginal price for power
- Natural gas prices have proven to be volatile and are expected to remain so, driven in part by increasing summer demand for power generation. Throughout the course of this project, natural gas spot prices remained well above historical averages, reaching the $6/MMBtu range going into the summer cooling season, or roughly 2-2.5 times higher than the historical average for that time of year. Although prices had decreased somewhat by the fall of 2003, the general tightness in supply is expected to continue for some time as natural gas demand is expected to grow, driven in large part by its environmental attributes. With limited ability to import gas into North America, the United States will continue to be susceptible to the gas price volatility it has experienced in the last 2-3 years.
- In the post-9/11 world, natural gas supply infrastructure is seen as vulnerable to disruption by terrorist attack. Thus, the electric industry is vulnerable both directly (via attacks on electric infrastructure) and indirectly (via attacks on natural gas infrastructure).

BLGCC has the potential to help address all of these concerns. First, it provides a way to diversify the electric power fuel mix, thereby reducing dependence on fossil fuel. Not only does this conserve finite resources, but it has the potential, along with other renewable energy technologies, to ease gas price volatility by easing pressure on the supply-demand balance for gas. Second, BLGCC power plants, even the "utility-scale" systems considered here, would be more numerous and dispersed than other central station power plants of equal capacity. All else equal, this would make the overall electricity supply infrastructure less vulnerable to disruption by terrorist attacks, and these plants could continue to operate in the event of a gas disruption, whatever the cause.

Within the national context, however, it is also worth discussing the potential role of BLGCC (and biomass gasification more broadly) within the emerging hydrogen economy. The full benefits of the hydrogen economy can be realized when the source of the hydrogen is domestically produced renewable energy, and biomass has the potential to be one of the lowest cost options for producing hydrogen from renewable resources. Thus, to the extent that BLGCC can serve as the springboard for a new biomass-based energy industry, it could ultimately be important in the development of a hydrogen energy infrastructure.

Economic Development

BLGCC could have important economic development benefits, stemming from the enhancement of the competitiveness of the pulp & paper industry. The BLGCC financial analysis illustrated the potential for attractive financial returns and significantly increased cash flows relative to Tomlinson technology. The benefits include preserving and growing employment in the industry and potentially adding to rural and semi-rural employment by creating increased demand for raw materials for paper production, and in the longer term, energy and other products derived from biomass. Obviously, these benefits will be most strongly felt in regions with a concentration of pulp & paper industry activity. However, if BLGCC helps serve as a catalyst for a new bio-energy industry, the national economic impacts could be more substantial and widespread.

Reaping the Benefits of Government RD&D Support for BLGCC

The U.S. Department of Energy has been supporting research, development, and demonstration (RD&D) of black liquor gasification technology for over 20 years at varying levels. It is clear that much has been learned as a result of this government investment, such that black liquor gasification technologies are now on the cusp of commercial readiness. (There probably have also been unanticipated and un-quantifiable R&D spin-off values.)

While a return on investment in BLGCC RD&D is difficult to quantify, it is possible to estimate the cost of delaying the additional RD&D needed to make BLGCC technology commercially ready. With delayed commercial implementation, some energy and emissions savings that would otherwise have occurred would be foregone. Delay in market introduction of BLGCC might be represented by the difference between the *low* and *aggressive* scenarios described earlier. The difference in cumulative energy savings between the scenarios might be thought of as the cost of delaying implementation, or conversely, the benefits of more aggressive deployment and of "front loading" the market penetration curve. If BLGCC technology were to penetrate slowly rather than rapidly into the market, the cumulative (25-year) energy savings would be roughly 1 to 3 quads less. The corresponding added energy costs would approach $4 billion. In addition, the value of lost SO_2, NO_x, and CO_2 emissions reductions (at $160/ton SO_2, $2,000/ton NO_x, and $25/ton CO_2) would be up to $4.7 billion (cumulative over 25 years). Thus, if the lag in market penetration between the *low* and *aggressive* scenarios is taken to represent the opportunity cost of delayed commercialization, this opportunity cost would exceed $8 billion.

Research, Development, and Demonstration Needed to Commercialize BLGCC

The analysis in this study has assumed N^{th}-plant levels of technological maturity for BLGCC systems, which assumes research, development, and demonstration (RD&D) will be successful at several levels over the next few years. Table S11 summarizes key RD&D issues.

Table S11. Technical research, development, and demonstration activities required to realize commercial BLGCC systems. Qualitative importance of each issue is as follows: ● = crucial; ◖ = important; ○ = relevant but not vital; --- = not applicable/not relevant.

ISSUE	CONCERNS	RELEVANCE	
		High T. BLGCC	**Low T. BLGCC**
Critical issues with uncertainty and where success of RD&D is assumed			
Alkali removal from syngas	Alkali compounds (especially as alkali sulfates) will cause corrosion of gas turbine blades. Trace levels (at most) can be tolerated in gas turbine fuel.	●	●
Tar removal from syngas	Fouling of downstream equipment, reduced gasification efficiency, potential disposal issue.	◖	●
Reliability of gasification island[a]	Shutdown of gasification island can cause very substantial negative impacts on the economics of gasification.	●	●
Areas where there is reasonable confidence in achieving predicted performance where success of RD&D is assumed			
Syngas fueling of gas turbine[a]	Low heating value of syngas (compared to natural gas) requires gas turbine combustor redesign and compressor air flow control. Feasibility of syngas fired turbines has been commercially demonstrated, e.g., in coal IGCC plants.	○	○
Oxygen-enriched combustion air for lime kiln	Modest capacity increases can be achieved by retrofitting existing air-blown kilns. New burner design and possibly new refractory may be required, but no fundamental difficulties anticipated up to 20% capacity increase.	◖	---
Solids handling and heat exchange	Considerable solids must be handled with the low-temperature gasifier design. Ability to handle high-temperature solids and transfer heat from them needs to be proven.	---	◖
Process integration and control	Achieving energy, environmental and economic benefits of gasification relies crucially on the tight integration of the gasification island, the power island and the mill. This requires both an appropriate design approach and proper control strategies.	●	●
Areas where new approaches (developed through RD&D) might be desirable			
In situ tar destruction	Increasing gasification temperature should help reduce tar production. New refractory materials for the gasifier may be needed.	◖	---
New sulfur recovery and integration with mill chemistry	A "brute force" arrangement was assumed in this study. New approaches to sulfur recovery may improve performance and/or reduce costs .	○	◖
Gasifier pressurization	Higher pressure operation will reduce vessel size, but the pulse combustor tube bundle and other aspects of the gasifier design would require thorough reconsideration.	---	●
Better refractory materials	Improved resistance to corrosion/erosion, leading to longer lifetimes, will improve reliability and reduce maintenance costs.	◖	◖
Direct causticizing	Incremental lime kiln load with BLGCC is especially large with low-temperature gasifiers. If direct causticization can eliminate the need for any kiln, considerable process simplification and cost reduction would be the result.	○	●
New black liquor gasifier designs	Other gasifier designs may provide different benefits.	---	---
Woody-biomass gasification	Higher efficiency of power generation (and greater production of exportable electricity) would be achievable if woody biomass were gasified instead of burned in a boiler (as in this study).	◖	◖
Expanding product slate of a biorefinery	System analyses would help understand energy, environment, and economic characteristics of biorefineries, e.g., co-producing fuels and electricity; results would help guide the pursuit of relevant technology RD&D.	◖	◖

(a) Issue in common with coal gasification research, development, and demonstration requirements.

Conclusions

This study has shown that black liquor gasification combined cycle (BLGCC) power/recovery technology offers the prospect for significant improvement in the efficiency with which steam and electricity are cogenerated at kraft pulp mills compared to existing state-of-the-art power/recovery technology (Tomlinson recovery boilers). Widespread commercial implementation of BLGCC systems in the United States would enable significant energy savings for the country as a whole. Significant reductions in emissions of criteria pollutants and greenhouse gases would also be achieved. Returns on investments in BLGCC systems relative to state-of-the-art Tomlinson systems (assuming N^{th} plant capital costs in both cases) appear suitably attractive, though efforts to reduce total capital investment requirements would certainly be beneficial.

The reasonable returns on N^{th} plant investments, together with the substantial public benefits that could be derived from BLGCC systems (summarized in Table S12) suggest a private-public partnership as an appropriate approach to addressing research, development, and demonstration (RD&D) issues during the next few years to bring BLGCC systems to commercial readiness. This study has identified several key RD&D issues to be addressed (Table S11). Addressing these issues will set the stage for building the first few commercial-scale units, costs for which can be expected to be higher than the N^{th}-plant cost levels estimated in this study, as BLGCC system costs begin descending a cost-learning curve.

Table S12. Prospective benefits of BLGCC implementation

Mill-Level Economic Benefits	• Higher pulp yields, reducing pulpwood requirements by approximately 7% per unit output • Internal rates of return (IRR) as high as 20% without consideration of potential value of environmental or renewable energy credits/value streams. • IRRs in excess of 30% assuming reasonable values for credits.
National Economic Benefits	• Higher pulp yields, reducing pulpwood requirements by approximately 7% per unit output • Up to $6.5 billion (constant 2002 dollars) in cumulative energy cost savings over 25 years. • Additional potential cumulative (over 25 years) emissions credit values in the range of $450 million for SO_2, $3.2 billion for NOx, and $3.1 billion for CO_2 • Job preservation and growth in the pulp & paper industry.
Environmental Benefits	• Higher pulp yields, reducing pulpwood requirements by approximately 7% per unit output • Potential for reduced cooling water and makeup water requirements, for the mill-scale BLGCC. All BLGCC options also result in reduced cooling water and makeup water requirements for the grid power displaced, and reduce solid waste production at grid power plants. • Up to 35 million tons net CO_2, 160,000 tons net SO_2 and 100,000 tons net NOx displaced annually within 25 years of introduction. Additional reductions of particulates, VOCs and TRS. • Additional benefits could accrue if BLGCC is able to “catalyze” a new biomass-based energy industry, resulting in the development and use of sustainable biomass supplies for additional energy and chemicals production.
Security Benefits	• Up to 156 billion kWh of distributed energy produced annually above Tomlinson BASE technology, within 25 years of introduction. Of this, as much as 62 billion kWh would be renewable. • Up to 360 trillion Btu/year of fossil energy savings within 25 years of introduction • Potential for fuels and chemicals production from black liquor and other biomass feedstocks directly displacing petroleum.
Knowledge Benefits	• Potential advances in materials science, syngas cleanup technology, alternative pulping chemistries, and other areas.

There is some urgency in bringing BLGCC systems to commercial readiness, since many U.S. kraft pulp mills will be facing the need for end-of-life replacement of Tomlinson boilers in the next 10 to 20 years. Many technology managers in the pulp and paper industry have a keen interest in accelerating the effort to commercialize BLGCC technology so that it is available as a viable Tomlinson replacement option in the 2010 timeframe. Some electric utilities in the Southeastern United States, where the majority of U.S. pulp mills are located, are also showing interest in pulp-mill based biomass electricity as a renewable generation option. This interest is motivated in part by the possibility that renewable portfolio standards or other schemes designed to increase new renewable energy use will be implemented in Southeastern states. Electricity generated by BLGCC systems could make important contributions in this context.

The pulp and paper industry is an important element of the U.S. economy. It is important that the industry maintain its global competitiveness since mill closures would cause significant disruption in communities whose economies are linked closely to the industry. The results of this study suggest that gasification-based power generation at pulp mills would help improve competitiveness.

For the longer term, black liquor gasification would provide a technology platform for more diversified production at pulp mill “biorefineries’. A modern pulp and paper mill today represents a first-generation biorefinery, with steam, power and a variety of pulp/paper products being made from woody biomass. The introduction of gasification would enable far more efficient power generation via combined cycle or fuel cell prime movers, as well as the production of additional value added products like transportation fuels (e.g., Fischer-Tropsch middle distillates or hydrogen) and chemicals. To the extent that fuels and chemicals produced at biorefineries substitute petroleum-based fuels and chemicals, U.S. dependence on imported oil could be reduced.

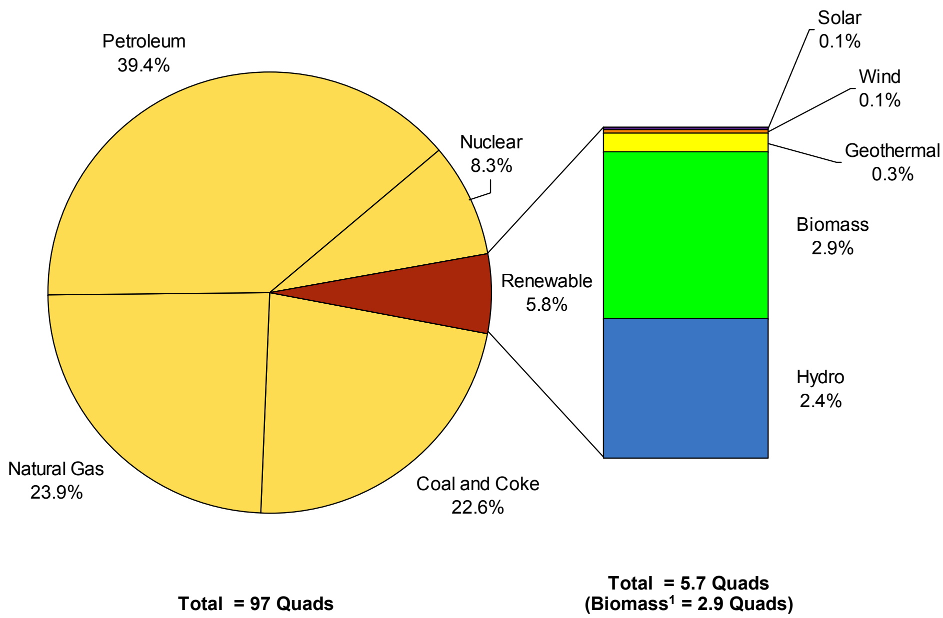
Black liquor gasification would be a first step toward a future biorefinery concept that could include two gasification technologies – one for black liquor and a second for solid biomass. The latter would be fueled by hog fuel and additional wood residues collected sustainably from the vicinity of the mills. The combined biomass energy input to this future powerhouse could be twice the level of black liquor considered in this study, which obviously would yield greater benefits than estimated here. In time, a gasification-based biorefinery industry might extend beyond the pulp and paper industry, whereby biomass crops would be grown for conversion to heat, electricity, fuels, chemicals, animal feedstocks, and other commodity products. By pursuing the commercialization of BLGCC technology, the pulp and paper industry would stand to share in the energy, environment, and economic benefits identified in this study, while catalyzing the creation of a larger biorefinery industry that might produce still greater private and public benefits.

Main Text

1 Introduction

1.1 Context

The U.S. pulp and paper industry is among the largest producers and users of renewable energy in the United States today, since much of the wood feedstocks used at pulp mills comes from sustainably-grown trees. Renewable resources used at pulp mills include bark, wood wastes, and black liquor, the lignin-rich by-product of cellulose-fiber extraction. The total of these biomass energy sources consumed at pulp mills in 2002 was an estimated 1.6 quads (one quad is 10^{15} BTU).[1] Additionally, there are substantial, ecologically-recoverable residues that remain behind after harvesting of trees for pulpwood. For comparison, all primary energy sources consumed in 2001 in the United States totaled 97 quads (Figure 1).



1. The data source Included in biomass the following: wood, wood waste, sludge waste, municipal solid waste, landfill gas and tires.
Source:DOE/EIA *Renewable Energy Annual 2001* (DOE/EIA-0603(2001))
One Quad equals 10^{15} Btu (1 quadrillion Btu) or 1.054 Exajoules (10^{18})

Figure 1. Primary energy use in the United States in 2001.

With substantial renewable energy resources at its disposal, the U.S. pulp and paper industry has the potential to contribute significantly to addressing climate change and U.S. energy security concerns, while potentially also improving its global competitiveness. A key requirement for achieving these goals is the commercialization of breakthrough technologies, including

[1] Approximately 1.2 quads of black liquor and 0.4 quads of hog fuel were generated and consumed annually in the U.S. paper industry in the mid-1990s.

gasification, that will enable the clean and efficient conversion of biomass to useful energy forms, including electricity and transportation fuels.

Gasification technology enables solid fuels like biomass to be converted with low pollution into a fuel gas ("syngas") consisting largely of hydrogen (H_2) and carbon monoxide (CO). This gas can be burned cleanly and efficiently in a gas turbine to generate electricity. It can be passed over appropriate catalysts to synthesize clean transportation fuels or chemicals. It can be converted efficiently into pure H_2 for use in fuel cells, whose only air emissions are water vapor.

While pulp and paper manufacturing facilities do not produce transportation fuels from biomass today, the infrastructure they represent for collecting and processing biomass resources provides an established foundation for future gasification-based "biorefineries" that might produce a variety of renewable fuels, electricity, and chemicals in conjunction with pulp and paper products (Figure 2).

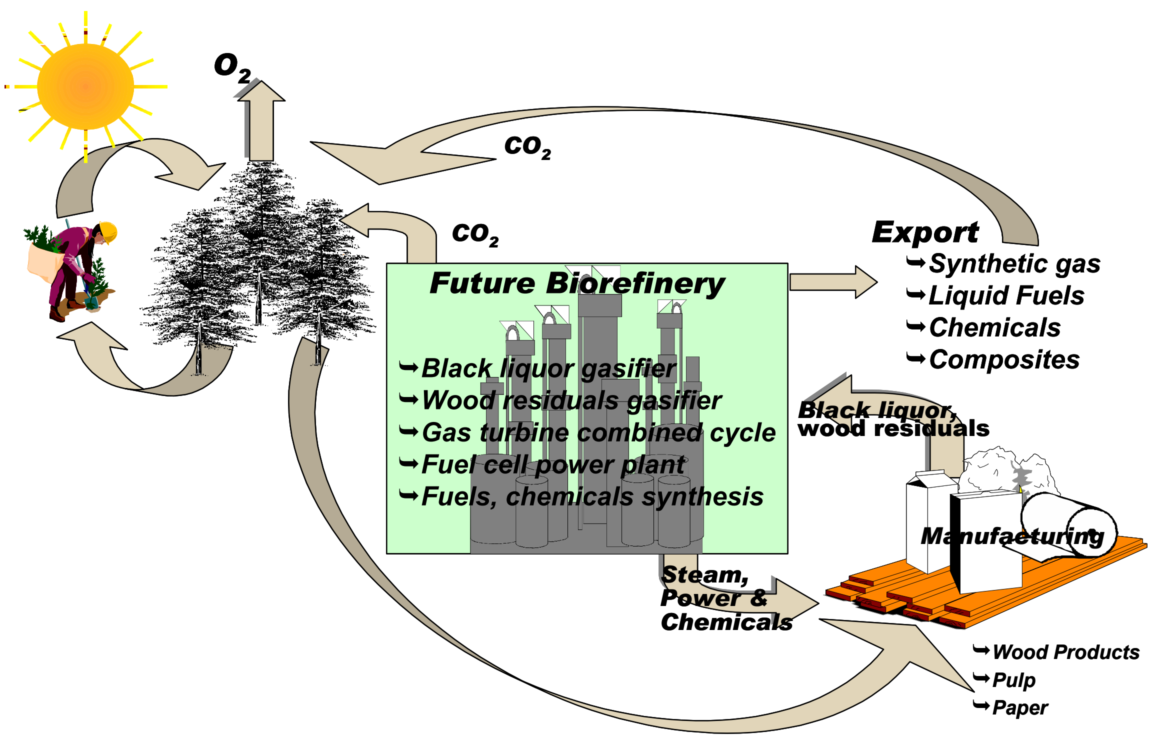


Figure 2. Future "biorefinery" concept based at a pulp and paper manufacturing facility.

If the biomass resources from which energy carriers are produced at such biorefineries are sustainably grown, there would be virtually no net emissions of CO_2 to the atmosphere associated with the production and use of bioenergy at such facilities. To the extent that the biomass-derived energy carriers replace energy that would otherwise have come from fossil fuels, there would be net reductions in CO_2 emissions from the energy system.

To understand the potential impact, consider if the 1.6 quads of biomass energy resources used by the pulp and paper industry today were to be converted to electricity using advanced technology (of the type assessed in this study), while also meeting the process steam demands of the pulp and paper industry. Up to 130 billion kWh/year of electricity could be generated. This is equivalent to about 7% of the electricity generated from coal in the United States in 2002 (1,942 billion kWh[2]). Displacing 130 billion kWh per year of electricity would reduce U.S. CO_2 emissions by about 23 million metric tonnes of carbon per year (assuming the grid average mix). For comparison, total carbon emissions from fossil-fuel electricity production in the U.S. in 2002 was about 590 million metric tonnes.

Potential energy-security implications of "biorefining" can be appreciated by another more future-looking back-of-the-envelope calculation. If the 1.6 quads of biomass energy resources were converted to hydrogen as a transportation fuel, the fuel needs could be met for some 45 million light duty vehicles operating with fuel cell engines.[3] This represents about one-third of the present U.S. passenger car fleet.[4] Gasoline savings would amount to some 25 billion gallons per year – equivalent to 15% of petroleum imports in 2001 – and CO_2 emissions would be reduced by about 66 million metric tonnes per year (or about 13% of current CO_2 emissions from U.S. transportation, which accounts for 1/3 of all U.S. emissions).[5]

If pulp and paper facilities do evolve into "biorefineries," the first likely feedstock to be used for gasification is black liquor, given that its generation and processing are integral to the manufacturing process and that its contained energy is about six times the energy contained in the other biomass by-products (bark and wood wastes) generated at a typical mill. Adoption of woody-biomass gasification would likely follow, once black liquor gasification is successfully introduced. This would then facilitate the collection and use of additional sustainable biomass resources.

1.2 Study Scope and Objectives

This study examines the prospective technical and financial feasibility and environmental impacts of black liquor gasification-based systems at kraft pulp mills for steam/power cogeneration and recovery of pulping chemicals as full replacements for Tomlinson recovery boiler systems, the current state-of-the-art technology in the industry. Specifically, the study examines black liquor gasification combined cycle technology (BLGCC), which couples gasification to the modern gas turbine. More advanced gasification-based "biorefinery" designs, e.g., including transportation fuels production (Berglin *et al.*, 2003), are not examined in this study.

The majority of Tomlinson boilers currently operating in the United States were built beginning in the late 1960s through the 1970s (Figure 3). A wave of rebuilds took place from the mid-1980s to the late 1990s. With lifetimes of 30 to 40 years, many of these units are approaching the time at which they will need to be rebuilt or replaced. Thus, over the next 10 to 20 years, there

[2] This amount of coal-derived electricity accounted for 54% of all electricity generated in 2002.

[3] Assuming biomass energy conversion efficiency (to H_2 on-board the vehicle) of 52%, which assumes conversion efficiency of biomass to H_2 of 62% (Katofsky, 1993) and an additional 10 percentage points loss in transportation and refueling. A passenger car fuel economy of 82 mi/gallon of gasoline equivalent is assumed for an H_2 fuel cell car, and average travel distance of 12,000 miles/year is assumed (Ogden, *et al.*, 2004).

[4] The total number of passenger cars registered in the U.S. in 2001 was 133.6 million (Center for Transportation Analysis, 2002).

[5] Total gasoline consumption by passenger cars was 72.8 billion gallons (or 9.1 quads) in 2001. Net petroleum imports were 10.9 million barrels per day, and transport sector carbon emissions (in 2000) were 522 million metric tones (Center for Transportation Analysis, 2002).

will be strong demand for replacement black liquor energy and chemical recovery systems. This fact, together with the considerable progress in the development of gasification technologies and in the understanding of likely commercial features of black liquor gasification since studies several years ago (Larson *et al.*, 2000a; Larson *et al.*, 2000b), warrant a re-assessment of prospective costs and benefits.

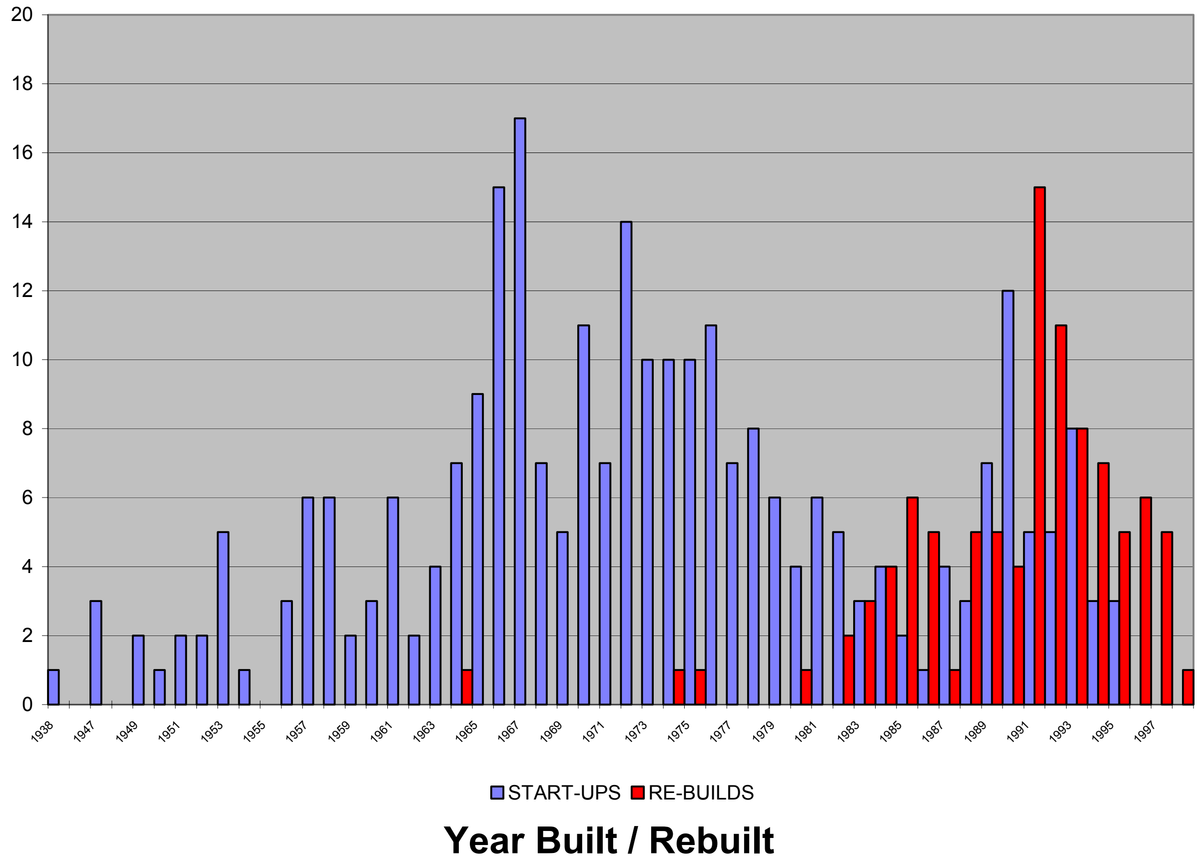


Figure 3. Age distribution of Tomlinson recovery boilers in the United States.

In addition to mill-level cost-benefit assessments, this study includes an assessment of potential regional and national energy and environmental impacts of the implementation of black liquor gasification technology under different future market penetration scenarios. The regional analysis focuses on the Southeastern United States, where two-thirds of kraft pulp mills are located (Figure 4).

This study aims to inform technology decision makers in the pulp and paper industry, in the utility and independent power generating industries, and in the U.S. Department of Energy and other government agencies regarding the prospective costs and benefits of black liquor gasification systems. The analysis has been carried out with guidance from an industry-government Steering Committee, review by a board of independent experts (Figure 5), and with inputs from many other individuals.

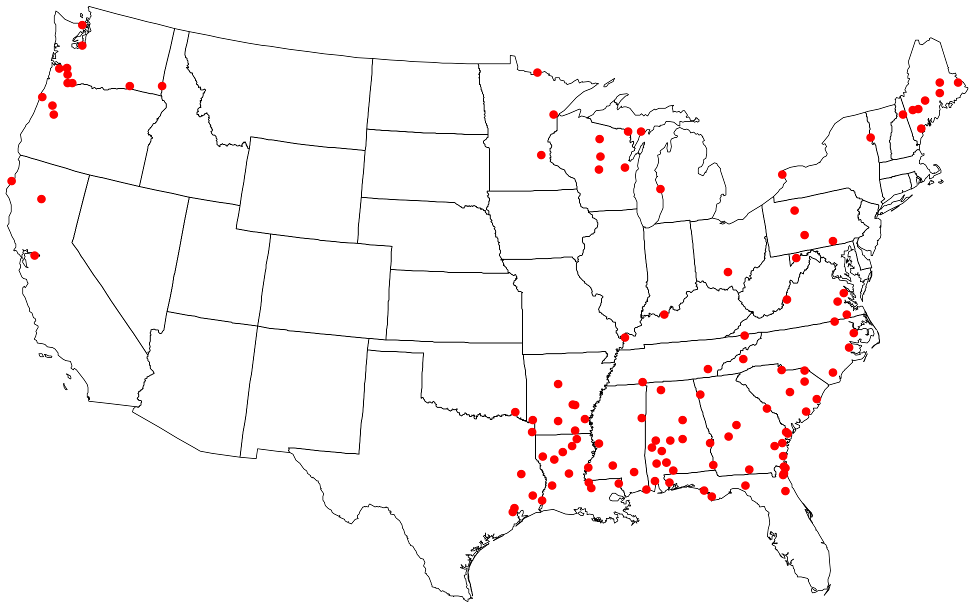


Figure 4. Location of U.S. pulp mills. Approximately 2/3 of all mills are located in the Southeast (Lockwood-Post, 2001).

Steering Committee

Bob Gemmer - DOE
Kerry Bowers - Southern Co.
Ben Thorp - Georgia-Pacific
Paul Tucker - International Paper
John Huyck - Mead Westvaco
Denny Hunter - Weyerhaeuser
Martha Rollins - TVA
Del Raymond - Weyerhaeuser (Leader)

Analytical Team

Tom Johnson - Southern Co.
Les Reardon - TVA
Eric Larson – Princeton University
Ryan Katofsky – Navigant Consulting
Shawna McQueen – Energetics, Inc.
John Huyck – Mead Westvaco (Leader)

Review Board

Jim Wolf - Consultant
Michael Farmer - GIT Public Policy Dept.
Dale Simbeck - SFA Pacific
Nathanael Greene - NRDC
Bob Gemmer - DOE (Leader)

Analytical Team Ad Hoc Members

Ken Friedman - DOE
Paul Tucker - International Paper
Craig Brown - Weyerhaeuser
Karl Morency - Georgia-Pacific
Bo Oscarsson – Fluor
Sam Tan - Nexant

Figure 5. Organizational structure and participants in this project.

2 Chemical Recovery and Power/Steam Cogeneration from Biomass at Kraft Pulp and Paper Mills

The pulp and paper industry represents one of the most energy-intensive industries in the United States in terms of energy use per dollar of value added output. Unlike other energy-intensive industries, however, a majority of the energy consumed by the industry is generated from renewable biomass by-products of pulp production. The kraft pulping process, by which most pulp is produced from wood in the United States, is illustrated generically in Figure 6.

At a typical kraft mill, logs are debarked and chipped, with the clean chips sent to the digester for cellulose extraction. The bark and waste wood (called "hog fuel") are used as a boiler fuel. The wood chips undergo cellulose extraction in the digester in a solution of sodium sulfide (Na_2S) and sodium hydroxide (NaOH) called "white liquor." A subsequent washing step separates the cellulose fibers from the remaining solution ("black liquor") containing the spent pulping chemicals and the lignin and hemicellulose fractions of the original wood chips. The cellulose fibers are processed into a final pulp product (at a stand-alone pulp mill) or into paper (at an integrated pulp and paper mill).

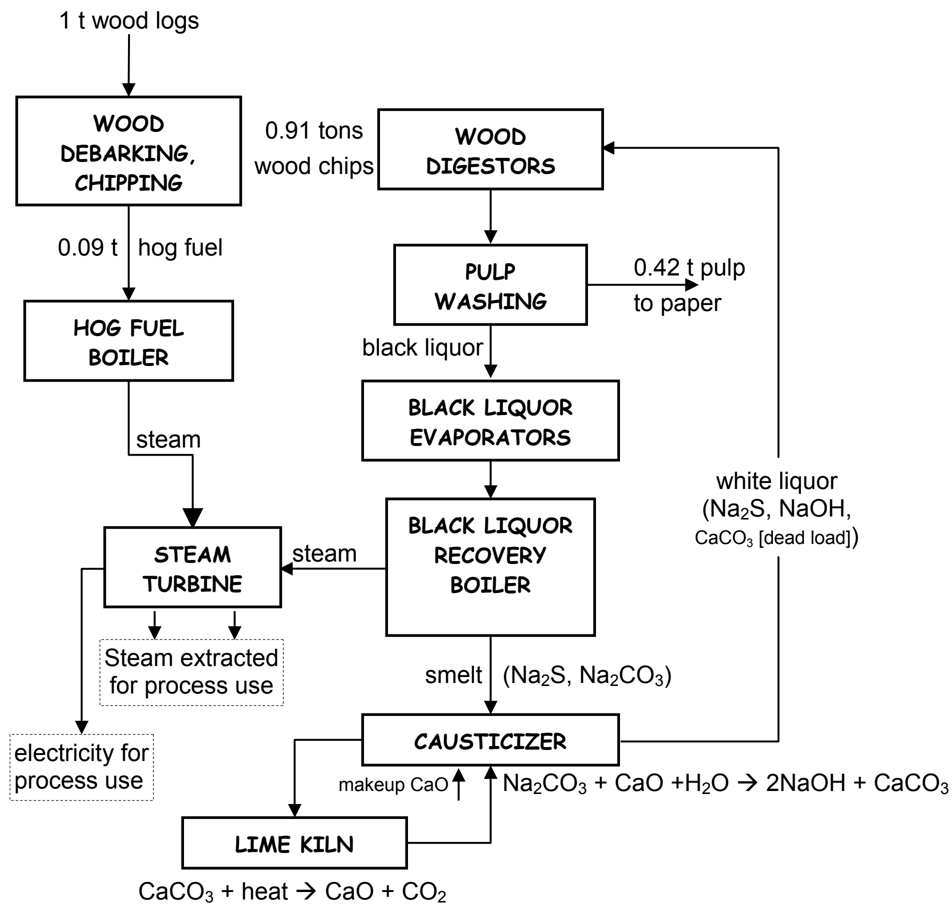


Figure 6. Simplified representation of kraft pulping and the associated chemical recovery cycle. Indicated mass flows are on a dry-matter basis and intended only to be illustrative.

The black liquor solids (BLS) carry about half the energy in the original wood chips sent to the digester, and thus represent a considerable energy resource. To make effective use of this energy, the black liquor is concentrated from a dilute solution (15-20% solids fraction) to one with a solids content of 75 to 80% in multiple-effect evaporators, with steam providing the heating in the evaporators. The concentrated black liquor is then burned in a Tomlinson recovery boiler. Steam from the Tomlinson boiler, together with steam from the hog fuel boilers, provides most[6] of the steam needed to run the pulp (or integrated pulp and paper) mill. The steam is raised at an elevated pressure and, before being used in the process, it is expanded to lower pressure through a steam turbine that generates electricity to operate the mill. Most U.S. mills must also purchase some electricity, since the amount generated from black liquor and hog fuel is not sufficient to meet all of the mill's electricity needs with the power generating technology in use today.

In a Tomlinson boiler, the organic fraction of the black liquor burns to produce heat and the inorganic fraction leaves as a molten smelt containing largely Na_2S and Na_2CO_3. Unlike in a conventional fuel or solid biomass boiler, boiler tube leaks are a considerable safety concern with Tomlinson systems, since water from the leak contacting molten smelt can result in a steam explosion, which can have deadly consequences.

The smelt is dissolved in water to form "green liquor" that is sent to a causticizer, where lime (CaO) is added to convert the Na_2CO_3 in the green liquor back to the desired NaOH pulping chemical. The lime is converted to calcium carbonate ($CaCO_3$) in the causticizer, and must be converted back to CaO by heating in the lime kiln. Typically, fuel oil or natural gas is burned in the kiln to generate the needed heat.

[6] In the case of the reference mill defined later in our analysis, all steam is provided by black liquor and hog fuel.

3 Black Liquor Gasification Technology

Gasification is being developed as a replacement technology for the conventional recovery boiler, and a number of concepts for black liquor gasification have been proposed previously (Consonni *et al.*, 1998). Serious technology commercialization efforts have been sustained for two of these concepts in joint initiatives between industry and government.

3.1 High-Temperature Gasification

One black liquor gasification process design under development by Chemrec, a Swedish company, is a partial oxidation process operated with either air or oxygen (Whitty and Nilsson, 2001; Lindblom, 2003). It is distinguished by the condensed phase material (inorganic material from the black liquor) leaving the reactor as a liquid (smelt) due to the high reactor temperature (950-1000^{o}C). In this regard, the Chemrec process is similar to entrained-flow coal gasification. For future large-scale commercial application, Chemrec envisions oxygen-blown operation at elevated pressure (Figure 7). The relatively large oxygen requirement will justify the cost of a dedicated air separation unit (ASU). Other uses of oxygen at the mill, e.g., for oxygen bleaching, effluent treatment, and lime kiln capacity enhancement (by firing with oxygen-enriched air), which might be cost-prohibitive on their own due to the small scales of use, may then also become feasible.

A pilot plant high-temperature gasifier was first started up in 1994 at a pulp mill near Karlstad, Sweden. This unit was designed for air gasification at 15 bar pressure and 975^{o}C temperature. The test plant included gas quenching, cooling, and sulfur capture based on green or white liquor scrubbing of the gas. The plant also demonstrated acceptable green liquor production from the smelt. The pilot plant was modified in 1997 to use oxygen instead of air, resulting in an increase in capacity to 10 t/day of black liquor solids. The unit was shut down in 2000, having provided significant data for further development of the technology. Weyerhaeuser installed a Chemrec atmospheric-pressure air-blown reactor (365 t/d BLS) at a mill in North Carolina in the late 1990s to augment the chemical recovery capacity provided by the existing Tomlinson boiler. That gasifier operated for three years before being shut down to repair an unanticipated problem with the pressure vessel. The unit was restarted in June 2003. Meanwhile, construction of a new Chemrec pilot plant has begun at a mill in Pitea, Sweden. The unit, which will include integrated vessel cooling with water, is designed to provide data for scale-up to full-scale Tomlinson boiler replacement applications. The unit will operate at 30 bar pressure with oxygen and have a capacity of 20 t/day of black liquor solids.

3.2 Low-Temperature Gasification

A second black liquor gasification process, under development by Thermochem Recovery International (TRI), an American company, utilizes indirectly-delivered heat via a bank of pulse-combustor heat exchange tubes immersed in a fluidized bed (Figure 8) (Mansour *et al.*, 2001). Steam is used to fluidize the bed in which the black liquor is gasified. With a moderate temperature maintained in the reactor (~600^{o}C), the condensed-phase material leaves as a dry solid.

This technology has been under development since the mid-1980s with support from the U.S. Department of Energy. TRI (or MTCI at the time) carried out gasification studies of spent pulping liquor in a 1000 lbs/day BLS pilot unit starting in the early 1990s. A nominal 50-ton per day BLS pilot plant completed a 500-hour continuous test at a Weyerhaeuser kraft pulp mill in North Carolina in 1994/1995. A commercial-scale (200 tpd BLS) unit is now under construction at a Georgia Pacific pulp and paper mill in Big Island, Virginia.[7]

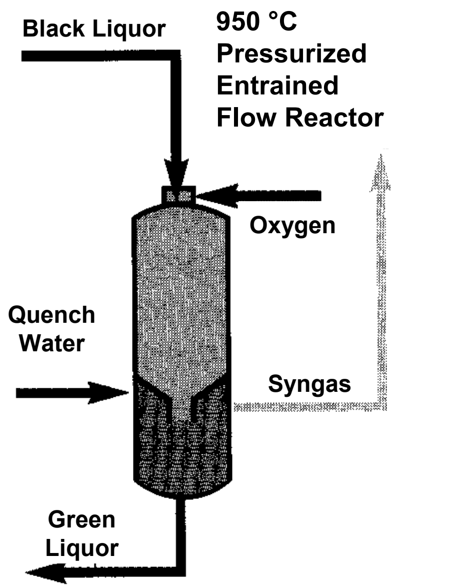


Figure 7. Chemrec black liquor gasification concept.

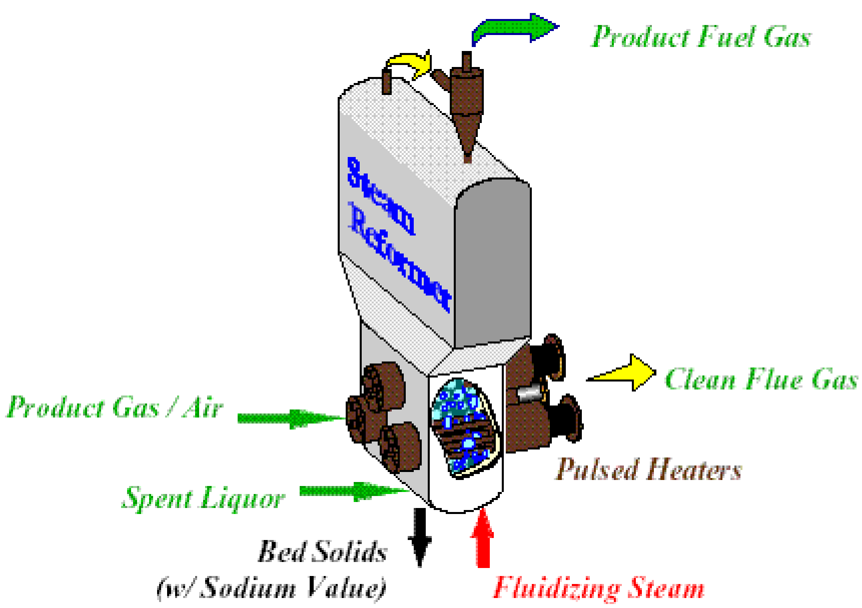


Figure 8. TRI black liquor gasification concept.

[7] The Big Island mill uses a non-sulfur pulping process.

3.3 Sulfur Cycle and Lime Cycle Issues with Kraft Black Liquor Gasification

Unlike in a Tomlinson boiler, where essentially all of the sodium and sulfur leave in the smelt, there is a natural partitioning of sulfur (mainly as hydrogen sulfide, H_2S) to the gas phase and sodium to the condensed phase during gasification of kraft black liquor. This split represents an important potential benefit to a pulp mill, since it can facilitate alternative pulping chemistries that can lead to increased pulp yields per unit of wood consumed (Linstrom *et al.*, 2002). Based on thermodynamic considerations, the lower the gasification temperature, the more complete will be the partitioning of sulfur and sodium.[8] With the low-temperature process described above, over 90% of the sulfur in the black liquor will leave the gasifier as H_2S in the product gas. With the high-temperature process described above, slightly more than half of the sulfur goes to the gas phase.

To take advantage of the natural separation of sulfur and sodium, it is necessary to recover H_2S from the gas in a form suitable for preparing modified pulping liquors. Capture of acid gases like H_2S is routinely practiced in other industries (e.g., petroleum refining) using patented physical or chemical absorption processes such as Selexol® or Rectisol®. It is also possible to capture H_2S using green liquor or white liquor as a scrubbing medium.

A negative consequence of the natural split of sulfur and sodium during gasification is a higher causticizing load, i.e., larger required lime kiln capacity and lime kiln fuel consumption per unit of black liquor solids processed compared to processing in a Tomlinson boiler. One cause of this increase is a larger amount of carbonate (Na_2CO_3) in the green liquor because less sulfur is available in the condensed phase to form sodium sulfide (Na_2S). In effect, for each unit of sulfur that goes to the gas phase, one additional unit of carbonate forms in the condensed phase. Since the carbonate must be converted to hydroxide (NaOH) through the causticizing cycle (Figure 6), one additional unit of lime must be generated at the lime kiln.

A second source of added causticizing load will appear if green or white liquor scrubbing is used to capture H_2S, since CO_2 in the gas will be co-absorbed and form additional Na_2CO_3 in the liquor, which must eventually be converted back to NaOH. If H_2S capture is effected using a commercial process like Selexol,® CO_2 co-absorption will also occur, but can be reduced by appropriate design of the absorbent. Alternatively, the problem of CO_2 co-absorption can be eliminated entirely if H_2S is captured using a commercial process (e.g., Selexol®) and then converted to elemental sulfur using a commercially available process (Claus/SCOT technology).

When elemental sulfur is mixed with a solution containing Na_2S at moderate temperature (<100°F), polysulfide forms, for example, $3S + Na_2S \rightarrow Na_2\text{-}S_3\text{-}S$. Polysulfide pulping increases digester yield compared to conventional white liquor pulping (Jameel and Renard, 2003), which enables a mill to decrease wood input compared to conventional pulping (for a fixed pulp production) or increase pulp production (for a fixed wood input). The cost impacts of integrating polysulfide pulping with black liquor gasification are considered in this study.

Some added causticizing load is unavoidable with the gasification processes described above, but research is ongoing on modified processes, e.g., "direct causticizing," which, if successful,

[8] Higher pressure also favors greater conversion of sulfur to the gas phase.

would completely eliminate the need for any causticizing at a pulp mill (Nohlgren, *et al.*, 2002; Warnqvist *et al.*, 2001; Richards *et al.*, 2002). Such a development would be especially important with low-temperature gasification processes, since these will incur considerably higher causticizing load penalties than high-temperature gasification. The concept of direct causticizing has only been demonstrated in laboratory-scale experiments to date. Additional research, development, and pilot demonstrations are required to prove commercial viability. Cost reductions that would come from eliminating the need for a separate causticizing area at a mill are significant enough to warrant continued investigation, but given the developmental status of direct causticization, the concept it is not considered in the detailed analysis for this study.

4 Reference Kraft Pulp/Paper Mill for Case Study Comparisons

To assess the prospective commercial competitiveness of black liquor gasification relative to Tomlinson recovery boiler systems, detailed process designs and energy and mass balances have been developed for several different power/recovery systems integrated into a pulp and paper production facility. The designs of the power/recovery areas were developed assuming the systems would be built as complete replacements of existing power/recovery systems at a hypothetical case study mill having characteristics representative of mills in the Southeastern U.S. in the 2010 time frame.

4.1 Process Characteristics of the Reference Mill

The reference mill is an integrated pulp and paper mill producing uncoated freesheet paper from a 65/35 mix of hardwood and softwood. Consistent with the forward-looking nature of this study and the continual improvements in process energy efficiency historically achieved by U.S. pulp and paper makers, the process steam demands at the mill are taken to be about 10% below current "best-practice" levels. The nominal scale of the case study mill is 6 million lbs/day of black liquor solids (BLS). Pulp mills processing 6 million lbs/day BLS or more account for about 1/3 of all U.S. capacity today, and this fraction is expected to grow over time as industry consolidation continues.

Key input mill parameter assumptions are shown in Table 1 for both conventional pulping and polysulfide pulping. The latter pulping chemistry is assumed to be implemented with black liquor gasification, giving a reduced wood input. Polysulfide pulping raises the digester yield, enabling a reduction in wood feed to the mill compared to conventional pulping (for the same paper production[9]). Wood cost savings amount to over $4 million per year for the assumptions of this study, as detailed below (Section 8.2). The higher digester yield reduces the amount of black liquor solids that must be processed through the recovery area. Consistent with industry trends toward higher solids concentration in black liquor sent to recovery, we have assumed a solids concentration of 80% as a standard. In one case, we examine the impact of extending this to 85% with an advanced configuration for a Tomlinson system (labeled HERB, for high-efficiency recovery boiler, in Table 1).

4.2 Tomlinson Power/Recovery Area at the Reference Mill

For all power/recovery system configurations in this study, including Tomlinson-based and gasification-based systems, detailed mass and energy balances were calculated on a consistent basis[10] using a process design and simulation tool that previously has been extensively applied and calibrated for combustion and gasification-based power systems, including black liquor-based systems (Consonni *et al.*, 1998; Larson *et al.*, 1999). The design of each system was developed in consultation with equipment developers, industrial design engineers who were engaged to estimate costs (see Section 7), and a variety of other experts.

[9] The implicit assumption here is that the mill is already operating at capacity (outside of the power/recovery area) when using conventional pulping, so that an increase in digester yield can be accommodated only by decreasing wood input, not by increasing pulp production.
[10] Appendix A provides complete details of the performance modeling and results of all power/recovery systems.

Table 1. Reference case study mill parameter assumptions.

POWER/RECOVERY SYSTEM →		Tomlinson BASE	Tomlinson HERB	Gasification
PULPING CHEMISTRY →		Conventional		Polysulfide
Product Flow (paper)	Machine-dry metric tons/day	1,725		
Unbleached Pulp Rate	Bone dry short tons/day	1,580		
Mill Hardwood/Softwood Mix	% HW, % SW	65% HW, 35% SW		
Digester Yield	% for softwood	45.50%		48.75%
	% for hardwood	46.50%		49.75%
Wood To Process (91% of total)	Bone dry short tons/day	3,434		3,208
Hog Fuel (9% of total)	Bone dry short tons/day	340		317
Total Wood Used	Bone dry short tons/day	3,774		3,525
Black Liquor Solids Concentration	% solids	80%	85%	80%
BL Solids Flow Rate	lb BLS per day	6,000,000		5,419,646
	kg BLS per day	2,721,555		2,458,311
BL Energy Content	kJ per kg of BLS (HHV)	13,892		13,874
	Btu per lb of BLS (HHV)	5,974		5,966
	MW, HHV	437.6		394.7
BL Solids Composition, mass%	C	33.46%		32.97%
	H	3.75%		3.70%
	O	37.35%		36.88%
	S	4.10%		4.27%
	Na	19.27%		20.03%
	K	1.86%		1.93%
	Ash/chlorides	0.21%		0.22%
Hog Fuel Energy Content (50% moisture content)	MJ / kg of hog fuel (HHV)	10		10
	Btu / lb of hog fuel (HHV)	4,300		4,300
	MWth, HHV	71.3		66.6
Mill Steam Use, 55 psig Steam (including evaporators, but excluding power/recovery area)	kg / kg of paper	3.384	3.362	3.207
	MWth	142.8	141.8	135.3
	MJ / mt of paper	7,149	7,100	6,774
Mill Steam Use, 175 psig Steam (including evaporators, but excluding power/recovery area)	kg / kg of paper	1.760	1.817	1.648
	MWth	69.3	71.5	64.8
	MJ / mt of paper	3,469	3,581	3,247
Total Mill Steam Use	MWth	212.1	213.3	200.1
Mill Electricity Use (excluding power/recovery)	kWh / mt of paper	1,407	1,406	1,407

The Tomlinson BASE case represents a state-of-the art power/recovery system assumed as the "business-as-usual" choice of technology when considering replacement of the existing power/recovery system at the reference mill. The process configuration for the Tomlinson BASE (Figure 9) features steam conditions of 1,250 psig (87.2 bar abs.) and temperature of 480°C (896°F), and a common high-pressure (HP) steam header for the Tomlinson and hog fuel boilers. The hog fuel boilers generate steam from bark and waste wood by-products of pulpwood preparation at the mill (Table 1). The HP steam expands through a back-pressure steam turbine with two extractions. There is one extraction at 175 psig (13 bar abs.) to provide steam for boiler air pre-heating (together with LP steam bled from the deaerator) and medium-pressure (MP) process steam for the mill, and a second extraction at 30 bar providing steam for soot blowing. The balance of steam exhausts at 55 psig or 4.8 bar abs. to provide the required low-pressure (LP) process steam. Because of the process-steam efficiency gains assumed for the reference mill (compared to most actual existing mills today), the amount of exhaust steam is more than needed for the process. A small condensing steam turbine is added to enable increased electricity generation. Flue gases leave the economizer section of the Tomlinson boiler at 170^{o}C with an oxygen content of 2% by volume (wet basis).

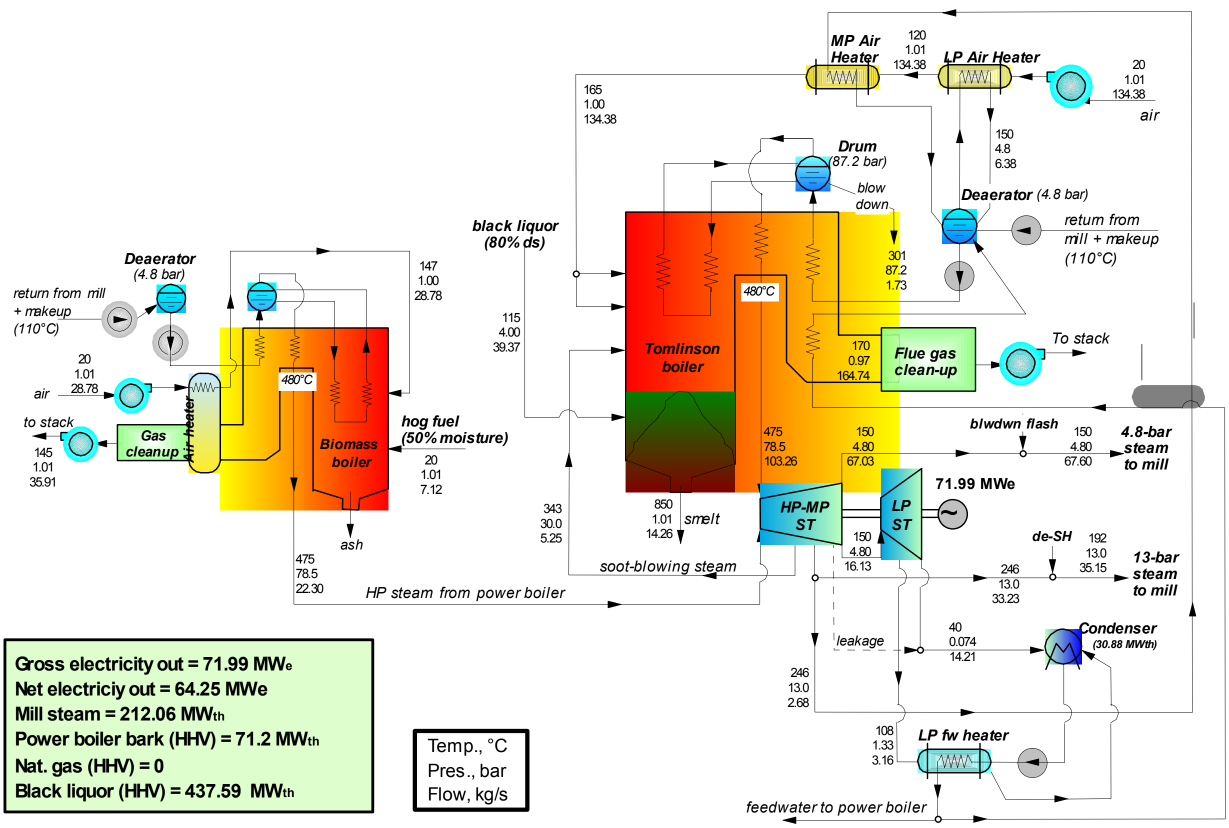


Figure 9. Energy/mass balance for the Tomlinson BASE recovery boiler.

The Tomlinson BASE power/recovery system shown in Figure 9 has a gross electricity generation of 72 MW_e, with a parasitic load of 7.8 MW_e. Considering both the black liquor and hog fuel inputs (438 and 71 MW_{HHV}, respectively), the net electricity generating efficiency of the system is 12.6%. Since the mill requires 100 MW_e for the process, the mill must purchase 36 MW_e to meet its needs.

First introduced commercially almost 70 years ago, Tomlinson technology continues to see marginal improvements. While the Tomlinson technology is not able to be a platform for "biorefining" of the type discussed in Section 1, its efficiency can be improved somewhat beyond the level calculated for the Tomlinson BASE. As a variant on the Tomlinson BASE system, the potential impact of a number of marginal improvements, not all of which have been proven commercially, are examined in the Tomlinson high-efficiency recovery boiler (HERB) case. The most significant changes are an increase in HP steam conditions to 1500 psig, 968^{o}F (104.5 bar abs., 520^{o}C) and an increase in black liquor dry solids concentration to 85%.

Experts in the pulp industry have expressed serious concern over the feasibility in practice of a Tomlinson system operating under these conditions. Of particular concern are boiler-tube corrosion effects (which are more pronounced at higher temperatures and pressures) and the attendant increased risk of recovery boiler explosions, as well as the difficulty and added cost of firing 85% solids black liquor, due to the properties of black liquor at these high solids concentrations.[11] One expert cited past experiences of the electric utility industry with supercritical boilers, which thermodynamically (on paper) promised superior performance, but where were never widely implemented due to practical operating difficulties.

Figure 10 shows the calculated energy and mass balance for a Tomlinson HERB. In addition to the higher steam conditions and black liquor dry solids content, several other changes have been incorporated based on Raukola, *et al.* (2002), Vakkilainen (2003), and Jarmo Kaila (Andritz Company, personal communication). These include reduced soot-blowing steam pressure (25 bar) and flow, HP feedwater heating using 25 bar steam, air pre-heating to 220°C (428°F) by a series of three heaters, the highest-temperature one fed by steam at 25 bar, oxygen content in the boiler flue gases reduced to 1% (volume basis, wet), and exit flue gas temperature reduced to 130°C (266°F).

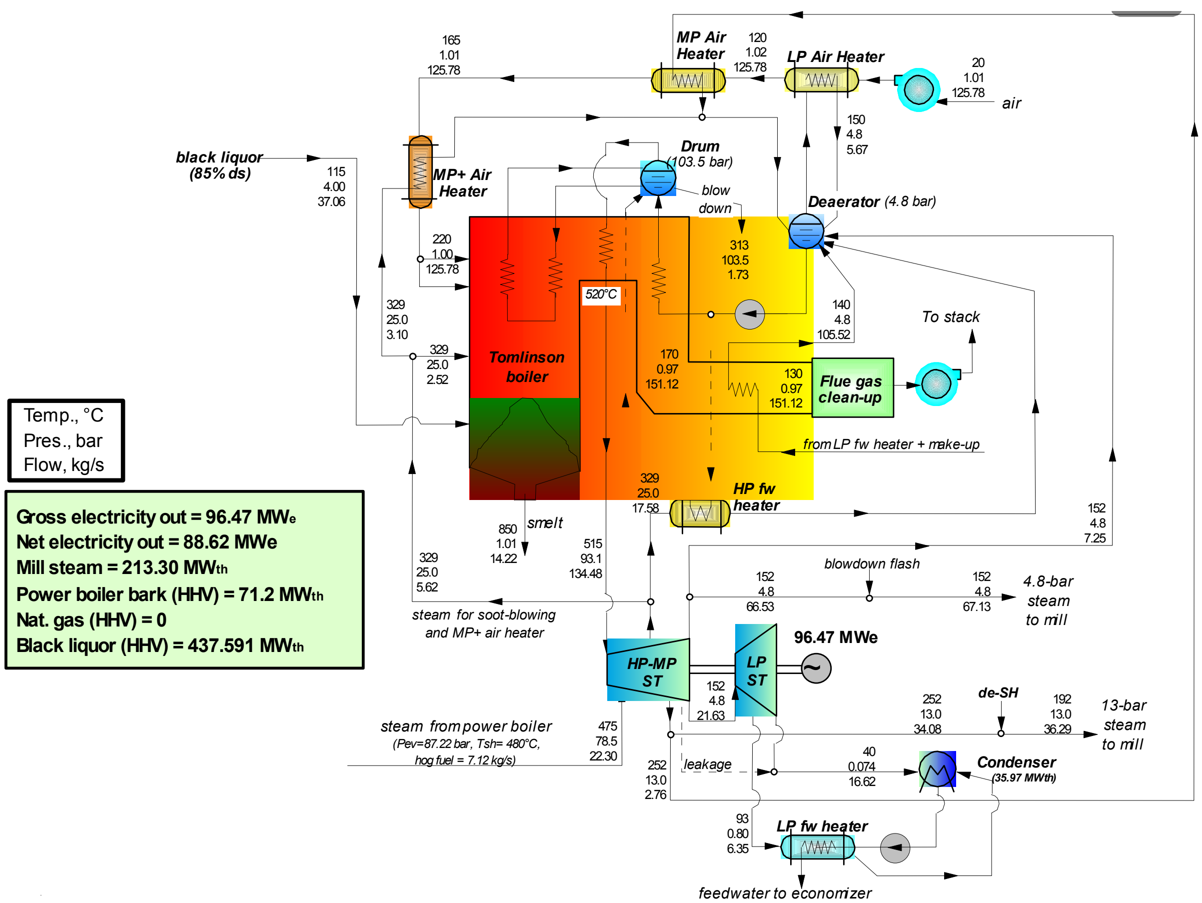


Figure 10. Energy/mass balance for high-efficiency Tomlinson recovery boiler (HERB).

[11] Ben Thorp (Georgia Pacific), Del Raymond (Weyerhaeuser Company), Denny Hunter (Weyerhaeuser Company), personal communication, 4 June 2003.

A new condensing steam turbine, coupled with higher steam-raising efficiency, enables more electricity generation than with the Tomlinson BASE design. Since hog fuel is still available at the mill, the existing hog fuel boilers are assumed to be used to raise additional steam (thereby avoiding any additional capital investment for use of the hog fuel). In this case, since the hog fuel boilers produce steam at lower pressure than the Tomlinson boiler, the hog fuel steam is admitted to the steam turbine following the first or second expansion stage. (For simplicity, the hog fuel boiler is not shown in Figure 10.)

The Tomlinson HERB has a calculated gross electricity generation of 97 MW_e, with a parasitic load of 7.9 MW_e. Considering both the black liquor and hog fuel inputs (438 and 71 MW_{HHV}, respectively), the net electricity generating efficiency of the system is 16.3%. Compared to the Tomlinson BASE case, no additional fuel is consumed, but 24 MW_e of additional electricity are generated, a 38% increase. The mill requires 100 MW_e of process electricity, so some electricity (12 MW_e) must still be purchased to meet the mill's process needs.

5 Kraft Pulp/Paper Mills with Integrated Black Liquor Gasifier Combined Cycle Power and Recovery Systems

To assess the energy and environmental performance of gasification-based power/recovery systems, three black liquor gasifier/combined cycle (BLGCC) plant designs were developed and energy/mass balances were calculated. One key objective of the present study is to assess the commercial viability of gasification technology in the long term. For this reason, the analysis in this study assumes that black liquor gasification systems are at a comparable level of technological maturity as Tomlinson systems. In particular, the commercial risk of installing a black liquor gasification system is assumed to be comparable to that of installing a Tomlinson system in the post-2010 time frame. The implicit assumption is that in the years between the present and the post-2010 time period, research, development, and demonstration work with black liquor gasification technology will enable it to be developed to the point where its reliability would approach that of Tomlinson technology.

This analysis considers full replacement of an existing Tomlinson boiler at the reference mill. An important additional market for black liquor gasification technology that was beyond the scope of consideration here is for incremental black liquor processing capacity. Such applications would arise when an existing Tomlinson boiler does not yet require replacing, but represents a mill's bottleneck to increased pulp/paper production. Such applications will involve considerably smaller black liquor processing requirements than considered in this study.

5.1 General Description of BLGCC Designs

Figure 11 gives a simplified representation of the black liquor gasification/combined cycle (BLGCC) power/recovery systems considered here. The black liquor is first gasified to produce syngas, which is then cooled, cleaned, stripped of H_2S (in a Selexol® unit), and burned in a gas turbine. The gas turbine exhaust passes to a heat recovery steam generator (HRSG). In the process designs considered here, the exhaust passes first through a "duct burner," wherein some syngas or natural gas is burned to generate additional heat for steam raising in the HRSG.[12] The steam drives a steam turbine, from which process steam for the mill is extracted at two pressures.

Three BLGCC systems representing a range of technologies and design philosophies were included in this study. Since commercial gas turbines are available in only a relatively few specific sizes (unlike steam turbines, which can be built to any desired size), the design of the BLGCC system is tied largely to the specific choice of gas turbine. For two of the BLGCC systems (one using a low-temperature gasifier and the other using a high-temperature gasifier), a "mill-scale" gas turbine was selected to match as closely as possible the syngas available from the black liquor gasifier. For the third case, a "utility-scale" gas turbine was selected having the same technological sophistication as the "mill-scale" turbine, but with a larger output capacity that required co-firing natural gas and syngas in the turbine.

[12] Because of the high air-fuel ratio that characterizes gas turbine combustion, there is sufficient oxygen in the gas turbine exhaust to burn additional fuel in the duct burner.

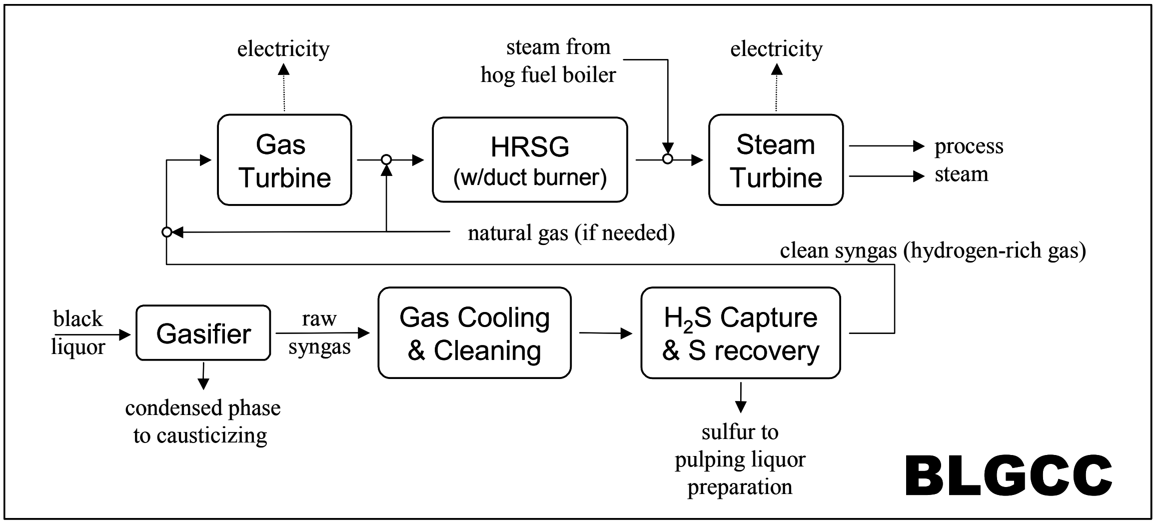


Figure 11. Simplified representation of power/recovery systems simulated in this study.

There are several motivations for examining a "utility-scale" case: *(i)* the relatively modest incremental capital cost that would be involved in stepping up to a larger gas turbine would enable incremental electricity production at low added cost, *(ii)* the ability to export renewable energy and capture potential renewable-energy credits for the fraction of the power generated from biomass, and *(iii)* the larger electricity output may be of greater interest to an electric utility that might partner with a paper company in the development of BLGCC projects.

The key technical features for all three BLGCC systems are described below and summarized in Table 2:

- A black liquor solids concentration of 80% is used in all three cases. This is the same solids concentration as in the Tomlinson BASE analysis.
- Higher steam pressure and temperature are used for the steam cycle than with Tomlinson systems, representing current state-of-the-art for combined cycle systems. This is possible since clean combustion products pass over the boiler tubes in the heat recovery steam generator. A steam pressure of 1870 psia is assumed in all cases. The larger combined cycle in the utility-scale case justifies a slightly higher steam temperature than in the other two cases.
- Back-pressure steam turbines are used in the bottoming cycle in the mill-scale cases. In the utility-scale case, more steam can be produced than needed for the process, so a condensing steam turbine is used to increase electricity production.
- Due to higher thermodynamic efficiencies, gas turbine-based cogeneration systems are characterized by a ratio of electricity-to-steam production that is inherently higher than with steam turbine-based systems. A consequence of this is that for the same process steam demand, a BLGCC requires additional fuel be consumed (purchased wood residues and/or natural gas) in order to produce sufficient process steam for the mill. (The efficiency with which the incremental fuel is used is typically high.)
    - o In the mill-scale BLGCC systems, hog fuel available from the mill is burned in the existing hog fuel boilers to supplement steam raising. Still more steam is needed, so

purchased wood wastes are used up to the assumed capacity of the existing hog fuel boilers at the mill.[13] Remaining heat for steam raising is provided by burning some natural gas in the HRSG duct burner.
    - In the utility-scale case, the heat in the gas turbine exhaust flow is sufficient to raise all process steam needed by the mill, but since some hog fuel is nevertheless available on-site, it is used to raise steam to generate additional electricity in the condensing steam turbine.
- The final row in Table 2 indicates that the BLGCC systems will require fuel consumption at the lime kiln (assumed to be fuel oil in this study) in excess of that required with Tomlinson technology, as was discussed earlier (Section 3.3) and in greater detail later in this section.

Table 2. Summary of BLGCC power/recovery systems case studies.

	Low-Temp Gasifier, Mill-scale GT	High-Temp Gasifier, Mill-scale GT	High-Temp Gasifier, Utility-scale GT
Gas turbine performance based on	General Electric 6FA		GE 7FA
Black liquor solids fraction (% dry)	80	80	80
Co-fire natural gas with syngas in turbine?	No	No	Yes
Steam cycle pressure, psia	1,870	1,870	1,870
Steam cycle temperature, ^{o}F	1,004	1,004	1,049
Steam turbine type	back pressure	back pressure	condensing
Use on-site hog fuel for steam raising?	Yes	Yes	Yes
Purchase wood wastes to raise more steam?	Yes	Yes	No
Natural gas used for supplemental steam?	Yes	Yes	No
Supplemental fuel needed for lime kiln?	Yes	Yes	Yes

5.2 Using Syngas as a Gas Turbine Fuel

Gasified black liquor represents an unconventional fuel for a gas turbine, so some additional discussion of issues relating to integration of the gas turbine is warranted. The calculations carried out for this study consider gas turbine characteristics modeled on two General Electric machines, the 6FA and 7FA. These models belong to the most advanced generation of operating machines now available on the market ("F" technology). The simulated performance is based on operating parameters and performances reported by General Electric (General Electric, 2003) (Table 3).

Using black liquor syngas in a gas turbine raises three major issues. First, the syngas must be free of particulates or contaminants capable of damaging the turbine blades by erosion or corrosion. Due to the presence of chlorine, sulfur and alkali in the black liquor, the syngas generated by the gasifier cannot be fed directly to the gas turbine. Low-temperature, wet scrubbing is considered in this study to ensure adequate removal of acid gases, alkali and particulates.

[13] For the analysis shown here, the hog fuel/wood waste boiler capacity assumed to pre-exist at the mill is 100 MW_{th}, which represents approximately 40% more capacity than is utilized in the Tomlinson process designs.

Table 3. Comparison between the natural-gas based gas turbine performance published by General Electric and predictions with simulation software used in this study. Performance predictions used in this study for syngas operation are also shown.

	6FA, 60 Hz				7FA, 60 Hz		
	conventional applications		low-T gasifier	high-T gasifier	conventional applications		high-T gasifier
fuel	natural gas		syngas		natural gas		syngas
ambient conditions	ISO (15°C, 1 atm)		20°C, 1 atm		ISO (15°C, 1 atm)		20°C, 1atm
air flow, kg/s	204.00	204.00	200.51	186.37	432.00	432.00	414.56
compressor outlet T, °C	n.a.	409	427	431	n.a.	402	420
fuel flow, kg/s	n.a.	4.43	11.92	29.73	n.a.	9.56	36.16
fuel LHV, MJ/kg	n.a.	48.91	20.95	9.32	n.a.	48.91	15.31
fuel mol weight, kg/Mol	n.a.	16.29	13.15	19.32	n.a.	16.29	18.85
exhaust flow, kg/s	n.a.	208.43	212.44	216.13	n.a.	441.56	450.69
pressure ratio	15.7	15.7	16.2	16.5	15.5	15.5	16.0
TIT, °C	n.a.	1,316	1,316	1,316	n.a.	1,316.0	1,316
TOT, °C	604	604	613	626	602.0	602.5	617
power output, MW	75.9	75.7	76.91	86.98	171.7	171.6	176
LHV efficiency, %	34.8	34.9	-	-	36.2	36.7	-
DP at compressor inlet, kPa	n.a.	0.0	1.0	1.0	n.a.	0.0	1.0
DP at turbine outlet, kPa	n.a.	0.0	4.0	4.0	n.a.	0.0	4.0
	GE data	our calculation			GE data	our calculation	

Second, the fuel mass flow rate needed to reach a given turbine inlet temperature (TIT) is much higher than that needed with a higher-calorific-value fuel like natural gas. This requirement affects the match between the compressor and turbine operating conditions, as discussed in Appendix A. The mismatch that would otherwise occur is taken into account in the simulations in this study by allowing up to a 5% increase in compressor pressure ratio (compared to operation on natural gas) and by decreasing air flow at the compressor inlet (simulating adjustments of inlet guide vanes) if further mass flow reduction is required. See Appendix A for details.

Third, combustor stability and emissions, and fuel injector pressure loss characteristics may be substantially different from those realized with natural gas. The first two effects are mainly related to the syngas chemical composition and heating value; the third to its flow rate. Based on pilot-scale experimental work and on coal integrated gasification combined cycle (IGCC) operating experience at refineries and steel plants, a fuel calorific value above 4-6 MJ/Nm^3 (1 Nm^3 = 1 m^3 at the "normal" conditions of 1 atm, 0°C) ensures stable combustion. The syngas heating values in this study considerably exceed this lower limit, so combustion stability will not be a concern. The increased fuel injector pressure losses can be accommodated either by increasing the fuel pressure or by increasing the injector cross-section. In the simulations reported here, the pressure of the syngas delivered to the fuel injector is assumed to be 50% higher than the combustor pressure, which exceeds by a substantial amount the typical delivery over-pressure for natural gas firing.

Despite these special considerations for operating gas turbines on syngas, it is worth noting that a great deal of development work has been done and operating experience has been acquired in connection with coal IGCC technology. For example, General Electric offers eight different gas turbines models, ranging from 10-300MW, for use with syngas (www.gepower.com), including the two models evaluated here.

5.3 Low-Temperature BLGCC with Mill-Scale Gas Turbine – Detailed Design and Performance[10]

The low-temperature BLGCC power/recovery system (Figure 12) is designed around the technology proposed by TRI. Because of the indirect heating of the black liquor, the heating value of the resulting gas is relatively high compared to the gas from a partial oxidation gasifier such as the high-temperature design considered in this study (Table 4). Another impact of the lower temperature is that most of the sulfur in the black liquor leaves the gasifier as gas-phase H_2S. This affects the design of the sulfur recovery system, as discussed in Section 3.3 and further below.

Table 4. Composition, heating value, and use of clean syngas in the BLGCC power/recovery system simulations.

	Low-Temp Gasifier Mill-scale GT	High-Temp Gasifier Mill-scale GT	High-Temp Gasifier Utility-scale GT
Composition (vol%)			
Ar	0.00	0.66	0.66
CH4	3.49	1.44	1.44
CO	23.74	26.09	26.09
CO2	10.50	11.27	11.27
COS	0.01	0.05	0.05
H2	61.91	27.51	27.51
H2O	0.34	32.73	32.73
N2	0.00	0.24	0.24
Higher heating value (MJ/kg)	20.95	9.32	9.32
Burned in gas turbine (MW, HHV)	249.7	277.0	291.6
Burned in pulse combustor (MW, HHV)	132.8	--	--
Burned in duct burner (MW, HHV)	23.8	14.4	--

The need to supply heat indirectly for the endothermic gasification reactions occurring at near-atmospheric pressure, together with the need to pressurize the syngas for gas-turbine fueling and for acceptable performance and cost of the physical absorption system for sulfur removal, demand tight integration between the gasification and power islands in this BLGCC design.

The design of the low-temperature BLGCC system was developed with extensive input from engineers at TRI.[14] In this design, the raw syngas leaving the gasifier at 600°C is cooled to 250°C (482°F) through HP and LP boilers, and the discharged bed solids are cooled to 250°C (482°F) by generating MP steam. Cooling of the syngas below 250°C is desirable to improve energy efficiency but would cause condensation of tars in the raw syngas (and corresponding

[14] Visit to TRI headquarters in Baltimore (April 2003), augmented by additional personal communication with TRI staff, including Ravi Chandran, Mansour Momtaz, Lee Rockvam, and others.

fouling of downstream equipment). The alkali, tar and most of the water vapor in the syngas are removed by scrubbing and cooling to 40°C (104°F), the operating temperature of the sulfur recovery unit (SRU). The clean syngas is then compressed to 320 psig (23 bar abs.) in an intercooled compressor and fed to the SRU; this pressure is needed to feed the fuel gas to the gas turbine and, at the same time, gives a reasonable performance and cost of the physical sulfur absorption system (Selexol®).

In the SRU H_2S is absorbed, and some CO_2 is co-absorbed (as discussed in Section 3.3). The sulfur in the absorbed "acid gas" must be recovered for reuse in pulping. This is accomplished by stripping 43% of the H_2S in the acid gas using green liquor to form Na_2S in the green liquor.[15] Some CO_2 is unavoidably co-absorbed, forming additional Na_2CO_3 in the green liquor.[16] The balance of the acid gas is sent to a Claus/SCOT plant, where elemental sulfur is generated and the CO_2 is vented. The elemental sulfur is then dissolved in low-sulfidity white liquor (generated by causticizing the green liquor). The Na_2S formed in the green liquor during acid gas stripping is necessary to provide a sufficient sulfide base in the white liquor to generate a polysulfide pulping liquor. As discussed in detail in Appendix A, this sulfur recovery scheme, when combined with an inherent increase in causticizing load due to increased Na_2CO_3 leaving a gasifier (relative to that found in a Tomlinson smelt) leads to an estimated increase in lime kiln load for this BLGCC system of 44% relative to the load with a conventional Tomlinson system. This estimate takes account of both the higher kiln load per unit of black liquor solids processed through the recovery area, as well as the reduction in black liquor flow to the recovery area in the BLGCC case due to the use of polysulfide pulping (which decreases the wood feed to the digester for a fixed pulp output rate.) The high incremental lime kiln load requires installation of an additional causticizer and lime kiln as part of this BLGCC system.

Following the SRU, the syngas is divided into two streams: one to the gas turbine, the other to the pulse combustors providing the heat required by the gasifier. Since the pulse combustors work at atmospheric pressure, the flow directed to them is first pre-heated to 450°C (842°F) and then expanded in a radial fuel-gas expander to recover part of the power needed by the syngas compressor; the low-pressure syngas discharged by the expander burns in air in the pulse combustors. The pulse combustor flue gases at 662°C (1224°F) are cooled to 535°C in a heat exchanger pre-heating the compressed syngas ahead of the syngas expander and are then mixed with the gas turbine exhaust ahead of the duct burner. For the specified black liquor flow and selected gas turbine, the syngas generated by the gasifier is slightly in excess of what is needed by the gas turbine plus pulse combustor. The excess gas (after following the same processing path as the syngas used for the pulse combustor) is burned in the duct burner.

---

[15] Stripping 43% of the H_2S enables a composition for the polysulfide liquor identical to the composition of the polysulfide liquor generated with the high-temperature BLGCC system.

[16] A selectivity factor of 9 is assumed for the relative rates of H_2S to CO_2 absorption in green liquor (Larson *et al.*, 2000b).

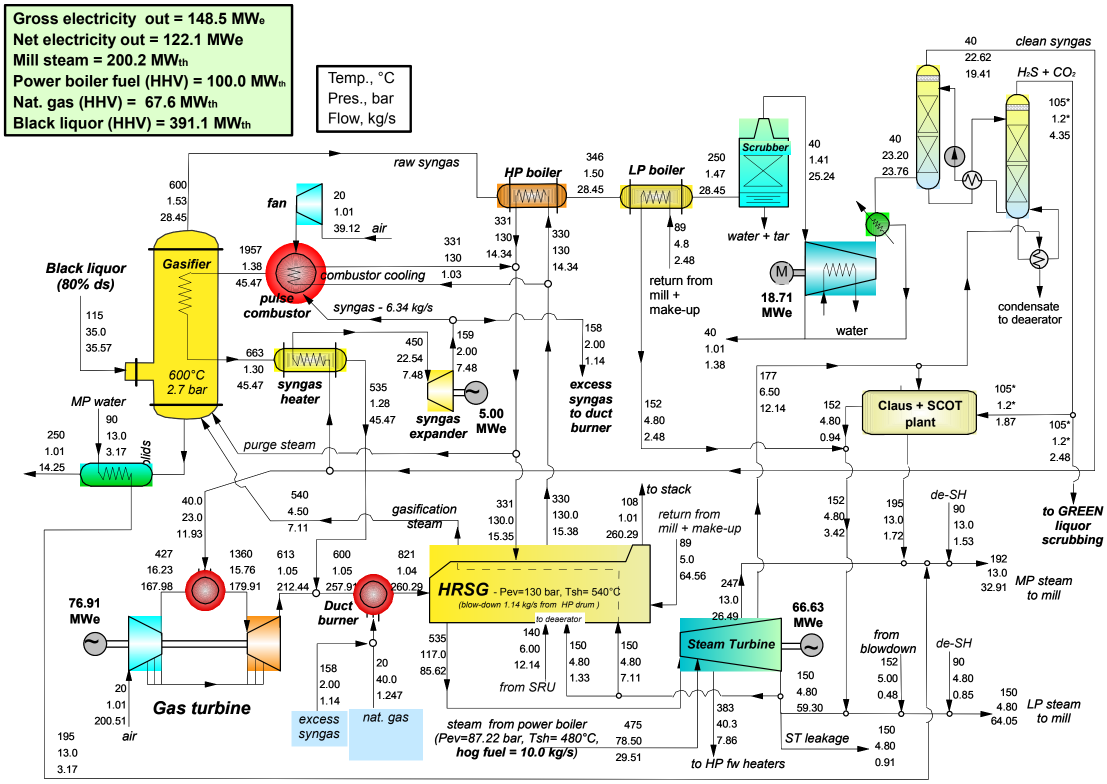


Figure 12. Energy/mass balance for BLGCC with low-temperature gasifier and mill-scale gas turbine.

The existing hog fuel boilers (not shown in Figure 12) provide 1,250 psig steam by burning 67 MW_{HHV} of hog fuel and 33 MW_{HHV} of purchased wood residuals. In addition to the steam that can be generated based on the black liquor, hog fuel, and purchased residuals, additional heat input is needed to meet the process steam demands of the mill. Natural gas is burned in the duct burner (together with syngas) to provide the needed heat.[17] Steam needed for fluidizing the bed and for the gasification reactions is taken from the LP header, superheated to 540°C (1004°F) in the HRSG and then fed to the gasifier.

This low-temperature mill-scale BLGCC power/recovery system has a gross electricity generation of 148.5 MW_e, 52% of which is produced by the gas turbine. The parasitic load is 26.4 MW_e, mostly due to the syngas compressor. Since the mill requires 100 MW_e for the process, 22 MW_e are available for export from the mill (Table 5).

Considering the black liquor, hog fuel, purchased wood residues, natural gas, and lime kiln fuel as energy inputs, the net electricity generating efficiency of the system is 20.0%, which is substantially higher than for the Tomlinson BASE case. Perhaps a better indication of improved energy efficiency is the efficiency with which additional purchased fuels are use for electricity generation relative to the Tomlinson BASE case. This value is a respectable 50% on a higher heating value basis (Table 5).

[17] An alternative way to provide the needed additional heat might be to install additional wood-waste boiler capacity. This option does not appear to be economically attractive unless the price of natural gas reaches more than \$5 per million Btu. The alternative between additional power boiler capacity and duct burner obviously depends on the relative costs of natural gas and hog fuel and would need to be verified on a case by case basis.

Table 5. Summary of performance estimates for all power/recovery system simulations.

	Tomlinson		BLGCC		
	BASE	HERB	Low-Temp Gasifier, Mill-scale GT	High-Temp Gasifier, Mill-scale GT	High-Temp Gasifier, Utility-scale GT
FUEL INPUTS, MW (HHV)					
Mill by-product fuels	**508.8**	**508.8**	**457.7**	**457.7**	**457.7**
Black liquor to gasifier	437.6	437.6	391.1	391.1	391.1
Hog fuel	71.2	71.2	66.6	66.6	66.6
Purchased fuels	**33.1**	**33.1**	**148.7**	**85.9**	**301.2**
Wood wastes (MW, HHV)	0	0	33.4	33.4	0.0
Natural gas to gas turbine (MW, HHV)	--	--	0.0	0.0	263.0
Natural gas to duct burner (MW, HHV)	--	--	67.6	14.3	--
Lime kiln #6 fuel oil (MW, HHV)	33.1	33.1	47.7	38.2	38.2
TOTAL FUEL INPUTS, MW (HHV)	**541.9**	**541.9**	**606.4**	**543.6**	**758.9**
STEAM TO PROCESS[a]					
LP (55 psig) steam to process	142.8	141.8	135.3	135.3	135.3
MP (175 psig) steam to process	69.3	71.5	64.9	64.9	64.9
Total process steam, MW	**212.1**	**213.3**	**200.2**	**200.2**	**200.2**
ELECTRICITY (MW)					
Gas turbine gross output	--	--	76.9	87.0	175.8
Steam turbine gross output	72.0	96.5	65.1	48.2	71.5
Syngas expander output	--	--	5.0	0.0	0.0
Total gross production	*72.0*	*96.5*	*147.0*	*135.1*	*247.4*
Air separation unit power use	--	--	--	14.3	14.3
Syngas compressor power use	--	--	18.7	--	--
Auxiliaries for steam cycle	6.7	6.8	1.9	1.2	2.6
Auxiliaries for gasification island	--	--	2.7	2.7	2.7
Auxiliaries for sulfur recovery unit	--	--	2.1	1.1	1.1
Auxiliaries for hog fuel boiler	1.0	1.0	1.2	1.2	1.0
Total recovery area use	*7.7*	*7.8*	*26.6*	*20.5*	*21.6*
NET POWER PRODUCTION, MW	**64.3**	**88.6**	**122.1**	**114.7**	**225.8**
Power in excess of Tomlinson BASE	--	24.3	57.8	50.4	161.5
Process use (excluding recovery area)	100.1	100.1	100.1	100.1	100.1
Excess power available for grid	- 35.8	- 11.5	22.0	14.6	125.7
EFFICIENCIES (HHV basis)					
(Steam + Electricity)/(Total fuel input)	0.510	0.557	0.531	0.579	0.561
(Net Electricity Output)/(Total fuel input)	0.119	0.163	0.201	0.211	0.298
Efficiency of purchased fuel use[b] (%)	--	--	0.500	0.955	0.602

(a) Excludes steam used in the power/recover area

(b) Defined for the BLGCC cases as the net electricity produced in excess of Tomlinson BASE electricity output divided by the difference in total purchased fuel between the BLGCC case and the Tomlinson BASE.

5.4 High-Temperature BLGCC with Mill-Scale Gas Turbine – Detailed Design and Performance[10]

The high-temperature BLGCC power/recovery system with the "mill-scale" gas turbine (Figure 13) is designed around a technology being developed by Chemrec. In this process the raw syngas undergoes an integral quench in the lower section of the gasifier vessel, leaving the reactor at 217°C, 35 bar. The gas is then cooled through a MP boiler and a water heater. Most of the water in the syngas condenses, thereby releasing most of the energy picked-up in the quench. Chemrec indicates that the flow of condensate in a counter-current heat exchanger favors the removal of alkali down to very low concentrations. The syngas passes from the water heater at about 120°C to a trim cooler, which it leaves at 40°C before entering the SRU.

As in the low-temperature BLGCC design, all of the H_2S and some of the CO_2 in the syngas are absorbed in the SRU. Unlike the low-temperature case, all of the H_2S is converted into elemental sulfur. This sulfur recovery scheme can be used because of the high gasification temperature, which leads to about half of the sulfur in the black liquor leaving the gasifier in the smelt, where it forms Na_2S. This sulfide subsequently appears in the white liquor, providing the needed base for polysulfide formation when elemental sulfur is dissolved in it. Because a substantial fraction of the sulfur entering the gasifier leaves with the smelt, and because all of the H_2S in the syngas is captured and converted to elemental sulfur without co-absorption of CO_2 into green liquor (as in the low-temperature BLGCC case), the estimated additional lime-kiln load for this BLGCC design (relative to the Tomlinson BASE system) is a relatively modest 16% (see Appendix A for details). This level of lime kiln load increment can likely be accommodated at many mills with no significant modifications. For this study, it is assumed that oxygen-enriched air is used to increase the throughput capacity of the existing kiln (see Appendix A). A small increase in the size of the air separation unit (needed to supply oxygen to the gasifier) provides a low-cost source of oxygen for this purpose.

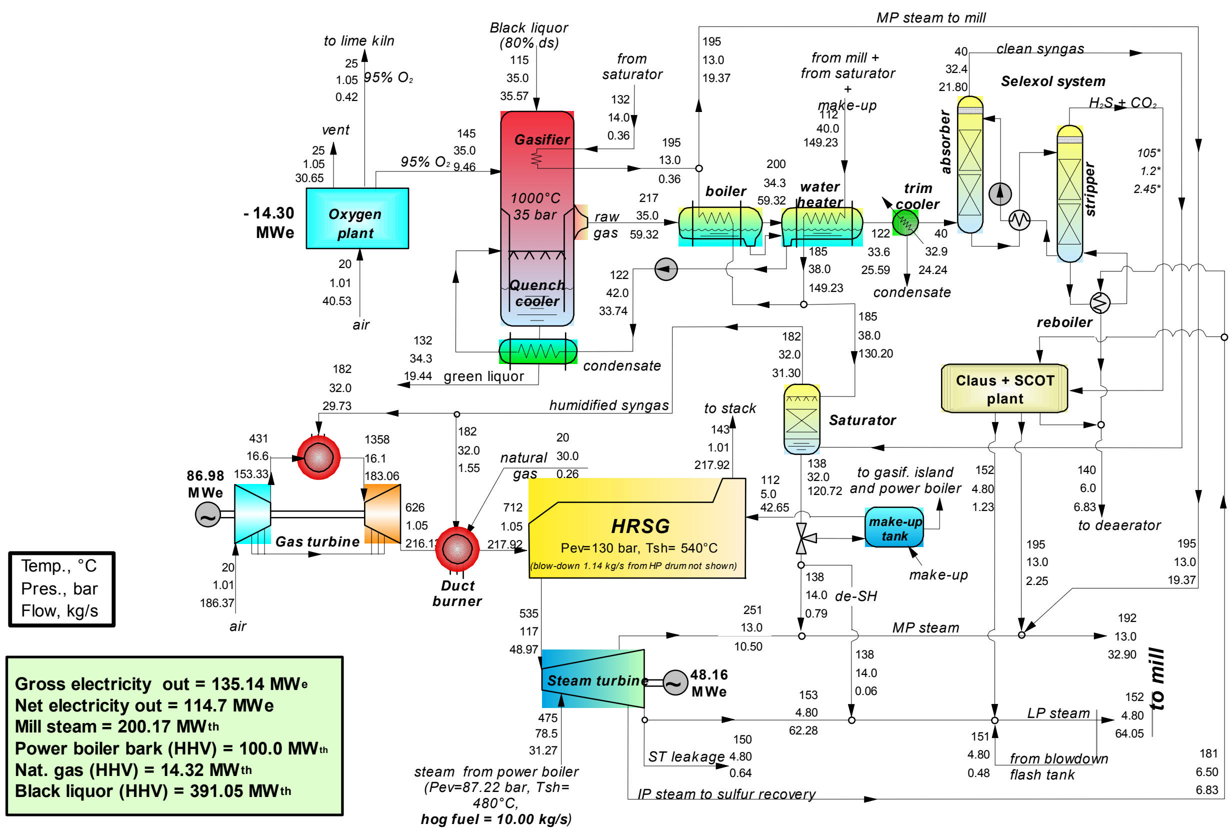


Figure 13. Energy/mass balance for BLGCC with high-temperature gasifier and mill-scale gas turbine.

The sulfur-free syngas leaves the SRU and travels to a saturator, wherein the gas is humidified by mixing with water pre-heated to 185°C. By humidifying the syngas, a significant increase in power production from the gas turbine can be achieved (due to increased syngas mass flow). The humidified gas also results in a lower flame temperature in the gas turbine combustor, thereby reducing thermal NO_x emissions.

The available black liquor enables slightly more syngas to be generated than is required to fuel the gas turbine (as with the low-temperature BLGCC process). Excess syngas is directed to a duct burner. Because of the relatively low heating value of the syngas fed to the gas turbine (Table 4), and hence the large required syngas mass flow, the gas turbine operates at its maximum allowable pressure ratio (taken to be 5% above the rating for natural gas firing) and with a reduced compressor air flow rate.

Hog fuel boilers (not shown in Figure 13) consume 67 MW_{HHV} of hog fuel and 33 MW_{HHV} of purchased wood residues (as in the low-temperature BLGCC case). A small amount of natural gas supplements the syngas burned in the duct burner to meet the mill's steam demand.

This BLGCC power/recovery configuration has a gross electricity generation of 135 MW_e, 64% of which is produced by the gas turbine. The parasitic load is 20.5 MW_e, mostly due to the cryogenic air separation unit. Since the mill requires 100 MW_e for the process, 14.5 MW_e are available for export (Table 5).

Considering the black liquor, hog fuel, purchased wood residues, natural gas, and lime kiln fuel as energy inputs, the net electricity generating efficiency of the system is 21.1%. The efficiency of added purchased fuel use for incremental electricity generation (relative to Tomlinson BASE) is 96% in this case. This very high value is simply due to the fact that with gasification, power is generated by a thermodynamic system – the combined cycle – inherently more efficient than the steam cycle used with the Tomlinson BASE system. Notice that the "Efficiency of purchased fuel use" reported at the bottom of Table 5 is a marginal efficiency defined as the ratio between two incremental values: extra-electricity divided by extra-fuel consumption; as such, it can take on any value, including greater than one or negative.

5.5 High-Temperature BLGCC with Utility-Scale Gas Turbine – Detailed Design and Performance[10]

The process configuration, including the sulfur recovery design, for the high-temperature BLGCC power/recovery system with a "utility-scale" gas turbine (Figure 14) is similar to the high-temperature BLGCC with "mill-scale" gas turbine. Unlike the latter, however, a larger gas turbine is used, requiring natural gas to supplement the syngas available from the black liquor.

No duct burner is needed in this configuration, since the amount of gas turbine exhaust heat is more than sufficient to generate the needed mill process steam. Since hog fuel boilers and by-product hog fuel are available on site, these are utilized to generate additional steam. All of the steam is expanded through a condensing steam turbine, with extractions at several pressure levels to provide the mill with process steam and the SRU with needed steam.

This power/recovery configuration has a gross electricity generation of 247 MW_e, 71% of which is produced by the gas turbine. The parasitic load is 21.6 MW_e, again mostly due to the cryogenic air separation unit. Since the mill requires 100 MW_e for the process, 126 MW_e are available for export sale (Table 5).

Considering the black liquor, hog fuel, natural gas, and lime kiln fuel as energy inputs, the net electricity generating efficiency of the system is 29.8%. The efficiency of incremental purchased fuel use for electricity generation (relative to Tomlinson BASE) is 60% (HHV basis), which is comparable to the efficiency achievable with large state-of-the-art natural gas combined cycles.

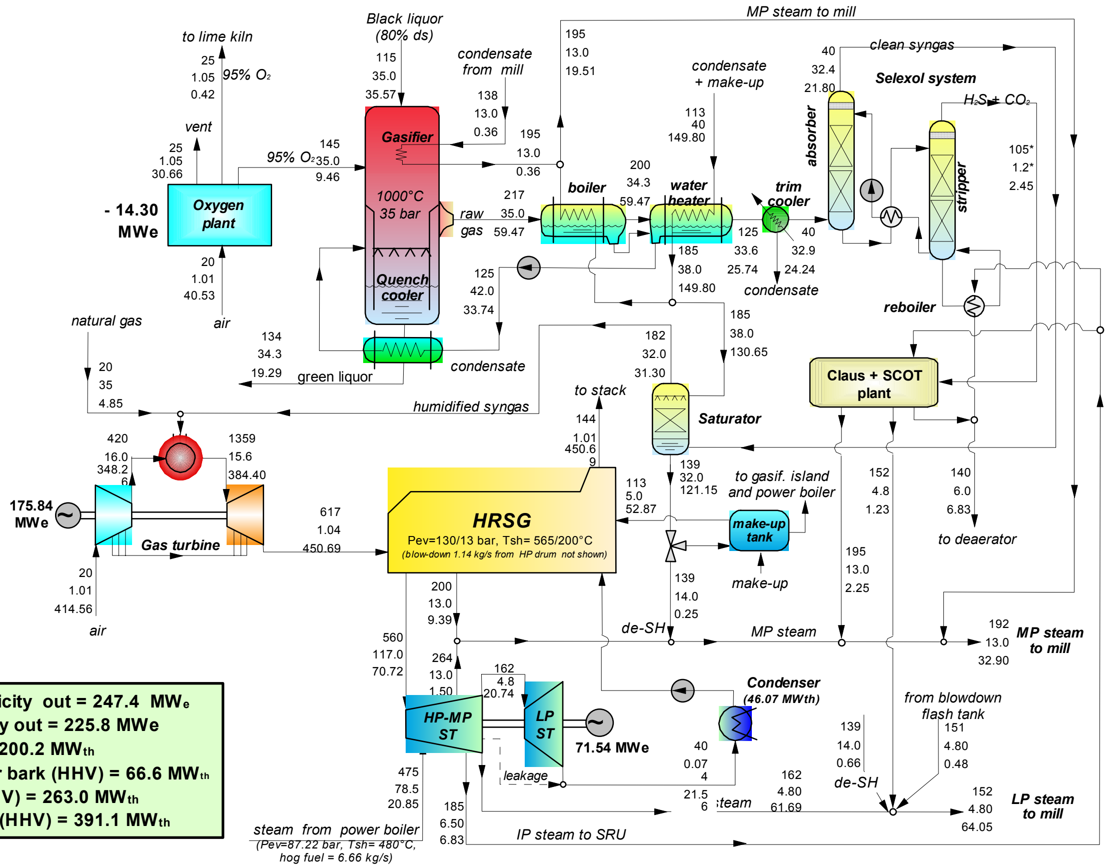


Figure 14. Energy/mass balance for BLGCC with high-temperature gasifier and utility-scale gas turbine.

5.6 Research, Development, and Demonstration Needs

The energy and mass balances for BLGCC systems presented above have assumed Nth-plant levels of technological maturity, which assumes successful research, development, and demonstration (RD&D) at several levels over the next few years.

In some areas of the simulated BLGCC systems, assumptions have been made on key issues around which there is considerable uncertainty today (such as the feasibility of removing essentially all alkali vapor from syngas before it is fired in the turbine). In these areas (as with other areas) the analysis in this study assumes RD&D efforts are successful. In other areas, there is reasonable confidence that optimized performance can be achieved as simulated in this study (e.g., the gas turbine operating on syngas), although a modest demonstration effort is required to fully prove this expectation. In still other areas, process designs may be sub-optimal, but can reasonably be assumed to be implementable (e.g., sulfur recovery from syngas), since they have been used in other applications. In these areas, new approaches could improve (substantially in some cases) overall performance of the system. Using this three-tier classification system, Table 6 summarizes key RD&D issues associated with commercializing BLGCC systems.

Table 6. Technical research, development, and demonstration activities required to realize commercial BLGCC systems. Qualitative importance of each issue is as follows: ● = crucial; ◖ = important; ○ = relevant but not vital; --- = not applicable/not relevant.

ISSUE	CONCERNS	RELEVANCE	
		High T. BLGCC	Low T. BLGCC
Critical issues with uncertainty and where success of RD&D is assumed			
Alkali removal from syngas	Alkali compounds (especially as alkali sulfates) will cause corrosion of gas turbine blades. Trace levels (at most) can be tolerated in gas turbine fuel	●	●
Tar removal from syngas	Fouling of downstream equipment, reduced gasification efficiency, potential disposal issue	◖	●
Reliability of gasification island[a]	Shutdown of gasification island can cause very substantial negative impacts on the economics of gasification	●	●
Areas where there is reasonable confidence in achieving predicted performance where success of RD&D is assumed			
Syngas fueling of gas turbine[a]	Low heating value of syngas (compared to natural gas) requires gas turbine combustor redesign and compressor air flow control. Feasibility of syngas fired turbines has been commercially demonstrated, e.g., in coal IGCC plants.	○	○
Oxygen-enriched combustion air for lime kiln	Modest capacity increases can be achieved by retrofitting existing air-blown kilns. New burner design and possibly new refractory may be required, but no fundamental difficulties anticipated up to 20% capacity increase.	◖	---
Solids handling and heat exchange	Considerable solids must be handled with the low-temperature gasifier design. Ability to handle high-temperature solids and transfer heat from them needs to be proven.	---	◖
Process integration and control	Achieving energy, environmental and economic benefits of gasification relies crucially on the tight integration of the gasification island, the power island and the mill. This requires both an appropriate design approach and proper control	●	●
Areas where new approaches (developed through RD&D) might be desirable			
In situ tar destruction	Increasing gasification temperature should help reduce tar production. New refractory materials for the gasifier may be needed.	◖	---
New sulfur recovery and integration with mill chemistry	A "brute force" arrangement was assumed in this study. New approaches to sulfur recovery may improve performance and/or reduce costs	○	◖
Gasifier pressurization	Higher pressure operation will reduce vessel size, but the pulse combustor tube bundle and other aspects of the gasifier design would require thorough reconsideration.	---	●
Better refractory materials	Improved resistance to corrosion/erosion, leading to longer lifetimes, will improve reliability and reduce maintenance costs.	◖	◖
Direct causticizing	Incremental lime kiln load with BLGCC is especially large with low-temperature gasifiers. If direct causticization can eliminate the need for any kiln, considerable process simplification and cost reduction would be the result.	○	●
New black liquor gasifier designs	Other gasifier designs may provide different benefits.	---	---
Woody-biomass gasification	Higher efficiency of power generation (and greater production of exportable electricity) would be achievable if woody biomass were gasified instead of burned in a boiler (as in this study).	◖	◖
Expanding product slate of a biorefinery	System analyses would help understand energy, environment, and economic characteristics of biorefineries, e.g., co-producing fuels and electricity; results would help guide the pursuit of relevant technology RD&D.	◖	◖

(a) Issue in common with coal gasification research, development, and demonstration requirements.

6 Environmental Considerations

6.1 Overview

In addition to the prospective energy benefits of BLGCC systems discussed in the previous section, attractive environmental attributes (relative to Tomlinson systems) are expected to characterize BLGCC systems. Water, air, and solid effluents are all of potential concern. In assessing the impact BLGCC systems would have on these effluents relative to levels found with Tomlinson power/recovery systems, one may consider changes both in direct effluents and in effluents associated with grid electricity generation that is displaced by BLGCC electricity.

Water quality, temperature, and the quantity used are all potential concerns with BLGCC. Over time, as demand rises for limited fresh water supplies, these issue are likely to only become more important. Moreover, the Southeast suffers from some of the more acute water availability problems in the United States. Briefly, the issues are as follows:

- *Water quantity*: any water savings results in a direct financial benefit to the mill and also addresses growing concerns over the availability of fresh water for other purposes (e.g., agriculture, human consumption).
- *Water quality* is of major concern for rare and endangered species, recreation, and for its effects on other users downstream (e.g., municipalities).
- *Thermal discharge*: The temperature of the water discharge is also of concern for its effect on flora and fauna.

Depending on the configuration (mill-scale or utility-scale), BLGCC will have different effects on water quantity and thermal discharge at the mill, but is not expected to significantly impact water quality. Wastewater streams from gas cleaning in the BLGCC cases (which do not exist in a Tomlinson system) are used to constitute green liquor, and are thereby effectively recycled. Water use for condenser cooling will be the main source of thermal water pollution with either the BLGCC or Tomlinson technologies. In this regard, since both the mill-scale BLGCC systems use back-pressure steam turbines, there is no condenser and therefore no discharge of cooling water. For the case study mill, this results in a decrease of approximately 2,200m^3/hour in cooling water discharge and a water savings of 80m^3/hour for makeup water to the cooling towers. For the utility-scale BLGCC system, there would be an increase in cooling water discharge of approximately 1,100m^3/hour and the need for an additional 40m^3/hour of makeup water, or roughly a 50% increase. (See Appendix A for more details) However, each of the BLGCC cases results in substantial reductions in grid power production relative to the Tomlinson BASE case, which would have associated reductions in cooling water requirements, since traditional central station power plants have significant water requirements for cooling towers.

Solid waste issues relate to the quantity and toxicity of any solids that must be disposed of. In this regard, BLGCC is not expected to result in significant changes at the mill, in part because the solids produced (mainly ash from biomass) are not problematic to deal with. However, as with water usage, the impacts of displaced grid power, particularly for the coal component of that grid power, could result in important reductions of solid waste generation.

Since the most significant effluent differences between BLGCC and Tomlinson systems are expected to be in air emissions, more detailed analysis of air emissions was carried out as part of this study. As discussed in detail below, air emissions were estimated for both BLGCC and Tomlinson power/recovery systems. Actual data are available for modern Tomlinson systems. Since emissions data do not exist for BLGCC systems, estimates were based on data for coal IGCC and natural-gas combined cycle power systems. Estimates for all systems also include emissions from the lime kiln and hog fuel boilers. Emissions from the duct burner in the mill-scale BLGCC cases and the pulse combustor in the low-temperature BLGCC case are also included to provide complete comparisons between all options. Estimates for grid power offsets (for both avoided purchases and exported power relative to the Tomlinson BASE) were also made.

The air emissions analysis presented below is not intended to serve as a full lifecycle analysis of BLGCC emissions. Rather the estimates provide indicative results of the potential impacts of BLGCC technology. Specifically, the analysis does not include an assessment of the emissions impacts *upstream* of the mill, that is, the growing, harvesting and transportation of wood, which includes the use of fossil fuels.[18] Similarly, upstream emissions for grid power are also not included, but these are relatively small compared to the power plant emissions themselves. To more completely understand the impact of BLGCC, including the long-term implications for other biomass use in the forest products industry, a more focused, full lifecycle impacts assessment would be required.

Air emissions fall into three basic categories: criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHGs). This study includes quantitative estimates for sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM),[19] and total reduced sulfur (TRS). Estimates are also made for carbon dioxide (CO_2), the major greenhouse gas. HAPs and other emissions issues are discussed qualitatively.[20] A distinctive feature of BLGCC technology is the expected low relative emissions for most of these pollutants compared to a modern Tomlinson system employing

---

[18] There are some carbon emissions associated with fuels (and for crops, fertilizers) used to grow, harvest and transport biomass, but these are small relative to carbon contained in the wood. For example, Paper Task Force (1995) concludes that "…for all grades of paper and for both virgin and recycled-fiber systems, manufacturing energy is the predominant use of energy by a large margin. Materials and residuals collection, processing and transport are all relatively small by comparison."

[19] For PM, the main concern is with the health impacts of fine particulates smaller than 10 and 2.5 microns in diameter (PM_{10} and $PM_{2.5}$, respectively). However, data for PM_{10} and $PM_{2.5}$ are not always reported with data for total PM emissions. For this reason, estimates here are for total PM. To estimate PM_{10} and $PM_{2.5}$ emissions, the reader can assume the following: For solid fuel combustion, if there is a PM control step, such as an electrostatic precipitator, the PM_{10} emissions are 50-80% of total PM emissions and $PM_{2.5}$ emissions are 25-70% (NCASI 2002c; EPA, 2002a). For natural gas combustion, the U.S. EPA assumes that all PM emissions are smaller than 2.5 microns so that PM, PM_{10} and $PM_{2.5}$ emissions are equal (EPA, 1998).

[20] According to Miner (2003) EPA's HAP rules focused on HAP metal emissions from recovery furnaces, using total particulate matter as a surrogate for metals emissions. For existing furnaces, they did require reductions in emissions of organic HAPs, e.g. methanol, that arose from direct contact evaporators, associated black liquor oxidation systems, or wet bottom ESPs. EPA also decided that recovery furnace HCl emissions did not merit reductions, since the risks posed by the HCl emissions were determined to be minimal. Further EPA opted not to address dioxin/furan emissions since there is no known control technology that could be applied to reduce them. Also, the industry believes dioxin/furan emissions from recovery furnaces are inconsequential. EPA did decide to impose a methanol (VOC surrogate) emission limit on new kraft recovery furnaces.

sophisticated pollution controls (Table 7). Low emissions are an intrinsic characteristic of BLGCC technology: considerable upstream removal of contaminants in the raw syngas is required to protect the gas turbine from damage, as well as to recover pulping chemicals from the gas. Also, gas turbine combustion is inherently efficient and complete due to high overall air-fuel ratios.

Biomass is a renewable fuel from a GHG perspective, if the CO_2 emitted in its use is photosynthetically removed from the atmosphere by replacement biomass growth. As noted above, there are some fossil fuel GHG emissions associated with upstream steps, but for this analysis, we have ignored them. Moreover, since the total biomass use in the Tomlinson and BLGCC cases is similar (See Table 5), the net effect of BLGCC on upstream biomass-related emissions will be small. Thus, the estimates of total net emissions of CO_2 described below for each power/recovery system assumes wood-derived fuels produce no net CO_2 emissions. However, for completeness, in this section we also show the actual emissions of CO_2 associated with the wood-derived fuels (in addition to the net emissions). Appendix B has additional details on these calculations. Biomass combustion also generates small amounts of non-CO_2 greenhouse gases - specifically, methane and nitrous oxide. However, even after considering the potency of methane and nitrous oxide as greenhouse gases, these emissions are small. As a result, they have not been included in the analysis.[21]

An additional feature of BLGCC power systems not evaluated here, but that could be important to overall mill operations as it relates to environmental discharges, is the potential to more tightly integrate and eliminate various waste steams.[22] In "next generation" mills, the desire is to "close up" various emissions sources as much as possible. For example, the pulp & paper industry has been trying to develop a cost-effective way to eliminate the effluent from bleached kraft pulp mills. The most likely approach for eliminating these effluents (primarily bleach plant filtrates) involves sending them to the recovery furnace, yet few mills currently recycle bleach plant filtrates to the recovery furnace because these furnaces are sensitive to a number of elements contained in the filtrates (chlorides and potassium being of special note) and the costs of removing these substances are high. If BLGCC turns out to be more amenable to this type of overall mill integration, it could be a significant advantage over conventional recovery systems.

6.2 Tomlinson Boiler Air Emissions

Modern Tomlinson boilers are characterized by emissions of criteria pollutants that are similar overall to grid power (some are higher like, CO and PM, while others are lower, like SO_2 and NOx). The most significant pollutants, in terms of both environmental impacts and relative emissions rates from Tomlinsons, are NO_x and particulates (Table 7). While many furnaces already have particulate controls in place, there is no effective form of NO_x after-treatment (see below). Furnace rebuilds and replacements trigger the New Source Review (NSR) process, which generally results in process modifications being made to reduce TRS emissions.[23] Installation of more efficient particulate control is also common following a NSR, and generally,

[21] For example, see "Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.0", a project by NCASI for ICFPA and available on the internet at www.ncasi.org.
[22] Personal communication with Reid Miner and Dr. John Pinkerton of NCASI, 3 December, 2002.
[23] Typically direct-contact evaporators and black liquor oxidation units are eliminated to reduce TRS emissions.

modern furnaces have better design and controls than older ones, which results in lower overall emissions.

Table 7. Qualitative indication of relative environmental impact of different emissions, together with relative emission rates for controlled and uncontrolled Tomlinson furnaces and with BLGCC technology (VL = very low, L = low, M = moderate, H = high).

Pollutant/ Discharge	Relative Environmental Impact of Pollutant[a]	Relative Emissions Rates from Tomlinson Furnaces (uncontrolled)	Relative Emissions Rates with Controls on Tomlinson	Relative Emissions Rates with BLGCC Technology
SO_2	H	L	L (not required)	VL
NOx	H	M	M[d]	VL
CO	L	M (can be highly variable)	M[d]	VL
VOCs	H	L	L[d]	VL
PM[b]	H	H[c]	L-M	VL
CH_4	L-M	L	L[d]	VL
HAPs	M-H	L[c]	L[c]	VL
TRS[e]	L	L	L[d]	VL
Waste Water[f]	M-H	L	L	VL-L
Solids	L	L	L	L

a) General importance, not specifically for the P&P industry.
b) PM = particulate matter. Of greatest concern with PM emissions are fine particulates smaller than 10 and 2.5 microns in diameter (PM_{10} and $PM_{2.5}$ respectively).
c) Current MACTII rules are expected to result in about a 10% reduction of HAPs and a modest reduction in PM.
d) Not generally practiced other than by maintaining good combustion efficiency.
e) Total reduced sulfur.
f) For power systems, the issue is mainly one of the cooling water (quantity and discharge temperature).
Note: Emissions per lb BLS may increase with BLGCC because total fuel use increases, especially in the utility-scale case.

The only regulatory trend regarding add-on controls to a Tomlinson system is to require installation of dry-bottom electrostatic precipitators (ESPs) on new kraft recovery furnaces. This is being driven by the current EPA MACT II[24] regulations designed to reduce HAP emissions from combustion sources in the pulp and paper industry. The MACT II rules will also result in reduced PM emissions, which are captured with >99% efficiency by ESPs. The pulp and paper industry must be in compliance with MACT II by March 2004.[25] Thus, compliance with MACT II forms the basis for comparison to a BLGCC system. This and other assumptions used in this study to estimate emissions in the Tomlinson BASE case are summarized in Table 8. Appendix B provides additional details on the resulting emissions factors.

[24] MACT stands for "maximum achievable control technology" and was put in place to reduce HAPs.
[25] MACT II may be revisited by EPA in 2009 (ten years after promulgation of the rule) to assess any "residual risk" but it is unclear if this will actually occur or if it is revisited, if it will result in new regulations.

Table 8. Assumed emissions characteristics of modern Tomlinson furnaces in this study.

Pollutant[a]	Characteristics	Study Assumption
CO_2	Since biomass is the fuel source for Tomlinson boilers (other than fuel oil or gas used at startup), net CO_2 emissions are zero.	Zero, per discussion in Section 6.1.
SO_2	Scrubbers are not needed since SO_2 emissions are typically low by virtue of the design and operation of a Tomlinson furnace and the higher solids firing rates in newer units. SO_2 typically measures less than 10 ppm @ 8% O_2.	10 ppm @ 8% O_2
NO_x	NOx remains the biggest issue for Tomlinsons. Emissions are typically in the 100-130 ppm range @ 8% O_2 (~2.5 lb/ton black liquor solids). Conventional NO_x after-treatment (e.g., SCR, SNCR) has not been considered technically feasible (Miner, 2003). The BACT standard is essentially combustion controls, e.g., a Tomlinson boiler is effectively a staged combustion device with multiple inlets for combustion air. These are "typical" approaches to controlling NOx with combustion modifications.	100 ppm @ 8% O_2
CO	CO can be highly variable but is typically low and is controlled by maintaining efficient combustion.	100 ppm @ 8% O_2
VOCs	VOCs are typically low, e.g., formaldehyde is about 1ppm	0.16 lb/ton black liquor solids
PM	PM is controlled to >99% efficiency using ESPs	0.57 lb/ton black liquor solids
TRS	Total reduced sulfur (TRS) is also low with a new furnace using an indirect-contact evaporator and no black liquor oxidation unit.	0.04 lb/ton black liquor solids

(a) Biomass combustion also generates small amounts of non-CO_2 greenhouse gases – specifically, methane and nitrous oxide. However, even after considering the potency of methane and nitrous oxide as greenhouse gases, these emissions are small. As a result, they have not been included in the analysis. For example, see "Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.0", a project by NCASI for ICFPA and available on the internet at www.ncasi.org.

References: NCASI, 1992; NCASI, 2002a; NCASI, 2002b; NCASI, 2002c; NCASI, 2002d; NCASI, 2003; NCASI, 2002e

6.3 BLGCC Air Emissions

BLGCC air emissions are likely to closely mirror those of modern gas turbines as the emissions are mainly associated with the combustion process taking place in the gas turbine. Instead of natural gas the BLGCC systems will burn either clean syngas or a mixture of syngas and natural gas.[26] Modern gas turbines are characterized by very low emissions of criteria pollutants. In this study we have assumed that mills would generally not be located in ozone non-attainment areas and therefore would not be required to install NO_x after-treatment such as SCR. Thus NO_x emissions are assumed to be consistent with dry low-NO_x gas turbine combustion, in the range of 25 ppm at 15% O_2.[27] Emissions of CO and VOCs are inherently low with gas turbines due to efficient combustion. PM in the syngas must be removed to very low levels in order to protect the gas turbine from damage, so PM emissions will also be low. There is considerable experience with successful use of inexpensive carbon bed filters for removal of mercury and other trace

[26] One uncertainty relates to the amount and chemical form of nitrogen (if any) that might be carried in the syngas originating from nitrogen in the black liquor. Empirical gasification data needed to know what form nitrogen takes leaving gasifier. We scrubbing may remove it in any case.

[27] Current BACT (best available control technology) for coal IGCC power plants in 15 ppm NOx @ 15% O_2 (www.gepower.com, accessed 6/16/2003).

elements from fuel gas in coal gasification systems.[28] A similar approach is assumed to be viable for BLGCC systems.

Operating experience with coal IGCC systems also provides a basis for estimating likely BLGCC air emissions, taking account of some important differences between black liquor and coal gasification. First, coal is much higher in ash and metals. Second, sulfur recovery efficiencies will be higher with black liquor (near 100%) because the goal is to capture sulfur for reuse in the pulping process. In comparison, coal IGCC plants are typically designed for sufficient sulfur removal (e.g., 98%) to meet permitting requirements. Table 9 summarizes emissions characteristics for gas turbines in BLGCC systems assumed in this study. Appendix B provides additional details on the resulting emissions factors.

Other sources of emissions in the different BLGCC systems in this study are the gas turbine exhaust duct burner in the case of the mill-scale systems and the pulse heaters in the case of the low-temperature gasifier. Emissions from duct burners firing a mixture of syngas and natural gas are expected to be similar to state-of-the art natural gas combustion. Emissions from the pulse heaters are also expected to be similar to or lower than natural gas combustion (Georgia Pacific, 1999). Additional details are provided in Appendix B.

Table 9. Emissions characteristics assumed in this study for gas turbines in BLGCC systems.

Pollutant	Characteristics	Study Assumption
CO_2	For any biomass-derived fuels used, net CO_2 emissions are assumed to be zero (see discussion in Section 6.1)	Varies, depending on fuel mix
SO_2	SO_2 emissions are expected to be very low since the fuel gas is scrubbed of nearly all H_2S to return the sulfur to the pulping process.	Same as pipeline natural gas
NO_x	Dry low-NOx combustion can reduce emissions with natural gas to as low as 9 ppm @ 15% O_2. For BLGCC operation we have assumed a more conservative value.	25 ppm @ 15% O_2
CO	CO is generally low from gas turbine combustors due to efficient combustion.	0.033 lb/MMBtu fuel input
VOCs	VOCs are generally low with gas turbines due to efficient combustion – uncontrolled values are assumed.	0.0021 lb/MMBtu fuel input
PM	PM are generally very low for gas turbine operation. Upstream wet-scrubbing of the gas is assumed to control PM to very low levels.	0.0066 lb/MMBtu fuel input
TRS	Total reduced sulfur (TRS) is essentially zero, since the fuel gas is scrubbed of H_2S to return the sulfur to the papermaking process.	Zero

References: Gasification Technologies Council, 2003; Orr and Maxwell, 2000; Ratafia-Brown , *et al.*, 2002; Simbeck, 2002a; Simbeck, 2002b; Teco Energy, 2002; Ubis, *et al.*, 2002; EPA, 2000a.

6.4 Grid Power Emissions and Offsets

In each of the BLGCC cases, the mill produces all of the power it needs to operate. Additionally, there is excess power for export. The difference in power generation between BLGCC and the Tomlinson BASE case would therefore result in an equal amount of power generation offsets

[28] For example, such filters have been in use for many years at the Eastman Chemicals coal gasification facility in Kingsport, Tennessee, where methanol is made from gasified coal.

from the grid. The environmental value of these grid power offsets is an important consideration and will vary depending on what type of power is being displaced.[29]

Determining what type of grid power BLGCC would displace is difficult. Even though BLGCC technology would provide baseload power, the operation of *existing* baseload power plants (typically large coal, nuclear and hydropower plants, and increasingly, gas-fired combined cycle plants) is not likely to change significantly by the addition of BLGCC capacity to the mix. Similarly, peaking and intermediate-load power plants, which would typically be smaller, older coal- or oil-fired plants, gas turbines and dispatchable hydropower, run intermittently and are thus not a good direct point of comparison for BLGCC, since their operation is dictated by the real-time needs of balancing supply and demand. Other renewable energy sources, like wind, solar and small hydro are also not likely to be directly displaced by BLGCC (or any other "dispatchable" power plant). These plants typically run whenever the resource is available and the grid can accept the power, with the load-following plants adjusting their output accordingly. Furthermore, these plants typically have very low marginal operating costs and would therefore be cost-effective to run whenever the resource is available.

A more complicated analysis would be to estimate the marginal mix of power, as this is what would be displaced by the "next kWh" of generation added to the grid (say, by a new BLGCC system). A simpler analysis is to compare BLGCC emissions to the grid average, since data are readily available. Given the scope and level of effort for this project, this was the recommendation of this study's Steering Committee, which included representatives from two large electric utilities (Figure 5). A useful follow-on activity would be to more carefully examine the impacts of BLGCC on the grid fuel mix and the associated emissions.

The largest environmental benefits would be associated with the displacement of coal-based generation, but as discussed above, this is not likely to be the case. Another comparison might be to a new natural gas-fired combined cycle, since this has become the technology of choice for new capacity and therefore, BLGCC could potentially offset some new construction of gas-fired GTCC capacity. In this case, the environmental benefits of BLGCC would be reduced since GTCC technology produces much lower emissions than coal-fired generation. For example, natural gas is virtually free of sulfur so BLGCC would not produce measurable SO_2 savings. GTCC plants also produce very low levels of criteria pollutants, often less than 10% that of a typical coal plant. Emissions would actually be quite similar (per MWh) for a gas-fired GTCC and BLGCC plant since they both use gas turbine technology.

In considering the average mix, coal-fired emissions would be higher, whereas emissions from a gas-fired GTCC would be lower, especially for criteria pollutants, as discussed above. CO_2 emissions also vary but to a lesser extent than criteria pollutants. Specifically, CO_2 emissions from a gas-fired GTCC are about 60% lower than those from coal plants and about 40% lower than the average mix. The difference are not as great with CO_2 as with criteria pollutants because a significant portion of the average mix emits no CO_2 (nuclear power and hydropower account for approximately 30% of total U.S. power generation). CO_2 emissions from a coal plant are on

[29] The impacts of BLGCC on HAP emissions were not quantified in the analysis. Given increasing concerns over HAPs emissions, a useful follow-on activity would be to quantify the benefits of BLGCC vis-à-vis HAP emissions. Of particular significance would be the hydrochloric acid and mercury emissions that would be reduced if coal-generated power on the grid was displaced by biomass-derived electricity.

the order of 2,100 lb/MWh, whereas the U.S. average is approximately 1,300 lb/MWh and that of a gas-fired combined cycle is approximately 800 lb/MWh.

Emissions from the marginal mix are likely to be similar to the average mix. The marginal mix is generally more heavily weighted in fossil fuels than the average (e.g., there is no nuclear power or baseload hydro in the marginal mix) but it also contains less coal and more oil and gas, since much of the coal capacity is baseload. Thus, the overall emissions rates of the marginal mix should be similar to the average mix.

For all of the above reasons, the average mix was chosen as a reasonable basis for estimating and illustrating environmental benefits. The projected average fuel mix for electricity generation used to estimate the grid emissions offsets is shown in Table 10. Additional details are available in Appendix B.

Table 10. Total average grid emissions (including non-fossil fuel sources) assumed in estimating grid offsets.[a]

	lb/MWh		
Southeast (FRCC, SERC, SPP)	**2008**	**2020**	**2035**
CO_2	1,350	1,273	1,199
SO_2	5.57	4.23	2.91
NOx	2.05	1.64	1.21
CO	0.21	0.17	0.14
VOC	0.03	0.02	0.02
PM	0.15	0.13	0.10
United States	**2008**	**2020**	**2035**
CO_2	1,322	1,279	1,228
SO_2	4.84	3.59	2.36
NOx	1.96	1.67	1.27
CO	0.20	0.17	0.13
VOC	0.03	0.02	0.02
PM	0.14	0.12	0.09

	lb/MMBtu[b]		
Southeast (FRCC, SERC, SPP)	**2008**	**2020**	**2035**
CO_2	140.0	142.5	146.7
SO_2	0.578	0.474	0.356
NOx	0.212	0.184	0.147
CO	0.022	0.019	0.017
VOC	0.003	0.003	0.002
PM	0.016	0.014	0.012
United States	**2008**	**2020**	**2035**
CO_2	136.1	140.2	146.3
SO_2	0.498	0.393	0.281
NOx	0.202	0.183	0.151
CO	0.020	0.018	0.015
VOC	0.003	0.002	0.002
PM	0.015	0.013	0.011

(a) Sources: EIA, 2002a; EPA, 2000b; EPA, 2002b, Navigant Consulting, Inc. analysis.

(b) lb/MWh are converted to lb/MMBtu using the grid average fossil fuel heat rate for that year.

6.5 Emissions Estimates for the Case Study Power/Recovery Systems

Total emissions in each of the case study power/recovery systems are calculated here based on the emission factors described in Appendix B. Additionally, in cases where grid electricity is displaced, grid emissions are offset, and these reductions in emissions are included in the estimate of total emissions.

Table 11 summarizes the net total emissions of each major pollutant for each of the case study systems, assuming that the grid emissions are those expected for the year 2008. For the HERB case, the mill-level emissions are unchanged from the BASE Tomlinson, but total net emissions are lower because of larger grid power offsets. Even if mill-level emissions are higher for a BLGCC case than the BASE (e.g., as with CO_2 due to use of some natural gas), total net emissions are also lower due to grid offsets. Generally, the BLGCC cases show lower total net emissions than the Tomlinson cases. The implications of these differences for regional and national environmental impacts are addressed in a later section.

Table 11. Estimated typical annual emissions for each case study power/recovery system.[a]

	Total Point Source Combustion Emissions					Biomass CO_2 Emissions (carbon neutral)					Grid Power Emissions Offsets Relative to BASE					Net Emissions of Each Option[b]				
	Tomlinson Cases		BLGCC Cases			Tomlinson Cases		BLGCC Cases			Tomlinson Cases		BLGCC Cases			Tomlinson Cases		BLGCC Cases		
	BASE	HERB	Low T Mill Scale	High T Mill Scale	High T Utility Scale	BASE	HERB	Low T Mill Scale	High T Mill Scale	High T Utility Scale	BASE	HERB	Low T Mill Scale	High T Mill Scale	High T Utility Scale	BASE	HERB	Low T Mill Scale	High T Mill Scale	High T Utility Scale
Tons per year																				
CO2	1,573,188	1,573,188	1,667,065	1,556,092	1,866,474	1,492,514	1,492,514	1,439,102	1,439,102	1,338,828	-	134,182	325,374	277,708	889,380	80,674	(53,508)	(97,411)	(160,719)	(361,734)
SO2	218	218	129	131	100	-	-	-	-	-	-	491	1,343	1,016	3,253	218	(273)	(1,214)	(885)	(3,152)
NOx	1,318	1,318	989	861	1,071	-	-	-	-	-	-	199	494	412	1,319	1,318	1,119	495	449	(248)
CO	1,207	1,207	1,114	1,032	844	-	-	-	-	-	-	20	50	41	131	1,207	1,187	1,064	991	713
VOC	98	98	37	31	31	-	-	-	-	-	-	3	7	5	17	98	96	31	26	14
PM	359	359	134	114	111	-	-	-	-	-	-	14	36	30	95	359	344	97	84	16
TRS	25	25	6	5	5	-	-	-	-	-	-	-	-	-	-	25	25	6	5	5
lb/ton BLS																				
CO2	3,022	3,022	3,545	3,309	3,969	2,867	2,867	3,060	3,060	2,847	-	258	692	591	1,891	155	(103)	(207)	(342)	(769)
SO2	0.42	0.42	0.27	0.28	0.21	-	-	-	-	-	-	0.94	2.86	2.16	6.92	0.42	(0.52)	(2.58)	(1.88)	(6.70)
NOx	2.53	2.53	2.10	1.83	2.28	-	-	-	-	-	-	0.38	1.05	0.88	2.81	2.53	2.15	1.05	0.95	(0.53)
CO	2.32	2.32	2.37	2.19	1.79	-	-	-	-	-	-	0.04	0.11	0.09	0.28	2.32	2.28	2.26	2.11	1.52
VOC	0.19	0.19	0.08	0.07	0.07	-	-	-	-	-	-	0.00	0.01	0.01	0.04	0.19	0.18	0.07	0.06	0.03
PM	0.69	0.69	0.28	0.24	0.24	-	-	-	-	-	-	0.03	0.08	0.06	0.20	0.69	0.66	0.21	0.18	0.03
TRS	0.05	0.05	0.01	0.01	0.01	-	-	-	-	-	-	-	-	-	-	0.05	0.05	0.01	0.01	0.01
lb/ton pulp																				
CO2	5,739	5,739	6,081	5,676	6,809	5,444	5,444	5,250	5,250	4,884	-	489	1,187	1,013	3,244	294	(195)	(355)	(586)	(1,320)
SO2	0.79	0.79	0.47	0.48	0.37	-	-	-	-	-	-	1.79	4.90	3.70	11.87	0.79	(1.00)	(4.43)	(3.23)	(11.50)
NOx	4.81	4.81	3.61	3.14	3.91	-	-	-	-	-	-	0.73	1.80	1.50	4.81	4.81	4.08	1.81	1.64	(0.91)
CO	4.40	4.40	4.07	3.76	3.08	-	-	-	-	-	-	0.07	0.18	0.15	0.48	4.40	4.33	3.88	3.61	2.60
VOC	0.36	0.36	0.14	0.11	0.11	-	-	-	-	-	-	0.01	0.02	0.02	0.06	0.36	0.35	0.11	0.09	0.05
PM	1.31	1.31	0.49	0.42	0.41	-	-	-	-	-	-	0.05	0.13	0.11	0.35	1.31	1.26	0.36	0.31	0.06
TRS	0.09	0.09	0.02	0.02	0.02	-	-	-	-	-	-	-	-	-	-	0.09	0.09	0.02	0.02	0.02
lb/MWh[c]																				
CO2	5,879	4,262	3,278	3,258	1,985	5,577	4,044	2,829	3,013	1,424	-	364	640	581	946	301.47	(145)	(192)	(336)	(385)
SO2	0.81	0.59	0.25	0.27	0.11	-	-	-	-	-	-	1.33	2.64	2.13	3.46	0.81	(0.74)	(2.39)	(1.85)	(3.35)
NOx	4.92	3.57	1.94	1.80	1.14	-	-	-	-	-	-	0.54	0.97	0.86	1.40	4.92	3.03	0.97	0.94	(0.26)
CO	4.51	3.27	2.19	2.16	0.90	-	-	-	-	-	-	0.05	0.10	0.09	0.14	4.51	3.22	2.09	2.07	0.76
VOC	0.37	0.27	0.07	0.07	0.03	-	-	-	-	-	-	0.01	0.01	0.01	0.02	0.37	0.26	0.06	0.05	0.02
PM	1.34	0.97	0.26	0.24	0.12	-	-	-	-	-	-	0.04	0.07	0.06	0.10	1.34	0.93	0.19	0.18	0.02
TRS	0.09	0.07	0.01	0.01	0.00	-	-	-	-	-	-	-	-	-	-	0.09	0.07	0.01	0.01	0.00

(a) These offsets are calculated assuming the average electric-utility fuel mix for the United States projected for 2008 by the DOE/EIA. Emissions for the Southeast U.S. are not substantially different.

(b) "Net" emissions are the "Total Point Source Emissions" minus the "Biomass CO_2" and the "Grid Power Offsets". To calculate the emissions savings of the HERB and BLGCC cases over the Tomlinson BASE, subtract the Net emissions of the BASE case from the Net emissions of the alternative. Net emissions lower than the Tomlinson BASE mean that total emissions, including grid offsets, are lower than for the Tomlinson BASE. Negative Net emissions numbers mean that grid offsets are greater than onsite emissions for that option, after biomass-related CO2 emissions have been subtracted.

(c) These values are per MWh of total generation.

7 Power/Recovery Capital and Operating Cost Estimates

As a basis for estimating prospective returns on investments in alternative power/recovery systems, two engineering firms were engaged to estimate capital, maintenance, operating labor, and consumables costs based on the process flow diagrams shown earlier (Figure 9, Figure 10, and Figure 12 through Figure 14).[30] Fluor, Inc. was selected to estimate costs for the BLGCC system based on low-temperature gasification largely because of their involvement in the design and construction of the commercial demonstration of the MTCI gasifier at Georgia Pacific's Big Island mill. Nexant, Inc. was selected to estimate costs for the Tomlinson cases and the BLGCC cases based on high-temperature gasification. Nexant, an affiliate of the Bechtel Corporation, has considerable experience in power plant design and engineering, including design and engineering of coal integrated gasifier/combined cycle systems with component technologies that are similar to many of those that would be found in a high-temperature BLGCC system.

Each engineering firm was asked to review initial mass and energy balances and provide recommendations for modifications. The gasifier developers, Chemrec and MTCI, also reviewed the initial mass and energy balances. On the basis of feedback from the engineering companies and the gasifier developers, the final set of mass and energy balances were generated (as described above). These balances provided the basis for the cost estimation work.

Capital costs by major plant area are estimated to be ±30% accuracy. Within each area, the engineering firms first determined the design parameters and required capacity of each major piece of equipment. These provided the basis for soliciting equipment cost quotes from vendors for the most important plant components, including the gasifier, sulfur capture system, gas turbine, and lime kiln. Where possible, the engineering firms verified these quotes against in-house data for similar equipment from prior work. Installation cost factors for similar equipment were used to determine total installed cost. The cost for minor equipment and bulk materials (cement, piping, insulation, etc.) were estimated by factoring from similar projects. In order to make the cost estimates among technologies and between firms as consistent as possible, the two engineering firms discussed and agreed on the percentage values to be used for construction indirects, engineering, contingencies, spare parts, and owner's costs.

The cost estimates assumed "Nth plant" levels of technology maturity and operational reliability, including 98% overall plant availability during 8500 hours per year of operation. Each of the BLGCC cost estimates include two gasifier vessels, each with 50% of the needed total capacity. This represents a level of gasifier reliability that has not often been reached in existing gasification projects with other feedstocks (coal, pet coke, etc.). However, given that at most large pulp mills today the Tomlinson recovery boiler is typically a single unit handling 100% of the black liquor recovery duty, it was judged feasible that a black liquor gasifier could reliably operate with no spare capacity in an "Nth plant" implementation.

The scope of the capital cost estimates included equipment in all major areas shown on the process flow diagrams discussed above, with the following exceptions:

---

[30] Cost reports prepared by these firms are available on request from the authors of this report.

- *Steam turbine*. In the Tomlinson BASE case, the steam turbine pre-existing at the reference mill is assumed to be kept. However, since in this case there is excess steam available after meeting process needs, it was determined to be financially beneficial to add a small (8 MW_e) condensing turbine to enable greater electricity generation. In all other cases, the existing steam turbine is replaced, and the cost for a new turbine is included in the capital estimate.
- *Hog fuel boilers*. Hog fuel boilers existing at the mill are assumed to be available for steam raising with the new power/recovery systems. The bark and waste wood available from the wood yard operations in the Tomlinson cases represents 71 MW of thermal input. Mills typically have excess hog fuel boiler capacity available on-site, and it is assumed that the available total capacity is up to 100 $MW_{th.}$ The steam pressure from the hog fuel boilers is lower than the design pressure at the inlet of the steam turbine in all cases, except the Tomlinson BASE. In those cases, steam from the hog fuel boilers is fed to the steam turbine after the first expansion stage (as shown earlier on the process flow diagrams).
- *Lime kiln and related equipment*. The incremental causticizing and calcining capacity needed in the BLGCC cases is included in the capital cost estimate, assuming installation of a new kiln and causticizing plant to augment the existing capacity. For the high-temperature BLGCC case, the estimated incremental kiln/causticizing capacity is 16% of the existing capacity. The estimate of incremental capacity is 44% of the existing capacity in the low-temperature BLGCC case. Appendix A provides details of these estimates.
- *Polysulfide generation systems*. In the BLGCC cases, polysulfide pulping liquor is generated in a mixing tank maintained at a temperature < 100^oF. The cost for this polysulfide generating unit is included in the capital cost estimate.

Table 12 summarizes the installed capital cost and non-fuel operating and maintenance cost estimates for the Tomlinson and BLGCC cases, respectively. Table 12 includes some adjustments to the original cost estimates provided by the engineering companies. The most significant of these adjustments include:

- For the BLGCC systems using the low-temperature gasifier, the originally-estimated cost for the lime kiln and causticizing area ($42.1 million total cost) was based on an estimated 100% incremental capacity requirement (compared to the existing Tomlinson system). Revised lime kiln calculations lowered this estimated requirement to 44% (See Appendix A). The original cost estimate has been scaled down to reflect the lower estimated incremental capacity requirement.
- For the BLGCC systems using the high-temperature gasifier, the original cost estimate did not include any cost for a polysulfide mixing tank or for the estimated 16% added lime kiln capacity that would be required. The total installed cost of the polysulfide dissolving tank designed for the low-temperature BLGCC system is added to the cost for the two high-temperature BLGCCs. Since the required lime kiln capacity increase is relatively modest, oxygen-enrichment of the combustion air at the existing lime kiln is utilized to achieve the added capacity. The cost of the air-separation unit has been scaled up from the original estimate to account for the added oxygen needed at the kiln, and an allowance of $1 million is included for costs to modify for oxygen-enriched firing the kiln existing at the case study mill before installation of the BLGCC.
- For the HERB system, the cost of contingencies is adjusted to be the same percentage of direct costs as in the mill-scale BLGCC cases, reflecting the fact that there are no Tomlinson

boilers operating today with design parameters assumed for the HERB. Also in the HERB case, the annual O&M cost has been adjusted to be the same as for the mill-scale BLGCC cases, reflecting the expected higher maintenance costs to address boiler-tube corrosion and black liquor feeding concerns (as discussed in Section 4.2).

Table 12. Installed capital costs (million 2002$) and non-fuel operating and maintenance costs (million 2002$ per year) estimated for Tomlinson-Base and BLGCC power/recovery systems.

	Tomlinson		BLGCC System		
	BASE	**HERB**	**Low-Temp Mill-Scale**	**High-Temp Mill-Scale**	**High-Temp Utility-Scale**
Recovery boiler (a)	87.479	90.748	0	0	0
Steam system modifications	7.792	32.798	0	0	0
Air separation unit	0	0	0	31.202	31.202
Gasifier island & green liquor filter (b)	0	0	40.815	46.640	46.640
Process gas handling	0	0	27.514	0	0
Gas cleanup and sulfur recovery	0	0	39.920	13.138	13.138
Combined cycle power island	0	0	62.861	61.441	99.803
Hog fuel boiler	0	0	0	0	0
Auxiliaries	0	0	5.194	0	0
Subtotal, Direct Costs (materials & labor)	**95.271**	**123.546**	**176.303**	**152.421**	**190.783**
Premium labor	0	0	1.043	0	0
Construction indirects	5.443	9.932	21.006	7.160	8.486
Sales tax, customs, duties	0	0	0	0.527	0.529
Engineering	8.309	9.640	23.043	7.124	10.962
Contingency	3.931	7.862	14.228	9.927	11.855
Escalation	1.274	1.295	0	0.000	0.000
Spare parts	1.797	1.989	5.107	4.872	4.631
Licensing fee	0	0	0.318	0.000	0.000
Owner's costs	5.704	6.525	11.460	9.888	12.389
Subtotal, Non-Direct Costs (c)	**26.458**	**37.244**	**76.207**	**39.497**	**48.850**
TIC BEFORE ADJUSTMENTS	**121.729**	**160.790**	**252.510**	**191.918**	**239.633**
Causticizing area adjustment, TIC (d)	--	**--**	- 18.365	+ 1.000	+1.000
Polysulfide tank adjustment, TIC (e)	--	**--**	Incl. Above	+ 1.050	+ 1.050
TOTAL INSTALLED CAPITAL COST	**121.729**	**160.790**	**234.145**	**194.418**	**242.133**
Annual non-fuel O&M cost	**6.940**	**10.611**	**10.611**	**10.611**	**11.151**

(a) The HERB recovery boiler cost has been estimated (conservatively) by scaling BASE recovery boiler cost by the ratio of the thermal power (MW) released in each boiler (338.8/321.5) using a 0.7 scaling exponent.

(b) 2 x 50% capacity gasifiers. The low-temperature gasifier vessel is of cylindrical design, which represents a considerable design departure from the rectangular geometry that characterizes all pilot-scale and demonstration units that have been built to date, including the commercial demonstration unit in Big Island, Virginia.

(c) The two engineering firms involved in generating these cost estimates coordinated their work to insure consistency on non-direct costs. The total of non-direct costs as a percentage of direct costs shown here is not the same in all cases, however, due to different conventions used for showing direct and non-direct costs.

(d) For the low-temperature case, the incremental lime kiln/causticizing plant cost ($42.1 million total installed cost for 517 short tpd incremental CaO) was included in the original gas cleanup/sulfur recovery line item. This corresponds, approximately, to a 100% increase in kiln capacity relative to the Tomlinson case. A revised estimate of the required percentage increase in kiln capacity is 44% (see Appendix A). The adjustment shown above, which accounts for the lower estimated kiln increment, was calculated from the original estimate using a scaling exponent of 0.7 on capacity, as recommended by Bo Oscarsson, the lead design engineer on this project at Fluor. For the high-temperature case, an allowance of $1 million is included for modifications needed to the kiln to enable firing with oxygen-enriched air, as discussed in detail in Appendix A.

(e) The polysulfide tank adjustment is the same in all BLGCC cases. In the low-temperature case, the cost is included in the cost for the gas cleanup/sulfur recovery area.

8 Mill-Level Economic Analysis

8.1 Approach and Assumptions

To assess the prospective economics of BLGCC technology at the mill level, a cash flow analysis was carried out assuming that an investment would be made in a new power/recovery system to replace an existing Tomlinson system (characterized by the Tomlinson BASE system described earlier) that had reached the end of its working life. Specifically, the internal rate of return (IRR) on the incremental capital investment required for a BLGCC over a new Tomlinson system was calculated. The associated net present value (NPV) was also calculated. The IRR and NPV were calculated both without and with consideration of the potential economic value of environmental benefits of the advanced recovery systems.

Key inputs to the financial analysis include the detailed mass/energy balances and engineering cost estimates for each power/recovery system discussed above. The analysis focused on the power/recovery area, but the operating-cost analysis also considered in the BLGCC cases the reduced wood costs due to higher digester yield with polysulfide pulping, the increased use of #6 fuel oil in the lime kiln, and (in the two BLGCC cases with the mill-scale gas turbine) the cost of purchased wood residues. Additional key input assumptions included expected future prices for natural gas, fuel oil, purchased wood fuel, electricity purchased by the mill and electricity sold to the grid, and financial assumptions (e.g., construction period, debt/equity split, cost of debt and return on equity, inflation rate, project life, and income tax rate).[31,32] Table 13, along with Table 5 and Table 12 summarize the key inputs to the financial analysis. Appendix D provides additional details on the financial model built for these calculations.

An important aspect of BLGCC economics will be the ability to convert environmental and renewable energy benefits of the technology into monetary value, e.g., by selling excess NO_x allowances or garnering a premium for renewable electricity sold to meet a renewable portfolio standard or voluntary green power program. In the longer term, carbon trading or some other scheme to reduce emissions of greenhouse gases may also come into play. Other factors affecting the economics of BLGCC include existing and potential federal and state incentives (tax exemptions and production tax credits) designed to promote the development of renewable energy resources. It is worth noting that it may not be possible to sell renewable energy certificates (RECs) and at the same time sell emissions credits, since the REC would in effect include the emissions benefits of the power.

[31] Since the power/recovery economics must ultimately be evaluated within the financial performance of the entire company, any negative net cash flows in early years (e.g., during construction and startup) were assumed to generate tax savings that could be captured elsewhere by the plant owner in that year. These savings were therefore factored into the IRR results shown here.

[32] The ownership structure (e.g., 100% mill, 100% utility, 100% third party, or some mix of these) will be critically important in actual implementation. However, different structures were not examined here, since this would complicate the analysis without fundamentally changing the relative costs/benefits of Tomlinson versus BLGCC technology – the comparison of interest in this study.

Table 13. Summary of key input assumptions for the financial analysis.

Financial Parameters[a]	
Inflation Rate	2.1%
Debt Fraction	50%
Equity Fraction	50%
Interest Rate on Debt	8%
Return on Equity	15%
Resulting Discount Rate used for NPV calculations	9.9% (after tax)
Income Tax Rate (combined Federal & State)	40%
Property Tax & Insurance	2%
Economic Life (years)	25
Depreciation Method	20-year MACRS rate schedule[b]
Construction time for Tomlinson systems	24 months
Construction time for BLGCC systems	30 months
Baseline Levelized Fuel and Feedstock Prices[c] (2002$)	
Utility Natural Gas ($/MCF) [$/MMBtu]	$3.86 [$3.76]
Industrial #6 Oil ($/gallon) [$/MMBtu]	$0.59 [$3.96]
Industrial Retail Electricity ($/MWh)[d]	$43.16
Exported Electricity ($/MWh)[e]	$40.44
Hog Fuel/Bark ($/MMBtu)	$1.50
Pulpwood ($/dry ton)	$51.26
P&P Industry/Mill Assumptions	
O&M cost inflator (% per year, current $)	2.7%
Annual Operating Hours	8,330
Average Annual Industry Growth Rate	1.2%
Start-up Assumptions (% of full output)	
Year 1 of Operation	80%
Year 2 of Operation	100%

(a) The resulting annual capital charge rate is 17.9%.

(b) The Modified Accelerated Cost Recovery System (MACRS) is a property depreciation system defined by the Internal Revenue Service that applies to assets placed in service after 1986. It results in more rapid depreciation than straight-line depreciation.

(c) For the Southeast United States. The model uses yearly forecasts derived mainly from EIA (2002a). These are the resulting levelized prices.

(d) Retail industrial electricity prices will change with the price of utility natural gas, since natural gas constitutes some fraction of the generating fuel mix. In practice, "fuel adjustment charges" are used to pass through changes in natural gas costs to the customer. We have assumed that changes in gas price from the base value in this table are passed through to the mill in proportion to the projected gas-based fraction of utility power generation.

(e) The price paid for exported electricity depends on the natural gas price, other fossil fuel prices, the status of market deregulation, and other factors (e.g., utility reserve margin and fuel mix). Since the natural gas-fired combined cycle remains the generating technology of choice for new capacity, and is increasingly setting the wholesale price, it was assumed here that over the long-term, the average export power price can be approximated by the all-in cost of power from a gas-fired combined cycle.

The impact on IRR of environmental improvements arising from the application of advanced power/recovery systems was examined by applying a range of monetary values to environmental impacts (Table 14). These values are estimated in most cases based on existing types of incentives and programs, assuming similar incentives might apply to advanced black liquor power/recovery systems, as detailed in the notes to Table 14.

Table 14. Monetary values assumed for environmental benefits.

Potentially Available Credit	Basis for Credit	Approach to Analysis
Renewable Energy Premium[a]	• MWh sales into a voluntary "green power" program or to satisfy a mandated Renewable Portfolio Standard (RPS), e.g. through sale of renewable energy certificates (RECs) or "green tags". • Green power programs continue to grow in popularity; 14 U.S. states have implemented a RPS; a Federal RPS is under discussion. • RECs are emerging as the dominant accounting system for RPS and other attribute-based standards, such as labeling, emission performance standards, and substantiation of marketing claims.	• Base value of $15/MWh, indexed to inflation (2002 base year), consistent with cap in proposed Federal RPS. • Higher value of $25/MWh, based on limited experience with RPS to date; could be as high as $50/MWh in some cases. • Applies to all incremental electricity generation above Tomlinson BASE, consistent with existing definitions of "new renewable generation," e.g., as in the current Massachusetts RPS.
Renewable Energy Production Tax Credit (PTC)[b]	• Federal or state tax incentive for renewable generation, similar to current Federal wind PTC and "closed-loop" biomass PTC. • Pending legislation in the U.S. Senate and House of Representatives would broaden definition of biomass eligible for the credit.	• $18/MWh for ten years from initial operation. • Applies to all incremental renewable generation over the Tomlinson "Base" (but in theory, may apply to ALL renewable generation if BLGCC plant is considered a "new generator").
Carbon Credit	• Future "cap and trade" system similar to that for SO_2 allowances	• $10-$50 per metric tonne carbon, indexed to inflation (base year = 2008) • Applies to net reductions, including grid offsets.[c]
NO_x Allowances	• Sale of allowances generated by reducing NO_x emissions	• $2,000/ton annual credit (in range of current year 2008 forward price), indexed to inflation (2008 base year). • Applies today in 21 NO_x SIP Call[d] states; a single price applies in all these states. • Applies to net reductions, including grid offsets.[c]
NO_x Emissions Reductions Credits (ERC)	• Sale of ERCs to someone in need of offsets for a new or modified source of emissions.	• Not modeled, since this applies today only in ozone non-attainment areas, which largely exclude areas with pulp and paper mills. • Prices vary considerably by state.

(a) Currently, there exist active government-sanctioned markets for renewable energy credits (RECs) in Texas (ERCOT), New England (NEPOOL), the mid-Atlantic states (PJM), the European Union, Australia and New Zealand. Japan will initiate a REC market in 2003. In the U.S., the current market price for RECs (per Evolution Markets 2/24/03) in Texas is $10.60/MWh and in New England, $25/MWh. In most cases, including the proposed Federal RPS, there is a ceiling price for RECs. In Massachusetts it is $50/MWh, whereas the proposed Federal RPS has a $15/MWh cap. The cap is set by establishing a penalty for non-compliance with required REC purchases.

(b) Under Section 45 of the Internal Revenue Code, qualifying renewable energy technologies receive a Renewable Energy Production Tax Credit (PTC), currently valued at 1.8¢/kWh for the first ten years of operation. For wind power, this has been a major factor in its recent success in the United States. The same PTC also exists for biomass power generated from "closed loop" biomass. However, the definition of closed loop biomass is restricted to energy crops, such that nobody has yet been able to take advantage of it. As noted in the table, if comprehensive Federal energy legislation is passed, it is very likely to include a broadening of the eligibility criteria for biomass, but the exact changes have yet to be finalized and it is still not certain that legislation will pass. Nevertheless, this suggests a recognition of the sustainability of supply of biomass other than dedicated energy crops. If passed, the definition change could be a significant incentive for biomass power development.

(c) Because significant environmental benefits of BLGCC occur as a result of displacing grid power, the emissions analysis here includes grid emissions that would be offset by BLGCC power. The rationale is that BLGCC technology creates the benefit and therefore the monetary value associated with it. Thus, the owner of the plant, even if not the electric utility, could monetize the benefits via some arrangement with the utility. Since BLGCC is a base-load technology, this analysis assumes that avoided grid emissions are those of the grid average. In practice, it would be difficult to monetize these indirect emissions benefits, but we have included them here to illustrate their potential value.

(d) The NO_x SIP Call is the U.S. EPA's "state implementation plan" for achieving NO_x reductions using a cap and trade approach similar to what was implemented for SO_2 under the Clean Air Act. The affected states are: AL, CT, DC, DE, IL, IN, KY, MA, MD, MI, NC, NJ, NY, OH, PA, RI, SC, TN, VA, WV, and the District of Columbia. Missouri and Georgia may also be required to join. Boilers over 15 MW are affected by these cap-and-trade rules.

8.2 Results of Financial Analysis

A cash flow/IRR analysis was carried out for each BLGCC system, considering the incremental investment and operating costs for the BLGCC system relative to a new Tomlinson BASE investment. Table 15 summarizes the annual material and energy flows used in these analyses. Additional details regarding the cash flow calculations are provided in Appendix D.

In addition to a baseline set of results, some sensitivity analyses were carried out around key input parameter values that have a high degree of uncertainty. Capital costs in this study have an estimated uncertainty of ±30% due to the level of detail included in the cost estimates and to inherent uncertainties in projecting "Nth plant" costs given the pre-commercial status of the BLGCC technology today. Future energy price levels are also uncertain,[33] and prices also can vary considerably from one region of the country to another.

The baseline and related sensitivity analyses take no account of environmental benefits of BLGCC technology, but financial performance with environmental credits and incentives included are also presented. In the latter analyses, it is assumed that 100% of the wood-derived fuels used at the mill are renewable and result in no net CO_2 emissions to the atmosphere.

8.2.1 BLGCC, High-Temperature Gasifier with Mill-Scale Gas Turbine

Figure 15 shows for the BLGCC system employing a high-temperature gasifier and mill-scale gas turbine the annual incremental cash flow, internal rate of return (IRR), and net present value (NPV) relative to the Tomlinson BASE technology under the baseline set of assumptions. The incremental investment of $73 million gives an IRR of 18.5%, with a positive NPV of $44.9 million. The added capital needed for the BLGCC plus purchase of additional wood residuals, lime kiln fuel, and a small amount of natural gas are compensated by the benefits of additional avoided power purchases over the Tomlinson BASE, the electricity sales, and the reduced pulpwood requirements (Table 15), leading to respectable financial performance. If a new Tomlinson HERB were to be considered as the alternative investment (rather than a Tomlinson BASE), the BLGCC system would give an IRR of 21.1% and NPV of $35.8 million on an incremental investment of $34 million (HERB results not shown in Figure 15).

For this BLGCC configuration vs. the Tomlinson BASE, Figure 16 shows the sensitivity of the IRR to the assumed incremental capital cost and to assumed retail electricity price. (Higher electricity prices result in higher avoided electricity costs for the mill). For a desired IRR and assumed electricity price, this figure shows how much capital investment could be afforded (relative to the investment for the conventional Tomlinson system).

[33] For example, the energy prices in this report are derived principally from EIA (2002a). EIA 2003a, which became available too late to incorporate here, estimates that long-term natural gas prices will be about $0.50/MMBtu higher than those forecast in EIA, 2002a.

Table 15. Annual material and energy flows for the alternative power/recovery systems.

Parameter	Units per year	Tomlinson		BLGCC		
		BASE	HERB	Low-Temp Gasifier, Mill-Scale GT	High-Temp Gasifier, Mill-Scale GT	High-Temp Gasifier, Utility-Scale GT
Annual Material Flows						
Mill Operating Hours	Hours	8,330				
Total Pulp Production	Bone dry short tons	548,277				
Total Wood to Mill	Bone dry short tons	1,309,943	1,309,943	1,223,482	1,223,482	1,223,482
Hog Fuel Production	Bone dry short tons	117,895	117,895	110,113	110,113	110,113
Hog Fuel Purchases	Bone dry short tons	---	---	55,158	55,158	---
Avoided Pulpwood Purchases	Bone dry short tons	---	---	86,461	86,461	86,461
Black Liquor Production	Short tons BLS	1,041,250	1,041,250	940,534	940,534	940,534
Annual Energy Flows						
Mill Electricity Use[a]	MWh	833,800				
Net Electricity Production[b]	MWh	535,203	738,188	1,017,260	955,309	1,880,622
Net Electricity Purchased	MWh	298,597	95,612	---	---	---
Net Electricity Exported	MWh	---	---	183,460	121,510	1,046,823
Incremental Total Electricity Production[c]						
Production relative to Base Tomlinson	MWh	---	202,985	482,057	420,107	1,345,420
Production relative to HERB Tomlinson	MWh	---	---	279,072	217,121	1,142,435
Incremental Renewable Electricity Production						
Production relative to Base Tomlinson	MWh		202,985	326,368	386,401	549,521
Production relative to HERB Tomlinson	MWh	---	---	123,101	183,415	346,536
Natural Gas Purchased	MMBtu per year	---	---	1,922,376	406,974	7,473,725
Total Lime Kiln Fuel	MMBtu per year	939,437	939,437	1,353,729	1,086,928	1,086,928
Incremental Lime Kiln Fuel	MMBtu per year	---	---	414,292	147,492	147,492
Hog Fuel + Wood Residuals Consumption	MMBtu per year	2,027,792	2,027,792	2,842,675	2,842,675	1,893,950
Purchased Wood Residuals	MMBtu per year	---	---	948,725	948,725	---

(a) Excludes power island parasitic loads.

(b) Net production is after subtracting power island parasitic loads.

(c) Total renewable electricity production is estimated by multiplying total electricity production by the fraction of total fuel input to the power island that is renewable (including all hog fuel and syngas). Incremental renewable generation is the difference between this number and the generation in the Tomlinson BASE case, which is 100% renewable. This approach is consistent with at least one state's (Massachusetts) definition of RPS-eligible renewable generation from a power plant that fires multiple fuels (MA DOER, 2002).

The above financial results were generated assuming no monetary value for the environmental or renewable energy attributes of BLGCC technology. If value is assigned to these attributes, as is increasingly the case in the United States and elsewhere, the IRR will increase relative to the baseline levels discussed above. Figure 17 shows the IRR (relative to an investment in

Tomlinson BASE technology) when a range of different environmental benefits are monetized. Some benefits, e.g., the sale of renewable energy certificates[34] (RECs – denoted in the table as a "green premium") and a production tax credit (PTC), would be additive,[35] so impacts of some plausible combinations of benefits are shown along with impacts of some individual benefits. Credits for emissions reductions are not shown as additive to RECs or a PTC, although it is possible that different emissions reductions could be additive with each other as well as with RECs or PTCs. [36]

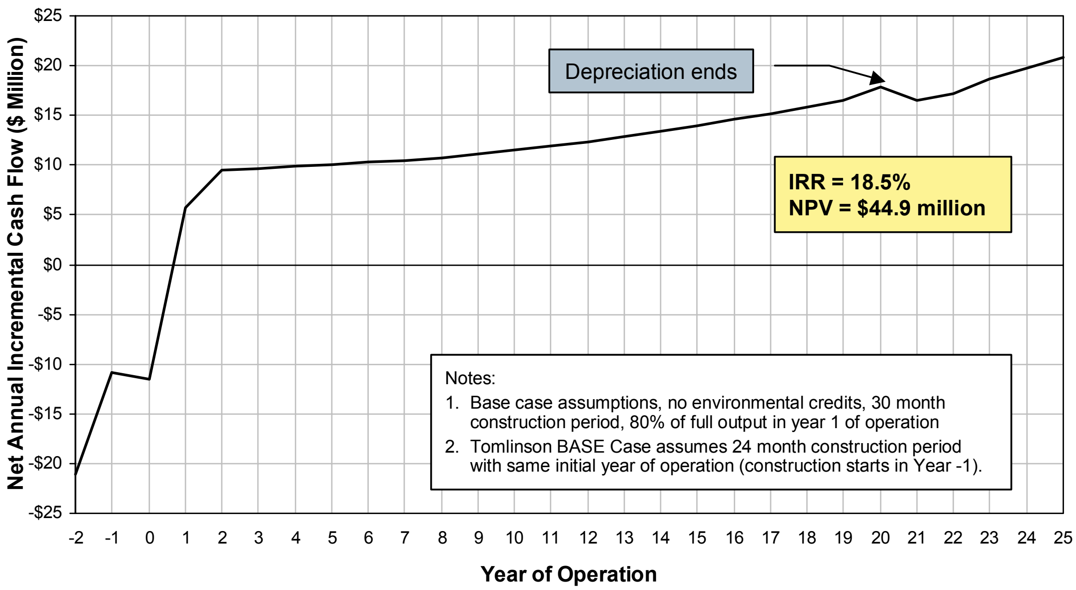


Figure 15. Net cash flows for the high-temperature BLGCC with mill-scale gas turbine relative to the Tomlinson BASE Case – nominal dollars.

In general, the highest returns are associated with environmental credits that are tied to incremental production of renewable electricity rather than emissions reductions. This is consistent with other recent analysis by Navigant Consulting which showed that among all the various renewable energy and emissions reductions programs, the REC value is potentially more important than all the emissions values combined (Navigant Consulting, Inc., 2003).[37] Even a modest "green premium" of $15/MWh provides a five percentage point improvement in IRR. Higher premiums in line with current values for RECs and green power programs (see Table 14),

---

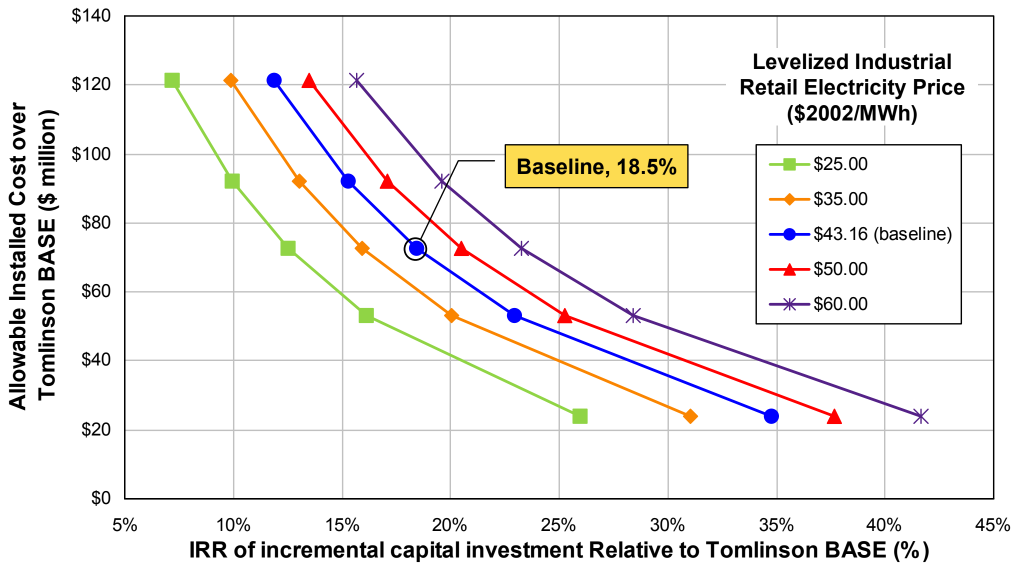
[34] For eligible renewable resources, every MWh of generation also produces a renewable energy certificate (REC). These RECs can then be sold to satisfy renewable portfolio standards or to meet voluntary green power programs. RECs are rapidly becoming the "currency" for the trading of renewable energy attributes.

[35] For example, in Texas today, wind farms receive a Federal PTC at the same time they receive payments for the Renewable Energy Certificates they generate that are used to satisfy the Texas renewable portfolio standard.

[36] Different emissions credits (e.g., NO_x allowances and CO_2 credits) could be additive to each other and to a PTC, and possibly to a REC, but some important certifying agencies (e.g., the Center for Resource Solutions, which provides "Green-e" certification) have taken the position that the attributes of "tradable renewable certificates" cannot be unbundled and must be sold together. This would effectively prevent someone from selling CO_2 credits and then using the same electricity associated with the CO_2 credit to sell a renewable energy certificate. These issues are not yet fully resolved.

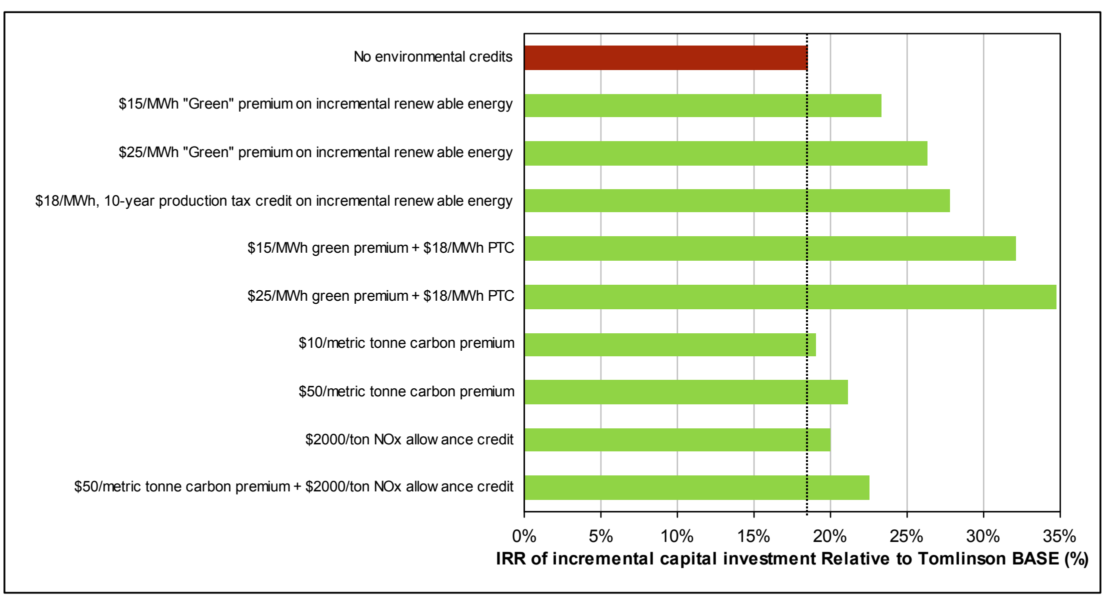
[37] RECs and other green power premiums will be easier to capture than the emissions credits calculated here, because the former are directly attributable to the BLGCC power plant, whereas the latter include grid offsets and are thus include indirect savings, which may be more difficult to monetize.

coupled with renewable energy production tax credits consistent with current and proposed Federal programs could result in IRRs in excess of 30% for BLGCC. When BLGCC is compared against a HERB (not shown), similar credit levels also produce IRRs in excess of 30%.



Note:
In all cases the levelized natural gas price is $3.76/MMBtu and the levelized export power price is $40.4/MWh. The total installed cost of the BLGCC system ranges ±25% and the installed cost of the Tomlinson BASE is $121.7 million. Although the overall analysis assumes that electricity prices are dependent on gas prices, there are other factors that influence electricity prices. There are also strong regional differences in electricity rates. This chart is meant to show, among other things, the impact of different industrial electric rates, all else equal.

Figure 16. Allowed incremental capital cost (high-temperature mill-scale BLGCC relative to Tomlinson BASE) to achieve different target IRR values with indicated retail electricity price.



Note: NOx allowances and CO2 credits would also be additive to production tax credits and possibly to renewable energy premiums. However, some certifying agencies (e.g., the Center for Resource Solutions, which provides "Green-e" certification) have taken the position that the attributes of "tradable renewable certificates" cannot be unbundled and must be sold together.

Figure 17. IRR values with different environmental benefits monetized – high-temperature BLGCC with mill-scale gas turbine. The baseline IRR is the top-most bar.

8.2.2 BLGCC, Low-Temperature Gasifier with Mill-Scale Gas Turbine

Figure 18 shows the annual net cash flow, baseline IRR, and baseline NPV of the incremental costs and benefits for the low-temperature, mill-scale BLGCC case relative to the Tomlinson BASE. The incremental capital required in this case is $112 million. Taken together with higher incremental lime kiln fuel requirements (Table 15) and higher natural gas consumption, this BLGCC option provides a modest return on incremental investment compared to the Tomlinson BASE. Under the baseline financial assumptions, this BLGCC option would show an IRR of 8.9%, and since this is slightly below the after-tax WACC of 9.9%, it has a negative NPV of $6.0 million. Figure 19 shows the allowable incremental capital cost (above Tomlinson BASE technology) as a function of a target IRR and different retail electricity prices. If capital costs are only slightly lower than estimated here, this option would show an IRR in excess of the after-tax WACC, with a corresponding positive NPV.

Figure 20 shows the IRR with different environmental benefits monetized. The highest returns are associated with credits tied to incremental production of renewable electricity. Because the baseline IRR is relatively low, the relative impacts of various renewable energy premiums is quite pronounced for this BLGCC case. With the maximum premiums assumed here ($25/MWh green premium + $18/MWh renewable energy production tax credit), the IRR exceeds 20%.

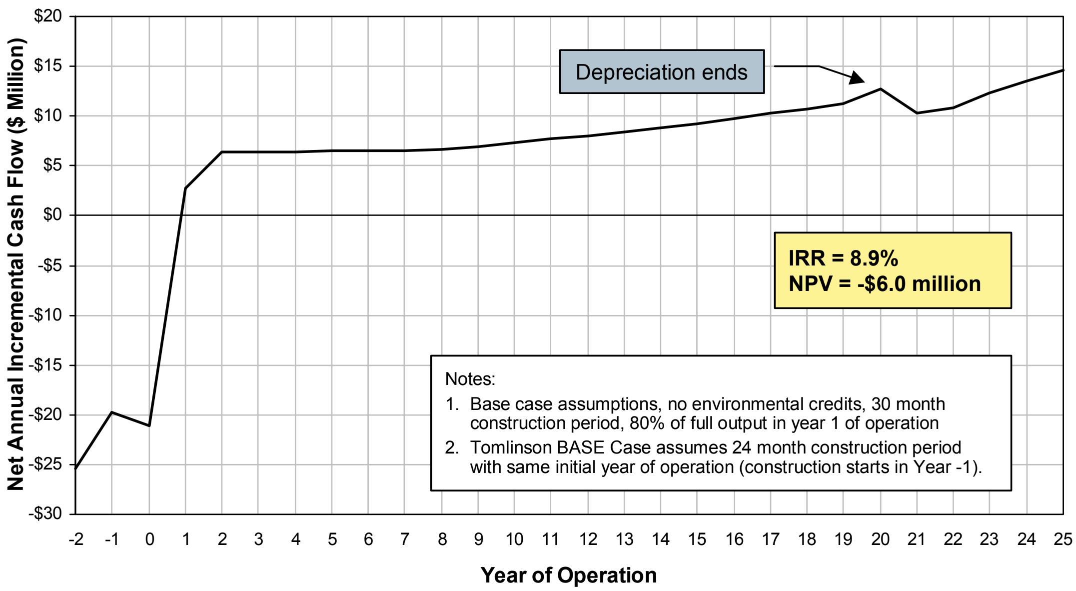
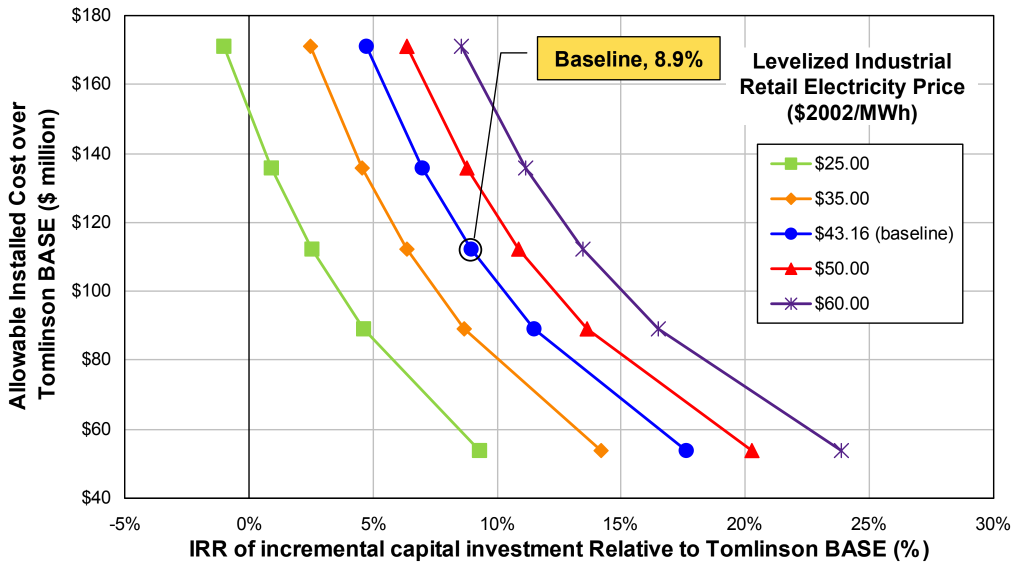
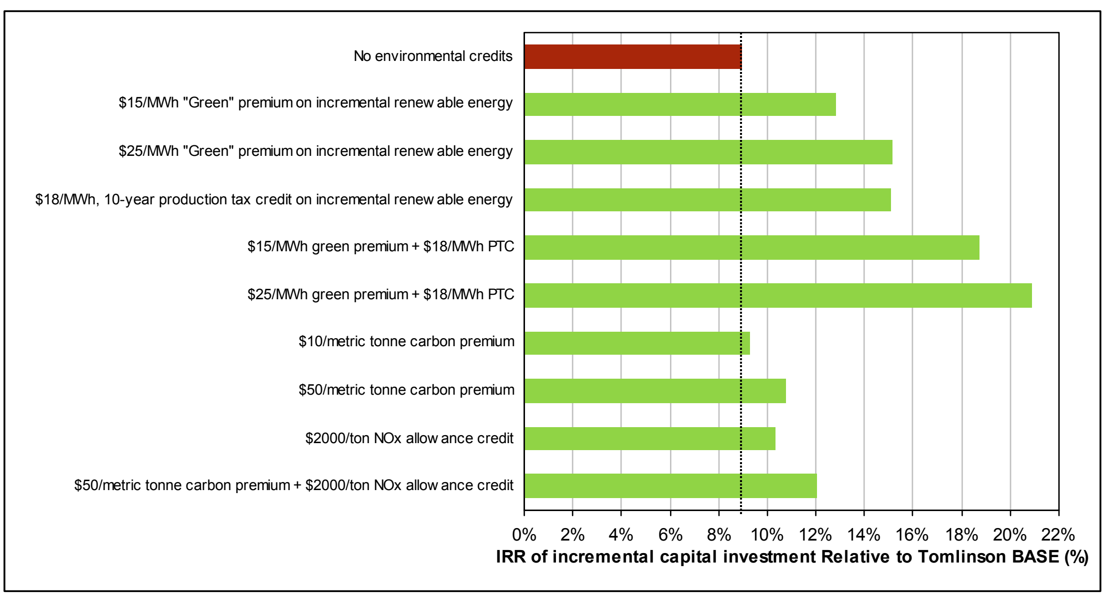


Figure 18. Net cash flows for the low-temperature BLGCC with mill-scale gas turbine relative to the Tomlinson BASE Case – nominal dollars.



Note:
In all cases the levelized natural gas price is $3.76/MMBtu and the levelized export power price is $40.4/MWh. The total installed cost of the BLGCC system ranges ±25% and the installed cost of the Tomlinson BASE is $121.7 million. Although the overall analysis assumes that electricity prices are dependent on gas prices, there are other factors that influence electricity prices. There are also strong regional differences in electricity rates. This chart is meant to show, among other things, the impact of different industrial electric rates, all else equal.

Figure 19. Allowed incremental capital cost (low-temperature mill-scale BLGCC relative to Tomlinson BASE) to achieve different target IRR values with indicated retail electricity price.



Note: NOx allowances and CO2 credits would also be additive to production tax credits and possibly to renewable energy premiums. However, some certifying agencies (e.g., the Center for Resource Solutions, which provides "Green-e" certification) have taken the position that the attributes of "tradable renewable certificates" cannot be unbundled and must be sold together.

Figure 20. IRR values with different environmental benefits monetized – low-temperature BLGCC with mill-scale gas turbine. The baseline IRR is the top-most bar.

8.2.3 BLGCC, High-Temperature Gasifier with Utility-Scale Gas Turbine

Figure 21 shows for the BLGCC system employing a high-temperature gasifier and utility-scale gas turbine the annual incremental cash flow, IRR, and NPV relative to the Tomlinson BASE technology under the baseline set of assumptions. The incremental investment in this case is \$120 million, which gives an IRR of 20.1%, with a positive NPV of \$83 million. Compared against a new advanced Tomlinson HERB investment (\$81 million incremental capital cost), the BLGCC investment would give an IRR of 22% and a positive NPV of \$74 million. The capital required for "oversizing" the gas turbine and the substantial costs for natural gas required to co-fire (with syngas) the gas turbine are more than offset by the much larger electricity output, resulting in the highest baseline IRR among all BLGCC cases considered here. Also notable is the much higher net cash flow, as illustrated by the NPV of \$83 million.

For this BLGCC configuration, Figure 22 shows the allowed incremental investment over a Tomlinson-Base system for different target IRRs, assuming different retail electricity prices. A lower IRR allows for a higher incremental cost. The same is true for a higher electricity price, since the avoided electricity purchase value is higher. However, since the relative cash-flow contribution of avoided electricity purchases is smaller in this case than in the other BLGCC cases, this option is less sensitive to changes in the retail industrial electricity price. Conversely, this option would be the most sensitive to changes in the export power price, all else equal.

This BLGCC configuration requires considerable natural gas consumption. As noted earlier (Table 13 notes), for this analysis the wholesale power price (i.e., the price received for power exported by the BLGCC) has been assumed to be tied to the cost of generation from a gas-fired combined cycle power plant. Thus the economics of this BLGCC configuration, despite the large natural gas requirements, are not sensitive to changes in gas price, since if gas prices were to rise, the assumption is that the price received for exported power would also rise correspondingly. (see notes to Table 13 for additional details). This is consistent with the concept that ultimately, the cost of power production is passed on to customers.

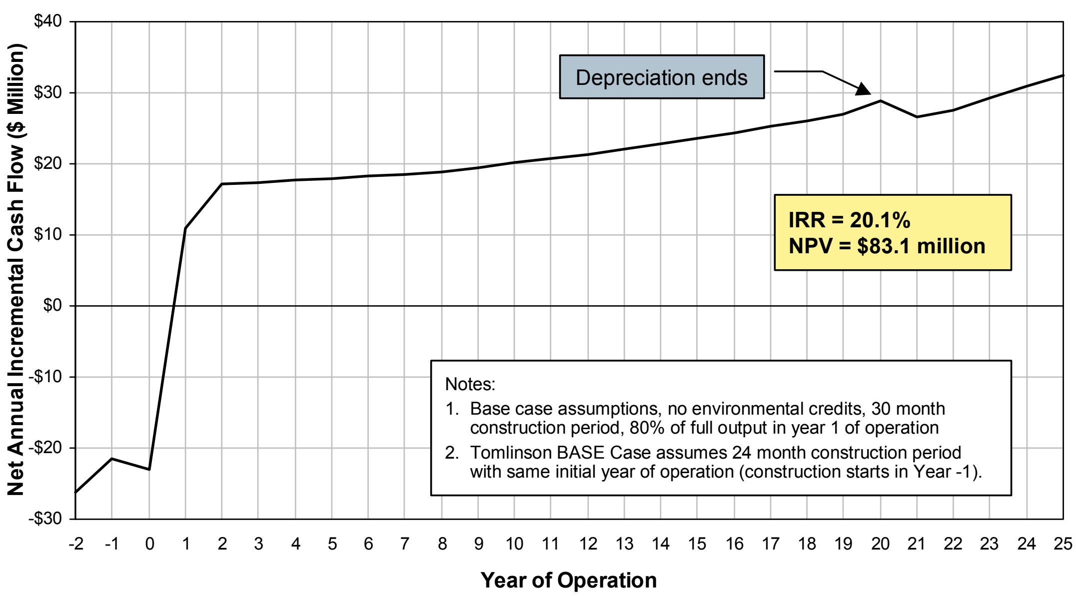
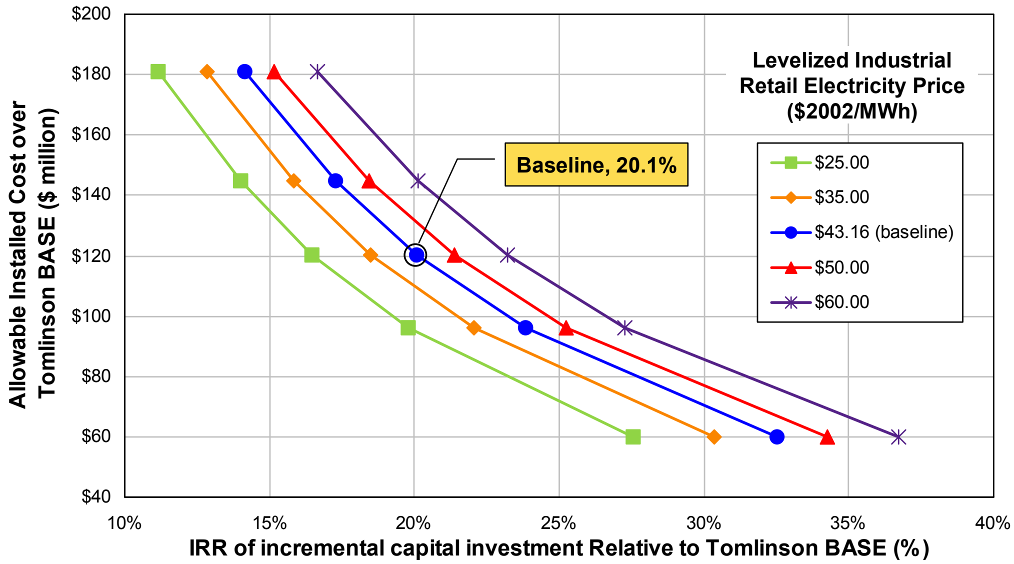


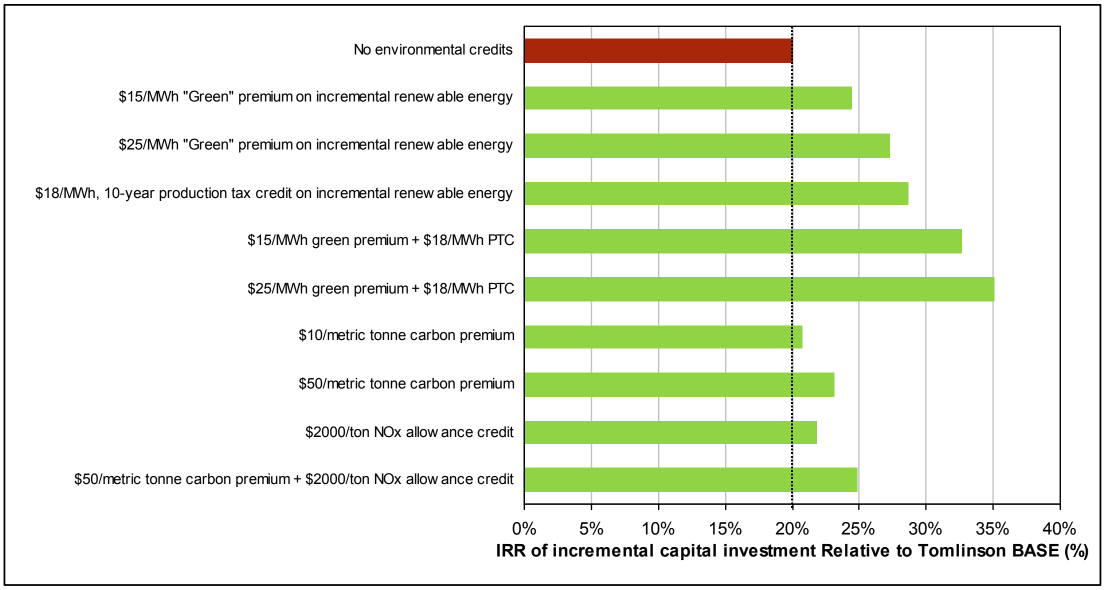
Figure 21. Net cash flows for the high-temperature BLGCC with utility-scale gas turbine relative to the Tomlinson BASE Case – nominal dollars.



Note:
In all cases the levelized natural gas price is $3.76/MMBtu and the levelized export power price is $40.4/MWh. The total installed cost of the BLGCC system ranges ±25% and the installed cost of the Tomlinson BASE is $121.7 million. Although the overall analysis assumes that electricity prices are dependent on gas prices, there are other factors that influence electricity prices. There are also strong regional differences in electricity rates. This chart is meant to show, among other things, the impact of different industrial electric rates, all else equal.

Figure 22. Allowed incremental capital cost (high-temperature utility-scale BLGCC relative to Tomlinson BASE) to achieve different target IRR values with indicated retail electricity price.

Figure 23 shows the IRR on incremental investment in this BLGCC case versus the Tomlinson-Base with different environmental benefits monetized. The baseline IRR (no environmental credits) is shown for comparison. As with the high-temperature mill-scale case, the highest returns are associated with credits tied to incremental production of renewable electricity. The value provided by the various renewable and environmental attributes could make this option very attractive, with IRRs easily exceeding 25%, and in some cases, approaching 35%.



Note: NOx allowances and CO2 credits would also be additive to production tax credits and possibly to renewable energy premiums. However, some certifying agencies (e.g., the Center for Resource Solutions, which provides "Green-e" certification) have taken the position that the attributes of "tradable renewable certificates" cannot be unbundled and must be sold together.

Figure 23. IRR values with different environmental benefits monetized – high-temperature BLGCC with utility-scale gas turbine. The baseline IRR is the top-most bar.

8.3 Summary and Discussion

By way of summarizing the financial analyses, IRR and NPV results are presented for all cases in Table 16 (for baseline assumptions) and Table 17 (with monetary values assigned to renewable energy attributes). Three sets of IRR/NPV values are shown in each table: "stand-alone" values are calculated assuming all avoided electricity purchases as positive cash flows and all O&M costs as negative cash flows; "relative to Tomlinson BASE" values are calculated based on incremental cash flows relative to those for a new Tomlinson BASE system, and; "Relative to Tomlinson HERB" values are calculated based on incremental cash flows relative to those for a new Tomlinson HERB system.

The incremental IRRs for the mill-scale high-temperature BLGCC cases relative to investments in either a new Tomlinson BASE or new HERB system are reasonably attractive for the baseline assumptions (18.5% to 21.1% IRR). The IRRs for the utility-scale BLGCC are higher still. When environmental values are explicitly included in the analysis (Table 17), the financial performance for the high-temperature BLGCC cases are overwhelmingly attractive for both mill-scale and utility-scale systems.

The lower financial performance of the low-temperature BLGCC is due largely to the high incremental lime kiln requirement. If the lime kiln requirement were eliminated (for example as at a pulp mill using a non-sulfur pulping process), the incremental IRR for this case relative to the Tomlinson BASE system would increase from 9% to an estimated 13%. This suggests that this technology may be preferable for use with non-sulfur black liquors, e.g., those found at pulp mills using the soda process. For kraft black liquor applications, the use of the low-temperature BLGCC presents the possibility of completely eliminating the lime kiln, e.g., using direct causticization (see Sections 3.3 and 5.6). Without accounting for added costs with direct causticizing, but eliminating all costs associated with the lime kiln, the IRR would nearly double to 17%. This result highlights the importance of proving the commercial feasibility of ways to reduce or eliminate the lime kiln at a kraft pulp mill with the low-temperature BLGCC system.

Table 16. Baseline financial results – Internal Rate of Return (IRR) and Net Present Values (NPV) – for all cases. Values shown are for stand-alone analysis[a] and incremental analysis (relative to Tomlinson BASE[b] or Tomlinson HERB[c]).

	TOTAL NET CASH FLOW					
	Stand-alone[a]		Relative to Tomlinson BASE[b]		Relative to Tomlinson HERB[c]	
	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)
Tomlinson – BASE	14.2%	28.0	N/A	N/A	N/A	N/A
Tomlinson – HERB	14.2%	37.0	14.2%	9.0	N/A	N/A
BLGCC – Low T Gasifier - Mill Scale	11.6%	21.9	8.9%	-6.0	6.1%	-15.0
BLGCC – High T Gasifier - Mill Scale	16.1%	72.8	18.5%	44.9	21.1%	35.8
BLGCC – High T Gasifier - Utility Scale	17.5%	111.1	20.1%	83.1	22.0%	74.1

(a) This is the total net cash flow of the option on a stand-alone basis, treating all avoided electricity purchases as positive cash flows and all O&M costs as negative cash flows.

(b) This is the difference between the total net cash flow of that option and the total net cash flow of the Tomlinson BASE, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

(c) This is the difference between the total net cash flow of that option and the total net cash flow of the HERB, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

Because the low-temperature system considered here operates at close to atmospheric-pressure and is inherently modular in design, it may also be an especially suitable technology for applications where relatively small amounts of incremental black liquor recovery capacity are required to augment existing Tomlinson recovery boiler capacity. Analysis of this application was beyond the scope of the present study.

While the highest baseline financial performance levels for BLGCC systems in this study appear attractive, they may not be sufficiently attractive to motivate BLGCC technology commercialization efforts by the private-sector alone, especially since the first few plants can be expected to give lower financial performance than with the N^{th} plant levels calculated here, and investors are likely to require a risk premium. However, when environmental benefits are monetized, financial performance reaches levels that might normally justify a fully-private commercialization effort. On the other hand, some environmental benefits will be difficult for private investors to capture (e.g., indirect benefits arising from grid emissions offsets). Furthermore, black liquor (and biomass in general) does not currently benefit from the same level of tax credits or image as a *green* technology as wind or solar power. Nevertheless, these benefits would be real, and they would accrue to society as a whole. This suggests that further analysis is warranted on the environmental benefits, including those discussed here only qualitatively (HAPs, water pollution, the impacts of reduced resource requirements due to polysulfide pulping).

Given the above discussion, a public-private partnership will likely be needed (and is arguably justifiable) for the first few BLGCC units, which will be higher on the cost-learning curve than the N[th]-plant cost levels used in this study. A concerted effort to educate the public and policymakers on the environmental and renewable energy attributes of biomass, especially when converted in advanced technology like BLGCC, is also needed.

In closing this wrap-up discussion, it can be noted that this study considered electricity as the only energy exported from gasification-based power/recovery systems. In this regard, the characteristics of black liquor gasification as a 'breakthrough" technology have not been fully investigated. In particular, conversion of black liquor to high-value chemicals and/or transportation fuels, e.g., Fischer-Tropsch (F-T) middle distillates or hydrogen, may give considerably different results. Systems studies of the type presented here, but for different product slates, should be a focus of future analysis to better understand the possibilities. Moreover, such studies should also examine the potential for gasifying hog fuel and wood wastes alongside black liquor in the power/recovery area. This configuration, which is consistent with the long-term vision of the pulp & paper industry, would result in additional high value products and could reduce or eliminate the need for fossil fuels to be used in the lime kiln and power cycles.

Table 17. Financial results assuming a renewable electricity premium of 2.5¢/kWh, together with a renewable electricity production tax credit equivalent to 1.8¢/kWh for ten years, applied to all incremental renewable generation above Tomlinson BASE.[a]

	TOTAL NET CASH FLOW					
	Stand-alone[b]		Relative to Tomlinson BASE[c]		Relative to Tomlinson HERB[d]	
	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)	IRR (%/yr)	NPV ($million)
Tomlinson – BASE	14.2%	28.0	N/A	N/A	N/A	N/A
Tomlinson – HERB	20.1%	86.2	37.8%	58.2	N/A	N/A
BLGCC – Low T Gasifier - Mill Scale	17.7%	100.9	20.9%	73.0	13.4%	14.8
BLGCC – High T Gasifier - Mill Scale	24.2%	166.4	34.8%	138.5	33.2%	80.3
BLGCC – High T Gasifier - Utility Scale	26.6%	244.2	35.1%	216.2	34.4%	158.0

(a) Assumes the credits are available whether the renewable energy is sold or used onsite, consistent with the use of renewable energy certificates, whereby the attributes of the electricity can be unbundled and sold separately (e.g., to meet a renewable portfolio standard). Assumes the production tax credit (PTC) is available for the first ten years of operation and is indexed to inflation, similar to current Federal PTC for wind power and closed loop biomass.

(b) This is the total net cash flow of the option on a stand-alone basis, treating all avoided electricity purchases as positive cash flows and all O&M costs as negative cash flows.

(c) This is the difference between the total net cash flow of that option to the total net cash flow of the Tomlinson BASE, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

(d) This is the difference between the total net cash flow of that option to the total net cash flow of the Tomlinson HERB, including all incremental effects on total wood consumption, avoided electricity purchases, electricity export (BLGCC only), lime kiln fuel, wood-waste purchases, natural gas purchases, and O&M costs.

9 Regional and National Impacts of BLGCC Implementation

In addition to the mill-level cost-benefit assessment, an analysis of potential impacts in the Southeast Region of the United States and for the entire United States were also carried out.

9.1 Market Penetration Scenarios

To estimate the energy and environmental impacts of widespread implementation of BLGCC technology, three market penetration scenarios were developed, based on the well-documented S-shaped trajectory for commercial market penetration of new industrial technologies (Gilshannon and Brown, 1996). When a new technology enters the market, the initial period is characterized by a low penetration rate by early adopters, while the bulk of the market waits for lower costs and/or more proven performance. Rapid adoption by the broader market follows the slow initial phase, and adoption tails off as the technology approaches saturation of the technical market potential.

The technical market potential was estimated here based on a detailed industry database of existing recovery boilers.[38] This estimate was made by applying assumptions about the age of boilers when they come due for rebuild and/or replacement. Given the uncertainty regarding the timing of introduction of BLGCC technology, some simplifying assumptions were made for the market penetration analysis:

- The current industry capacity was taken as the starting point for the analysis. Given the recent contraction of the industry this was felt to be a reasonable starting assumption. Also, because further industry consolidation and mill closures are expected, and few if any new mills are likely to be built, the analysis is based on total capacity rather than the number of mills in operation.
- Since DOE is targeting 2008 as the first year BLGCC technology will be commercially available, any boiler requiring rebuild or replacement prior to 2008 was assumed to be rebuilt using conventional technology and thereby not available for replacement by BLGCC until the next rebuild cycle for that boiler. Starting in 2008, boilers coming due for rebuild or replacement are assumed to be eligible for repowering with BLGCC, but due to the nature of the market penetration curve, broader adoption does not occur before about 2013. Thus, the market penetration analysis effectively captures the time required for validation and refinement of the commercial design, which would then be followed by broader adoption of the "Nth" plant design by the industry in the post-2013 timeframe.
- Based on data and forecasts supplied by the American Forest and Paper Association (AF&PA, 2002) a 1.2% growth rate on total pulp production was assumed, starting in the first year BLGCC is available.

[38] The Black Liquor Recovery Boiler Committee (BLRBC) of the American Forest and Paper Association maintains a database of individual recovery boilers, with information on capacity, location, age, rebuild year (if any), and in some cases, the nature of the rebuild. This database can be used to calculate the average boiler size, average boiler age when a rebuild occurred (~20 years), and to identify which boilers will be ready for replacement in any given future year.

The output of the technical market potential analysis is a year-by-year estimate of the annual and cumulative boiler capacity eligible for replacement by BLGCC.

To quantify the market penetration, a Fisher-Pry model (Fisher and Pry, 1971) was used to generate an S-curve trajectory calibrated based on knowledge about BLGCC relative to historical market adoption rates for new industrial technologies. New technologies that are capital intensive, have long equipment lives (>20 years), and entail major changes at the facility level (as opposed to changes to individual process steps), typically have market saturation times[39] of 25-40 years. Other factors that influence market penetration include the growth rate of the industry, the industry's risk tolerance, and whether or not government regulations are forcing changes. These factors and the significant technology change that BLGCC would represent for the pulp and paper industry, suggest that saturation times greater than 25 years could be expected. However, the situation with Tomlinson recovery boilers presents unique conditions that also suggest that more rapid penetration may occur. First, the Tomlinson boiler fleet is old and is facing the need for another major wave of rebuilds in the next 10-20 years. Second, competitive pressures from foreign producers may drive the U.S. pulp and paper industry to accelerate adoption of technologies like BLGCC that can help maintain its competitive position in global markets. Third, increasing implementation of Renewable Portfolio Standards and other mechanisms to stimulate renewable energy markets in North America and Europe may create additional financial incentives to accelerate the deployment of BLGCC, e.g. via the involvement of partnerships with utilities.[40]

To cover a range of possible market deployment scenarios, three market penetration scenarios were developed (Table 18). The "High" market penetration scenario assumed a 25-year saturation time and relatively shorter replacement/rebuild cycles for Tomlinson boilers. The "Low" scenario assumed a 30-year saturation time and longer replacement/rebuild cycles. The "Aggressive" scenario assumed the same replacement/rebuild cycle as the High scenario, but a 10-year saturation time. While this saturation time is more typical of rapid-payback, discretionary-spending investments, it was used here to illustrate what might be possible given the unique drivers outlined above. In all cases, the ultimate adoption of the technology was assumed to be 90% of the total industry capacity, to reflect the fact that some mills will never adopt BLGCC technology.

The final element of the market penetration analysis was to apply a reasonable growth rate to the industry. Based on historical data and near-term forecasts provided by the AF&PA, a growth rate of 1.2% per year was assumed, as noted earlier.

The assumptions in Table 18 give the market penetration estimates (in million lbs/day black liquor solids capacity) in Figure 24 (United States) and Figure 25 (Southeastern U.S.) used to assess the national and regional impacts of BLGCC technology.

---

[39] Defined as the time required to go from a market penetration of 10% to 90% of the technical potential.

[40] Of course, BLGCC and biomass must be considered eligible technologies to benefit. At the time of this writing, the U.S. Congress continues to consider comprehensive energy legislation. Among proposed changes are modifications to the Federal renewable energy production tax credit to broaden the definition of eligible biomass. If enacted, this could have significant implications for biomass power, including options using black liquor.

Table 18. Summary of BLGCC market penetration scenarios developed in this study.

	High Scenario	*Low* Scenario	*Aggressive* Scenario
Technical Market Potential[a]	• 186 operable recovery boilers (119 in Southeast, 67 in Rest of US) • Combined capacity of ~460 million lbs/day dry solids (~83 million t/yr)		
Ultimate Adoption Rate	• 90% of the technical market potential		
Industry Growth	• 1.2% per year, based on total capacity		
Basis	• Traditional market penetration "S" curve for capital intensive, facility-level investments		• Aggressive penetration curve assuming that normal rules of market penetration may not apply due to the age of the Tomlinson boiler fleet and other market drivers (see main text for discussion)
Saturation Time (years)[b]	25	30	10
Age of "New" boilers when replacement with BLGCC is considered	30	35	30
Age of "Rebuilt" boilers when replacement with BLGCC is considered	10	15	10

(a) Because additional industry consolidation and mill closures are expected, and few if any new mills are likely to be built, the analysis is based on total capacity rather than number of mills.

(b) Defined as the time required to go from 10% penetration to 90% penetration.

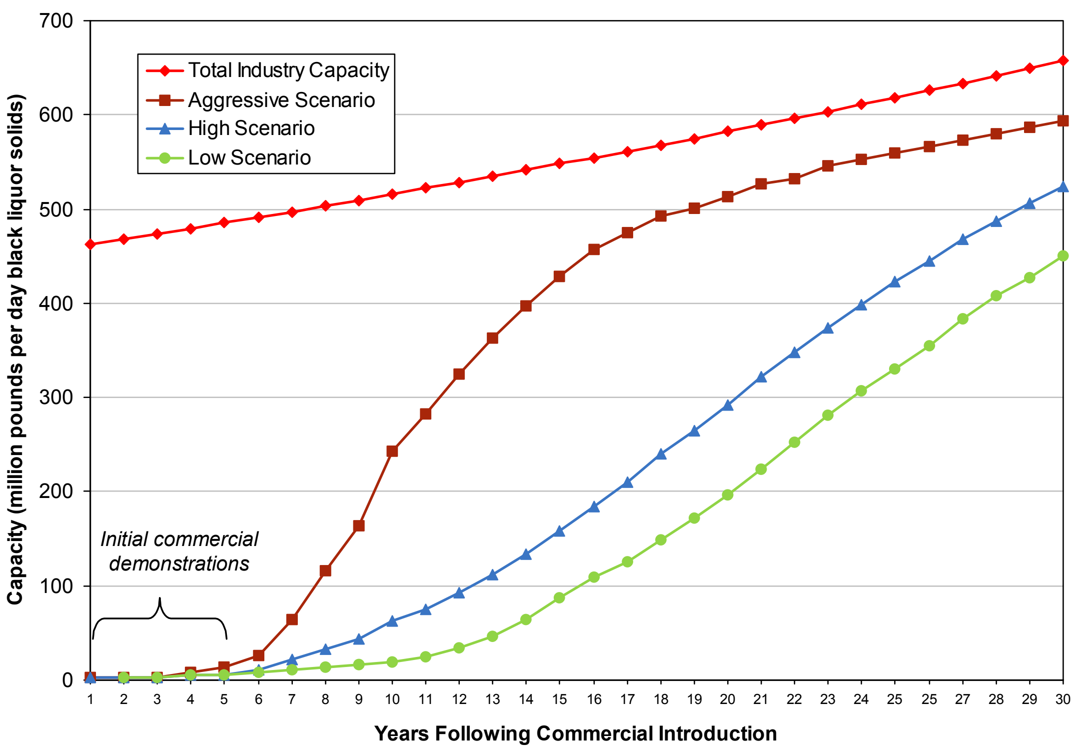


Figure 24. Market penetration estimates used to assess energy and environmental impacts of BLGCC implementation in the United States.

9.2 Impacts for the Southeastern United States

Given the importance of the forest products industries in the Southeastern U.S.,[41] BLGCC technology has the potential to provide a range of benefits for this region. Some of these benefits can be quantified, whereas others are by nature more qualitative. Where possible, this study has attempted to quantify benefits on the basis of the market penetration scenarios described above.

Impacts in the Southeast Region have been divided into six categories. Each is discussed below:

- Regional Energy Supply & Demand
- Renewable Energy Markets
- Emissions Reductions
- Fuel Diversity and Energy Security
- Economic Development
- Grid Interconnection Issues

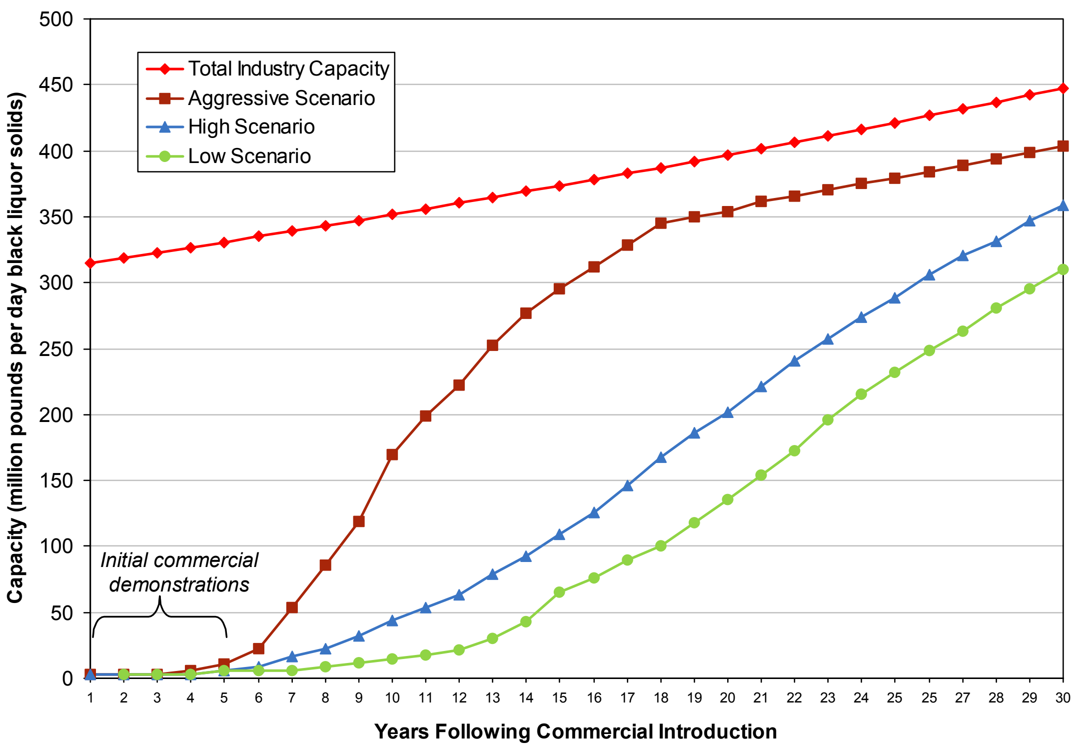
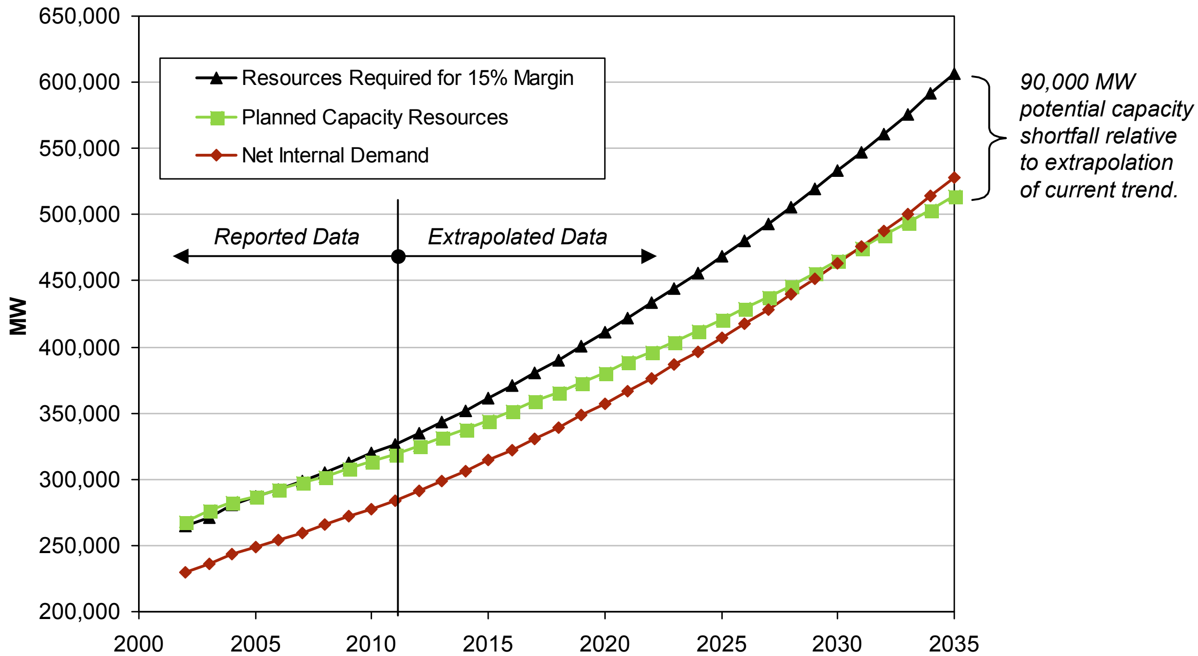


Figure 25. Market penetration estimates used to assess energy and environmental impacts of BLGCC implementation in the Southeastern United States.

[41] For the purposes of this study the Southeast is defined by the following three North American Electric Reliability Council (NERC) regions: The Southeastern Electric Reliability Council (SERC), Florida Reliability Coordinating Council (FRCC) and the Southwest Power Pool (SPP).

9.2.1 Regional Energy Supply & Demand

The Southeast is one of the fastest growing regions in the United States in terms of population and electricity demand. Despite adequate near-term power generation capacity, significant new capacity will be needed to meet expected demand growth (Figure 26) over the next two decades and beyond. Based on current projections and extrapolations of demand and supply growth,[42] total electricity demand in the Southeast region could double by 2030. In addition, the rate at which capacity is expected to be added over the next ten years is slower than the rate of demand growth. Extrapolating this trend, as much as 90 GW of additional new supply – beyond extrapolations of current capacity build forecasts – will be needed by 2035 to maintain a 15% reserve margin, the amount typically considered necessary to maintain a proper balance between supply and demand. These figures also do not factor in retirement of existing capacity so that even if actual demand growth is slower than shown, it is clear that the Southeast will require significant new electric generating capacity in the coming decades.



Note: Here, the Southeast is defined by the three NERC regions: FRCC, SPP and SERC.
Source: FRCC 2002 Load and Capacity Report, SPP 2002 EIA 411, SERC 2002 EIA 411, NCI analysis.

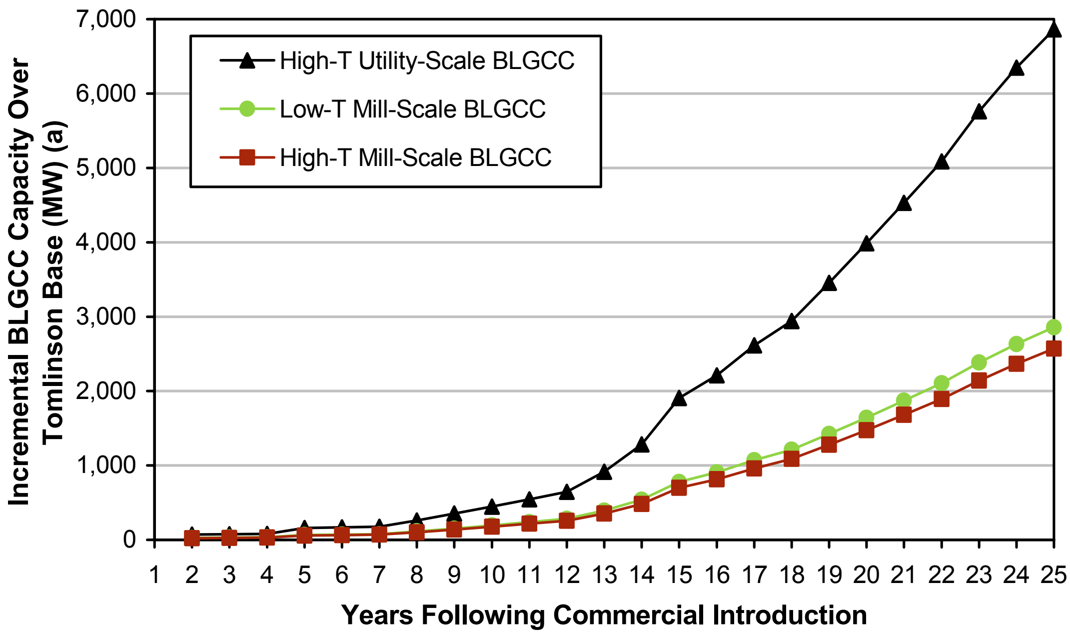
Figure 26. Forecasted Southeast regional electricity supply/demand balance.

Based on the market penetration scenarios described earlier, BLGCC technology has the potential to contribute in a meaningful way to the overall supply of electricity in the Southeast region. Specifically, BLGCC in the configurations with the mill-scale gas turbine could provide from 2,500-3,000 MW within 25 years of introduction in the *Low* scenario (Figure 27) to nearly 3,500 MW in the *High* scenario (Figure 28), to more than 4,000 MW in the *Aggressive* scenario (Figure 29). In the utility-scale configuration, because of the much larger unit size, total capacity contributions would exceed 11,000 MW within 25 years of introduction in the *Aggressive* Scenario. While short of the total expected requirements for new capacity, these amounts still

[42] FRCC 2002 Load and Capacity Report, SPP 2002 Form EIA 411, SERC 2002 Form EIA 411.

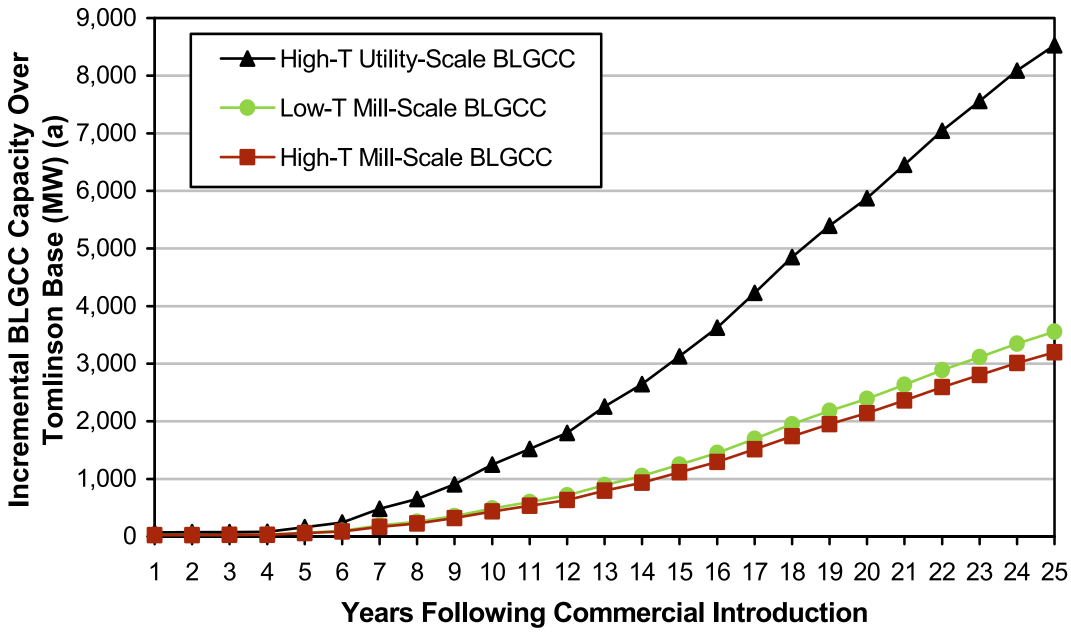
suggest that BLGCC is a potentially important resource in a diversified Southeast capacity mix (and even more important in regions within the Southeast with higher concentrations of mills).

These capacity contributions are over and above the roughly 3,000 MW that the pulp and paper industry currently generates from black liquor in the Southeast. Also, they represent only what is possible with black liquor. Were the pulp and paper industry to develop additional sources of biomass, as discussed earlier in this report, the potential exists to approximately double the incremental biomass-fired generation in the region compared to the black-liquor-only capacity.



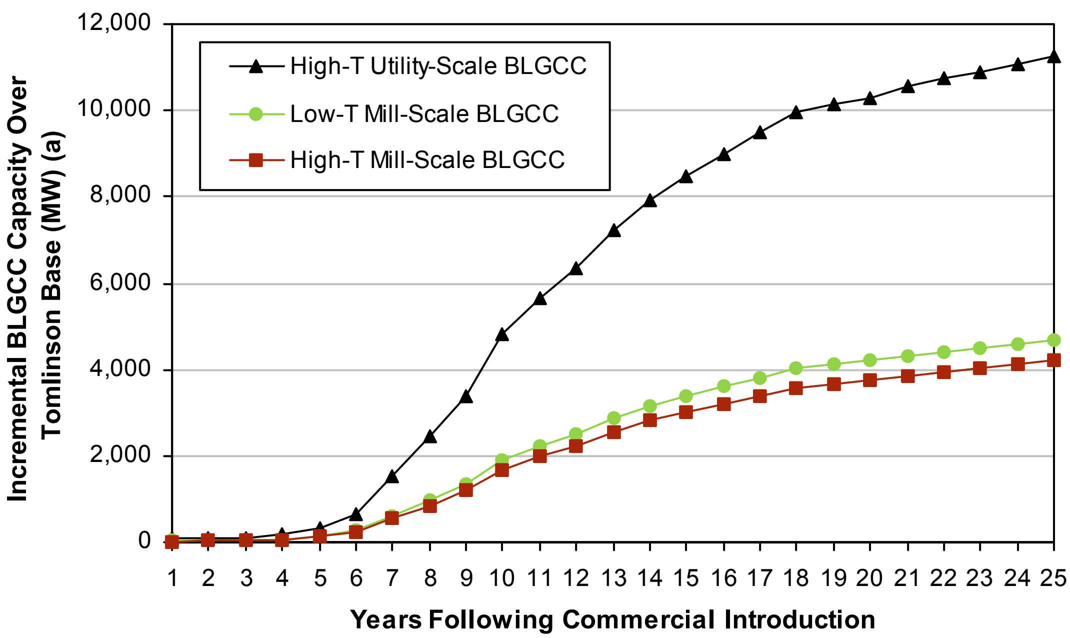
(a) Incremental BLGCC capacity over Year-1 Tomlinson BASE capacity (assuming organic industry growth in all cases).

Figure 27. Potential incremental generation capacity additions in Southeast U.S. in *LOW* market penetration scenario for BLGCC in configurations with mill-scale and utility-scale gas turbines.



(a) Incremental BLGCC capacity over Year-1 Tomlinson BASE capacity (assuming organic industry growth in all cases).

Figure 28. Potential incremental generation capacity additions in Southeast U.S. in *HIGH* market penetration scenario for BLGCC in configurations with mill-scale and utility-scale gas turbines.



(a) Incremental BLGCC capacity over Year-1 Tomlinson BASE capacity (assuming organic industry growth in all cases).

Figure 29. Potential incremental generation capacity additions in Southeast U.S. in *AGGRESSIVE* market penetration scenario for BLGCC in configurations with mill-scale and utility-scale gas turbines.

9.2.2 Renewable Electricity Markets

Distinct markets for renewable energy and its associated attributes are developing in the United States and elsewhere. Aside from applications where renewables are cost competitive with conventional power, these markets are being driven by Renewable Portfolio Standards (RPS), voluntary green power programs offered through utilities and retail power marketers, and emissions trading markets, especially where renewables receive "set-aside" allowances.[43] These various programs effectively create markets for the attributes of renewable energy that are separate from energy markets, adding a second revenue stream for renewable generators. These markets may be regional, national or even international (e.g., with carbon trading).

Because biomass is potentially the most significant renewable energy resource in the Southeast, and given that the pulp and paper industry is the largest user of biomass for energy, and that black liquor is the dominant form of biomass energy, BLGCC could be of major importance in meeting future renewable energy requirements in the Southeast. To illustrate this, we examined a hypothetical RPS for the Southeast. RPS is emerging in the United States as the dominant driver for renewable electricity capacity growth – twelve states already have renewable portfolio standards and three others have renewable electricity "best effort" goals/targets (essentially a voluntary RPS). As shown in Section 8, a premium value for renewable power, combined with other monetized externality values (like emissions credits or offsets) would considerably increase the value of BLGCC electricity relative to non-renewable electricity sources in the marketplace, provided that BLGCC were eligible to receive such credits.

To illustrate the value of BLGCC in this context, consider a hypothetical RPS for the Southeast region, in which 5% of all electricity sales in 2020 must come from new renewable resources. Eligible renewable resources are those that come online after 2002. For the Southeast region in 2020, 82.7 billion kWh would need to be procured from **new** RPS-eligible renewable resources. Thus by 2020, total renewable generation for the Southeast under the 5% RPS would be 147.9 billion kWh, more than double the **total** renewable electricity generation of 65.2 billion kWh in 2002. For comparison, the DOE EIA baseline forecast (no RPS) for the same region is for 83.4 billion kWh of total renewable generation in 2020. Thus, even a modest 5% RPS by 2020 would require the addition of significant renewable energy generation.

The contribution by BLGCC technology to a 5% regional RPS could vary considerably depending on the market penetration scenario. Given the uncertainty in the timing of BLGCC deployment, Table 19 shows the potential contributions of the pulp & paper industry to the RPS assuming all black liquor is used in either Tomlinson boilers or BLGCC systems (i.e., independent of market penetration assumptions). If the pulp & paper industry continued to use Tomlinson BASE technology, organic growth of the industry would only produce up to 4.4 billion kWh/yr of new renewable generation by 2020, or about 5% of the RPS requirement. In comparison, HERB technology would produce about four times this amount or 20% of the RPS requirement. BLGCC technology, with its much higher electricity efficiency, would generate in excess of 36 billion kWh/yr of incremental renewable generation (based on the average of the three cases), or nearly 45% of the 5% RPS requirement. The total incremental investment (above the replacement cost of the Tomlinson systems) required to achieve this amount of generation from BLGCC would be approximately $6.3 billion (again, based on the average of the three

[43] Renewable "set-asides" are essentially free emissions allowances created by regulatory mechanisms and given to renewable energy producers, who can sell them in the marketplace to those who need allowances to operate.

BLGCC systems).[44] If this amount of renewable energy were to be produced from new wind power, about 12,000 MW of wind turbines would need to be installed at a capital investment of $8.3-9.4 billion.[45]

Table 19. Incremental Renewable Energy Generation Potential (billion kWh/yr) from black liquor in the pulp and paper industry in the Southeastern United States.[a]

	Total Renewable Generation in 2002	Renewable Energy Requirements Under a 5% RPS by 2020	Incremental BL Potential by 2020	
			Billion kWh	% of RPS
Tomlinson BASE[b]	All Renewables: 65.2	New RPS-Eligible Renewable Generation: 82.7 Total Renewable Generation: 147.9	4.4	5.3%
Tomlinson HERB[c]			16.7	20.2%
BLGCC[c]			36.2	43.8%

(a) Incremental potential assumes industry capacity is same in 2008 as today and grows 1.2% per year after that. All figures are relative to the potential generation in 2008 from black liquor using BASE Tomlinson technology.

(b) Represents organic growth of the entire industry in SE at 1.2%/year, assuming continued use of BASE technology.

(c) Incremental capacity relative to current generation assuming all mills that have been repowered (with HERB or BLGCC), including the effects of industry growth at 1.2% per year. *BLGCC* case is based on the average for the three BLGCC technology cases.

9.2.3 Emissions Reductions

Here the potential emissions impacts of BLGCC in the Southeast United States are illustrated with results for the utility-scale case, *Aggressive* market penetration scenario. (Details of all cases are given in Appendix B). The key assumptions used to generate these results include:

- Emissions savings estimates are made relative to the use of Tomlinson BASE technology for the same degree of market penetration and industry growth, i.e., the estimates show the **difference** between Tomlinson BASE technology and BLGCC technology.[46]
- Estimates include all mill-level emissions sources and the net offsets from grid power
- Grid-power emissions change over time (see Table 10) in line with expected changes in fuel mix and emissions as forecast in the DOE *Annual Energy Outlook 2002*.
- CO_2 emissions shown here exclude the CO_2 originating from biomass, but the reader is referred back to Table 11 for quantification of biomass-associated CO_2 emissions.
- Estimates do not assume any improvements in mill efficiency over time, which may be a conservative assumption.

[44] This estimate is therefore conservative, since a portion of the investment in the utility-scale BLGCC system is for non-renewable generation.

[45] Assumes an annual capacity factor of 35% for a moderate speed (Class 4) wind site and an installed cost of $700-800/kW, the mature price and performance for wind power expected in the 2013 timeframe.

[46] Even if the industry were to never deploy BLGCC technology, as the industry grows it will generate more power internally and therefore offset additional grid power. This "moving baseline" forms the basis for evaluating the incremental impacts of BLGCC.

Relative to Tomlinson BASE technology, BLGCC has the potential to offset more than 25 million tons of CO_2 per year in the Southeast United States (Figure 30). It also has the potential to significantly reduce SO_2 and NO_x emissions, even as the grid emissions rates (lb/MWh) of these pollutants continue to fall as a result of fuel mix changes and compliance with the 1990 Clean Air Act Amendments. Other emissions would also be reduced, but to a lesser extent, mainly because the total tonnages of these emissions are smaller to begin with. With the rapid market penetration assumed in the *Aggressive* scenario, the cumulative CO_2 offsets would amount to roughly 7.5% of the expected increase in total CO_2 emissions from the grid in the 2008-2035 timeframe (absent a contribution to reductions by BLGCC technology).

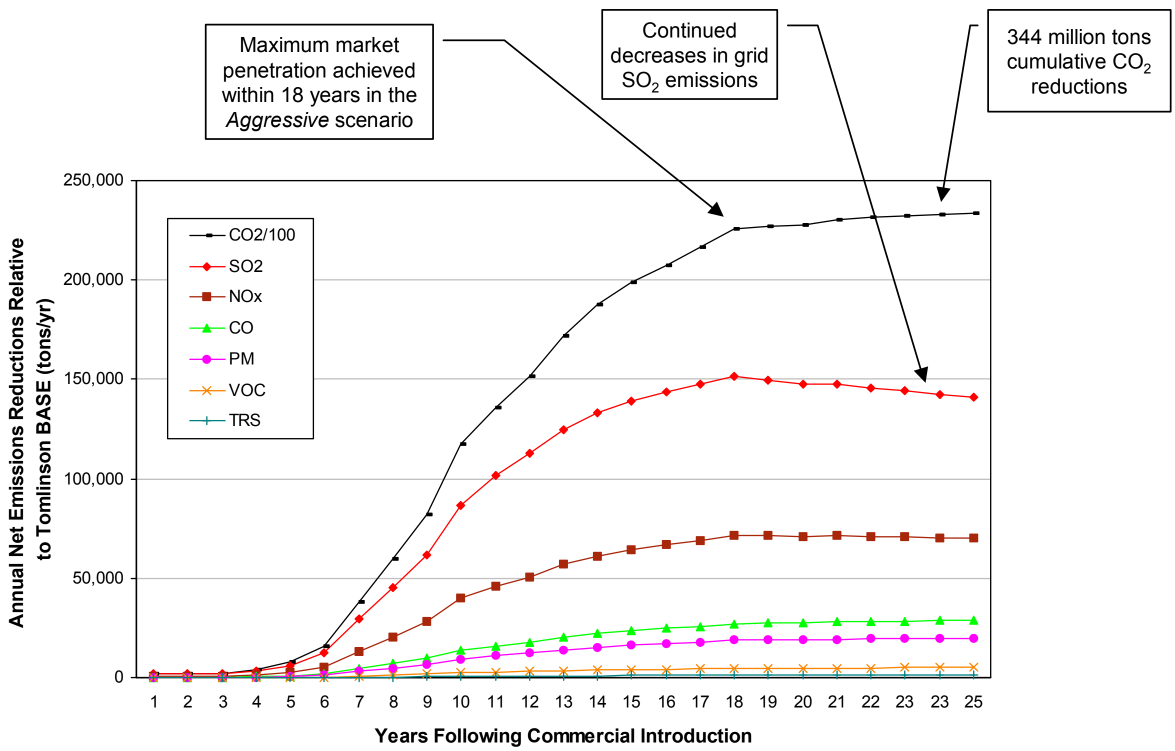


Figure 30. Net emissions reduction from Utility-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Aggressive* market penetration scenario.

It is noteworthy that SO_2 and NO_x have economic value today, because of existing emissions trading regimes. At $160/ton (the current price for SO_2 allowances), and assuming prices remain at this level in real terms, the SO_2 reductions have a market value of nearly $400 million for the 25-year forecast period. NO_x, if conservatively valued at $2,000/ton over the same period, would have a market value of $2.2 billion. If a system for trading CO_2 is put in place, the CO_2 value could be $2.1 billion at a price of $25/metric ton of carbon (a mid-range value of various estimates).

These illustrative results suggest that BLGCC technology has the potential to provide significant environmental benefits.

9.2.4 Fuel Diversity and Energy Security

The nation's power sector remains heavily dependent on fossil fuels and is becoming increasingly dependent on gas-fired combined cycle technology for new power generation capacity, and the Southeast is no exception. The shift to gas-fired GTCC is driven by several factors, including low capital and operating costs, high efficiency, low emissions, rapid construction, and small footprint. These factors have combined to make GTCC technology the lowest cost option for new power plants. They also greatly facilitate financing and siting, relative to other central station generation options.

Despite the shift to gas for new capacity, the Southeast is expected to maintain a diverse fuel mix for the foreseeable future. Nevertheless, the increasing reliance on natural gas has some important energy cost, fuel diversity and energy security implications:

- Natural-gas fired power plants will increasingly set the marginal price for power.
- Natural gas prices have proven to be volatile and are expected to remain so, driven in part by increasing summer demand for power generation.[47] Throughout the course of this project, natural gas spot prices remained well above historical averages, reaching the $6/MMBtu range going into the summer cooling season, or roughly 2-2.5 times higher than the historical average for that time of year. Although prices had decreased somewhat by the fall of 2003, the general tightness in supply is expected to continue for some time as natural gas demand is expected to grow, driven in large part by its environmental attributes. With limited ability to import gas into North America, the United States will continue to be susceptible to the gas price volatility it has experienced in the last 2-3 years.[48]
- In the post-9/11 world, natural gas supply infrastructure is seen as vulnerable to disruption by terrorist attack. Thus, the electric industry is vulnerable both directly (via attacks on electric infrastructure) and indirectly (via attacks on natural gas infrastructure)

BLGCC has the potential to help address all of these concerns. First, it provides a way to diversify the electric power fuel mix, thereby reducing dependence on fossil fuels. Not only does this conserve finite resources, but it has the potential, along with other renewable energy technologies, to ease gas price volatility by easing pressure on the supply-demand balance for gas. Second, BLGCC power plants, even in the *utility scale* configuration, would be more numerous and dispersed than other central station power plants of equal capacity. All else equal, this would make the overall electricity supply infrastructure less vulnerable to disruption by terrorist attacks, and these plants could continue to operate in the event of a gas disruption, whatever the cause.

---

[47] For example, the summer months are used to add natural gas to underground storage, for use during winter, but with increasing amounts of natural gas being used in the summer for power generation, this creates the possibility of having too little gas in storage heading into the winter heating season. All else equal, this tends to increase price volatility, as occurred in the winter of 2000-2001.

[48] Environmental considerations are also decreasing the ability of large gas users like electric utilities to fuel switch (e.g., to #2 oil). This is making demand for gas less elastic than in the past. Similarly, gas production can only respond so quickly to match demand. Thus, while overall supply and demand are in relative balance, short term drivers (e.g., a cold winter or hot summer) can lead to price volatility by temporarily upsetting the supply-demand balance.

9.2.5 Economic Development

BLGCC technology could have important economic development benefits, stemming from the enhancement of the competitiveness of the pulp and paper industry. The benefits include preserving and growing employment in the industry and potentially adding to rural and semi-rural employment by creating increased demand for raw materials for paper production, and in the longer term, energy and other products derived from biomass. If BLGCC is successful, this could be the catalyst for the development of a broader industry based on biomass, both within and outside the pulp & paper industry.

9.2.6 Grid Interconnection Issues

A key additional impact to address when shipping large amounts of power into the grid is the ease and cost with which the interconnection can be made. This requires that certain power system analyses be conducted and that an interconnection agreement be put in place with the host utility. Assessing interconnection requirements is by definition, site specific, and the necessary system impact and facilities studies will ultimately determine the impact of each particular interconnection. Studying any particular site in detail was beyond the scope of this report, but a high level review of the issues along with some specific site analyses were conducted with cooperation from Southern Company. Appendix C provides additional details regarding the issues summarized here.

Three factors are expected to make the interconnection of BLGCC projects relatively simple in comparison to other new generation projects:

- First, many pulp and paper mills currently have existing "behind the fence" generators and a substation that supplies electricity to the mill. Upgrading the existing substation is generally a simpler process than tapping into an existing circuit, acquiring necessary rights of way, and other issues normally associated with interconnection of a new (greenfield or brownfield) generator.
- Second, the current grid interconnections and mill substations are sized to meet the full load of the mill and often have excess capacity (e.g., if the existing onsite generation were offline, the mill could continue to operate by purchasing all of its electricity). For the mill-scale BLGCC cases, the amount of power that would be exported is a small fraction of the rated capacity of the equipment (15-20% of the total mill demand). In the utility scale case, the power to be delivered to the grid will be approximately the same as the power that was being delivered to the pulp and paper mill. Consequently, it is very unlikely that re-conductoring or the addition of new circuits would be necessary for the radial interconnection of the BLGCC power plant to the main grid.
- Third, many mills in the Southeast are relatively close to the "backbone" of the transmission system, so that if line upgrades are necessary, the distances involved are not large, which would help control costs.

Given these considerations, the expected interconnection costs for BLGCC power plants are between \$0.5 and \$4 million per facility, based on estimates made for several pulp mills in Southern Company service territory. These costs are relatively minor, especially compared to a \$150-250 million investment in the BLGCC system.

It is worth noting that the installation of BLGCC systems will add more capacity resources to the region, which would increase the reserve margin and likely aid in overall system reliability. It is also important to note that adding generation at strategic locations on the transmission grid may actually defer capital investments in the transmission and distribution system, if those upgrades were primarily driven by load growth. Thus, even modest deferrals in other transmission investments as a result of adding BLGCC at key locations could more than cover BLGCC interconnection costs.

9.3 National Impacts

The potential national benefits are generally similar to the Southeast regional benefits. Benefits related to economic development, job retention, and industry competitiveness are obviously similar but may not be as significant in relative terms at a national level due to the concentration of pulp and paper mills in the Southeast. Emissions reductions and energy security/diversity benefits are quite similar and are roughly 1/3 higher in absolute terms than in the Southeast. Conversely, benefits relating to electricity supply and demand are less relevant in a national context compared to a regional context. Rather, other quantifiable national benefits include total fossil fuel energy savings and greenhouse gas reductions. A more difficult benefit to quantify is the value of spin-offs from the R&D that would be required to bring the BLGCC technology to market.

Some national benefits are discussed in more detail below:

- National Fossil Energy Savings
- Renewable Energy Markets
- Emissions Reductions
- Fuel Diversity, Energy Security and the Hydrogen Economy
- Economic Development
- Reaping the Benefits of Government RD&D
- Realizing the Biorefinery concept

9.3.1 National Fossil Energy Savings

Fossil fuel displacement is a strategic, national-level benefit that is relatively straight-forward to quantify. The benefits of fossil fuel displacement include the associated emissions reductions, the conservation of finite resources, the positive effects on fossil fuel price volatility, and in the case of petroleum, the reduction of imports, which enhances energy supply security. Generally, an economy that is less dependent on fossil fuels is less susceptible to the negative impacts of fuel price volatility, which has increased in recent years.

National fossil energy savings are estimated relative to the continued use of Tomlinson BASE technology for the same degree of industry growth and assuming displaced grid electricity generation results in savings based on the average utility fuel mix and heat rate (which change over time – see Table 10) projected by DOE in their *Annual Energy Outlook 2002.* No improvement in mill energy efficiency over time is considered, which may be conservative.

Figure 31 shows that BLGCC (in the configuration with utility-scale gas turbine) relative to Tomlinson BASE technology, has the potential to offset more than 360 trillion Btu/year within

25 years of introduction (*Aggressive* scenario). These reductions are net reductions and consider all the fossil fuel use at the mill and the fossil fuel savings on the grid. The utility-scale case produces the largest impacts due to the large amount of grid power displaced, despite using by far the largest quantity of natural gas at the mill. The two mill-scale cases produce less net fossil fuel savings despite using less natural gas onsite. They differ from one another in the amount of natural gas used and the lime kiln load, both of which are somewhat higher in the low-temperature case. This illustrates the potential importance of the development of direct causticizing, which would eliminate the lime kiln altogether.

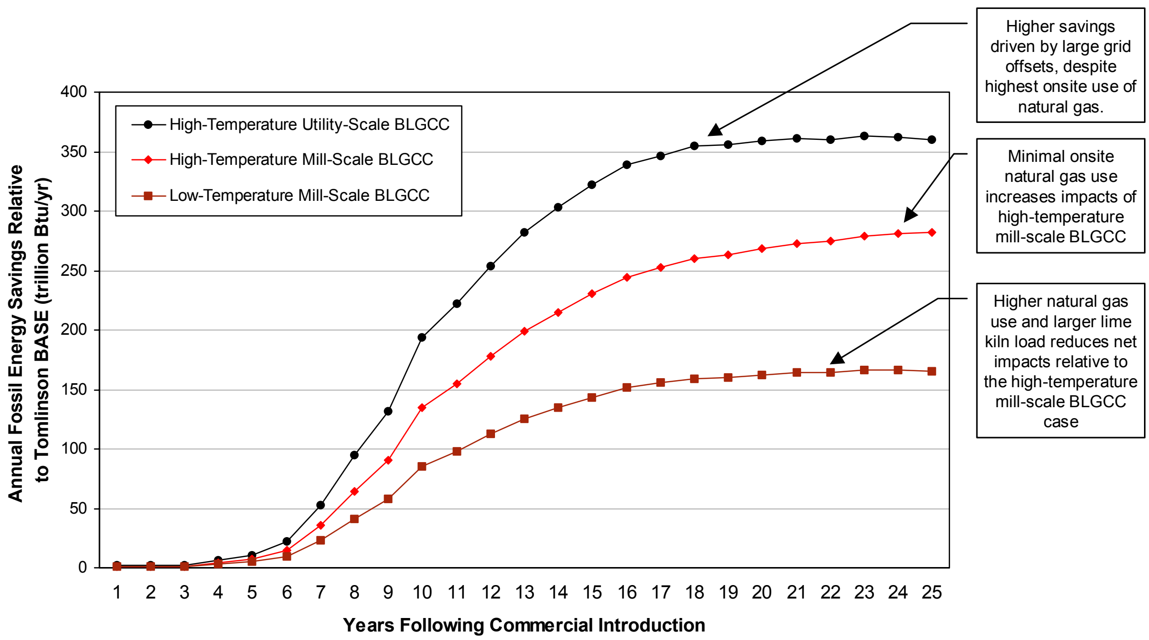


Figure 31. Net fossil fuel savings with BLGCC relative to Tomlinson BASE, Total U.S. Market, *Aggressive* market penetration scenario.

Figure 32 shows the cumulative fossil fuel savings in the three BLGCC market penetration scenarios for the first 25 years following introduction. Net fossil fuel savings with BLGCC relative to continued use of Tomlinson BASE technology range from 0.75 to 2.5 quads (*Low* scenario) up to 2.3 to 5.5 quads (*Aggressive* scenario). As noted above, this analysis assumes constant energy efficiency in pulp and paper manufacturing. Reductions in manufacturing energy intensities would lead to higher energy savings than estimated here.[49]

The energy savings shown in Figure 32 will not necessarily translate into energy cost savings, since energy savings from grid electricity displacement includes a substantial fraction of coal-generated power, whereas more-expensive natural gas is the marginal fuel in the BLGCC cases. Figure 33 shows the relative impacts of grid offsets vs. onsite fuel use for the mill-scale high-

[49] The case-study integrated pulp and paper mill in this analysis is relatively efficient (e.g., with process steam use about 10% lower than typical "best practice" in the U.S. industry today), but no additional efficiency gains are assumed over the 25 year analysis period. Efficiency gains could: *(i)* reduce or eliminate the need for natural gas use in the mill-scale cases and might also enable syngas to displace some lime kiln fuel or reduce the need for purchased wood wastes; *(ii)* enable greater electricity generation from the condensing steam turbine in the utility-scale case; *(iii)* reduce mill electricity demand, enabling greater power exports. All of these benefits would translate directly to increased energy and emissions benefits, in addition to cost savings to the mill.

temperature BLGCC system. In this case there are cumulative energy cost savings ranging from $3 billion (*Low* penetration) to nearly $7 billion (*Aggressive* penetration) over the 25-year forecast period. The situation is similar for the low-temperature mill-scale BLGCC case, but total savings are smaller due to higher natural gas and lime kiln fuel use compared to the high-temperature case. In contrast, total net energy costs in the utility-scale BLGCC case are actually higher than in the Tomlinson BASE case because of the greater use of natural gas and the high cost of gas relative to the average cost of fossil fuels used for grid electricity.

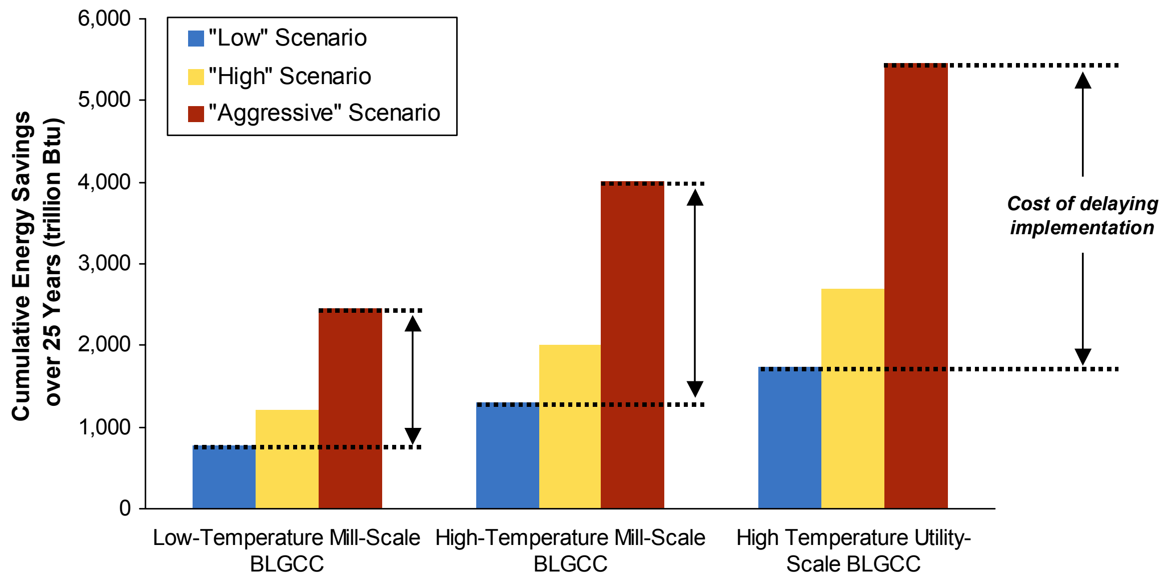


Figure 32. Cumulative (25-year) net fossil fuel savings relative to Tomlinson BASE, Total U.S. Market, under different market penetration scenarios.

9.3.2 Renewable Energy Markets

If a national RPS were to be put in place such that renewable energy certificates (RECs) could be traded nationally, BLGCC and other biomass gasification technologies could clearly play an important role in meeting the overall targets and would also ensure that many of the benefits of renewable energy (e.g., reduced emissions) would be more evenly distributed around the country.[50] Using the same approach as outlined for estimating the Southeast regional impacts, BLGCC has the potential to provide up to 53 billion kWh/yr of incremental renewable generation in 2020 compared to current production with Tomlinson technology. If the industry continued to use Tomlinson BASE technology, the amount of incremental renewable electricity generation due to organic growth of the industry, would only be 6.5 billion kWh/yr. The equivalent wind power capacity required to produce 53 billion kWh with moderate (Class 4) wind resources would be about 17,000 MW, requiring a capital investment of approximately

[50] Wind power is the leading source for new renewable energy today and is likely to play a major role in meeting any future Federal RPS. However, good wind power sites are distributed unevenly across the country, which could turn some regions into major exporters of RECs and others into importers. In contrast, biomass is more evenly distributed across the country. If options such as BLGCC were to not be available, then the Southeast might need to satisfy its obligations under a Federal RPS by purchasing large quantities of RECs from other regions, thus incurring the costs of compliance without receiving the benefits of compliance.

$12-14 billion.[45] In comparison, the incremental investment in BLGCC relative to replacement with Tomlinson BASE technology would be approximately $9.2 billion.[51]

In order for biomass to play this role, however, it must be considered an eligible resource. A review of existing state RPS rules (NCI, 2003) shows that unlike wind power, biomass is not always considered to be RPS-eligible, or if it is, there are often additional restrictions on the types of biomass resources or conversion technologies that can be used to meet an RPS.

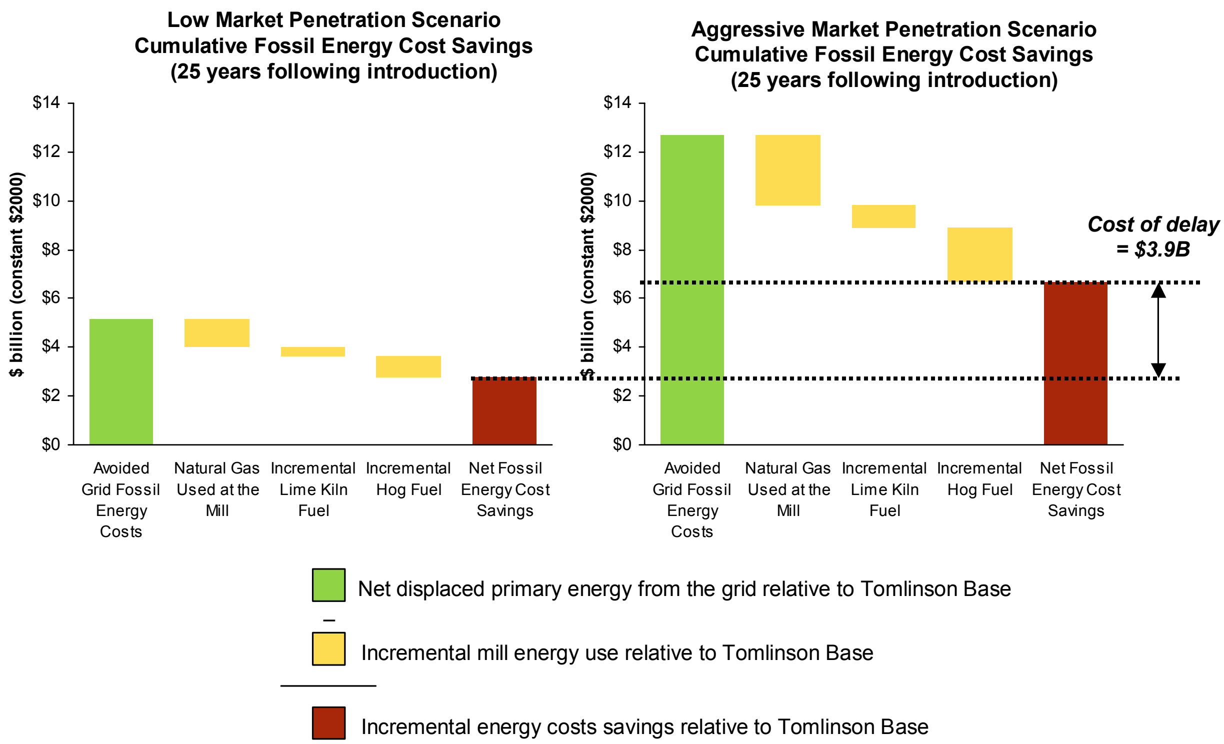


Figure 33. Cumulative (25-year) net fossil fuel cost savings for the High-temperature Mill-Scale BLGCC relative to Tomlinson BASE, Total U.S. Market.

9.3.3 Emissions Reductions

Figure 34 illustrates the potential emissions impacts of BLGCC in the United States using the utility-scale case and the *Aggressive* market penetration scenario. (Details for all cases are given in Appendix B.) Key assumptions are as noted in Section 9.2 for the Southeast regional emissions analysis.

BLGCC technology, relative to Tomlinson BASE technology, has the potential to offset more than 35 million tons of CO_2 per year in the United States (Figure 34). It could also significantly reduce SO_2 and NO_x emissions. Other emissions would also be reduced, but to a lesser extent, mainly because their total emissions are smaller to begin with. With the rapid market penetration assumed in the *Aggressive* scenario, the cumulative CO_2 offsets would amount to roughly 4% of

---

[51] This estimate is therefore conservative, since a portion of the investment in the utility-scale BLGCC system is for non-renewable generation.

the expected increase in total CO_2 emissions from the grid in the 2008-2035 time frame (absent the introduction of BLGCC systems).

As in the Southeast emissions analysis, it is possible to estimate a market value for SO_2 and NO_x emissions reductions. At $160/ton (the current price for SO_2 allowances), and assuming prices remain at this level in real terms, SO_2 reductions have a cumulative value of nearly $450 million over the 25-year period following commercial introduction of BLGCC. NO_x, if valued at $2,000/ton over the same period, has a market value of $3.2 billion. If a system for trading CO_2 is put in place, the CO_2 value could be $3.1 billion at a price of $25/metric ton of carbon.

As in the case with energy savings, this emissions analysis assumed constant energy efficiency in pulp and paper manufacturing. Reductions in manufacturing efficiency would lead to greater emissions reductions than estimated here.[49]

9.3.4 Fuel Diversity, Energy Security and the Hydrogen Economy

The fuel diversity and energy security benefits are very similar to those described in the section on Southeast U.S. benefits and the reader is referred to that section. Within the national context, however, it is worth discussing the potential role of BLGCC (and biomass gasification more broadly) within a potential emerging hydrogen economy. The full benefits of the hydrogen economy can be realized when the source of the hydrogen is domestically produced renewable energy, and biomass has the potential to be one of the lowest cost options for producing hydrogen from renewables resources (Williams *et al.*, 1994). Thus, to the extent that BLGCC can serve as the springboard for a new biomass-based energy industry, it could ultimately be important in the development of a hydrogen energy infrastructure.

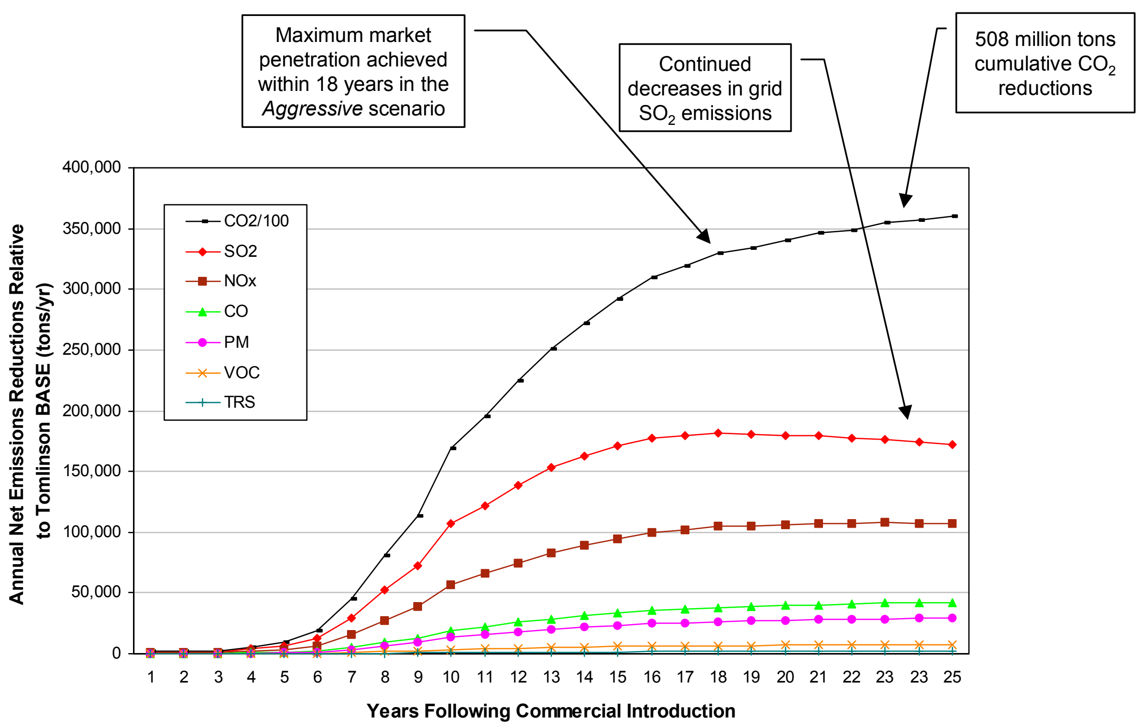


Figure 34. Net emissions reduction from Utility-Scale BLGCC relative to Tomlinson BASE, Total United States, *Aggressive* market penetration scenario.

9.3.5 Economic Development

BLGCC technology could have important economic development benefits, stemming from the enhancement of the competitiveness of the pulp & paper industry. The BLGCC financial analysis illustrated the potential for attractive financial returns and significantly increased cash flows relative to Tomlinson technology. The benefits include preserving and growing employment in the industry and potentially adding to rural and semi-rural employment by creating increased demand for raw materials for paper production, and in the longer term, energy and other products derived from biomass. On a national level these impacts are likely to me modest, but in certain regions or states, the impacts could be important. However, if BLGCC helps serve as a catalyst for a new bio-energy industry, the national economic impacts could be more substantial.

9.3.6 Reaping the Benefits of Government RD&D Support for BLGCC

The U.S. Department of Energy has been supporting research, development, and demonstration (RD&D) of black liquor gasification technology for over 20 years at varying levels (NRC, 2001). It is clear that much has been learned as a result of this government investment, such that black liquor gasification technologies are now on the cusp of commercial viability. (There probably have also been unanticipated and un-quantifiable R&D spin-off values.)

While a return on investment in BLGCC RD&D is difficult to quantify, it is possible to estimate the cost of delaying the additional RD&D needed for BLGCC technology to become commercially ready. With delayed commercial implementation, some energy and emissions savings that would otherwise have occurred would be foregone. Thus, delay in market introduction of BLGCC might be represented by the difference between the *low* and *aggressive* penetration scenarios described earlier. The difference in cumulative energy savings between the scenarios might be thought of as the cost of delaying implementation, or conversely, the benefits of more aggressive deployment and of "front loading" the market penetration curve. If BLGCC technology were to penetrate slowly rather than rapidly into the market, the cumulative (25-year) energy savings would be roughly 1 to 3 quads less (Figure 32). The corresponding added energy costs would be up to \$3.9 billion (Figure 33). In addition, the value of lost SO_2, NO_x, and CO_2 emissions reductions (at \$160/ton SO_2, \$2,000/ton NO_x, and \$25/ton CO_2) would be up to \$4.7 billion (cumulative over 25 years). Thus, if the lag in market penetration between the *low* and *aggressive* scenarios is taken to represent the opportunity cost of delayed commercialization of BLGCC technology, this opportunity cost would be up to \$8.6 billion.

9.3.7 Realizing the Future Biorefinery Concept

A modern pulp and paper mill arguably represents the first generation of the concept of a biorefinery, with steam, power, and a variety of products being made from woody biomass. Black liquor gasification is a key technology platform for the realization of the biorefinery of the future (Figure 2), in which more efficient power generation would be accomplished via combined cycle or fuel cell prime movers and additional value added products like fuels and chemicals would be produced. The new products could include clean transportation fuels such as hydrogen, Fischer-Tropsch diesel, or dimethyl ether, which could substitute petroleum-based fuels and chemicals, thereby reducing United States' dependence on imported oil.

The pulp and paper industry's vision of the powerhouse of the future includes two gasifiers – one for black liquor and a second for solid biomass. The latter would be fueled by hog fuel and additional wood residues collected sustainably from the vicinity of the mills. The combined biomass energy input to this future powerhouse could be twice the level of black liquor considered in this study, which obviously would yield substantially greater benefits than estimated here.

In time, a gasification-based biorefinery industry might extend beyond the pulp and paper industry, whereby biomass crops would be grown for conversion to heat, electricity, fuels, chemicals, animal feed, and other commodity products. The potential also exists for integrating biomass at existing fossil fuel refineries and petrochemical plants. By pursuing the commercialization of BLGCC technology, the pulp and paper industry would stand to share in the energy, environment, and economic benefits identified in this study, while catalyzing the creation of a larger biorefinery industry.

10 Conclusions and Final Thoughts

This study has shown that black liquor gasification combined cycle (BLGCC) power/recovery system offers the prospect for significant improvement in the efficiency with which steam and electricity are cogenerated at kraft pulp mills compared to existing state-of-the-art power/recovery technology (Tomlinson recovery boilers). Widespread commercial implementation of BLGCC systems in the United States would enable significant energy savings for the country as a whole. Significant reductions in emissions of criteria pollutants and greenhouse gases would also be achieved. Returns on investments in BLGCC systems relative to state-of-the-art Tomlinson systems (assuming N^{th} plant capital costs in both cases) appear suitably attractive, though efforts to reduce total capital investment requirements would certainly be beneficial.

The reasonable returns on N^{th} plant investments, together with the substantial public benefits that could be derived from BLGCC systems (summarized in Table 20) suggest a private-public partnership as an appropriate approach to addressing research, development, and demonstration (RD&D) issues during the next few years to bring BLGCC systems to commercial readiness. This study has identified key RD&D issues to be addressed (Table 6). Addressing these issues will set the stage for building the first few commercial-scale units, costs for which can be expected to be higher than the N^{th}-plant cost levels estimated in this study, as BLGCC systems begin descending the cost-learning curve.

There is some urgency in bringing BLGCC systems to commercial readiness, since many U.S. kraft pulp mills will be facing the need for end-of-life replacement of Tomlinson boilers in the next 10 to 20 years. Many technology managers in the pulp and paper industry have a keen interest in accelerating the effort to commercialize BLGCC technology so that it is available as a viable Tomlinson replacement option beginning in the 2010 timeframe. Some electric utilities in the Southeastern United States, where the majority of U.S. pulp mills are located, are also showing interest in pulp-mill based biomass electricity as a renewable generation option. This interest is motivated in part by the possibility that renewable portfolio standards or other schemes designed to increase new renewable energy use (as are already in place in over a dozen states) will be implemented in Southeastern states. As described in this study, electricity generated by BLGCC systems could make important contributions in this context.

The pulp and paper industry is an important element of the U.S. economy, and plays an especially important role in the Southeast region. It is important that the industry maintain its global competitiveness since mill closures would cause significant disruption in communities whose economies are linked closely to the industry. The results of this study suggest that gasification-based power generation at pulp mills would help improve competitiveness.

For the longer term, black liquor gasification would provide a technology platform for more diversified production at pulp mill “biorefineries’. A modern pulp and paper mill today represents a first-generation biorefinery, with steam, power and a variety of pulp/paper products being made from woody biomass. The introduction of gasification would enable far more efficient power generation via combined cycle or fuel cell prime movers, as well as the production of additional value added products like transportation fuels (e.g., Fischer-Tropsch middle distillates or hydrogen) and chemicals. To the extent that fuels and chemicals produced at biorefineries substitute petroleum-based fuels and chemicals, U.S. dependence on imported oil could be reduced.

Black liquor gasification would be a first step toward a future biorefinery concept that could includes two gasifiers – one for black liquor and a second for solid biomass. The latter would be fueled by hog fuel and additional wood residues collected sustainably from the vicinity of the mills. The combined biomass energy input to this future powerhouse could be twice the level of black liquor considered in this study, which obviously would yield significantly greater benefits than estimated here. In time, a gasification-based biorefinery industry might extend beyond the pulp and paper industry, whereby biomass crops would be grown for conversion to heat, electricity, fuels, chemicals, animal feedstocks, and other commodity products.

Table 20. Prospective benefits of BLGCC implementation

Mill-Level Economic Benefits	• Higher pulp yields, reducing pulpwood requirements by approximately 7% per unit output • Internal rates of return (IRR) as high as 20% without consideration of potential value of environmental or renewable energy credits/value streams. • IRRs in excess of 30% assuming reasonable values for credits.
National Economic Benefits	• Higher pulp yields, reducing pulpwood requirements by approximately 7% per unit output • Up to \$6.5 billion (constant 2002 dollars) in cumulative energy cost savings over 25 years. • Additional potential cumulative (over 25 years) emissions credit values in the range of \$450 million for SO_2, \$3.2 billion for NOx, and \$3.1 billion for CO_2 • Job preservation and growth in the pulp & paper industry.
Environmental Benefits	• Higher pulp yields, reducing pulpwood requirements by approximately 7% per unit output • Potential for reduced cooling water and makeup water requirements, for the mill-scale BLGCC. All BLGCC options also result in reduced cooling water and makeup water requirements for the grid power displaced, and reduce solid waste production at grid power plants. • Up to 35 million tons net CO_2, 160,000 tons net SO_2 and 100,000 tons net NOx displaced annually within 25 years of introduction. Additional reductions of particulates, VOCs and TRS. • Additional benefits could accrue if BLGCC is able to “catalyze” a new biomass-based energy industry, resulting in the development and use of sustainable biomass supplies for additional energy and chemicals production.
Security Benefits	• Up to 156 billion kWh of distributed energy produced annually above Tomlinson BASE technology, within 25 years of introduction. Of this, as much as 62 billion kWh would be renewable. • Up to 360 trillion Btu/year of fossil energy savings within 25 years of introduction • Potential for fuels and chemicals production from black liquor and other biomass feedstocks directly displacing petroleum.
Knowledge Benefits	• Advances in materials science, syngas cleanup technology, alternative pulping chemistries, and other areas.

11 References

American Forest & Paper Association and Franklin Associates, Ltd. Table: *Historical and Projected Paper and Paperboard New Supply and Production, 1980-2006*. Personal Facsimile Communication from Richard Campbell, December 2002.

American Forest & Paper Association. *U.S. Pulp and Paper Industry Energy Report 1996*. Washington, DC: American Forest & Paper Association, 1996.

Bressan, L. and O'Keefe, L., 2001. *PIEMSA IGCC Project Environmental and Economical Benefits*. Presented at Gasification Conference, San Francisco, October.

Berglin, N., Lindblom, M. and Ekbom, T., 2003, "Preliminary Economics of Black Liquor Gasification with Motor Fuels Production," *Proceedings of the Colloquium on Black Liquor Combustion and Gasification* (L. Baxter and K. Whitty, chairmen), Park City, Utah, 13-16 May.

Bureau of Labor Statistics. 2002. Office of Compensation Levels and Trends. *Employment Cost Index*. Washington, DC: Bureau of Labor Statistics, October.

Center for Transportation Analysis, 2002. *Transportation Energy Data Book*, 22nd edition, Oak Ridge National Laboratory, Oak Ridge, TN.

Consonni, S., Larson, E.D., Kreutz, T.G. and Berglin, N., 1998. "Black Liquor Gasifier/Gas Turbine Cogeneration," *J. of Engineering for Gas Turbines and Power*, 120: 442-449.

Energy Information Administration (EIA), 2002a. *Annual Energy Outlook 2002 with Projections to 2020*. DOE/EIA-0383 (2002). Washington, DC: U.S. Dept. of Energy, January.

Energy Information Administration (EIA), 2002b. *Renewable Energy Annual 2001 with Preliminary Data For 2001*. Washington, DC: U.S. Department of Energy, November.

Energy Information Administration (EIA), 2003a. *Annual Energy Outlook 2003 with Projections to 2025*. DOE/EIA-0383 (2003). Washington, DC: U.S. Department of Energy, January.

Energy Information Administration (EIA), 2003b. *Assumptions to the Annual Energy Outlook 2003 with Projections to 2025*. DOE/EIA-0554 (2003). Washington, DC: U.S. Department of Energy, January.

Environmental Protection Agency (EPA), 1998. *AP-42, Compilation of Air Pollutant Emission Factors*. Section 1.4: Natural Gas Combustion. Research Triangle Park, NC: U.S. Environmental Protection Agency, July.

Environmental Protection Agency, 1990. *AP-42, Compilation of Air Pollutant Emission Factors*. Section 10.2: Chemical Wood Pulping. Research Triangle Park, NC: U.S. Environmental Protection Agency, September (reformatted January 1995).

Environmental Protection Agency (EPA), 2000a. *AP-42, Compilation of Air Pollutant Emission Factors*. Section 3.1: Stationary Gas Turbines. Research Triangle Park, NC: U.S. Environmental Protection Agency, April.

Environmental Protection Agency (EPA). 2000b. *National Air Pollutant Emission Trends, 1900 to 1998*. Chapter 3.0. Research Triangle Park, NC: U.S. Environmental Protection Agency, March.

Environmental Protection Agency (EPA), 2001. Federal Register, Part IV. *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources as Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills; Final Rule*. 40 CFR Part 63. Vol. 66, No. 9. Research Triangle Park, NC: U.S. Environmental Protection Agency, January.

Environmental Protection Agency (EPA), 2002a. *AP-42, Compilation of Air Pollutant Emission Factors*. Section 1.6:Wood Residue combustion in Boilers. Research Triangle Park, NC: U.S. Environmental Protection Agency, March.

Environmental Protection Agency (EPA), 2002b. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*. EPA 430-R-02-003. Washington, DC: U.S. Environmental Protection Agency, April.

Fisher, J.C. and Pry, R.H., 1971. "A Simple Substitution Model of Technological Change", *Technological Forecasting and Social Change,* 3: 75-88.

Forte, R. and Porter, F. (U.S. EPA), Tavoulareas, E.S. (Energy Technologies Enterprises Inc.), and Ratafia-Brown, J. (Science Applications International, Inc.), 2002. *Coal Gasification and Air Emissions*. Presented at Nineteenth Annual Pittsburgh Coal Conference, September.

Gasification Technologies Council, 2003, *Gasification Offers Significant Environmental and Economic Benefits,* accessed at http://www.gasification.org, 16 June.

Georgia Pacific, 1999. "Project XL Full Scale Steam Reformer Black Liquor Gasification," presentation at Big Island, Virginia November 4.

General Electric Company website, http://www.gepower.com, 2003.

Gilshannon, S.T. and Brown, D.R., 1996. *Review of Methods for Forecasting the Market Penetration of New Technologies,* Pacific Northwest National Laboratory, December.

Jameel, H. and Renard, J., 2003. "Pulping Options with Black Liquor Gasification," *Proceedings of the Colloquium on Black Liquor Combustion and Gasification* (L. Baxter and K. Whitty, chairmen), Park City, Utah, 13-16 May.

Katofsky, R.E., 1993. *The Production of Fluid Fuels from Biomass*, MSE thesis, Mechanical and Aerospace Engineering Dept., Princeton Univ., Princeton, NJ.

Larson, E.D., Kreutz, T.G. and Consonni, S., 1999. "Combined Biomass and Black Liquor Gasifier/Gas Turbine Cogeneration at Pulp and Paper Mills," *J. of Engineering for Gas Turbines and Power*, 121: 394-400.

Larson, E.D., Consonni, S. and T.G. Kreutz, 2000a, "Preliminary Economics of Black Liquor Gasifier/Gas Turbine Cogeneration at Pulp and Paper Mills," *J. of Engineering for Gas Turbines and Power*, 122: 255-261, April.

Larson, E.D., McDonald, G.W., Yang, W., Frederick, J., Iisa, K., Kreutz, T.G., Malcolm, E.W. and Brown, C.A., 2000b. "A Cost-Benefit Assessment of BLGCC Technology," *Tappi J.*, **83**(6), June.

Lindblom, M., 2003. "Overview of Chemrec Process Concepts," *Proceedings of the Colloquium on Black Liquor Combustion and Gasification* (L. Baxter and K. Whitty, chairmen), Park City, Utah, 13-16 May.

Lindstrom, M., Kirkman, A., Jameel, H., Cheng, J., Huggins, C. and Bray, B., 2002. "Economics of Integrating Black Liquor Gasification with Pulping: Part I, Effect of Sulfur Profiling," *Proceedings of the Tappi Pulping and Engineering Conference*, San Diego, California, September.

Lockwood-Post, *Directory of the Pulp, Paper, and Allied Trades*, Lockwood-Post, 2001.

Mansour, M.N., Chandran, R.R. and Rockvam, L., 2001. "The Evolution of and Advances in Steam Reforming of Black Liquor," *Proceedings of the Tappi Chemical Recovery Conference*, Tappi Press, Atlanta.

Massachusetts Division of Energy Resources (MA DOER), 2002. *Massachusetts Renewable Energy Portfolio Standard Regulations*. 225 CMR 14.00. Boston, MA: Massachusetts Division of Energy Resources, April.

Miner, Reid. Personal Communication, August 21, 2003.

National Council for Air and Stream Improvement, Inc. (NCASI), 1992. *An Analysis of Kraft Recovery Furnace NO_x Emissions and Related Parameters*. Technical Bulletin No. 636. New York, NY: National Council of the Paper Industry for Air and Stream Improvement, Inc., July.

National Council for Air and Stream Improvement, Inc. (NCASI), 2002a. *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*. Version 1.0. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc., December.

National Council for Air and Stream Improvement, Inc. (NCASI), 2002b. *Compilation of Speciated Reduced Sulfur Compound and Total Reduced Sulfur Emissions Data for Kraft Mill Sources*. Technical Bulletin No. 849. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc., August.

National Council for Air and Stream Improvement, Inc. (NCASI), 2002c. *Performance of EPA Stack Sampling Methods for PM_{10}, $PM_{2.5}$ and Condensible Particulate Matter on Sources*

Equipped With Electrostatic Precipitators. Technical Bulletin No. 852. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc., September.

National Council for Air and Stream Improvement, Inc. (NCASI), 2002d. Table: *Summary of 'Air Toxic' Emissions from NDCE Kraft Recovery Furnaces*. Personal Facsimile Communication from John Pinkerton, December.

National Council for Air and Stream Improvement, Inc. (NCASI), 2002e. *Sulfur Dioxide and Nitrogen Oxides Emissions from Pulp And Paper Mills In 2000*. NCASI Special Report No. 02-06, December 2002.

National Council for Air and Stream Improvement, Inc. (NCASI), 2003. *Factors Affecting NO_x Emissions from Lime Kilns*. Technical Bulletin No. 855. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc., January.

National Research Council, Division on Engineering & Physical Sciences, Board on Energy and Environmental Systems, Committee on Benefits of DOE R&D in Energy Efficiency and Fossil Energy, 2001. *Energy Research at DOE, was it worth it? Energy Efficiency and Fossil Energy Research 1978-2000, Appendix E: Case Studies for the Energy Efficiency Program,"* National Academy Press, Washington, DC.

Navigant Consulting Inc., 2003, *The Changing Face of Renewable Energy: A Navigant Consulting Multi-Client Study*, Public Release Document, June.

Nohlgren, I., Zhuang, Q., Theliander, H., and van Heiningen, A.R.P., 2002, "Direct Causticization Using Titinates in a Fluidized Bed Reactor," *Nordic Pulp & Paper Res. J.*, **17**(3): 246-253.

North American Electric Reliability Council (NERC), 2002. Reliability Assessment 2002-2011. *The Reliability of Bulk Electric Systems in North America*. Princeton, NJ: North American Reliability Council, October.

Ogden, J.M, Williams, R.H., and Larson, E.D., "Societal Lifecycle Costs of Cars with Alternative Fuels/Engines," *Energy Policy*, 32: 7-27, 2004.

Ohio Environmental Protection Agency, 1998. Pulp and Paper Industry Maximum Achievable Control Technology (MACT). Ohio EPA Technical Summary, April.

Orr, D. and Maxwell, D., 2000. A Comparison of Gasification and Incineration of Hazardous Wastes: Final Report. DCN 99.803931.02. Austin, TX: Radian International, LLC, March.

Paper Task Force. 1995. "Paper Task Force Recommendations for Purchasing and Using Environmentally Preferable Paper – Project Synopsis." Environmental Defense Fund.

Raukola, A., Ruohola, T., and Hakulinen, A., 2002. "Increasing power generation with black liquor recovery boiler," presented at the Tappi Fall Conference & Trade Fair.

Ratafia-Brown, J.A., Manfredo, L.M., Hoffmann, J.W., and Massood, R. (Science Applications International Inc.) and Gary J. Stiegel (U.S. DOE/National Energy Technology Laboratory),

2002. “An Environmental Assessment of IGCC Power Systems,” presented at the 19th Annual Pittsburgh Coal Conference, September.

Richards, T., Nohlgren, I., Warnqvist, B. and Theliander, H., 2002. “Mass and Energy Balances for a Conventional Recovery Cycle and for a Recovery Cycle Using Borates or Titinates,” *Nordic Pulp & Paper Res. J.*, **17**(3): 213-221.

Simbeck, D, 2002a. “Future of U.S. Coal-Fired Power Generation: Band-Aids or Corrective Surgery,” presented at the Gasification Technologies Conference, San Francisco, October.

Simbeck, D., 2002b. “Process Screening Analysis of Alternative Gas Treating and Sulfur Recovery for Gasification,” presented at the Nineteenth Annual Pittsburgh Coal Conf., Sept.

Teco Energy, 2002. “Polk Power Station IGCC”, DOE/NARUC Clean Coal Technology Forum, December 8.

Ubis, T., Bressan, L. and O’Keefe, L., 2000. “The 800 MW PIEMSA IGCC Project,” presented at the Gasification Technologies Conference, San Francisco, October.

Vakkilainen, E., 2003. “Evolution of Recovery Boiler Designs,” *Proceedings of the Colloquium on Black Liquor Combustion and Gasification* (L. Baxter and K. Whitty, chairmen), Park City, Utah, 13-16 May.

Warnqvist, B., Delin, L., Theliander, H. and Nohlgren, I., 2001. “Techno-Economical Evaluation of Black Liquor Gasification Processes,” *Proceedings of the Tappi International Chemical Recovery Conference*, Tappi Press, Atlanta.

Whitty, K. and Nilsson, A., 2001. “Experience from a High Temperature, Pressurized Black Liquor Gasification Pilot Plant,” *Proceedings of the Tappi Chemical International Recovery Conference*, Tappi Press, Atlanta, pp. 655-662.

Williams, R.H., Larson, E.D., Katofsky, R.E., and Chen, J., “Methanol and Hydrogen from Biomass for Transportation,” *Energy for Sustainable Development*, 1994.

This page intentionally left blank

Appendices

1. **Calculation of Heat and Mass Balances for Power/Recovery Systems**
2. **Detailed Emissions Estimates for Power/Recovery Systems**
3. **BLGCC Grid Interconnection Analysis**
4. **Detailed Financial Calculations**

Appendix A: Calculation Of Heat And Mass Balances for Power/ Recovery Systems

The mass and energy balances and overall performance of each configuration were predicted by a computer code called GS (Gas-Steam cycles) developed at Politecnico di Milano and Princeton University. The code is a powerful and flexible tool that can be used to predict rather accurately the performances of a very wide variety of systems for electricity production or cogeneration.

A.1 GS Computer Code

GS was originally conceived to calculate gas turbine/steam turbine cycles for power production. It was later progressively extended and developed to calculate complex systems including chemical reactors, gas treatment units, saturation towers, fuel cells, and steam sections with different evaporation levels and with extraction of water or vapor at different points of the cycle. Accordingly, the code has become powerful and flexible enough to be used practically for any plant for the generation of power from fossil fuels or biomass.

A.1.1 System Components

Using GS, the system to be calculated is defined modularly by specifying type, characteristics and inter-connections of its components. Figure A1 lists the 16 types of components which can be used to "build" a system:

1. pump
2. compressor
3. combustor
4. gas turbine expander (zero-dimensional model)
5. heat exchanger
6. mixer
7. flow splitter
8. heat recovery steam cycle (for combined cycles)
9. air splitter plant
10. shaft connecting different rotating machines
11. saturator
12. chemical converter
13. solid oxide fuel cell
14. intercooled compressor
15. gas turbine expander (one-dimensional model)
16. steam cycle (for conventional power plant)

The total number of components and interconnecting flows is limited only by RAM size and calculation speed. In practice, the performance of modern personal computers allows the calculation of even very complex systems with 100 components and more than 250 fluxes within just a few seconds. The plants considered in this study have been modeled with 60-80 components and 90-130 fluxes.

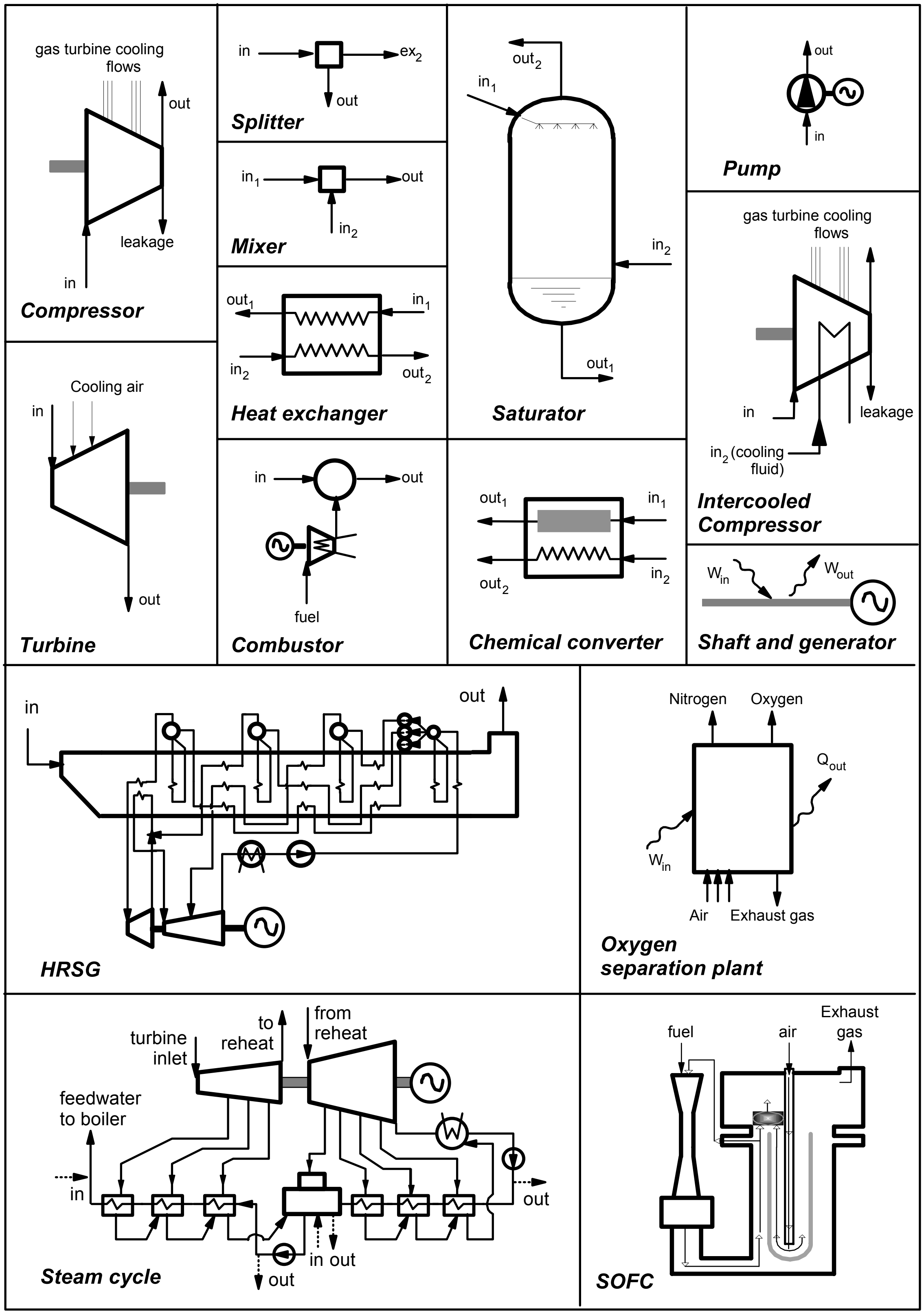


Figure A1. Components handled by the GS code.

The input parameters, the modeling construction, and the format of results vary with the type of component. The heat exchanger (#5) and the mixer (#6) allow the chemical composition of input flows to be varied until it reaches chemical equilibrium. Instead, the combustor (#3) always assumes the complete oxidation of an input fuel. Components #4 and #15 both evaluate the cooled expansion that takes place in modern gas turbines; the former based on a simplified hypotheses about geometry and flow kinematic conditions, the latter based on a stage-by-stage, mean-line, one-dimensional design. The blade coolant can be air, superheated steam or any other fluid behaving like an ideal gas; its flow rate is calculated according to a rather detailed model which accounts for geometry, heat transfer mechanism (convection, film, impingement), coolant-side pressure loss, technological sophistication, and other parameters.

Component #8 (heat recovery cycle), #9 (air separation unit), #13 (solid oxide fuel cell) and #16 (steam cycle) actually represent a combination of many elementary components; for example, the heat recovery steam cycle includes the heat recovery steam generator (which can have up to three evaporation pressures and reheat), the steam turbine, the condenser, the feedwater heaters, the feedwater pump, etc. Calculating the steam cycle within a single "complex" component (rather than with a series of individual elements) provides some significant advantages:

- Fewer input data; calculating the steam cycle as an ensemble of elementary components would require a detailed (and rather tedious) description of the boiler configuration (sequence of heat transfer tube banks) and of the flow diagram;
- The steam section can be calculated through a specific and much more efficient algorithm that accounts for the peculiarities of the steam cycle;
- The iterations for the calculation of the steam cycle are nested within the iterations for the calculation of the whole system, which may give higher computing time but also provides greater computational robustness.

A.1.2 Distinctive Features

In addition to the flexibility provided by the variety of elementary components and their modular interconnection - whereby there is the possibility for modeling a very wide range of power (or cogeneration) plants - the basic strength of the code lies in its capability to predict reasonably well the performances of key plant components based on built-in models and correlations, thereby requiring very few inputs to predict the overall system performances. More specifically, the following can be noted:

- Turbomachinery efficiencies (gas turbine compressor and expander, steam turbine) are evaluated through correlations that embody the effect of scale (performances vary with the size of the equipment) and of the main operating parameters (volumetric flows, enthalpy drop, speed of revolution, etc.). These correlations have been calibrated against the performance of a variety of actual commercial engines and allow a rather accurate prediction of commercial gas turbine and steam turbine performance without requiring sensitive data.
- Similar to turbomachinery, built-in correlations allow estimates of the efficiency of pumps and electric generators.
- The model of the cooled expansion in the gas turbine allows the use of coolant fluids other than air (notably steam) to be evaluated, as well as variations in operating conditions (pressure, temperature) and maximum allowable blade temperature.

- The complex sequence of tube banks within the heat recovery steam generator (economizer, evaporators, superheaters, reheaters) is automatically optimized for maximum power production. Tube banks may be arranged in parallel to achieve the best match between the temperature profile of the hot gas and the profile of water and steam.
- Independent of the component type, the thermodynamic properties of all molecular species are calculated using a consistent methodology and the same data bases: JANAF tables for all gases and S.I. tables for water and steam. The properties of additional, new species may be added simply by modifying one of the input files.

A.1.3 Convergence

Once the system to be calculated has been defined and the coherence of the component characteristics and their inter-connections have been verified, the code sequentially calculates the mass, energy and atomic species balances of all plant components until it reaches the convergence of thermodynamic conditions and component characteristics calculated at each iteration. To avoid useless iterations, convergence is verified on a relatively small number of thermodynamic properties and component characteristics (typically 20-30) that are specified by the user. Which convergence variables are specified depends on the structure of the system to be calculated; the choice is left to the experience and insight of the user.

After reaching convergence, the code can carry out a complete entropy (or "Second-Law") analysis to calculate the destruction of exergy and reversible work within each component and their input/output flows for the whole system.

A.1.4 Limits and Applicability

Over the last 15 years the code has been used at Politecnico di Milano to model a very wide variety of energy conversion systems: combined cycles; integrated gasification combined cycles fed with coal, residual oil, biomass, black liquor; waste-to-energy plants, fossil fuel combustion plants with CO_2 sequestration and even nuclear plants. As a consequence, considerable experience with the code has been accumulated and extensions and improvements to verify the reliability of its predictions for a large number of applications have been carried out. To fully appreciate the actual potential of GS, it is important to be aware of the following limitations.

- The code does not model any chemical kinetics or transport phenomena (heat, momentum or mass). Therefore it gives no information regarding time dependence. The system to be calculated is always assumed to be at steady-state conditions.
- The code cannot handle real gases, with the sole exception of steam and water which, as already mentioned, are calculated according to the SI tables.
- The code calculates only "on-design" performances, i.e. it assumes that all components have been specifically designed to operate at the conditions being calculated. Off-design calculation would require a rather different calculation algorithm. In most cases this limit is irrelevant, because it concerns the operation rather than the design of the system.
- The correlation used to predict the performance of the most important components (gas turbine, steam turbine, pumps, etc.) have been calibrate against the performances of current commercial machinery. Their extension to unconventional machinery must be considered with care.

- The code has the capability to optimize one or more key plant parameters (for example, evaporation pressures of the heat recovery steam cycle). However, when the system is complex and there are more than two or three optimization variables, computational time may become prohibitive.

A.2 Gas Turbines

In this study, calculations were carried out based on two General Electric heavy-duty gas turbines, both belonging to the most advanced generation now in commercial operation ("F" technology):

- 6FA
- 7FA

For both machines we have assumed the operating parameters and the performance reported at the General Electric web site. Then, a few relevant inputs to the gas turbine model have been fine tuned to achieve the best agreement possible with the overall performance published by GE. Table A1 compares the performances quoted by GE with those generated by the calculation model for operation on natural gas fuel at ISO conditions (15°C, 1 atm).

Table A1. Comparison between the performances at ISO conditions (15°C, 1 atm) published by General Electric and the predictions of the GS code for the two gas turbines considered in this study when fired with natural gas. The table also reports the performance predicted for operation on syngas at the ambient temperature of 20°C considered in this study.

	6FA, 60 Hz				7FA, 60 Hz		
	conventional applications		low-T gasifier	high-T gasifier	conventional applications		high-T gasifier
fuel	natural gas		syngas		natural gas		syngas
ambient conditions	ISO (15°C, 1 atm)		20°C, 1 atm		ISO (15°C, 1 atm)		20°C, 1atm
air flow, kg/s	204.00	204.00	200.51	186.37	432.00	432.00	414.56
compressor outlet T, °C	n.a.	409	427	431	n.a.	402	420
fuel flow, kg/s	n.a.	4.43	11.92	29.73	n.a.	9.56	36.16
fuel LHV, MJ/kg	n.a.	48.91	20.95	9.32	n.a.	48.91	15.31
fuel mol weight, kg/Mol	n.a.	16.29	13.15	19.32	n.a.	16.29	18.85
exhaust flow, kg/s	n.a.	208.43	212.44	216.13	n.a.	441.56	450.69
pressure ratio	15.7	15.7	16.2	16.5	15.5	15.5	16.0
TIT, °C	n.a.	1,316	1,316	1,316	n.a.	1,316.0	1,316
TOT, °C	604	604	613	626	602.0	602.5	617
power output, MW	75.9	75.7	76.91	86.98	171.7	171.6	176
LHV efficiency, %	34.8	34.9	-	-	36.2	36.7	-
DP at compressor inlet, kPa	n.a.	0.0	1.0	1.0	n.a.	0.0	1.0
DP at turbine outlet, kPa	n.a.	0.0	4.0	4.0	n.a.	0.0	4.0
	GE data	our calculation			GE data	our calculation	

A.2.1 Operation on Syngas from Black Liquor Gasification

Commercial gas turbines were no originally designed to operate on synthetic, low-calorific value syngas, because its use constitutes a rather rare (often unique) case. Feeding a gas turbine with the syngas generated by black liquor gasification raises three types of issues:

1. The syngas must not contain particulate or contaminants capable of damaging the gas turbine by erosion or corrosion;
2. The fuel flow rate needed to reach a given Turbine Inlet Temperature (TIT) is much higher than that needed with a high-calorific-value fuel like natural gas or distillate fuel;
3. Combustor pressure loss, flame and emission characteristics may be substantially different from those realized with natural gas or distillate fuel.

A.2.2 Fuel gas clean-up

The first issue must be addressed with adequate syngas treatment. Due to the presence of chlorine, sulfur and alkali in the black liquor, the syngas generated by the gasifier cannot be fed directly to the gas turbine. Low-temperature, wet scrubbing considered in this study is assumed to provide adequate removal of acid gases, alkali and particulates.

Hot gas clean-up would have no beneficial effects on the high-temperature gasifier design considered in this study, since the raw syngas is quenched and exits the gasifier at low temperature in any case. Instead, hot gas clean-up could be beneficial for the low-temperature gasifier design, although its commercial implementation in the near future appears very unlikely.

A.2.3 Turbine Operating Conditions

The increase in fuel flow rate with syngas firing, and thus the increase in mass flow through the turbine, affects the match between compressor and turbine operating conditions. The calculation carried out in GS assumes that the reduced mass flow, G, of the gas turbine expander is constant, i.e. the expander operates under aerodynamically choked conditions. This corresponds to the operating conditions of essentially all commercial gas turbines. The reduced mass flow, G (a non-dimensional quantity), is defined as:

$$G = \frac{\dot{m}\sqrt{R \cdot T}}{p \cdot A}$$

where m is the mass flow rate, R is the gas constant, T and p are total temperature and total pressure ahead of the expansion, and A is an equivalent flow cross-sectional area. When firing low-calorific syngas, the fuel flow rate must increase to provide sufficient heat input to the combustor to reach the design TIT. If the air flow supplied by the gas turbine compressor is constant – which is most likely, given that axial compressors typically run at close to choked conditions – a higher fuel flow translates into a higher turbine flow m. In order for G to remain constant, one or more of the parameters appearing in the definition above must change. In practice, the only possibility is to increase the pressure ahead of the turbine, i.e. to increase the gas turbine pressure ratio. Higher pressure ratios move the compressor toward the stall limit, so there is a limit to the mass flow increase that can be tolerated by the gas turbine. In our calculations we have assumed that:

- The Turbine Inlet Temperature (TIT) is the same as with the natural gas firing;
- The compressor can operate with a compression ratio up to 5% above its value with natural gas;
- Further increases in fuel flow must be accommodated by reducing the air flow entering the compressor (by simulating the adjustment of inlet guide vanes).

Due to the different flow rate and thermo-physical properties of syngas compared to natural gas, maintaining the same TIT of the natural-gas version implies higher temperatures throughout the expansion and thus – everything else equal – higher blade metal temperatures and shorter life of the hot parts of the engine. This is why syngas-fired gas turbine are typically de-rated (TIT lower by 10-30°C) to maintain the same life and reliability of the natural gas-fired version. Our assumption of no change in TIT implies an increase in Turbine Outlet Temperature (TOT) of 10-20°C and can be justified by considering that by the time the N^{th} BLGCC plant is realized, TIT and TOT of state-of-the-art gas turbines will be significantly higher than those adopted today.

The 5% increase in pressure ratio is within the range typically tolerable by the compressors of heavy-duty engines. Whether such an increase is compatible with lower air flow can only be verified by the gas turbine manufacturer (when air flow is decreased by closing the Inlet Guide Vanes, the compressor stall margin decreases).

A.2.4 Combustor

As for the combustor operating parameters, syngas firing affects combustion stability, emissions, and pressure loss through the fuel injection system. The first two effects are mainly related to the syngas chemical composition and heating value; the third effect is related to flow rate. Based on pilot-scale experimental work and operation of gas turbines in IGCC, refinery, and steel plants, as long as the fuel calorific value is above 4-6 MJ/Nm^3 (1 Nm^3 = 1 m^3 at the "normal" conditions of 1 atm, 0°C) combustion stability should not be a major issue. In the systems considered here, the fuel fed to the gas turbine has a calorific value considerably higher than 4-6 MJ/Nm^3, so no particular flame stability problems are envisaged. The increase of pressure loss to be applied across the fuel injectors can be accommodated either by increasing the fuel pressure (which will increase fuel compression work and thus reduce overall net efficiency) or by increasing the injector cross-sectional area (which requires some extra design work and thus would increase cost). In our calculations we have used a fuel pressure 50% higher than the combustor pressure.

A.3 Recovery Boiler, Gasifier and Steam Cycle

Table A2 summarizes the assumptions adopted for the recovery boiler and the gasifier. The assumptions for the Tomlinson cases correspond to the state-of-the-art for recovery boilers and have been discussed with recovery boiler manufacturers. Similarly, the gasifier assumptions have been reviewed and/or suggested by TRI and Chemrec; the final values – as well as the plant configurations – adopted here are the outcome of a number of consultations on several crucial features of each technology.

Table A2. Summary of assumptions adopted for the power island.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Assumptions for power island						
Wood used	bone dry kg/s	39.63	39.63	37.01	37.01	37.01
	kWth HHV	792,558	792,558	740,246	740,246	740,246
DS flow	kg/s	31.50	31.50	28.45	28.45	28.45
DS in black liquor	%	80.0	85.0	80.0	80.0	80.0
Total black liquor flow	kg/s	39.37	37.06	35.57	35.57	35.57
	kWth HHV	437,591	437,591	391,053	391,053	391,053
T of black liquor	°C	115.0	115.0	115.0	115.0	115.0
Pressure of raw syngas	bar	-	-	1.5	35.0	35.0
Temperature of raw syngas	°C	-	-	600	1,000	1,000
Gasif. Heat loss to environment	% of BL HHV	-	-	1.0	0.5	0.5
Heat to gasifier cooling flows	% of BL HHV	-	-	3.0	2.0	2.0
Carbon conversion	%	100.0	100.0	98.5	99.9	99.9
Methane in raw syngas	% vol in dry raw gas	-	-	2.8	1.5	1.5
Tars in raw syngas	% w of input C as phenol	-	-	1.50	-	-
T pulse combustor flue gases	°C	-	-	662	-	-
O2 pulse combustor flue gases	% vol wet	-	-	2.5	-	-
T solids/green liquor from gasifier	°C	-	-	250	120	120
Fluidization steam	kg/kgDS	-	-	0.25	-	-
Purge steam	kg/kgDS	-	-	0.01	-	-
Recycle gas to reformer	% of clean syngas	-	-	0.0	-	-
# of evaporation pressures		1	1	1	1	2
steam reheat		NO	NO	NO	NO	NO
HP steam pressure	psig	1,250	1,500	1,870	1,870	1,870
	bar	87.2	104.5	130.0	130.0	130.0
HP steam temperature	°C	480	520	540	540	565
MP steam pressure	psig	-	-	-	-	175
	bar	-	-	-	-	13.1
HP steam temperature	°C	-	-	-	-	200
Blowdown	% of DS flow	5.25	5.50	4.0	4.0	4.0
	% of steam to ST	1.4	1.1	1.0	1.4	1.2
Sootblowing steam	bar	30.0	25.0	-	-	-
	% of DS flow	16.6	8.0	-	-	-
	% of RB HP steam	4.2	1.6	-	-	-
O2 in flue gases	%, wet basis	2.0	1.0	-	-	-
T of flue gases	°C	170	130	-	-	-
T pre-heated air	°C	165	220	-	-	-
HP feedwater heater		NO	YES	-	-	-
MP air heater		YES	YES	-	-	-
MP+ air heater		NO	YES	-	-	-
Condensing steam turbine		YES	YES	NO	NO	YES

A.3.1 Gasifier

The operating conditions of the gasifier have been chosen in accordance with literature and information provided by the manufacturers. In the final stage of this study, TRI proposed a new gasifier design that would use no cooling for the pulse combustors. Our heat/mass balances still consider that 3% of the BLS heating value is extracted from the combustor to generate HP steam; the efficiency improvement that would ensue from eliminating pulse combustor cooling is marginal and would not qualitatively affect the considerations and conclusions of this study.

A.3.2 Steam Conditions

The advanced HP steam conditions assumed for the Combined Cycle cases (1,870 psig, 540/565°C) have become common in the installations installed in recent years. Except for the Utility-Scale case, we've considered only one evaporation pressure because for a back-pressure cycle with massive steam extraction at relatively high pressure (13 bar) like the one considered here, additional evaporation pressures would give negligible benefits. The Utility-Scale case includes an intermediate evaporation pressure for the generation of saturated MP steam (13 bar) to be sent directly the mill; as shown in Figure 14 in Section 5, the amount of steam generated at such pressure level is somewhat lower than what is required by the mill, so that an additional amount must be extracted from the steam turbine.

In no case have we considered steam reheat because at the scale of the plants considered in this study and given the large amount of steam extracted for the mill, its economic attractiveness is questionable.

A.3.3 Steam Turbine

For the base Tomlinson case it was assumed that the steam turbine existing previously at the mill is kept and thus the HP steam conditions are the same as at the "pre-existing" plant. These steam conditions are the same as for the existing power boilers. The reduction in the amount of process steam required by the mill – 10% with respect to current "best practice" – leads to a significant amount of steam being available for expansion to low pressure. This situation can be accommodated either by reducing the amount of hog fuel burned in the power boilers or by installing a new condensing section with its own electric generator and condenser. Given that there is a certain amount of hog fuel available on site in any case, we have assumed the latter. The new condensing steam turbine would have a power output of about 8 MW_e (see Table A8).

For all other cases we assume the pre-existing steam turbine is replaced with a new machine capable of handling steam at higher pressure and temperature, as generated by the new boiler (HERB case) or the HRSG. The steam generated by the existing power boilers – which are not replaced – is admitted to the steam turbine through a secondary port after the first 1 or 2 stages. To limit the cost (and the efficiency penalties) of the steam turbine, such secondary admission will most likely be uncontrolled – i.e. no provision to vary the steam flow coming from the power boilers.

The turbine considered for the Mill-Scale cases is a back-pressure unit, because in such cases the amount of hog fuel available on site is significantly lower than the amount needed to match the mill steam demand. As a consequence, additional waste wood is purchased to be burned in the existing power boilers (up to the assumed capacity of the boilers – about 40% more than in the Tomlinson Base design) and natural gas is burned in the duct burner just to meet the mill steam demand. No extra steam is available for expansion down to low pressures.

In the HERB and Utility-Scale BLGCC cases the steam generated by the boiler/HRSG and using the hog fuel available on site is in excess of what is required by the mill so that, as in the base Tomlinson case, we've assumed expansion of the excess steam down to 0.074 bar (40°C) in a condensing section. Unlike the base Tomlinson case however, in the HERB and Utility-Scale cases the condensing section is an integral part of the new steam turbine, mounted on the same shaft and serving the same electric generator as the HP and MP turbine sections.

A.4 Bark (Hog Fuel) Boiler

Table A3 summarizes assumed parameter values for the auxiliary hog fuel boiler and the gasifier. For all cases, it is assumed that hog fuel/wood waste boilers up to a capacity of 100 MW HHV energy input are already available and operable on site, so that the only difference among the cases considered lies in the amount of hog fuel burned to generate steam at 1250 psig, 480°C:

- In the base Tomlinson, HERB and Utility-Scale BLGCC cases, only the amount of hog fuel made available as a byproduct of the wood feed to the mill is used in the boilers;
- In the Mill-Scale BLGCC cases we've assumed additional wood wastes are burned with the hog fuel up to the maximum capacity of the boiler (100 MW HHV input); this turns out to be insufficient to meet the mill steam demand, so some natural gas is also burned (in the HRSG duct burner) to further increase steam production.

Table A3. Summary of assumptions adopted for the bark boiler.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Bark boiler						
Bark input	kg/kgDS	0.2260	0.2260	0.3515	0.3515	0.2342
	kg/s	7.12	7.12	10.00	10.00	6.66
	kg / kg bone dry wood	0.180	0.180	0.270	0.270	0.180
	kWth, HHV	71,189	71,189	100,000	100,000	66,622
	imported kWth, HHV	0	0	33,378	33,378	0
Steam evap. Pressure	psig	1,250	1,250	1,250	1,250	1,250
	bar_abs	87.2	87.2	87.2	87.2	87.2
Superheated steam temp., °C		480	480	480	480	480
O2 in flue gases, % wet		4.0	4.0	4.0	4.0	4.0
T of flue gases at eco outlet, °C		230	230	230	230	230
air pre-heating		145	145	145	145	145
steam production in power boiler	kg HP steam / sec	22.30	22.30	29.56	31.27	20.85
	kg HP steam /kg hog fuel	3.13	3.13	2.96	3.13	3.13

A.5 Auxiliary Fuel and Oxygen

Table A4 summarizes the requirements of fossil fuels for all cases and, for the gasification cases, oxygen requirements. The lime kiln is fired with fuel oil. Natural gas is 97.1% CH_4 by volume, with minor fractions of C_2H_4, CO_2, H_2 and N_2 to give a HHV of 54.24 MJ/kg (23,323 Btu/lb) and LHV 48.91 MJ/kg (21,032 Btu/lb). 95% pure oxygen (with 3.65% Argon and 1.35% N2) is produced at atmospheric pressure by a conventional cryogenic Air Separation Unit; compression up to gasification pressure is carried out by an intercooled oxygen compressor.

Table A4. Summary of auxiliary fuel and oxygen consumption.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Lime kiln, natural gas and oxygen						
Lime requirements	% increase	-	-	59.5	28.0	28.0
	mt of lime/mt DS	0.136	0.136	0.217	0.174	0.174
Residual fuel oil for lime kiln	GJ/mt of lime	7.72	7.72	7.72	7.72	7.72
	GJ/mt DS	1.049	1.049	1.674	1.344	1.344
	kW, HHV	33,056	33,056	47,630	38,231	38,231
	% increase	-	0.0	44.1	15.7	15.7
natural gas flow to GT	kg/s	-	-	0.00	0.00	4.85
natural gas to pulse combustors	kg/s	-	-	0.00	0.00	0.00
natural gas to duct burner	kg/s	-	-	1.25	0.26	0.00
total nat gas flow	kg/s	-	-	1.25	0.26	4.848
	kW, HHV	0.00	0.00	67,637	14,319	262,956
Oxygen (95% pure) to gasifier	kg/ kg DS	-	-	-	0.333	0.333
	kg/s	-	-	-	9.46	9.46
Oxygen (95% pure) to kiln	kg/MJ HHV extra Fuel Oil	-	-	-	0.081	0.081
	kg/s	-	-	-	0.42	0.42
Total Oxygen (95% pure)	kg/ kg DS	-	-	-	0.347	0.347
	kg/s	-	-	-	9.88	9.88

A.5.1 Lime Kiln

The increased causticizing requirements with gasification, and the corresponding increases in lime kiln fuel consumption, have been calculated based on the estimated sodium carbonate leaving the gasifiers in the condensed phase (compared to Tomlinson boiler smelt) and additionally, for the low-temperature gasifier, the further generation of sodium carbonate due to co-absorption of CO_2 with H_2S in the green liquor scrubber that removes 43% of the H_2S from the acid gas captured by the Selexol system. Section A.11 gives more details on the assumptions and the inputs used to estimate the causticization load. The estimated 44% increase for the low-temperature gasifier and 16% increase for the high-temperature gasifier are based on the assumption that the ratio of Active Alkali in the pulping liquor to the wood feed to the digester for the polysulfide process is the same of the conventional process utilizing Tomlinson recovery boilers. This assumption must be verified based on a more careful estimates of the heat/mass balances of polysulfide pulping. It is worth noting that, due to the higher yield of the polysulfide process assumed with gasification, the increase in kiln load (kW or kg/s of fuel oil) is significantly smaller than the increase in specific lime requirements (t of lime per t of BLS), which is 28% for the high-temperature gasifier and 60% for the low-temperature gasifier.

A.5.2 Natural Gas

Natural gas is used in the duct burner of the Mill-Scale BLGCC cases to generate enough steam to meet the mill demand. In the Utility-Scale case natural gas is mixed with syngas to fully load the GE 7FA gas turbine. An alternative for the Mill-Scale cases would be to add power boiler capacity and generate more steam by additional, imported hog fuel (or fossil fuel); however, a preliminary economic evaluation indicated this option would be more appealing than using natural gas in the duct burner only for natural gas prices above 4.5-5 \$/GJ HHV (and hog fuel price 1.5 \$/GJ HHV). It is also worth noting that reductions in mill steam use are likely over time, which will reduce the need for duct burner supplementary firing during the life of the BLGCC, so it is not unrealistic to think that natural gas will be used in the duct burner for only a relatively few years – at least with the high-temperature gasifier, which requires a rather small amount of supplementary firing. Also for this reason, the choice of the lowest capital cost option of the duct burner appears most sensible.

A.5.3 Oxygen

The oxygen consumption of the high-temperature gasifier is determined by the composition, concentration and heating value of the dry solids and by the temperature to be reached in the gasifier (in our case 1000°C). It is worth emphasizing that oxygen consumption – as well as the whole heat/mass balances – are very sensitive to the Oxygen/Carbon ratio in the black solids. Given the uncertainties on the actual composition of black liquor under polysulfide operating conditions, further work is needed to get reliable estimates of dry solids composition and properties at the conditions the mill will operate when integrated with a BLGCC.

Given the relatively modest increase in the capacity required for the lime kiln in the high-temperature gasification case, we've assumed that the extra capacity would be met by oxygen-enrichment of the combustion are. Section A.11.2 gives details on how such extra-oxygen requirement as been evaluated.

A.6 Sulfur Recovery Unit (SRU)

The basic characteristics and the steam balance of the Sulfur Recovery Unit are summarized in Table A5. The single components of the SRU have not been modeled in detail. Estimates of the steam and power consumption supplied by Fluor and by Nexant for the whole SRU have been used as an input to evaluate the heat/mass balance of the BLGCC.

A.6.1 Selexol Physical Absorption

After the syngas has been cooled down to 40°C, thereby removing most of the water and hopefully all alkalis and tar, it enters the Selexol absorber which removes essentially all H_2S and about 2 moles of CO_2 per mole of H_2S. The Selexol solvent rich in H_2S and CO_2 then goes to the stripping section, where we assume an acid gas is released with the same 2:1 mol ratio of CO_2 to H_2S. This is conservative, because by adopting more sophisticated (but commercially proven) configurations with intermediate flash chambers (possibly ventilated with N_2 generated by the Air Separation Unit, if available) it would be possible to decrease the amount of CO_2 in the stripped acid gas and thus, in the scheme with the low-temperature gasifier, to reduce modestly the causticizing load. The optimal configuration of a Selexol unit should in the future be evaluated based on more detailed performance and cost evaluations for the SRU and the causticizing area.

A significant amount of 75 psig steam is needed for the stripper to fully de-absorb the H_2S. This is assumed to be bled from a specific extraction port of the steam turbine at the Intermediate Pressure (IP) of 6.5 bar abs (80 psig). The amount of steam required for stripping is assumed to be proportional to the amount of H_2S removed – an assumption that must be verified based on more detailed modeling of the SRU.

A.6.2 Acid Gas Treatment

The treatment of the stripped acid gas consisting of 1/3 H_2S and 2/3 CO_2 (by volume) varies with the gasification technology.

In the high-temperature gasifier, the whole flow goes to a Claus plant where H_2S is converted to elemental sulfur, which is then dissolved in a low-sulfidity white liquor (containing Na_2S formed in the gasifier smelt) to make a polysulfide liquor.

Table A5. Basic characteristics and steam balance of the Sulfur Recovery Unit

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Sulfur recovery						
Total Sulfur flow	kg/s	-	-	1.215	1.215	1.215
IP (80 psig) Steam for SRU	kg/kg of H2S removed	-	-	10.0	10.0	10.0
syngas flow to sulfur removal (40°C)	bar	-	-	23.20	32.90	32.90
	kg/s	-	-	23.76	24.24	24.24
	kg/Mol	-	-	15.01	21.03	21.03
H2S in syngas to sulfur removal	% mol	-	-	2.250	1.737	1.737
	% mass	-	-	5.097	2.815	2.815
CO2 in syngas to sulfur removal	% mol	-	-	14.289	19.325	19.325
	% mass	-	-	41.886	40.442	40.442
sulfur to be removed from syngas	kg/s of H2S	-	-	1.211	0.682	0.682
	kg/s of S	-	-	1.140	0.641	0.641
	% of S in	-	-	93.81	52.74	52.74
CO2 co-captured by S-removal (ends up vented in Claus plant)	CO2/H2S, molar	-	-	2.00	2.00	2.00
	kg/s	-	-	3.134	1.766	1.766
IP steam consumption for Sulfur removal plant (Selexol+SCOT)	kg/kgH2S	-	-	10.00	10.00	10.00
	kg/s	-	-	12.11	6.82	6.82
	kg/kgDS	-	-	0.426	0.240	0.240
	kWth			25,124	14,159	14,159
MP steam from SRU	kg/kgH2S	-	-	1.419	3.300	3.300
	kg/s	-	-	1.718	2.252	2.252
	kWth	-	-	3,386	4,438	4,438
LP steam from SRU	kg/kgH2S	-	-	0.774	1.800	1.800
	kg/s	-	-	0.937	1.228	1.228
	kWth	-	-	1,980	2,595	2,595
Net steam use for SRU	kWth			19,758	7,126	7,126

In the low-temperature gasifier, 43% of the H_2S in the Selexol strip gas is absorbed into green liquor via a scrubber. The gas containing the remaining 57% of theH2S is sent to a Claus plant to generate elemental sulfur. Scrubbing 43% of the H_2S from the Selexol strip gas is required to provide a white liquor with sufficient sulfidity that, when elemental S is dissolved into it, will form the same polysulfide liquor as generated in the high-temperature case.

The Claus plant generates MP (13 bar abs) and LP (4.8 bar abs) steam which is exported to the MP and LP headers serving the mill. The amount of steam produced is proportional to the amount of H_2S converted. The tail gas exiting the Claus plant is further treated in a SCOT unit, which also requires IP steam (6.5 bar abs) to regenerate the solvent used to absorb SO_2.

A.7 Gas Turbine

The gas turbine operating conditions are summarized in Table A6. With the low-temperature gasifier the heating value of the syngas is relatively high (almost 40% of natural gas, on a mass basis) and thus the increase in fuel mass flow compared to natural gas is relatively small; the resulting increase in pressure ratio (see Section A.2.3) is smaller than the 5% margin assumed here, and thus it is not necessary to cut the air flow. The same holds for the Utility-Scale case, where the gas turbine is fed with a mixture of syngas and natural gas. Instead, in the high-T, Mill-Scale case, the heating value of the syngas is so low (9.3 MJ/kg, less than 20% of the heating value of natural gas) that it is necessary to cut significantly the air flow in order to limit the rise of the pressure ratio to the maximum allowable value of 5% stipulated here.

Table A6. Basic gas turbine operating parameters

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Gas Turbine						
syngas flow to GT	kg/s	-	-	11.92	29.73	31.30
Ar	% mol	-	-	0.000	0.661	0.661
CH4	% mol	-	-	3.486	1.436	1.436
CO	% mol	-	-	23.738	26.094	26.094
CO2	% mol	-	-	10.503	11.272	11.272
COS	% mol	-	-	0.014	0.053	0.053
H2	% mol	-	-	61.914	27.507	27.507
H2O	% mol	-	-	0.344	32.730	32.730
N2	% mol	-	-	0.000	0.243	0.243
Total	% mol	-	-	99.999	99.996	99.996
HHV syngas to GT	MJ/kg	-	-	20.945	9.318	9.318
HHV syngas power to GT	kW	-	-	249,664	277,024	291,634
syngas flow to pulse combustor	kg/s	-	-	6.34	-	-
HHV syngas to pulse combustor	MJ/kg	-	-	20.945	-	-
HHV syngas power to pulse combus	kW	-	-	132,791	-	-
syngas flow to duct burner	kg/s	-	-	1.136	1.550	-
HHV syngas to duct burner	MJ/kg	-	-	20.945	9.318	-
HHV syngas power to duct burner	kW	-	-	23,794	14,443	-
air flow to GT	kg/s	-	-	200.51	186.37	414.56
GT pressure ratio	-	-	-	16.17	16.50	16.00
total fuel flow to GT	kg/s	-	-	11.92	29.73	36.16
TIT	°C	-	-	1,316	1,316	1,316
TOT	°C	-	-	613	626	617
T HRSG flue gases	°C	-	-	108	164	144
HRSG flue gas flow	kg/s	-	-	260.29	217.92	450.69

The variations in Turbine Outlet Temperature (TOT) shown in the table are the outcome of variations in pressure ratio, thermo-physical properties of the flow expanding through the turbine and cooling flows. As already mentioned, these TOTs are higher than those for which GE would warranty the same life as for a natural gas-fired turbine. On the other hand, progress in gas turbine technology is very likely (following historical trends) to make the temperatures assumed here to be fully acceptable within a few years.

A.8 Steam and Power Production

Table A7and Table A8 report the major steam flows and overall power balances for all cases. The significant reduction in the steam consumption of the mill from the Tomlinson to the gasification cases is due to lower BLS flow (while steam consumption per kg of BLS actually increases).

Table A7. Basic characteristics of the steam cycle.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Steam						
Flow at HRSG HP SH outlet	kg/s	103.26	134.48	85.62	48.97	70.72
Flow at power boiler SH outlet	kg/s	22.30	22.30	29.51	31.27	20.85
Total flow to steam turbine	kg/s	125.56	156.78	115.13	80.24	91.57
Blowdown	kg/s	1.73	1.73	1.138	1.138	1.138
Sootblowing	kg/s	5.25	2.52	-	-	-
LP steam to deaerator	kg/s	0.00	7.25	1.33	0.00	0.00
Steam to HP feedwater heater	kg/s	0.00	17.58	7,86	0.00	0.00
HP steam from gasification island to	kg/s	-	-	14.35	0.00	0.00
MP steam from gasification island tc	kg/s	-	-	0.00	19.37	19.51
LP steam from gasification island to	kg/s	-	-	2.48	0.00	0.00
Total MP steam to mill	kg/kgDS	1.116	1.152	1.157	1.156	1.156
	kg/s	35.15	36.29	32.91	32.90	32.90
	kWth	69,278	71,513	64,857	64,837	64,837
Total LP steam to mill	kg/kgDS	2.146	2.131	2.251	2.251	2.251
	kg/s	67.60	67.13	64.05	64.05	64.05
	kWth	142,783	141,785	135,289	135,289	135,289
Total steam to mill	kWth	212,061	213,298	200,146	200,126	200,126

The power consumption of the gasifier auxiliaries is assumed to be proportional to the black liquor power (HHV), with a consumption of 2 MW for a plant handling about 300 MW HHV. The power consumption of the SRU is assumed to be proportional to the mass of H_2S removed, while the consumption of the power boiler auxiliaries is scaled from that of the base Tomlinson case with a scale exponent 0.5.

The power consumption of the Air Separation Unit for the high-temperature gasifier is the total needed to generate both the oxygen for the gasifier and the oxygen for the lime kiln.

The low-temperature gasifier case suffers a very substantial efficiency penalty for gas compression, which suggests the attractiveness of a pressurized configuration. On the other hand, the high-temperature gasifier suffers a significant penalty in the ASU power consumption.

A.9 Marginal Electric Efficiency and Electricity Chargeable to Renewable Sources

Table A9 illustrates the calculation of "marginal electric efficiency", defined as the ratio between the extra-electricity generated by each plant (compared to the Tomlinson case) and the extra-fuel used to generate this extra electricity. This marginal efficiency gives a sense of the energy efficiency of each configuration, although it must be taken with care because it lumps together the extra input energy supplied as fuel oil, hog fuel and natural gas.

Table A8. Gross and net power generation.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Power						
GT gross power output	kWel	0	0	76,910	86,980	175,840
Gross power of (HP+MP) ST	kWel	63,951	85,507	66,629	48,163	60,845
Gross power of condensing ST	kWel	8,039	10,965	0	0	10,690
Total gross ST output	kWel	71,990	96,472	66,629	48,163	71,536
Syngas expander power ouptut	kWel	0	0	5,004	0	0
TOTAL GROSS PRODUCTION	kWel	71,990	96,472	148,543	135,143	247,376
ASU power consumption	kWel	-	-	-	14,297	14,297
Syngas compressor power cons.	kWel	-	-	18,712	-	-
Auxiliaries for steam cycle/HRSG	kWel	-	-	1,977	1,194	2,574
Auxiliaries for gasification island	kWel	-	-	2,667	2,667	2,667
Auxiliaries for SRU	kWel	-	-	1,823	1,058	1,058
Auxiliaries for rec boiler	kWel	6,690	6,804	-	-	-
Auxiliaries for steam cycle/power bo	kWel	1,050	1,050	1,244	1,244	1,016
TOTAL UTILITIES	kWel	7,740	7,854	26,423	20,459	21,611
NET electric power output	**kWel**	**64,250**	**88,618**	**122,120**	**114,683**	**225,765**
Mill electricity consumption	kWel	100,096	100,096	100,096	100,096	100,096
Power exportable to grid	**kWel**	**-35,846**	**-11,477**	**22,025**	**14,588**	**125,669**

Table A9. Marginal electrical efficiencies.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Efficiencies						
Net electric eff. (excluding kiln)	% HHV	12.63	17.42	21.86	22.69	31.33
Net thermal eff. (excluding kiln)	% HHV	41.68	41.92	35.82	39.60	27.77
Extra Fuel Oil for Kiln	kWth HHV	0	0	14,574	5,175	5,175
Imported Hog Fuel	kWth HHV	0	0	33,378	33,378	0
Imported Nat Gas	kWth HHV	0	0	67,637	14,319	262,956
Total Extra+Imported Fuel	kWth HHV	0	0	115,590	52,872	268,130
Extra Electricity	kWel	0	24,369	57,871	50,434	161,515
Marginal Efficiency	**%**	**-**	**-**	**50.07**	**95.39**	**60.24**

Table A10 illustrates the calculation of the electricity "chargeable" to renewable sources, obtained by subtracting from the total net electric output the electricity which could otherwise have been generated by the fossil fuels used in the plant. To do this, it is assumed that fuel oil could otherwise generate electricity with a net efficiency of 40% and that natural gas could otherwise generate electricity with a net efficiency of 55%. These values correspond to the state-of-the-art of new large Rankine steam cycles and new large Combined Cycles, respectively.

Since the average efficiency with which fuel oil and natural gas are actually used to generate electricity in the Southeastern U.S. are significantly lower than these values, the estimate of electricity "chargeable" to renewable sources and related efficiencies in Tab. A.10 are rather conservative, i.e., they are lower than the values one would evaluate when comparing gasification with the current power generation system.

Table A10. Electricity chargeable to renewable sources.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Renewable energy - kiln included						
Electr chrgble to Fuel Oil (40%)	kW el	13,222	13,222	19,052	15,292	15,292
Electr chrgble to Nat Gas (55%)	kW el	0	0	37,201	7,876	144,626
Electr chrgble to Rnwbl Energy - 1	kW el	51,027	75,396	65,868	91,515	65,847
Eff Electr from Rnwbl Energy - 1	% HHV	10.03	14.82	13.41	18.64	14.39
Renewable energy - kiln excluded						
Electr chrgble to Rnwbl Energy - 2	kW el	64,250	88,618	84,920	106,808	81,139
Eff Electr from Rnwbl Energy - 2	% HHV	12.63	17.42	17.29	21.75	17.73

A.10 Water requirements

For the processes and the systems analyzed in this study, gasification brings about variations in water requirements in two areas:

- Water used for slaking the green liquor (see further Figure A2, Figure A3 and Figure A4);
- Cooling water for the condenser of the steam plant.

The second effect is much more significant than the first. Table A11 reports preliminary estimates of variations in water requirements based on the following assumptions:

- Water for slaking is evaluated as illustrated in Figure A2, Figure A3 and Figure A4;
- The condenser of the steam cycle is cooled by water undergoing a temperature increase of 12°C; such water is supplied by wet cooling towers where 1% of the circulating water is lost by drifting and 0.5% is lost by purging;
- Variations in the pulping process do not yield any other notable variation of water requirements.

The tower make-up water reported in Table A11 is the sum of three components:

- Water lost by evaporation;
- Water lost by drifting;
- Water lost due to purging.

Table A11. Variations in water requirements for the cooling towers and for slaking.

		Tomlinson		Gasification cases		
		Base	HERB	Low-T	High-T medium	High-T large
Water for cooling towers and slaking						
Power rejected by condenser	kW th	30,885	35,974	0	0	46,069
Water to cooling towers (DT=12°C)	m3/hr	2,213	2,578	0	0	3,302
Make-up water for cooling towers	m3/hr	78.7	91.7	0.0	0.0	117.4
Water for slaking	m3/hr	5.0	5.0	8.1	5.7	5.7
Increase with respect to base case	%	-	15.5	-90.4	-93.2	47.2

The table makes clear that the variations in water consumption due to slaking are negligible with respect to those for the cooling towers. Being fully back-pressure, the mill-scale gasification cases do not require any cooling water for the condenser, and thus give very large reductions in water requirements. If the base Tomlinson case had also been fully back-pressure – as many of the existing ones actually are – the water consumption of the mill-scale gasification cases would be about the same as the base Tomlinson case.

It must be emphasized that the estimates in Table A11 relate only to the water requirements of the cooling tower and the slaker. They do not account for variations possibly induced by the introduction of the polysulfide process. A more accurate evaluation requires a model of the whole pulping process, which is beyond the scope of this study.

A.11 Calculation of Causticization Load

As already mentioned, a negative consequence of the split of sulfur and sodium during gasification is a higher causticizing load. This is due to two circumstances:

1. Larger amount of carbonate (Na_2CO_3) in the green liquor;
2. Co-capture of CO_2 (together with H_2S) in green liquor used to scrub the acid gas stripped by the Sulfur Recovery Unit (SRU).

Effect (1) is inherent to gasification, because less sulfur is available in the condensed phase to form sodium sulfide (Na_2S) and thus sodium inevitably forms more carbonate. The presence of effect (2) depends on whether the gas stripped by the SRU is scrubbed with green liquor. In an earlier version of this study, we considered scrubbing with white liquor; white liquor captures H_2S more easily, but it also co-captures CO_2 indiscriminately from H_2S, thus giving a larger overall increase in causticization load. Scrubbing with green liquor is preferable, although its feasibility and reliability must be verified.

With the high-temperature gasifier, the amount of Na_2S generated in the smelt is apparently sufficient to generate a polysulfide liquor; thus, all the acid gas stripped in the SRU goes to the Claus/SCOT plant where the H_2S is converted to elemental sulfur to be dissolved in the low-sulfidity white liquor. With the low-temperature gasifier, it appears that some of the H_2S in the SRU strip gas must be converted into sulfide (Na_2S) in order generate a polysulfide liquor with the same composition as in the high-temperature case. The strip gas is scrubbed with green liquor to accomplish this. To compare the high- and low-temperature gasification technologies on the same basis, we have imposed the requirement that the amount of elemental sulfur dissolved in the polysulfide generating tank be the same in both cases. This amount of elemental sulfur is the output of the Claus/SCOT plant fed with 100% of the SRU strip gas generated in the high-temperature case. With the low-temperature gasifier, the same flow of elemental sulfur is obtained by diverting to the Claus plant only 57% of the H_2S in the SRU strip gas; the remaining 43% is scrubbed into green liquor ahead of the Claus plant. The amount of CO_2 co-captured in the green liquor scrubber is estimated by assuming that the ratio between the mass transfer coefficient of H_2S and CO_2 is 9.0 – an intermediate value of the range quoted in the literature (see reference in main text).

A.11.1 Mass Balances

The amount of lime (CaO) required for causticizing the green liquor can be evaluated from the mass balance of the mill sub-system that generates white liquor from the condensed phase (e.g., smelt) collected from the Tomlinson boiler (or the gasifier).

The situation for the base Tomlinson case and the two gasification cases is depicted in Figure A2, Figure A3 and Figure A4, where for the sake of clarity we've grouped in the same box the components which do not significantly affect the mass balance. The basic inputs required to calculate the mass flow in the figure are the following.

- Black liquor composition, which is assumed to be the same as used in all other calculations relating to the Tomlinson and gasification systems.
- Reduction efficiency, i.e. the ratio between Na_2S and (Na_2S+Na_2SO_4) when all species are expressed as equivalent kg of Na_2O. The estimates in the figures assume 95% reduction efficiency for the Tomlinson and 100% for gasification. Higher reduction efficiencies with gasification are justified by the lower oxygen content throughout the reacting zone.
- Amount of NaOH in the smelt. We assumed here a ratio of 0.026 between NaOH and (NaOH+Na_2CO_3) – again expressed as equivalent kg of Na_2O – for the Tomlinson and the high-temperature gasifier. We assumed zero NaOH in the solids generated by the low-temperature gasifier. The value of 0.026 is apparently representative of current Tomlinson technology. In the high-temperature gasifier the smelt is generated at a higher temperature (~950°C vs. ~850°C for Tomlinson), which should give a higher fraction of NaOH. Assuming the same fraction of NaOH is conservative, because if the NaOH in the smelt increases, the causticization load decreases. As for the low-temperature gasifier, no NaOH is apparently formed in the solid phase made available by this technology.
- Causticization efficiency, which we assumed to be 80% for the Tomlinson case. We adjusted this efficiency in the gasification cases to maintain the same ratio (0.183) between Active Alkali and wood charge. Active Alkali is the sum, Na_2S+NaOH, expressed in equivalent kg of Na_2O. In order to get the same ratio between Active Alkali and wood charge, the causticization efficiency must increase to 81% for the high-temperature gasifier and to 81.3% for the low-temperature gasifier. These variations are within the realm of what could actually be achieved in practice, although they will require some change in the slaker and the causticizer.

In addition, a number of other (less relevant) assumptions are needed to evaluate the composition and the concentration of the weak wash: they are highlighted by the yellow background in the figures. The calculations underlying the estimates in Figure A2, Figure A3 and Figure A4 are based on a simple model supplied by Prof. Jim Frederick at Chalmers University (Sweden).

It is important to emphasize that the procedure followed to generate the estimates in Figure A2, Figure A3 and Figure A4 is approximate, because in reality the black liquor composition is not given, rather it is an output of the model of the whole integrated process. Such a model should include the digesters and account for the properties of the wood charge, so to generate the mass flows and the composition of each stream depending on the design specs of each subsystem. Despite this approximation, the procedure adopted here appears accurate enough to estimate satisfactorily the variations in causticization load. A complete integrated model is strongly recommended both to verify our estimates and to properly account for all the changes ensuing from the adoption of a polysulfide process.

As can be seen from Figure A2, Figure A3 and Figure A4, the lime requirement increases from 370 metric tons/day for the base Tomlinson case to 428 metric tons/day for the high-temperature gasifier and 533 metric tons/day for the low-temperature gasifier. This means an increase of 15.7% for the high-temperature case and 44.1% for the low-temperature case. The latter could be decreased by reducing the amount of CO_2 in the acid gas stripped by the SRU, which in turn could be achieved by modifying the Selexol plant. Reducing the CO_2/H_2S ratio in the acid gas generated by the Selexol plant increases capital cost, as well as steam consumption and auxiliary power consumption. In the limit of zero CO_2 co-co-absorption with H_2S, the increase in lime requirement with respect to the base case would be 39.7%. This number corresponds to the amount of lime needed to convert the extra carbonate generated during gasification (compared to the Tomlinson case). The optimum value of CO_2 co-capture will be determined by the trade-off between the extra-cost and consumption of the SRU and the extra-cost of the kiln.

A.11.2 Oxygen Enrichment

The increase in causticization load for the high-temperature gasifier case (~16%) is within the realm of the capacity increase achievable with oxygen enrichment of the air used in the kiln. Given that the high-temperature gasifier already requires an Air Separation Unit, and given the very high capital cost of an additional kiln (which is subject to strong economies of scale), oxygen enrichment appears the most attractive option to meet modest capacity increases.

The same option does not look feasible for the low-temperature gasifier, because the 44% increase in kiln load required in this case is beyond what could be achieved with oxygen enrichment. In addition, with the low-temperature gasifier there is no Air Separation Unit and even if the increase in kiln load could be satisfied by oxygen enrichment, the cost of the oxygen would likely be prohibitive.

The oxygen consumption for the lime kiln in the high-temperature gasifier case has been estimated by assuming that:

- The extra-fuel oil required to meet the additional lime kiln load is oxidized by a mixture of 95% oxygen, 3.65% Ar, 1.35% N_2 (by volume), i.e. the same composition assumed for the oxygen supplied to the gasifier;
- The oxygen content in the lime kiln flue gases remains 2% vol. (dry basis), as in the conventional case with no enrichment.

For a typical high-sulfur fuel oil with HHV 43.2 MJ/kg, 2.6% sulfur by weight and hydrogen/carbon atom ratio of 0.137 (by weight), the amount of air needed to generate flue gases with 2% oxygen by vol. (dry basis) is ~15.5 kg per kg of fuel oil. The amount of 95% pure oxygen needed to generate flue gases with the same oxygen content is ~3.5 kg per kg of fuel oil, or 0.081 kg of 95% pure O_2 per MJ of HHV. This value has been adopted to estimate the extra-oxygen requirement and the extra electricity consumption of the Air Separation Unit reported in Table A4 and Table A8, respectively.

According to Mike Ryan (a lime kiln expert with Process Labs), in order to achieve a capacity increase of 16% - which would be called medium level enrichment - the kiln will most likely require more expensive refractories (like those generally used in the cement industry), a new burner to prevent the flame from becoming too short and hot and possibly two burners on overhead trolleys to allow a roll-in, roll-out operation depending on oxygen use. A capital cost allowance for these retrofits of $1 million has been included in the high-temperature gasifier cases.

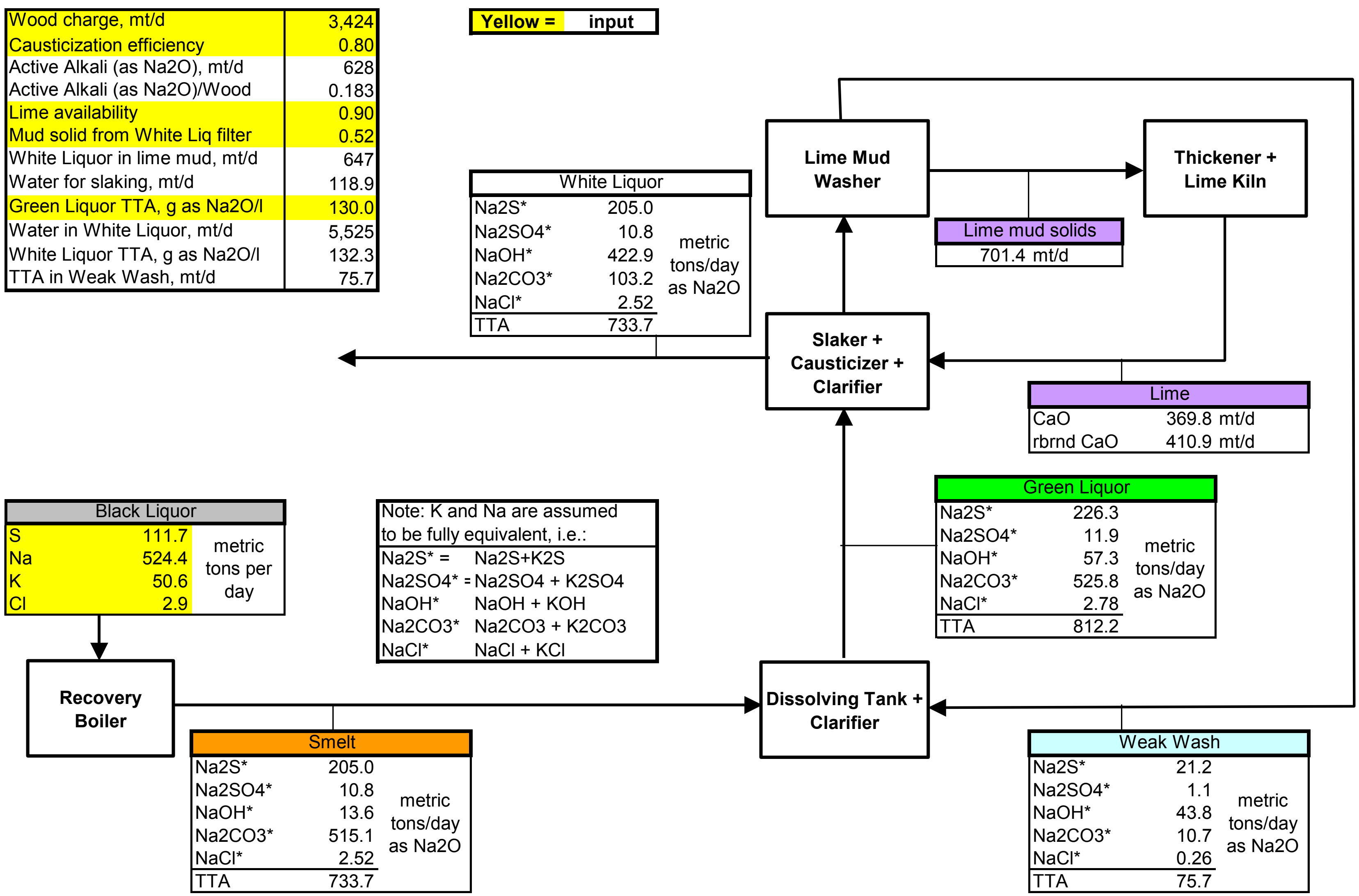


Figure A2. Estimate of causticization load for the Tomlinson base case. TTA = Total Titratable Alkali.

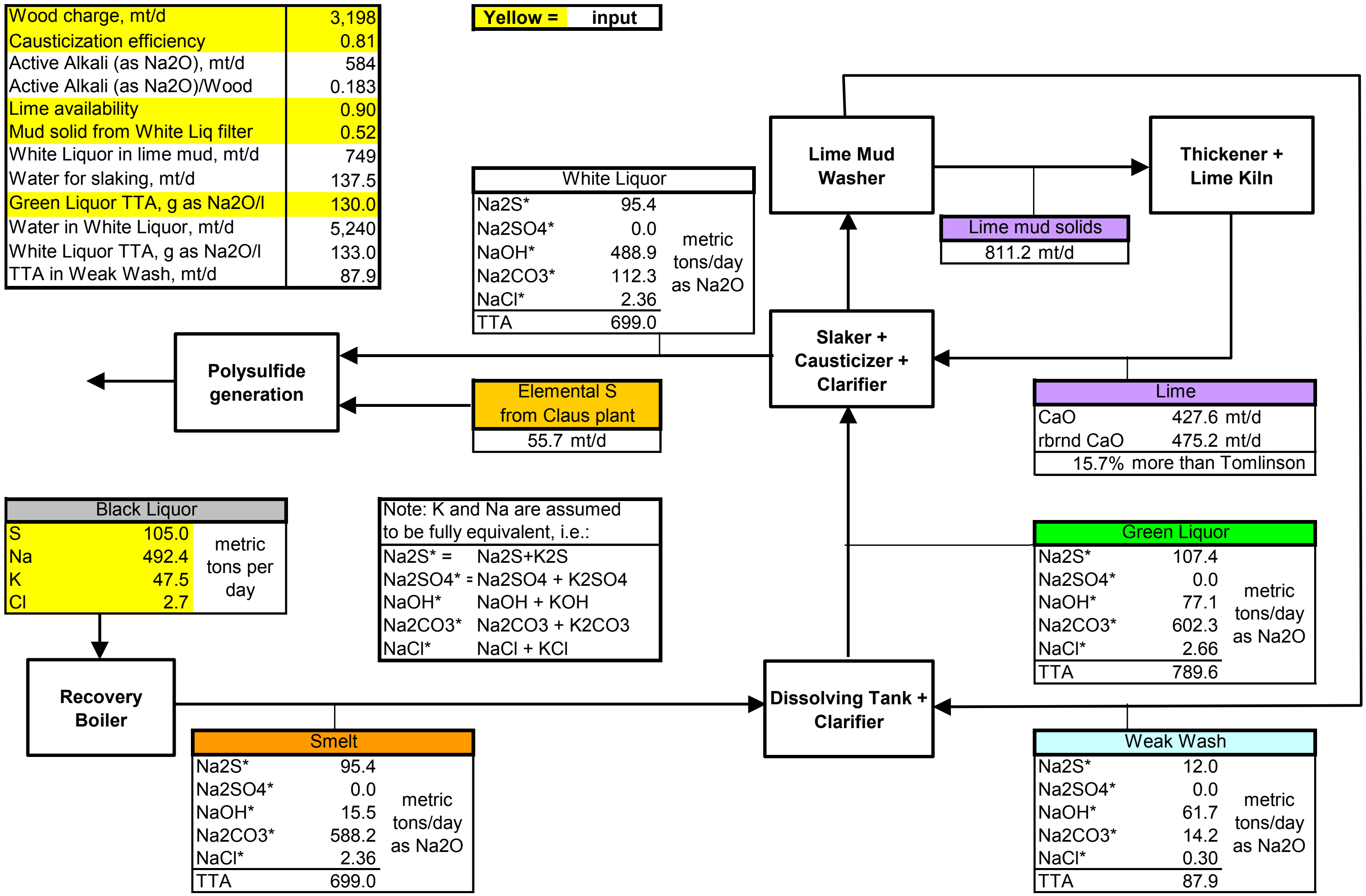


Figure A3. Estimate of causticization load for the high-temperature gasification case. TTA = Total Titratable Alkali.

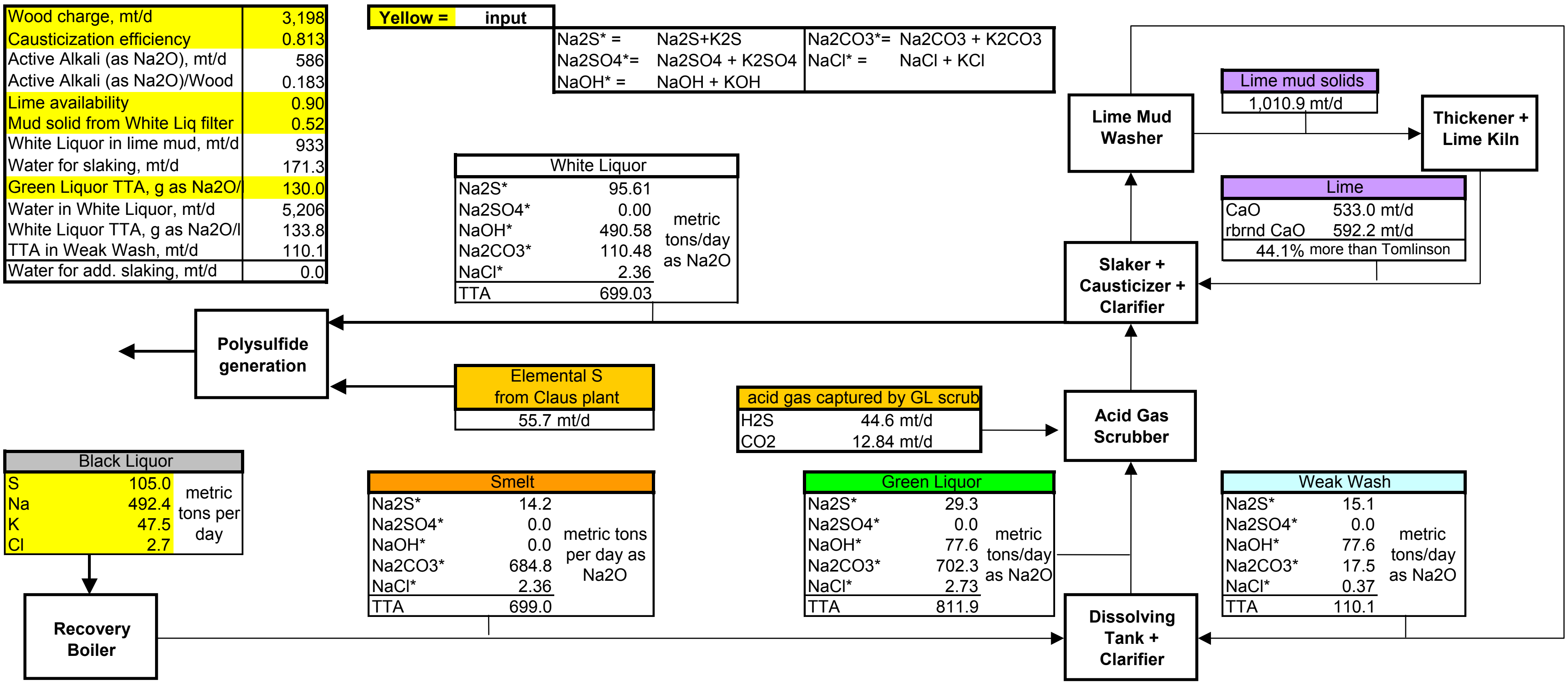


Figure A4. Estimate of causticization load for the low-temperature gasification case. TTA = Total Titratable Alkali.

Appendix B: Emissions Estimates

B.1 Emissions Factors

Table B1 and Table B2 show the emissions factors used for the analysis, expressed on a common basis. In Table B1, primary energy represents the energy contained in the fuel consumed in the indicated step, e.g., black liquor in the case of the Tomlinson boilers. In the case of the BLGCC systems, the primary energy is a mixture of fuels in some cases, e.g. in the utility-scale case, the fuel is a mix of syngas and natural gas. For the lime kiln, emissions are based on the use of #6 fuel oil. Because of the reactions taking place inside a lime kiln, emissions of criteria pollutants burning #6 oil are not substantially different from emissions using natural gas. Table B2 shows the total emissions for each power/recovery case considering emissions from all power island combustion sources (i.e., it excludes the lime kiln and hog fuel boilers – those emissions factors are used separately in the analysis). The table shows these total emissions normalized by the mass of black liquor solids consumed in each case. Table B3 shows the same figures expressed per unit of pulp production, which is the same in all the case study mills.

To estimate the net emissions impacts in the regional and national benefits analysis, the CO_2 associated with all biomass use was assumed to be zero (see main text for discussion). Thus, the CO_2 emissions factor for hog fuel use in all cases was assumed to be zero, as was the CO_2 emissions factor for the black liquor combustion in the Tomlinson cases. For the BLGCC cases, the CO_2 emissions factors shown in Table B3 were reduced by 4,589 lb/ton pulp, the CO_2 associated with the black liquor.

Table B1. Unit emission factors assumed for each combustion source.

	Emissions - lb/MMBtu primary energy (HHV)						
	CO_2	SO_2	NO_x	CO	VOCs	PM	TRS
Tomlinson Base or HERB	205.2	0.021	0.154	0.094	0.013	0.048	0.003
Low-T Mill Scale BLGCC – GT	140.3	0.002	0.090	0.033	0.002	0.007	-
Low-T Mill Scale BLGCC – Duct Burner	123.0	0.001	0.097	0.082	0.005	0.007	-
Low-T Mill Scale BLGCC – Pulse Combustor	140.3	0.002	0.083	0.034	0.001	0.018	-
Hi-T Mill Scale BLGCC – GT	221.0	0.004	0.090	0.033	0.002	0.007	-
High-T Mill Scale BLGCC – Duct Burner	168.9	0.001	0.097	0.082	0.005	0.007	-
Utility Scale BLGCC	171.3	0.002	0.090	0.033	0.002	0.007	-
Hog Fuel Boiler	213.0	0.070	0.220	0.600	0.013	0.054	-
Lime Kiln (residual fuel oil)	171.8	0.029	0.286	0.029	0.004	0.015	0.009

Notes:

- *Primary Energy* is the energy consumed in the process step shown. In the case of the Tomlinson boilers this is black liquor. In the case of the BLGCC systems it is syngas or natural gas or a mixture of the two.
- CO_2 emissions for the Tomlinson case includes carbon that leaves in the smelt as $CaCO_3$ and is eventually converted to CO_2 in the lime kiln.
- CO_2 emissions from the BLGCC process steps are based on the estimated fuel mix from the mass/energy balances presented in Section 6.3 and 6.4. The relatively small amount of CO_2 from carbon that leaves in the smelt/solids from the gasifiers and from sulfur recovery is in addition to the amount shown here.
- Hog fuel boiler emissions are from the latest revision of the EPA AP-42 *Compilation of Air Pollutant Emissions Factors*.
- Lime kiln emissions are from NCASI (personal communication with Dr. John Pinkerton, February 27, 2003). Sulfur emissions are low due to the alkaline environment within the kiln.

Table B2. Total emissions from use of black-liquor and natural gas in each power/recovery system, normalized by black liquor solids consumed.

	Emissions - lb/ton BLS						
	CO_2	SO_2	NO_x	CO	VOCs	PM	TRS
Tomlinson Base or HERB	2,452	0.26	1.84	1.12	0.16	0.57	0.04
Low-T Mill Scale BLGCC	2,654	0.02	1.03	0.52	0.03	0.10	-
Hi-T Mill Scale BLGCC	2,467	0.03	0.84	0.35	0.02	0.06	-
Utility Scale BLGCC	3,341	0.04	1.50	0.55	0.04	0.11	-

Note: CO_2 includes all sources relating to black liquor and natural gas use in the power island, including carbon from $CaCO_3$ in the smelt converted to CO_2 in the lime kiln, and for the BLGCC systems, the CO_2 vented during the sulfur recovery process. CO_2 from fuel use in the lime kiln and hog fuel boiler are excluded here and counted separately in the analysis.

Table B3. Total emissions from use of black-liquor and natural gas in each power/recovery system, normalized by pulp production.

	Emissions – lb/ton pulp (bone dry)						
	CO_2	SO_2	NO_x	CO	VOCs	PM	TRS
Tomlinson Base or HERB	4,656	0.49	3.50	2.13	0.30	1.08	0.08
Low-T Mill Scale BLGCC	4,553	0.04	1.76	0.88	0.06	0.17	-
Hi-T Mill Scale BLGCC	4,231	0.06	1.43	0.60	0.04	0.11	-
Utility Scale BLGCC	5,732	0.07	2.58	0.95	0.06	0.19	-

Note: CO_2 includes all sources relating to black liquor and natural gas use in the power island, including carbon from $CaCO_3$ in the smelt converted to CO_2 in the lime kiln, and for the BLGCC systems, the CO_2 vented during the sulfur recovery process. CO_2 from fuel use in the lime kiln and hog fuel boiler are excluded here and counted separately in the analysis.

B.2 Results from the Market Penetration Analysis

Figure B1 through Figure B9 summarize the results of the emissions analysis for all the BLGCC cases and market penetration scenarios for the Southeast United States. Figure B10 through Figure B18 show the corresponding results for the entire United States.

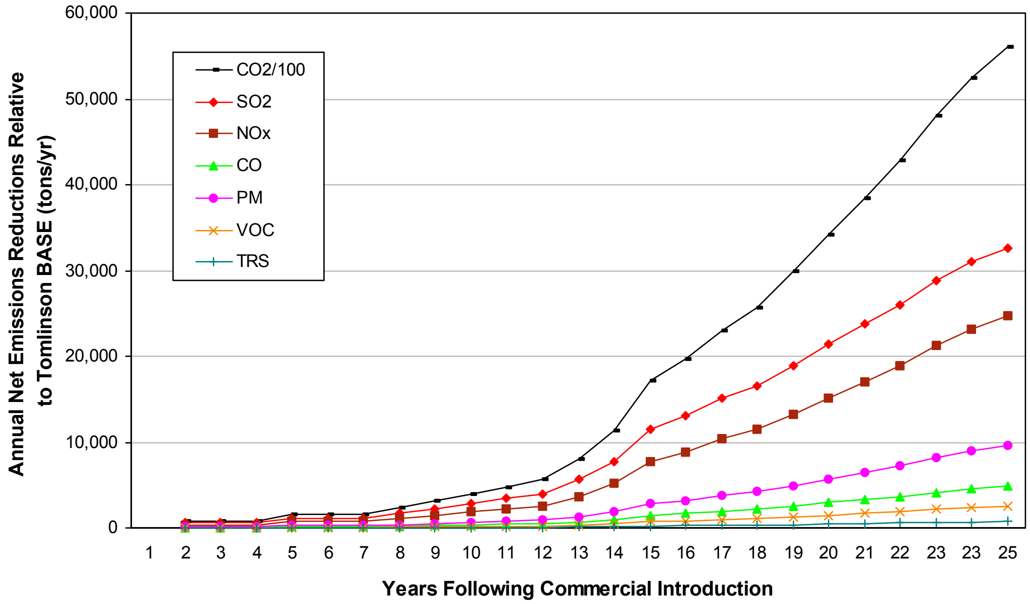


Figure B1. Net emissions reduction from Low-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Low* market penetration scenario.

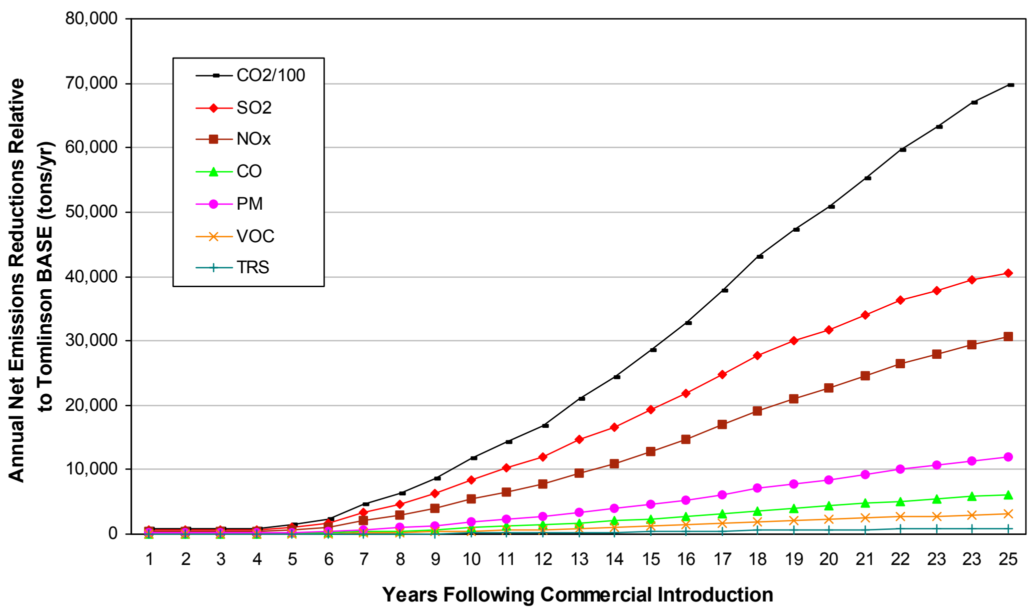


Figure B2. Net emissions reduction from Low-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *High* market penetration scenario.

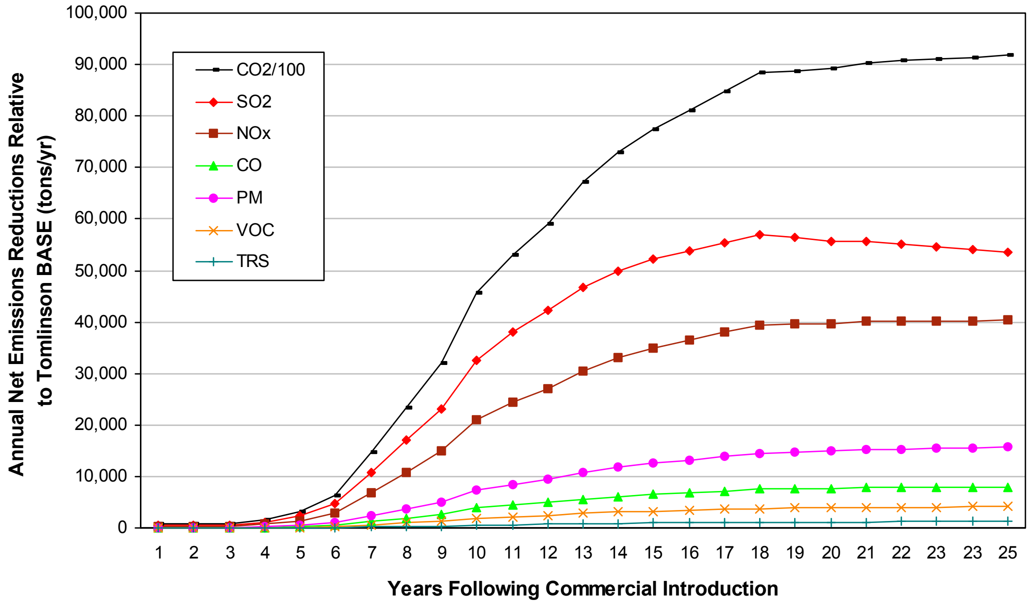


Figure B3. Net emissions reduction from Low-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Aggressive* market penetration scenario.

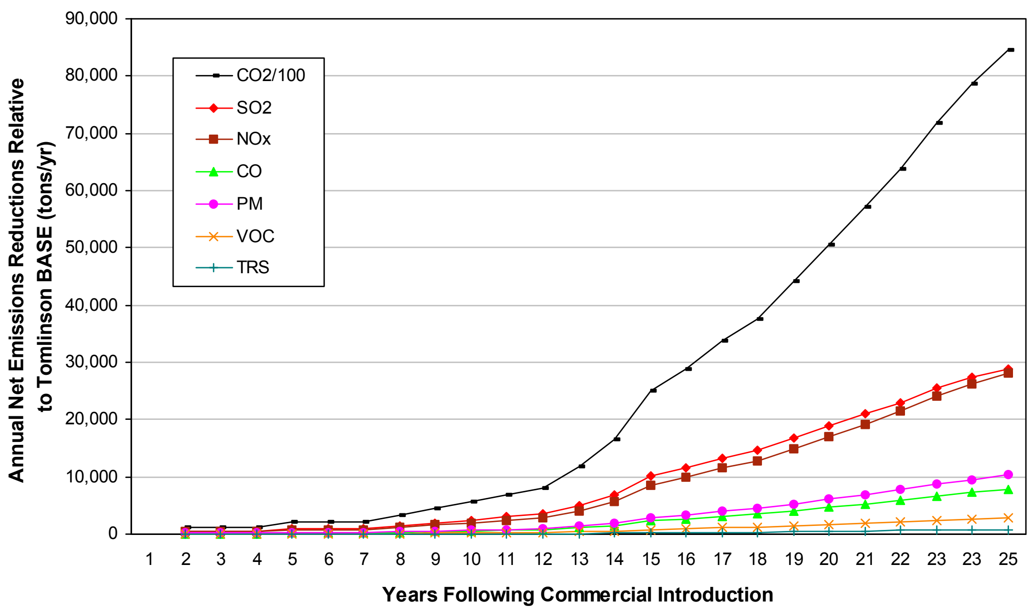


Figure B4. Net emissions reduction from High-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Low* market penetration scenario.

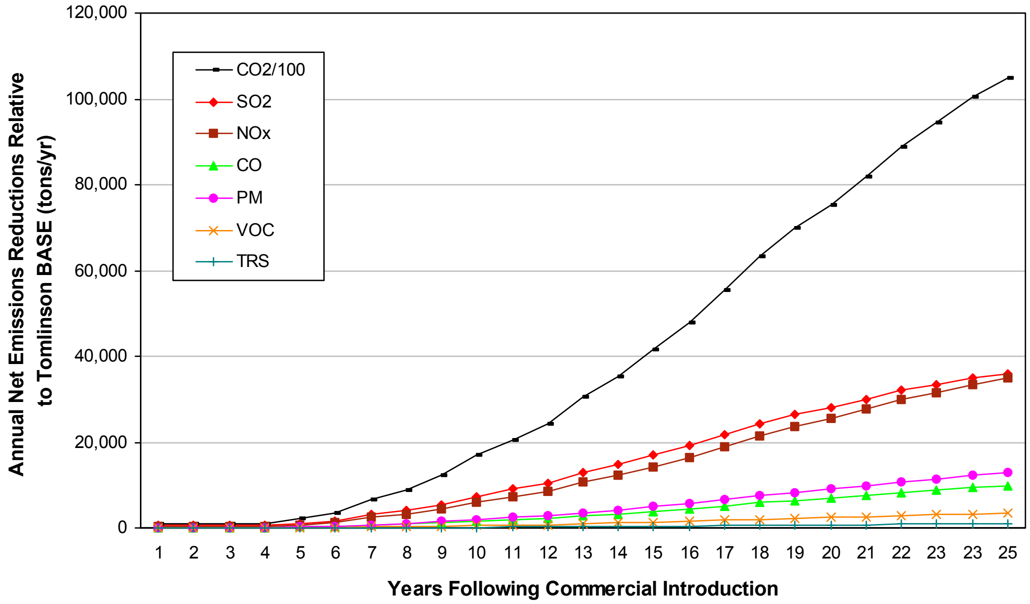


Figure B5. Net emissions reduction from High-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *High* market penetration scenario.

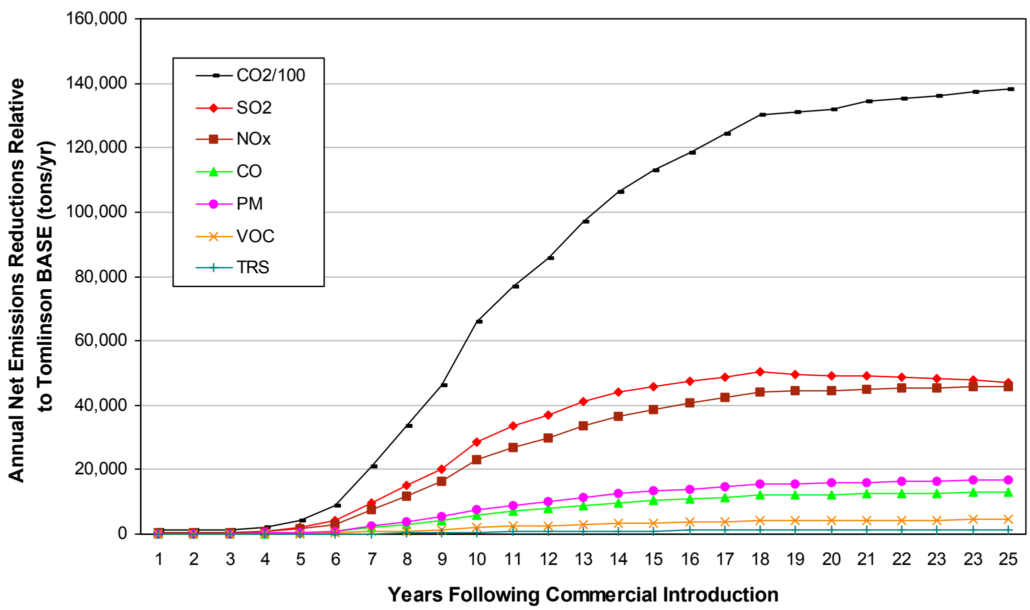


Figure B6. Net emissions reduction from High-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Aggressive* market penetration scenario.

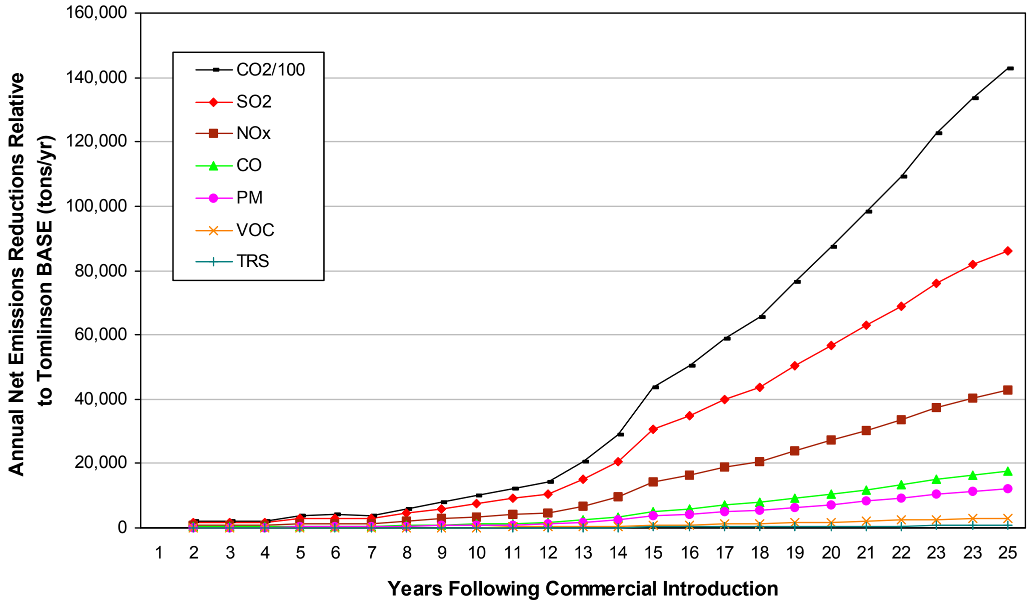


Figure B7. Net emissions reduction from High-Temperature, Utility-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Low* market penetration scenario.

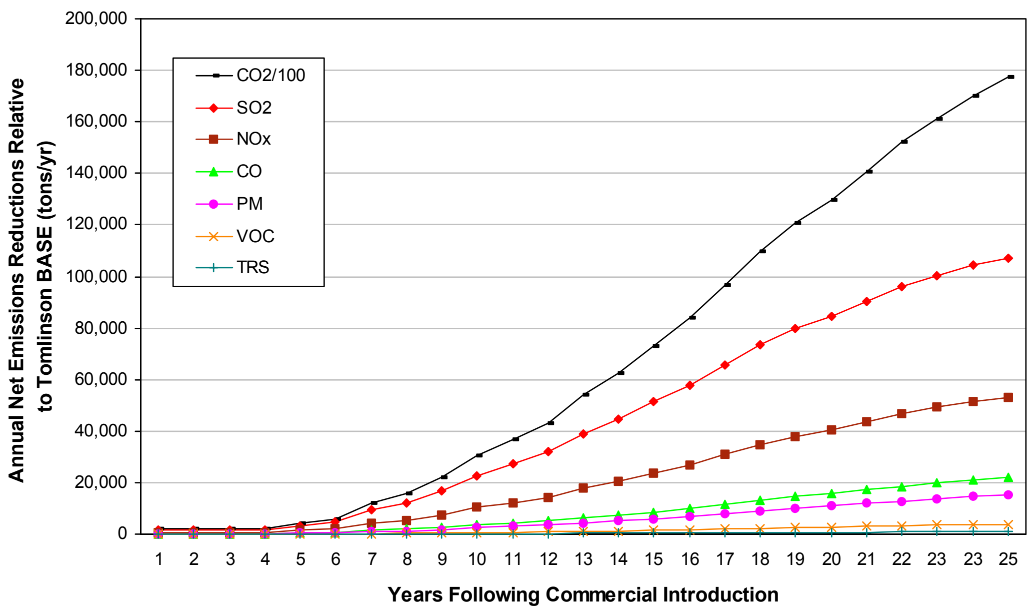


Figure B8. Net emissions reduction from High-Temperature, Utility-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *High* market penetration scenario.

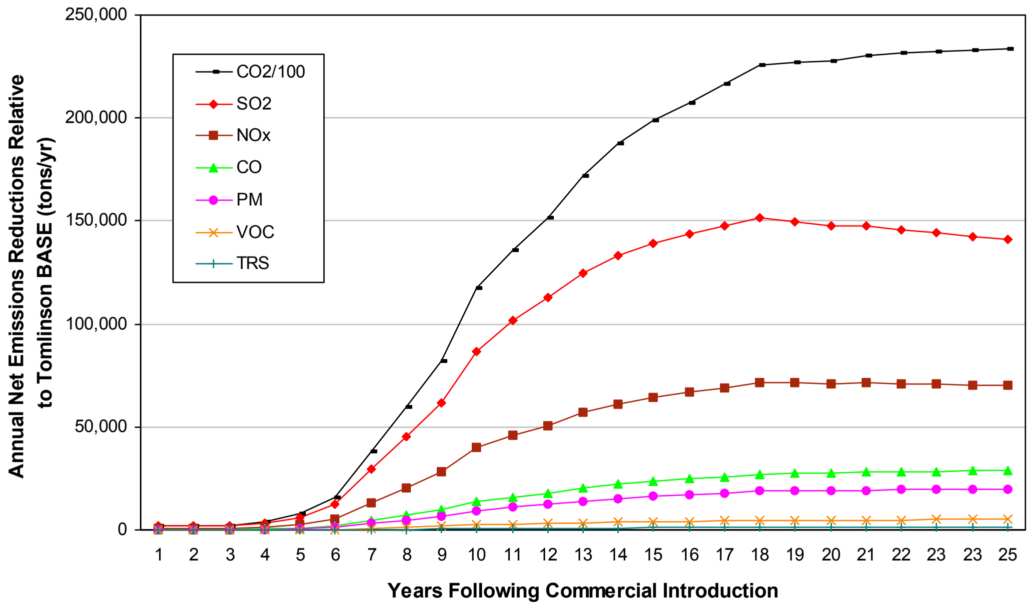


Figure B9. Net emissions reduction from High-Temperature, Utility-Scale BLGCC relative to Tomlinson BASE, Southeast United States, *Aggressive* market penetration scenario.

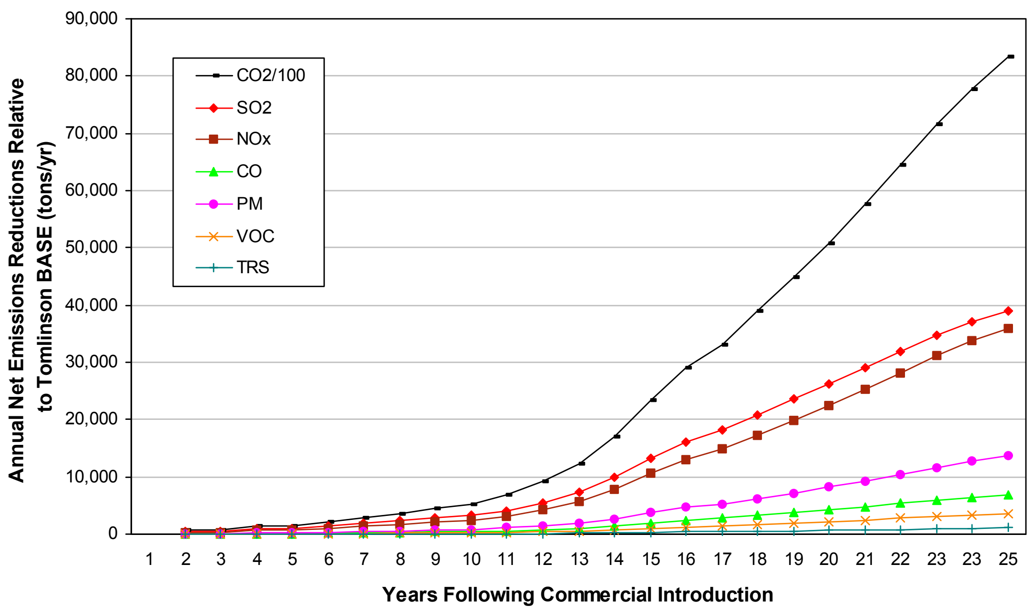


Figure B10. Net emissions reduction from Low-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Total United States, *Low* market penetration scenario.

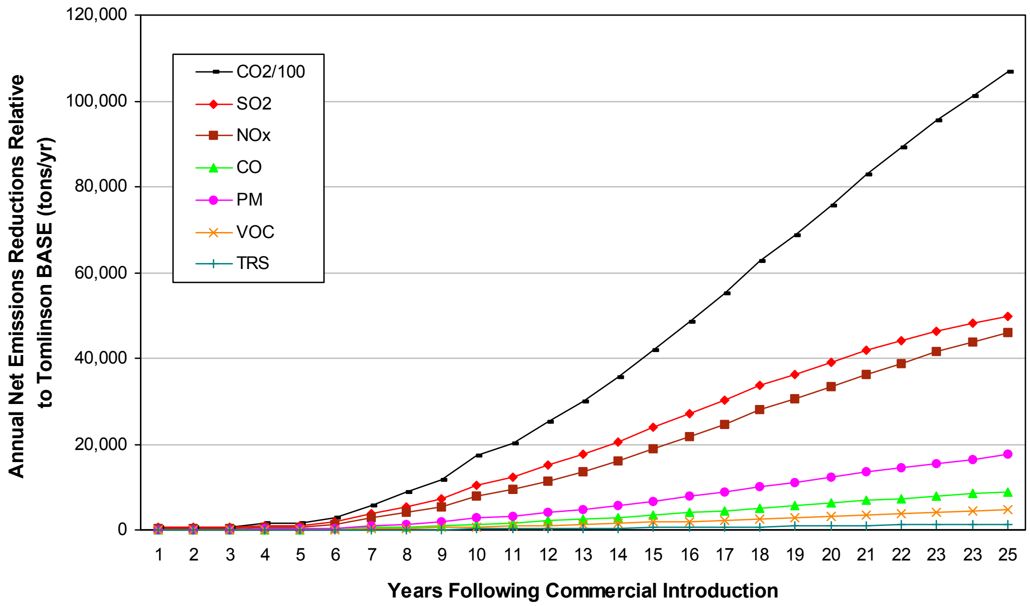


Figure B11. Net emissions reduction from Low-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Total United States, *High* market penetration scenario.

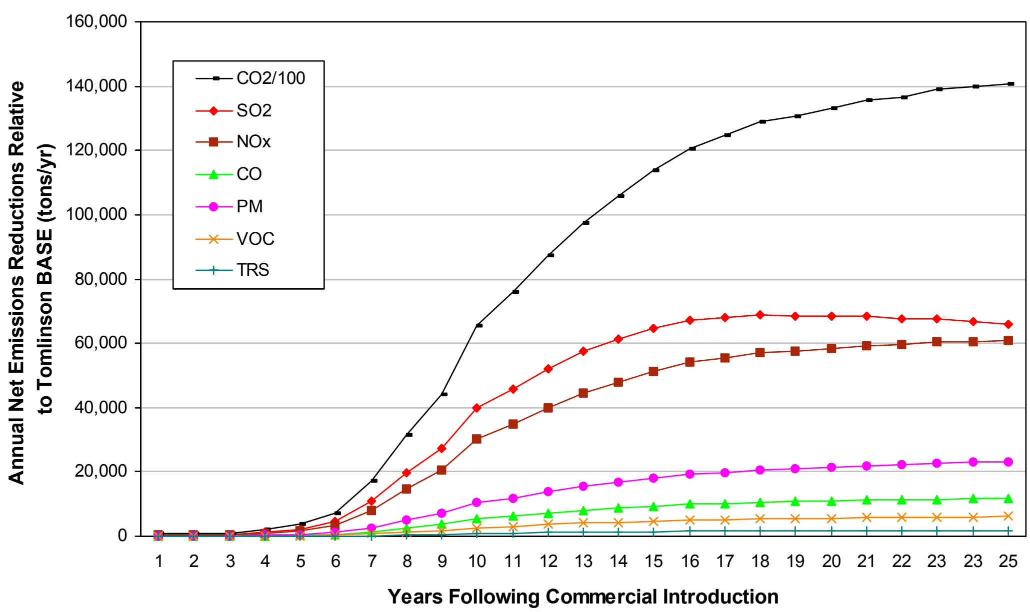


Figure B12. Net emissions reduction from Low-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Total United States, *Aggressive* market penetration scenario.

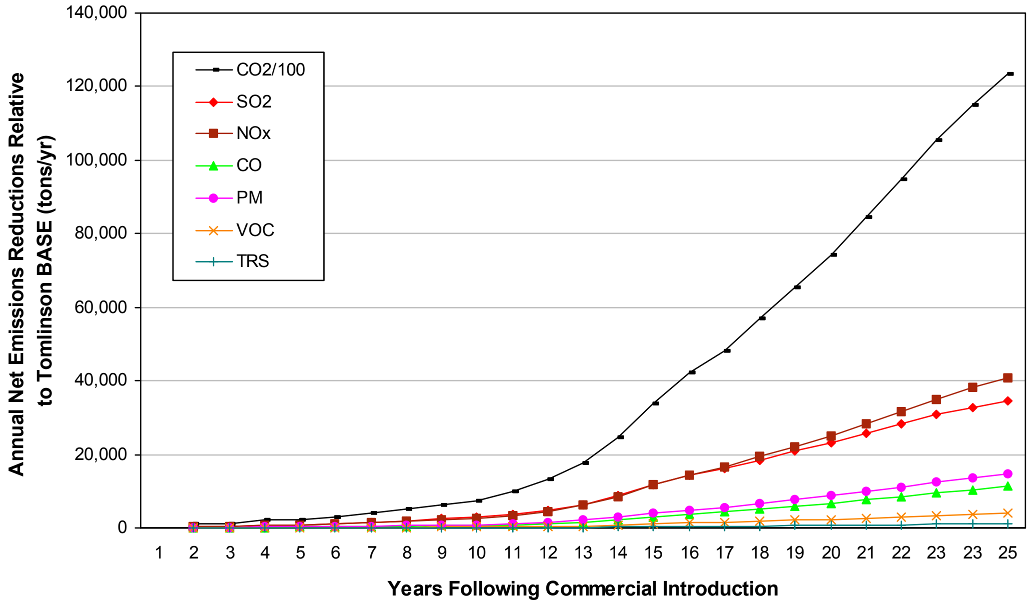


Figure B13. Net emissions reduction from High-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Total United States, *Low* market penetration scenario.

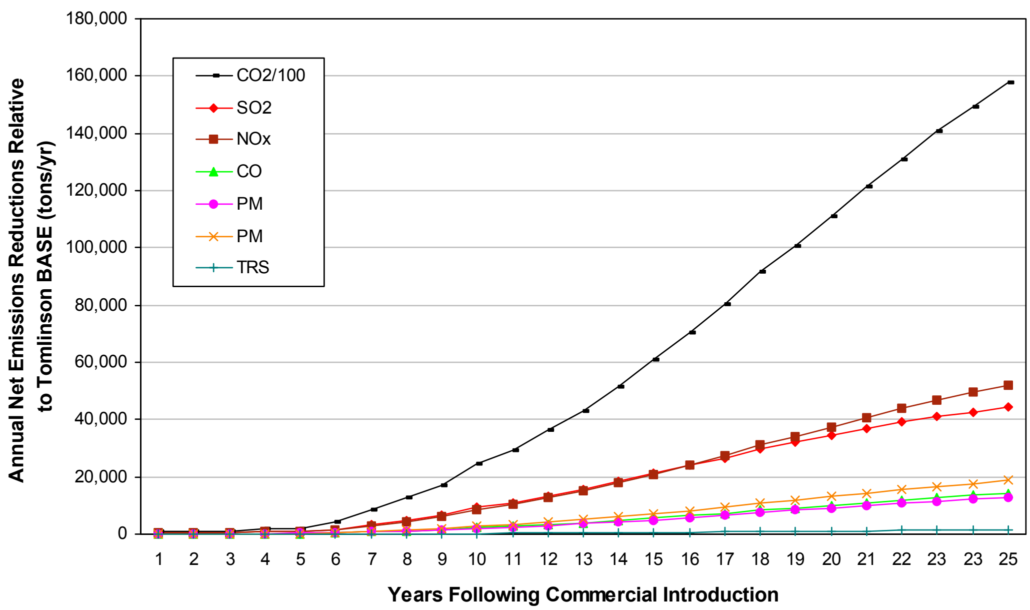


Figure B14. Net emissions reduction from High-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Total United States, *High* market penetration scenario.

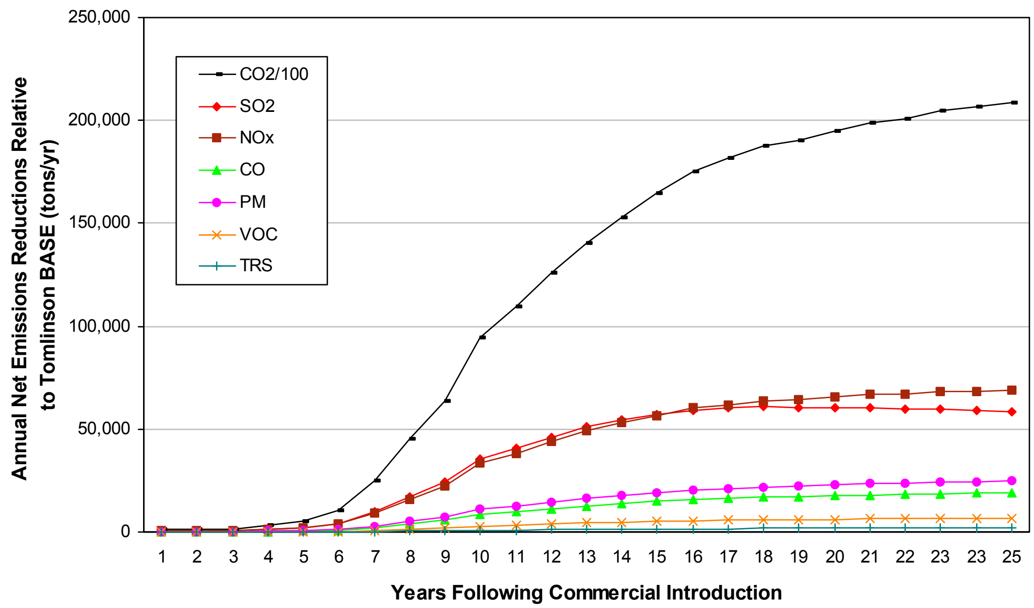


Figure B15. Net emissions reduction from High-Temperature, Mill-Scale BLGCC relative to Tomlinson BASE, Total United States, *Aggressive* market penetration scenario.

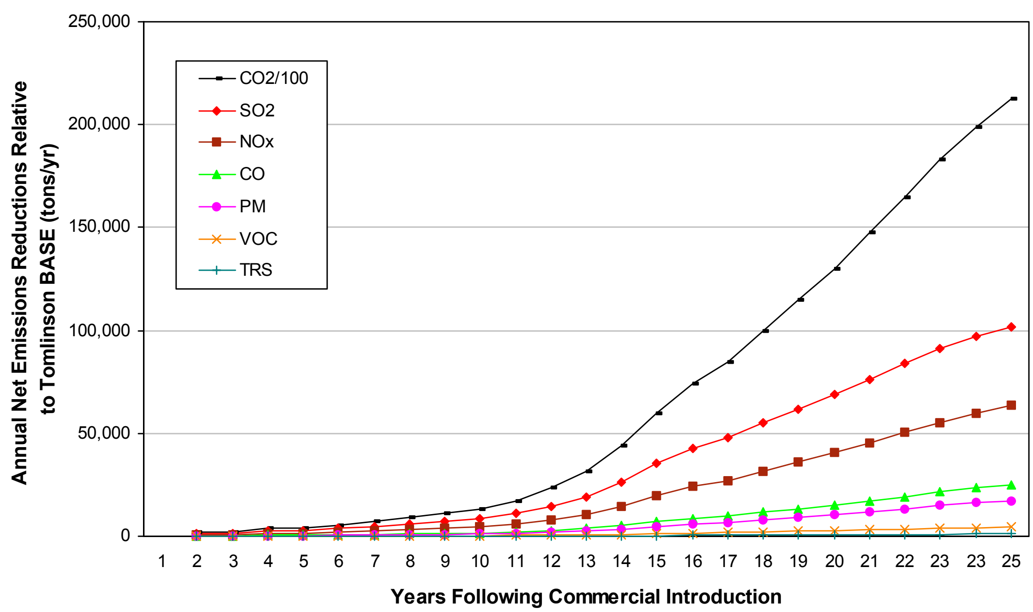


Figure B16. Net emissions reduction from High-Temperature, Utility-Scale BLGCC relative to Tomlinson BASE, Total United States, *Low* market penetration scenario.

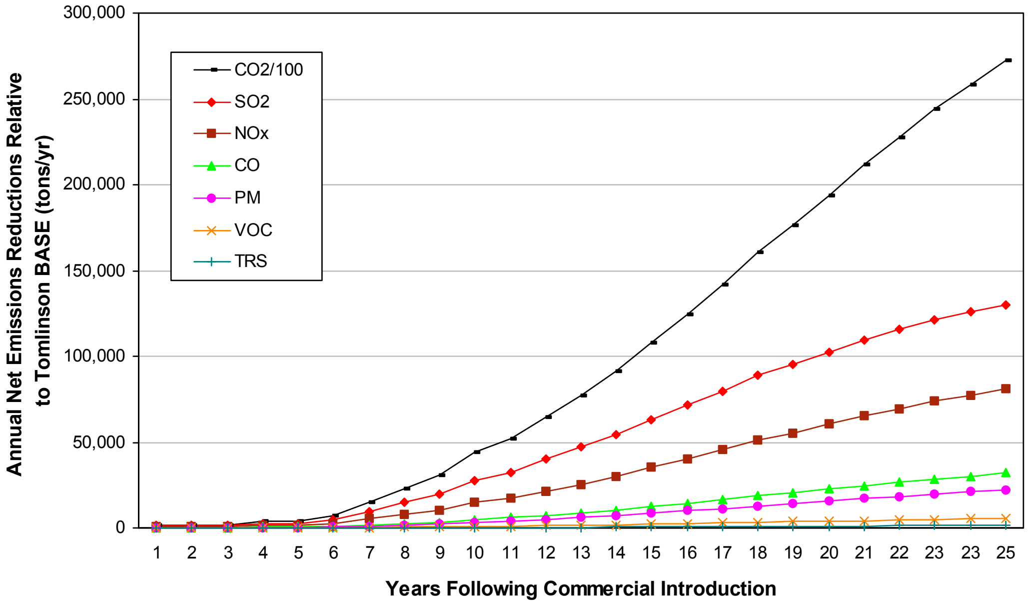


Figure B17. Net emissions reduction from High-Temperature, Utility-Scale BLGCC relative to Tomlinson BASE, Total United States, *High* market penetration scenario.

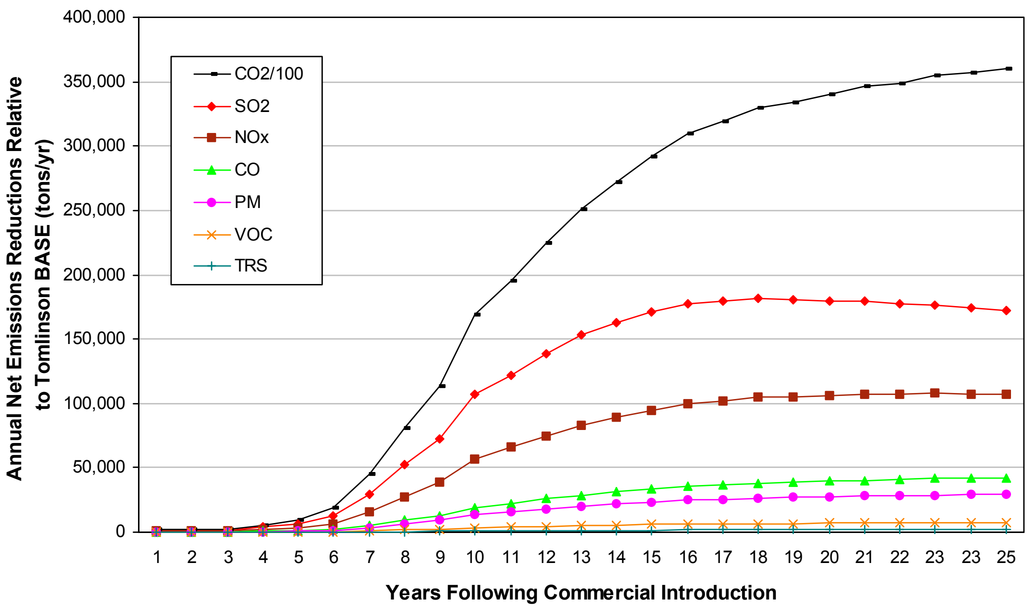


Figure B18. Net emissions reduction from High-Temperature, Utility-Scale BLGCC relative to Tomlinson BASE, Total United States, *Aggressive* market penetration scenario.

Appendix C: Interconnecting BLGCC Projects to the Grid

A key difference between BLGCC and Tomlinson technology is the need to sell power back to the grid. This requires that certain power system analyses be conducted and that an interconnection agreement be put in place with the host utility. Appendix ? provides a generic description of this process. Here we discuss the key issues related to interconnecting BLGCC resources to the grid.

Assessing interconnection requirements is by definition, site specific, and the necessary system impact and facilities studies will ultimately determine the impact of each particular interconnection, and the costs for connecting the BLGCC generation to the grid. Studying any particular site in detail was beyond the scope of this report, but a high level review of some specific sites was conducted with cooperation from Southern Company.

C.1 Generic Interconnection Process for New Generating Resources

The design of an electric system is first and foremost, an exercise in ensuring that the supply of power occurs reliably. In order to interconnect a generator, there are a number of issues that need to be reviewed to ensure that the reliability of the grid as a whole is maintained. The general process consists of two base studies – the first determines whether the interconnection is feasible as proposed (often referred to as the System Impact Study) and second determines the ultimate cost of interconnection equipment and any required system upgrades (often referred to as the Facilities Study). The process of interconnecting a new generation source is similar to what is described below for many transmission owners.

C.1.1 System Impact Study

The System Impact Study evaluates the electric system in the general vicinity of the desired interconnection point. Depending on the capability of the proposed generator, this may include a relatively localized area, or it may include a significant portion of the local system and may require regional coordination. The primary purpose of the System Impact Study is to ensure that the addition of generation capacity can be achieved while maintaining the reliability of the electric grid. For this study, a conceptual design for the direct interconnection is developed and used for analysis. Since most pulp and paper mills consume relatively large amounts of power and typically have their own substations, this aspect is probably not problematic. The System Impact Study evaluates the following areas:

- ***Thermal*** – a power analysis is conducted to confirm that the generation can be added to provide net injection into the grid without overloading the transmission system for differing levels of plant output.
- ***Voltage and Reactive Support*** – the power flow study is used to confirm that the voltage is adequate on the transmission system to meet reliability criteria, given the characteristics of the new generating resource to be added. Deficiencies are identified so that remedial design changes or system upgrades can be agreed upon between the developer and the transmission owner. Generating resources must be able to deliver or absorb reactive power with a power factor consistent with the interconnecting transmission owner's requirements. Typically the

power factor will be measured at the high side of a generator step up transformer and must be adequate to support voltage at the point of interconnection. Units must be equipped with Automatic Voltage Regulation (AVR) with status indication reported remotely to the appropriate dispatch center. The AVR must be operated continuously to maintain scheduled voltage at a point designated by the system operator unless otherwise directed or approved by the system operator. The transmission owner is responsible for recommending the desired scheduled voltage and regulated point and may recommend a specific generator step up transformer tap setting.

- ***First Contingency Criterion*** – the transmission system is designed to be operated such that a fault, and subsequent tripping of any element will not cause any other element to exceed its appropriate emergency rating. The study performs a contingency analysis to ensure that the addition of the generator will not cause this criterion to be violated, either through the tripping of the generator itself, or because of the increased flows combined with loss of some other element. A determination is then made as to the appropriate remedy for violations of the criteria.
- ***Short Circuit / Circuit Breaker Fault Duty*** – under short circuit conditions, each generator contributes to the current on the system. As resources are added, the short circuit currents can increase to the point where the ability of circuit breakers to interrupt the current can be compromised. The study identifies those breakers that may have to be upgraded to allow interconnection of the generating resource.
- ***Stability*** – this portion of the study assesses the ability of the proposed plant to remain in synchronism with the grid following a fault, as well as looking at the other plants in the system with respect to damping of the system oscillations that can be caused by a fault.
- ***Substation Grounding*** – a portion of the study assesses the adequacy of substation grounding, which may be an issue when modifying the generator characteristics.

These studies typically are done in accordance with the interconnection queuing order that is maintained by the connecting transmission owner or the ISO/RTO, assuming that there are a number of proposed projects that are in the process of development. It is necessary, then to make assumptions regarding the existence or non-existence of proposed additions to the system when studying an individual project. When the impact of a proposed generator is localized, it is relatively clear what upgrades are required and the what will be the cost impact to the developer. When there are a number of projects under development or proposed in an area, or when upgrades are required that affect the ability of other transmission customers to use the system, the assignment of costs and transmission rights is not always clearly defined and can be a contentious process. These issues are generally outlined in a FERC-approved Open Access Transmission Tariff (OATT), and are currently under discussion in FERC's Notice of Proposed Rulemaking (NOPR) on generator interconnection policy and FERC's NOPR on standard market design. A white paper of these issues is expected to be issued by FERC in April 2003.

C.1.2 Facilities Study

The second study, the Facilities Study, is conducted if the System Impact Study determines that there are issues that need to be addressed in order to facilitate transmission service for delivery of the generator's power to the grid. The results of the study provide the generation developer with the upgrades that are required to mitigate concerns identified in the System Impact Study. Depending on the particular structure of the OATT, these upgrades may be optional or mandatory. Essentially, this type of study addresses the deliverability of the energy produced by the generator. It is not a guarantee of transmission service, however.

C.1.3 Interconnection Agreement

The final step before the generator can interconnect to the system is the execution of an interconnection agreement with the transmission owner. This agreement details the obligations of both parties, and outlines the transmission owner's requirements for metering, relay protection, access to facilities, coordination requirements, and ownership of the interconnection facilities, as a minimum. It also outlines the physical interconnection process, with the testing requirements that must be met prior to the declaration that the generator is ready for commercial operation.

The interconnection agreement may also include requirements for ancillary services, curtailment, definitions of emergency conditions and actions that are allowed under those circumstances, as well as the rights of the generator and transmission owner. If these items are not contained in the interconnection agreement, they may be contained in an operating agreement.

C.2 BLGCC Interconnection Issues

C.2.1 Summary

There are three factors that are expected to make the interconnection of BLGCC projects relatively simple in comparison to other new generation projects:

- First, many pulp and paper mills currently have existing "behind the fence" generators and a substation that supplies electricity to the mill. Upgrading the existing substation is generally a simpler process than tapping into an existing circuit, acquiring necessary rights of way, and other issues normally associated with interconnection of a new (greenfield or brownfield) generator.
- Second, the current grid interconnections and mill substations are sized to meet the full load of the mill and often have excess capacity (e.g., if the existing onsite generation were offline, the mill could continue to operate by purchasing all of its electricity). For the mill-scale BLGCC cases, the amount of power that would be exported is a small fraction of the rates capacity of the equipment (15-20% of the total mill demand). In the utility scale case, the power to be delivered to the grid will be approximately the same as the power that was being delivered to the pulp and paper mill. Consequently, it is very unlikely that reconductoring or new circuits would be necessary for the radial interconnection of the BLGCC power plant.
- Third, many mills in the Southeast are relatively close to the "backbone" of the transmission system, so that if line upgrades are necessary, the distances involved are not large, which help control costs.

C.2.2 Southern Company's System

Southern Company's transmissions system was used to explore BLGCC interconnection issues. Southern Company serves approximately 25 pulp & paper mills. Its transmission system consists of over 26,000 miles of wire, at voltage levels ranging from 44 kilovolts (kV) to 500kV. About 2000 miles of 500kV transmission forms the backbone of the system, providing transmission to the major load centers in Georgia, Mississippi, and Alabama, such as Atlanta and Birmingham. This backbone provides a reliable high voltage network around the system as well as interconnections to TVA, Entergy, South Carolina and Florida. About 7000 miles of 230kV transmission provide service to other areas, with the remainder connected at 115kV, 69kV and 44kV voltage levels. Many of the pulp mills are connected at the 115kV or 230kV levels.

According to EIA-411 data, Southern Company is projected to have a reserve margin between 12% and 14% between 2003 and 2011. The conversion of some of the pulp and paper mills to BLGCC will add more capacity resources to the region, increasing the reserve margin and aiding in the overall system reliability.

C.2.3 Pulp and Paper Mill Locations in Alabama and Georgia

Several sites in Alabama and Georgia were identified as potential BLGCC conversion locations (see Table C1). Most of these sites are interconnected at either 115 kV or 230 kV. For Southern Company, the 115kV lines are designed to accommodate between 90 and 200 MW, while the 230kV lines are designed to handle flows of up to 350MW. As indicated above, the relatively small deliveries to the grid, of even the utility scale case suggests that interconnection costs will not be excessive for those pulp mills connected at 115 kV or above (see table below). Some upgrades of the local transmission may be required for those pulp mills with 69 kV interconnections. These system upgrades may involve conversion of the plant interconnection to 115 kV, but discussions with Southern Company indicated that this is already the trend, in order to provide more capacity to their growing system.

Table C1. Candidate locations for BLGCC projects in Southern Company's service territory.

Mill Name/City	Owner
Alabama	
Brewton	Smurfit-Stone
Coosa Pines	US Alliance (Alliance Forest Products)
Cottonton	Mead Coated Board
Courtland	International Paper
Demopolis	Gulf States Paper
Jackson	Boise Cascade
Mobile	Kimberly-Clark Tissue Co.
Pennington	Georgia-Pacific
Pine Hill	Weyerhaeuser
Prattville	International Paper
Selma	International Paper
Georgia	
Augusta	International Paper
Brunswick	Georgia-Pacific
Cedar Springs	Georgia-Pacific
Macon	Riverwood International
Port Wentworth	Smurfit-Stone
Riceboro	Interstate Paper
Rome	Inland
Savannah	International Paper
St. Mary's	Durango-Georgia Paper
Valdosta	Packaging Corporation of America

Based on information provided by Southern Company, the pulp and paper sites located in Alabama may be more difficult to convert to BLGCC technology in the near term due to queuing and stability issues in the Alabama grid. Over time, these issues will change, however. At present, the locations in Georgia have been indicated as the most attractive. Table C2 summarizes the expected interconnection and grid upgrades that would be necessary for selected BLGCC plants in Georgia. These costs range from $500,000 to $4 million in most cases. In one case, where an upgrade from 69kV to 115kV would be required, total upgrade costs are in the $11 million range.

Table C2. Estimated upgrade costs for selected Georgia pulp and paper mills.

Mill Name/Owner	Upgrades	Estimated Cost
Augusta - International Paper	Metering, Line Breakers, System Upgrades	$1,550,000
Brunswick - Georgia-Pacific	Metering, System Upgrades	$500,000 - $3,500,000
Macon - Riverwood International	Metering, Relaying, Line Breakers, System Upgrades	$2,200,000
Riceboro - Interstate Paper	Metering, Breakers, System Upgrades	$4,100,000
St. Mary's - Durango-Georgia Paper[a]	Metering, Line Breakers, System Upgrades	$1,300,000 - $2,300,000
Valdosta - Packaging Corp. of America	Metering, Conversion 69kV to 115 kV, Breakers, System Upgrades	$11,400,000

(a) At the time of writing this mill was shut down due to a recovery boiler explosion.

C.2.4 Other Key Interconnection Considerations

The primary difference between a relatively small "behind the fence generator" and one that supplies energy to the grid is the need for communication and coordination with the system operator, for instance for voltage adjustments and energy output, to ensure that the reliability of the transmission grid is not compromised. When significant amounts of this type of generation is placed into service, there may also be a need to coordinate daily schedules, maintenance schedules, and plant shut-downs to be certain that the grid, as a whole, has sufficient resources to meet peak daily demand. These issues are not new to the electric power industry, but would be new to the pulp & paper industry.

It is also important to note that adding generation at strategic locations on the transmission grid may actually defer capital investments in the transmission and distribution system, if those upgrades were primarily driven by load growth. Given this potential, the expected interconnection costs are considered to be quite minor, especially compared to a $200+ million investment in BLGCC technology.

Appendix D: Financial Analysis

D.1 Financial Model

To assess the prospective costs and benefits of BLGCC technology at the mill level, a simplified cash flow model was developed for each of the five cases. The model includes the costs, savings, and potential revenues (e.g., power sales) associated with the conversion of black liquor. For the purposes of the cash flow analysis, avoided costs (e.g., avoided grid power purchases) are treated the same as revenues.

Using the total net cash flows for each case, the model then calculates the incremental cash flow of the BLGCC option relative to the Tomlinson option (Base or HERB), in order to determine the IRR and NPV of the incremental investment over a 25-year operating life. The analysis was carried out assuming that an investment would need to be made in a new power/recovery system to replace an existing Tomlinson system that had reached the end of its working life.

The analysis focused on the power/recovery area, but also considered, in the BLGCC cases, the reduced wood costs due to higher digester yield with polysulfide pulping, the increased use of #6 fuel oil in the lime kiln, the purchased natural gas, and (in the two BLGCC cases with the mill-scale gas turbine) the cost of purchased wood residues. Thus, the cash flow model effectively accounts for all major changes to mill operations that result from the application of BLGCC technology. Table D1. summarizes the key input parameters that form the basis of the cash flow analysis.

Key inputs to the financial analysis include:

- The detailed mass/energy balances and engineering cost estimates for each of the five systems discussed above
- Expected future prices for natural gas, fuel oil, purchased wood residuals, electricity purchased by the mill and electricity sold to the grid
- Financial assumptions (e.g., construction period, debt/equity split, cost of debt and return on equity, inflation rate, project life, and income tax rate).

The model provides for sensitivity analysis of fuel and feedstock prices, capital costs, monetization of renewable energy and environmental benefits and the application of renewable energy production tax credits.

Depreciation:

- Depreciation is computed using the 20-year Modified Accelerated Cost Recovery System (MACRS). This depreciation schedule, defined by the Internal Revenue Service, applies to assets placed in service after 1986. It results in more rapid depreciation than straight-line depreciation.

Table D1. Key inputs to the cash flow analysis.

	Applicability of Cash Flow Element			
	Tomlinson Base	Tomlinson HERB	Mill-Scale BLGCC	Utility-Scale BLGCC
Revenues				
Electricity Sales (export)			✓	✓
Renewable Energy Premium (on all incremental renewable generation)*		✓	✓	✓
Carbon Trading Credit (on net carbon reduction)*		✓	✓	✓
NOx Credit (on net NOx reduction)*		✓	✓	✓
Avoided Cost Savings				
Avoided Electricity Purchases	✓	✓	✓	✓
Avoided Wood Purchases*			✓	✓
Direct Operating Costs				
Natural Gas Purchases			✓	✓
Incremental Lime Kiln Fuel (#6 oil)*			✓	✓
Hog Fuel Purchases			✓	
Non Fuel Operations & Maintenance	✓	✓	✓	✓
Offsets to taxable income				
Renewable energy production tax credit (on all incremental renewable generation)*		✓	✓	✓

Note: Items with a (*) are computed as incremental costs or revenues relative to the Tomlinson Base case. All other items are total costs or revenues.

Financing costs on debt are calculated as follows:

- During the construction period, the principal payment is the cumulative amount of debt financed divided by the project life. During operations, principal is amortized in annual payments equal to the total amount of debt financed divided by the project economic life. The final two principal payments are adjusted to account for the principal payments that were made during the construction phase.
- Interest payments are computed annually by multiplying the net unamortized debt by the interest rate.

Taxes

- Taxes are calculated on the net income after subtracting interest and depreciation. Any negative net income (e.g., during construction and startup) is assumed to generate tax savings that lead to increased after tax cash flows[52]. This approach assumes that the implementation of the project would ultimately be evaluated with the financial performance of the entire company. Thus the tax benefits of reductions in total net income derived from the BLGCC project are factored into the IRR and NPV calculations.

[52] e.g., if the net cash flow before taxes is \$(4,000,000), the taxable income is \$(1,000,000) and the tax rate is 40%, then the tax savings in that year is \$400,000, for a net after tax cash flow of \$(3,600,000).

D.2 Baseline Cash Flow Statements

The tables that follow show:

- Summary total net cash flows, IRR and NPV for each option
- Incremental net cash flows, IRR and NPV for the HERB and BLGCC cases relative to the Tomlinson BASE
- Incremental net cash flows, IRR and NPV for BLGCC cases relative to the Tomlinson HERB
- Detailed cash flow statements for each option

	Construction------------------------------------>			Operation-->											
Total Net Cash Flow (a)	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Tomlinson - "Base"	$ -	$ (33,051,858)	$ (35,613,036)	$ 4,852,669	$ 9,849,317	$ 9,960,343	$ 10,115,190	$ 10,331,381	$ 10,508,466	$ 10,640,547	$ 10,879,504	$ 11,364,637	$ 11,907,744	$ 12,503,177	$ 13,015,774
IRR	**14.22%**														
NPV ($ million)	**$ 27.96**														
Tomlinson - "HERB"	$ -	$ (43,657,701)	$ (47,040,722)	$ 6,258,853	$ 13,028,478	$ 13,173,098	$ 13,376,508	$ 13,663,034	$ 13,894,119	$ 14,061,755	$ 14,375,413	$ 15,019,393	$ 15,741,123	$ 16,534,418	$ 17,212,951
IRR	**14.22%**														
NPV ($ million)	**$ 36.99**														
BLGCC - Low Temperature Gasifier - Mill Scale	$ (25,430,020)	$ (52,830,605)	$ (56,726,777)	$ 7,540,913	$ 16,229,015	$ 16,345,843	$ 16,513,693	$ 16,791,738	$ 17,032,029	$ 17,208,433	$ 17,554,999	$ 18,345,015	$ 19,219,226	$ 20,174,358	$ 21,002,964
IRR	**11.61%**														
NPV ($ million)	**$ 21.94**														
BLGCC - High Temperature Gasifier - Mill Scale	$ (21,115,350)	$ (43,866,922)	$ (47,102,038)	$ 10,641,375	$ 19,350,251	$ 19,616,365	$ 19,966,660	$ 20,410,187	$ 20,787,056	$ 21,095,487	$ 21,574,655	$ 22,442,177	$ 23,412,182	$ 24,466,532	$ 25,392,011
IRR	**16.14%**														
NPV ($ million)	**$ 72.82**														
BLGCC - High Temperature Gasifier - Utility Scale	$ (26,297,581)	$ (54,632,953)	$ (58,662,046)	$ 15,741,688	$ 27,018,732	$ 27,363,082	$ 27,768,927	$ 28,290,296	$ 28,777,352	$ 29,207,132	$ 29,813,600	$ 30,878,178	$ 32,037,328	$ 33,283,481	$ 34,408,866
IRR	**17.53%**														
NPV ($ million)	**$ 111.06**														
Total Net Cash Flow Variance from Tomlinson BASE (a)															
Tomlinson - "HERB"	$ -	$ (10,605,843)	$ (11,427,686)	$ 1,406,184	$ 3,179,161	$ 3,212,755	$ 3,261,318	$ 3,331,653	$ 3,385,653	$ 3,421,208	$ 3,495,909	$ 3,654,756	$ 3,833,379	$ 4,031,241	$ 4,197,178
IRR on Variance	**14.22%**														
NPV of Variance ($ million)	**$ 9.03**														
BLGCC - Low Temperature Gasifier - Mill Scale	$ (25,430,020)	$ (19,778,747)	$ (21,113,741)	$ 2,688,244	$ 6,379,698	$ 6,385,499	$ 6,398,503	$ 6,460,357	$ 6,523,563	$ 6,567,887	$ 6,675,495	$ 6,980,378	$ 7,311,482	$ 7,671,181	$ 7,987,191
IRR on Variance	**8.93%**														
NPV of Variance ($ million)	**$ (6.02)**														
BLGCC - High Temperature Gasifier - Mill Scale	$ (21,115,350)	$ (10,815,064)	$ (11,489,001)	$ 5,788,706	$ 9,500,934	$ 9,656,022	$ 9,851,470	$ 10,078,806	$ 10,278,590	$ 10,454,940	$ 10,695,151	$ 11,077,540	$ 11,504,438	$ 11,963,355	$ 12,376,237
IRR on Variance	**18.47%**														
NPV of Variance ($ million)	**$ 44.86**														
BLGCC - High Temperature Gasifier - Utility Scale	$ (26,297,581)	$ (21,581,095)	$ (23,049,010)	$ 10,889,019	$ 17,169,414	$ 17,402,739	$ 17,653,737	$ 17,958,915	$ 18,268,886	$ 18,566,586	$ 18,934,096	$ 19,513,541	$ 20,129,584	$ 20,780,304	$ 21,393,092
IRR on Variance	**20.10%**														
NPV of Variance ($ million)	**$ 83.10**														
Total Net Cash Flow Variance from Tomlinson HERB (a)															
BLGCC - Low Temperature Gasifier - Mill Scale	$ (25,430,020)	$ (9,172,904)	$ (9,686,055)	$ 1,282,060	$ 3,200,537	$ 3,172,745	$ 3,137,185	$ 3,128,704	$ 3,137,910	$ 3,146,679	$ 3,179,586	$ 3,325,622	$ 3,478,103	$ 3,639,941	$ 3,790,013
IRR on Variance	**6.11%**														
NPV of Variance ($ million)	**$ (15.05)**														
BLGCC - High Temperature Gasifier - Mill Scale	$ (21,115,350)	$ (209,221)	$ (61,315)	$ 4,382,522	$ 6,321,773	$ 6,443,267	$ 6,590,152	$ 6,747,153	$ 6,892,937	$ 7,033,732	$ 7,199,242	$ 7,422,784	$ 7,671,059	$ 7,932,114	$ 8,179,059
IRR on Variance	**21.13%**														
NPV of Variance ($ million)	**$ 35.83**														
BLGCC - High Temperature Gasifier - Utility Scale	$ (26,297,581)	$ (10,975,252)	$ (11,621,324)	$ 9,482,836	$ 13,990,253	$ 14,189,984	$ 14,392,419	$ 14,627,262	$ 14,883,233	$ 15,145,378	$ 15,438,187	$ 15,858,785	$ 16,296,205	$ 16,749,063	$ 17,195,914
IRR on Variance	**22.03%**														
NPV of Variance ($ million)	**$ 74.06**														

(a) Construction costs are financed assuming debt fraction of 50%

Total Net Cash Flow (a)	13	14	15	16	17	18	19	20	21	22	23	24	25
Tomlinson - "Base"	$ 13,616,090	$ 14,209,883	$ 14,819,641	$ 15,443,883	$ 16,085,041	$ 16,741,665	$ 17,416,214	$ 19,193,581	$ 16,644,711	$ 17,372,872	$ 18,120,203	$ 20,046,162	$ 21,934,075
IRR													
NPV ($ million)													
Tomlinson - "HERB"	$ 18,011,838	$ 18,801,189	$ 19,611,893	$ 20,442,005	$ 21,294,747	$ 22,168,216	$ 23,065,675	$ 25,420,152	$ 22,060,505	$ 23,029,790	$ 24,024,761	$ 26,576,944	$ 29,079,269
IRR													
NPV ($ million)													
BLGCC - Low Temperature Gasifier - Mill Scale	$ 21,962,407	$ 23,011,961	$ 24,089,148	$ 25,190,998	$ 26,322,055	$ 27,479,396	$ 28,667,614	$ 31,973,344	$ 26,953,681	$ 28,233,309	$ 30,437,210	$ 33,521,407	$ 36,550,328
IRR													
NPV ($ million)													
BLGCC - High Temperature Gasifier - Mill Scale	$ 26,460,207	$ 27,617,944	$ 28,808,204	$ 30,028,836	$ 31,283,940	$ 32,571,425	$ 33,895,452	$ 36,988,981	$ 33,181,305	$ 34,616,148	$ 36,830,855	$ 39,789,322	$ 42,715,135
IRR													
NPV ($ million)													
BLGCC - High Temperature Gasifier - Utility Scale	$ 35,672,085	$ 37,031,247	$ 38,424,794	$ 39,849,777	$ 41,311,025	$ 42,805,644	$ 44,338,517	$ 48,067,600	$ 43,193,862	$ 44,841,058	$ 47,450,943	$ 50,978,188	$ 54,455,454
IRR													
NPV ($ million)													

Total Net Cash Flow Variance from Tomlinson BASE (a)	13	14	15	16	17	18	19	20	21	22	23	24	25
Tomlinson - "HERB"	$ 4,395,748	$ 4,591,306	$ 4,792,252	$ 4,998,121	$ 5,209,706	$ 5,426,551	$ 5,649,460	$ 6,226,571	$ 5,415,794	$ 5,656,918	$ 5,904,558	$ 6,530,783	$ 7,145,194
IRR on Variance													
NPV of Variance ($ million)													
BLGCC - Low Temperature Gasifier - Mill Scale	$ 8,346,317	$ 8,802,078	$ 9,269,508	$ 9,747,115	$ 10,237,014	$ 10,737,731	$ 11,251,399	$ 12,779,763	$ 10,308,970	$ 10,860,437	$ 12,317,007	$ 13,475,245	$ 14,616,253
IRR on Variance													
NPV of Variance ($ million)													
BLGCC - High Temperature Gasifier - Mill Scale	$ 12,844,117	$ 13,408,061	$ 13,988,563	$ 14,584,953	$ 15,198,899	$ 15,829,760	$ 16,479,238	$ 17,795,399	$ 16,536,595	$ 17,243,276	$ 18,710,652	$ 19,743,160	$ 20,781,060
IRR on Variance													
NPV of Variance ($ million)													
BLGCC - High Temperature Gasifier - Utility Scale	$ 22,055,995	$ 22,821,364	$ 23,605,153	$ 24,405,894	$ 25,225,984	$ 26,063,980	$ 26,922,302	$ 28,874,019	$ 26,549,152	$ 27,468,186	$ 29,330,740	$ 30,932,026	$ 32,521,379
IRR on Variance													
NPV of Variance ($ million)													

Total Net Cash Flow Variance from Tomlinson HERB (a)	13	14	15	16	17	18	19	20	21	22	23	24	25
BLGCC - Low Temperature Gasifier - Mill Scale	$ 3,950,569	$ 4,210,772	$ 4,477,256	$ 4,748,993	$ 5,027,308	$ 5,311,180	$ 5,601,939	$ 6,553,192	$ 4,893,177	$ 5,203,519	$ 6,412,448	$ 6,944,462	$ 7,471,059
IRR on Variance													
NPV of Variance ($ million)													
BLGCC - High Temperature Gasifier - Mill Scale	$ 8,448,369	$ 8,816,755	$ 9,196,311	$ 9,586,831	$ 9,989,193	$ 10,403,209	$ 10,829,778	$ 11,568,829	$ 11,120,801	$ 11,586,358	$ 12,806,094	$ 13,212,378	$ 13,635,866
IRR on Variance													
NPV of Variance ($ million)													
BLGCC - High Temperature Gasifier - Utility Scale	$ 17,660,247	$ 18,230,058	$ 18,812,901	$ 19,407,773	$ 20,016,279	$ 20,637,428	$ 21,272,842	$ 22,647,449	$ 21,133,358	$ 21,811,268	$ 23,426,182	$ 24,401,243	$ 25,376,185
IRR on Variance													
NPV of Variance ($ million)													

(a) Construction costs are financed assuming debt fraction of

Tomlinson BASE Cash Flows	Construction------------------------------------->			Operation-->											
	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue															
Electricity Sales (export)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bark/Hog Fuel Sales				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy Premium (on all incremental renewable)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Avoided Cost Savings															
Avoided Electricity Purchases				$ 20,424,434	$ 25,927,663	$ 26,548,177	$ 27,212,729	$ 27,955,527	$ 28,609,299	$ 29,168,411	$ 29,886,147	$ 30,771,652	$ 31,711,860	$ 32,743,773	$ 33,645,530
Subtotal - Avoided Cost Savings	**$ -**	**$ -**	**$ -**	**$ 20,424,434**	**$ 25,927,663**	**$ 26,548,177**	**$ 27,212,729**	**$ 27,955,527**	**$ 28,609,299**	**$ 29,168,411**	**$ 29,886,147**	**$ 30,771,652**	**$ 31,711,860**	**$ 32,743,773**	**$ 33,645,530**
Revenue+Avoided Cost Savings	**$ -**	**$ -**	**$ -**	**$ 20,424,434**	**$ 25,927,663**	**$ 26,548,177**	**$ 27,212,729**	**$ 27,955,527**	**$ 28,609,299**	**$ 29,168,411**	**$ 29,886,147**	**$ 30,771,652**	**$ 31,711,860**	**$ 32,743,773**	**$ 33,645,530**
Direct Operating Costs															
Operation and Maintenance				$ 6,940,000	$ 7,125,435	$ 7,315,824	$ 7,511,300	$ 7,712,000	$ 7,918,062	$ 8,129,630	$ 8,346,851	$ 8,569,876	$ 8,798,861	$ 9,033,963	$ 9,275,348
Subtotal - Operating Costs	**$ -**	**$ -**	**$ -**	**$ 6,940,000**	**$ 7,125,435**	**$ 7,315,824**	**$ 7,511,300**	**$ 7,712,000**	**$ 7,918,062**	**$ 8,129,630**	**$ 8,346,851**	**$ 8,569,876**	**$ 8,798,861**	**$ 9,033,963**	**$ 9,275,348**
Financing															
Interest (a)	$ -	$ 2,337,197	$ 4,577,010	$ 4,382,244	$ 4,187,478	$ 3,992,711	$ 3,797,945	$ 3,603,178	$ 3,408,412	$ 3,213,646	$ 3,018,879	$ 2,824,113	$ 2,629,346	$ 2,434,580	$ 2,239,814
Principal (a)	$ -	$ 1,217,290	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580
Subtotal - Financing	**$ -**	**$ 3,554,487**	**$ 7,011,590**	**$ 6,816,824**	**$ 6,622,058**	**$ 6,427,291**	**$ 6,232,525**	**$ 6,037,758**	**$ 5,842,992**	**$ 5,648,226**	**$ 5,453,459**	**$ 5,258,693**	**$ 5,063,926**	**$ 4,869,160**	**$ 4,674,394**
Total Expenses Before Taxes	**$ -**	**$ 3,554,487**	**$ 7,011,590**	**$ 13,756,824**	**$ 13,747,492**	**$ 13,743,115**	**$ 13,743,825**	**$ 13,749,758**	**$ 13,761,054**	**$ 13,777,856**	**$ 13,800,310**	**$ 13,828,569**	**$ 13,862,787**	**$ 13,903,123**	**$ 13,949,742**
Income Taxes	$ -	$ (934,879)	$ (1,830,804)	$ 1,814,941	$ 2,330,854	$ 2,844,719	$ 3,353,713	$ 3,874,389	$ 4,339,779	$ 4,750,009	$ 5,206,332	$ 5,578,446	$ 5,941,329	$ 6,337,473	$ 6,680,015
Renewable Energy Production Tax Credit (on all incremental renewable)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ -**	**$ 2,619,608**	**$ 5,180,786**	**$ 15,571,765**	**$ 16,078,346**	**$ 16,587,834**	**$ 17,097,539**	**$ 17,624,147**	**$ 18,100,833**	**$ 18,527,864**	**$ 19,006,643**	**$ 19,407,015**	**$ 19,804,116**	**$ 20,240,596**	**$ 20,629,757**
Net Cash Flow from Operations	**$ -**	**$ (2,619,608)**	**$ (5,180,786)**	**$ 4,852,669**	**$ 9,849,317**	**$ 9,960,343**	**$ 10,115,190**	**$ 10,331,381**	**$ 10,508,466**	**$ 10,640,547**	**$ 10,879,504**	**$ 11,364,637**	**$ 11,907,744**	**$ 12,503,177**	**$ 13,015,774**
Equity Capital Invested (a)	$ -	$ (30,432,250)	$ (30,432,250)												
Total Net Cash Flow	**$ -**	**$ (33,051,858)**	**$ (35,613,036)**	**$ 4,852,669**	**$ 9,849,317**	**$ 9,960,343**	**$ 10,115,190**	**$ 10,331,381**	**$ 10,508,466**	**$ 10,640,547**	**$ 10,879,504**	**$ 11,364,637**	**$ 11,907,744**	**$ 12,503,177**	**$ 13,015,774**
IRR	**14.22%**														
NPV ($ million)	**$ 27.96**														

(a) Construction costs are financed assuming debt fraction of 50%

Tomlinson BASE Cash Flows	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Revenue													
Electricity Sales (export)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bark/Hog Fuel Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy Premium (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Avoided Cost Savings													
Avoided Electricity Purchases	$ 34,698,313	$ 35,748,470	$ 36,830,411	$ 37,945,096	$ 39,093,518	$ 40,276,697	$ 41,495,686	$ 42,751,568	$ 44,045,460	$ 45,378,511	$ 46,751,908	$ 48,166,871	$ 49,624,659
Subtotal - Avoided Cost Savings	**$ 34,698,313**	**$ 35,748,470**	**$ 36,830,411**	**$ 37,945,096**	**$ 39,093,518**	**$ 40,276,697**	**$ 41,495,686**	**$ 42,751,568**	**$ 44,045,460**	**$ 45,378,511**	**$ 46,751,908**	**$ 48,166,871**	**$ 49,624,659**
Revenue+Avoided Cost Savings	**$ 34,698,313**	**$ 35,748,470**	**$ 36,830,411**	**$ 37,945,096**	**$ 39,093,518**	**$ 40,276,697**	**$ 41,495,686**	**$ 42,751,568**	**$ 44,045,460**	**$ 45,378,511**	**$ 46,751,908**	**$ 48,166,871**	**$ 49,624,659**
Direct Operating Costs													
Operation and Maintenance	$ 9,523,182	$ 9,777,639	$ 10,038,894	$ 10,307,130	$ 10,582,533	$ 10,865,295	$ 11,155,612	$ 11,453,687	$ 11,759,725	$ 12,073,941	$ 12,396,553	$ 12,727,785	$ 13,067,867
Subtotal - Operating Costs	**$ 9,523,182**	**$ 9,777,639**	**$ 10,038,894**	**$ 10,307,130**	**$ 10,582,533**	**$ 10,865,295**	**$ 11,155,612**	**$ 11,453,687**	**$ 11,759,725**	**$ 12,073,941**	**$ 12,396,553**	**$ 12,727,785**	**$ 13,067,867**
Financing													
Interest (a)	$ 2,045,047	$ 1,850,281	$ 1,655,514	$ 1,460,748	$ 1,265,982	$ 1,071,215	$ 876,449	$ 681,682	$ 486,916	$ 292,150	$ 97,383	$ -	$ -
Principal (a)	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 2,434,580	$ 1,217,290	$ -
Subtotal - Financing	**$ 4,479,627**	**$ 4,284,861**	**$ 4,090,094**	**$ 3,895,328**	**$ 3,700,562**	**$ 3,505,795**	**$ 3,311,029**	**$ 3,116,262**	**$ 2,921,496**	**$ 2,726,730**	**$ 2,531,963**	**$ 1,217,290**	**$ -**
Total Expenses Before Taxes	**$ 14,002,809**	**$ 14,062,499**	**$ 14,128,988**	**$ 14,202,458**	**$ 14,283,095**	**$ 14,371,090**	**$ 14,466,641**	**$ 14,569,949**	**$ 14,681,221**	**$ 14,800,671**	**$ 14,928,516**	**$ 13,945,075**	**$ 13,067,867**
Income Taxes	$ 7,079,414	$ 7,476,088	$ 7,881,782	$ 8,298,755	$ 8,725,382	$ 9,163,943	$ 9,612,831	$ 8,988,038	$ 12,719,527	$ 13,204,968	$ 13,703,189	$ 14,175,634	$ 14,622,717
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 21,082,224**	**$ 21,538,588**	**$ 22,010,770**	**$ 22,501,213**	**$ 23,008,477**	**$ 23,535,033**	**$ 24,079,472**	**$ 23,557,987**	**$ 27,400,749**	**$ 28,005,639**	**$ 28,631,705**	**$ 28,120,710**	**$ 27,690,584**
Net Cash Flow from Operations	**$ 13,616,090**	**$ 14,209,883**	**$ 14,819,641**	**$ 15,443,883**	**$ 16,085,041**	**$ 16,741,665**	**$ 17,416,214**	**$ 19,193,581**	**$ 16,644,711**	**$ 17,372,872**	**$ 18,120,203**	**$ 20,046,162**	**$ 21,934,075**
Equity Capital Invested (a)													
Total Net Cash Flow	**$ 13,616,090**	**$ 14,209,883**	**$ 14,819,641**	**$ 15,443,883**	**$ 16,085,041**	**$ 16,741,665**	**$ 17,416,214**	**$ 19,193,581**	**$ 16,644,711**	**$ 17,372,872**	**$ 18,120,203**	**$ 20,046,162**	**$ 21,934,075**
IRR													
NPV ($ million)													

(a) Construction costs are financed assuming debt fraction of

Tomlinson HERB Cash Flows	Construction----------------------------------->			Operation--->											
	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue															
Electricity Sales (export)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bark/Hog Fuel Sales				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy Premium (on all incremental renewable)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Avoided Cost Savings															
Avoided Electricity Purchases				$ 28,170,778	$ 35,761,209	$ 36,617,064	$ 37,533,659	$ 38,558,178	$ 39,459,904	$ 40,231,070	$ 41,221,021	$ 42,442,370	$ 43,739,170	$ 45,162,454	$ 46,406,220
Subtotal - Avoided Cost Savings				**$ 28,170,778**	**$ 35,761,209**	**$ 36,617,064**	**$ 37,533,659**	**$ 38,558,178**	**$ 39,459,904**	**$ 40,231,070**	**$ 41,221,021**	**$ 42,442,370**	**$ 43,739,170**	**$ 45,162,454**	**$ 46,406,220**
Revenue+Avoided Cost Savings	**$ -**	**$ -**	**$ -**	**$ 28,170,778**	**$ 35,761,209**	**$ 36,617,064**	**$ 37,533,659**	**$ 38,558,178**	**$ 39,459,904**	**$ 40,231,070**	**$ 41,221,021**	**$ 42,442,370**	**$ 43,739,170**	**$ 45,162,454**	**$ 46,406,220**
Direct Operating Costs															
Operation and Maintenance				$ 10,611,000	$ 10,894,522	$ 11,185,621	$ 11,484,497	$ 11,791,359	$ 12,106,420	$ 12,429,900	$ 12,762,023	$ 13,103,020	$ 13,453,128	$ 13,812,592	$ 14,181,660
Subtotal - Operating Costs	**$ -**	**$ -**	**$ -**	**$ 10,611,000**	**$ 10,894,522**	**$ 11,185,621**	**$ 11,484,497**	**$ 11,791,359**	**$ 12,106,420**	**$ 12,429,900**	**$ 12,762,023**	**$ 13,103,020**	**$ 13,453,128**	**$ 13,812,592**	**$ 14,181,660**
Financing															
Interest (a)	$ -	$ 3,087,168	$ 6,045,704	$ 5,788,440	$ 5,531,176	$ 5,273,912	$ 5,016,648	$ 4,759,384	$ 4,502,120	$ 4,244,856	$ 3,987,592	$ 3,730,328	$ 3,473,064	$ 3,215,800	$ 2,958,536
Principal (a)	$ -	$ 1,607,900	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800
Subtotal - Financing	**$ -**	**$ 4,695,068**	**$ 9,261,504**	**$ 9,004,240**	**$ 8,746,976**	**$ 8,489,712**	**$ 8,232,448**	**$ 7,975,184**	**$ 7,717,920**	**$ 7,460,656**	**$ 7,203,392**	**$ 6,946,128**	**$ 6,688,864**	**$ 6,431,600**	**$ 6,174,336**
Total Expenses Before Taxes	**$ -**	**$ 4,695,068**	**$ 9,261,504**	**$ 19,615,240**	**$ 19,641,498**	**$ 19,675,333**	**$ 19,716,945**	**$ 19,766,543**	**$ 19,824,340**	**$ 19,890,556**	**$ 19,965,415**	**$ 20,049,148**	**$ 20,141,992**	**$ 20,244,192**	**$ 20,355,996**
Income Taxes	$ -	$ (1,234,867)	$ (2,418,282)	$ 2,296,685	$ 3,091,232	$ 3,768,633	$ 4,440,207	$ 5,128,601	$ 5,741,445	$ 6,278,760	$ 6,880,193	$ 7,373,829	$ 7,856,054	$ 8,383,845	$ 8,837,273
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ -**	**$ 3,460,201**	**$ 6,843,222**	**$ 21,911,925**	**$ 22,732,731**	**$ 23,443,966**	**$ 24,157,151**	**$ 24,895,144**	**$ 25,565,785**	**$ 26,169,315**	**$ 26,845,608**	**$ 27,422,977**	**$ 27,998,046**	**$ 28,628,037**	**$ 29,193,268**
Net Cash Flow from Operations	**$ -**	**$ (3,460,201)**	**$ (6,843,222)**	**$ 6,258,853**	**$ 13,028,478**	**$ 13,173,098**	**$ 13,376,508**	**$ 13,663,034**	**$ 13,894,119**	**$ 14,061,755**	**$ 14,375,413**	**$ 15,019,393**	**$ 15,741,123**	**$ 16,534,418**	**$ 17,212,951**
Equity Capital Invested (a)	$ -	$ (40,197,500)	$ (40,197,500)												
Total Net Cash Flow	**$ -**	**$ (43,657,701)**	**$ (47,040,722)**	**$ 6,258,853**	**$ 13,028,478**	**$ 13,173,098**	**$ 13,376,508**	**$ 13,663,034**	**$ 13,894,119**	**$ 14,061,755**	**$ 14,375,413**	**$ 15,019,393**	**$ 15,741,123**	**$ 16,534,418**	**$ 17,212,951**
IRR	**14.22%**														
NPV ($ million)	**$ 36.99**														

(a) Construction costs are financed assuming debt fraction of 50%

Tomlinson HERB Cash Flows	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue													
Electricity Sales (export)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bark/Hog Fuel Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy Premium (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Avoided Cost Savings													
Avoided Electricity Purchases	$ 47,858,290	$ 49,306,738	$ 50,799,025	$ 52,336,475	$ 53,920,457	$ 55,552,379	$ 57,233,692	$ 58,965,890	$ 60,750,514	$ 62,589,150	$ 64,483,433	$ 66,435,047	$ 68,445,728
Subtotal - Avoided Cost Savings	**$ 47,858,290**	**$ 49,306,738**	**$ 50,799,025**	**$ 52,336,475**	**$ 53,920,457**	**$ 55,552,379**	**$ 57,233,692**	**$ 58,965,890**	**$ 60,750,514**	**$ 62,589,150**	**$ 64,483,433**	**$ 66,435,047**	**$ 68,445,728**
Revenue+Avoided Cost Savings	**$ 47,858,290**	**$ 49,306,738**	**$ 50,799,025**	**$ 52,336,475**	**$ 53,920,457**	**$ 55,552,379**	**$ 57,233,692**	**$ 58,965,890**	**$ 60,750,514**	**$ 62,589,150**	**$ 64,483,433**	**$ 66,435,047**	**$ 68,445,728**
Direct Operating Costs													
Operation and Maintenance	$ 14,560,589	$ 14,949,643	$ 15,349,093	$ 15,759,216	$ 16,180,297	$ 16,612,629	$ 17,056,513	$ 17,512,258	$ 17,980,180	$ 18,460,604	$ 18,953,866	$ 19,460,307	$ 19,980,280
Subtotal - Operating Costs	**$ 14,560,589**	**$ 14,949,643**	**$ 15,349,093**	**$ 15,759,216**	**$ 16,180,297**	**$ 16,612,629**	**$ 17,056,513**	**$ 17,512,258**	**$ 17,980,180**	**$ 18,460,604**	**$ 18,953,866**	**$ 19,460,307**	**$ 19,980,280**
Financing													
Interest (a)	$ 2,701,272	$ 2,444,008	$ 2,186,744	$ 1,929,480	$ 1,672,216	$ 1,414,952	$ 1,157,688	$ 900,424	$ 643,160	$ 385,896	$ 128,632	$ -	$ -
Principal (a)	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 3,215,800	$ 1,607,900	$ -
Subtotal - Financing	**$ 5,917,072**	**$ 5,659,808**	**$ 5,402,544**	**$ 5,145,280**	**$ 4,888,016**	**$ 4,630,752**	**$ 4,373,488**	**$ 4,116,224**	**$ 3,858,960**	**$ 3,601,696**	**$ 3,344,432**	**$ 1,607,900**	**$ -**
Total Expenses Before Taxes	**$ 20,477,661**	**$ 20,609,451**	**$ 20,751,637**	**$ 20,904,496**	**$ 21,068,313**	**$ 21,243,381**	**$ 21,430,001**	**$ 21,628,482**	**$ 21,839,140**	**$ 22,062,300**	**$ 22,298,298**	**$ 21,068,207**	**$ 19,980,280**
Income Taxes	$ 9,368,792	$ 9,896,098	$ 10,435,495	$ 10,989,975	$ 11,557,398	$ 12,140,783	$ 12,738,016	$ 11,917,257	$ 16,850,870	$ 17,497,060	$ 18,160,374	$ 18,789,896	$ 19,386,179
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 29,846,453**	**$ 30,505,549**	**$ 31,187,132**	**$ 31,894,471**	**$ 32,625,711**	**$ 33,384,164**	**$ 34,168,018**	**$ 33,545,738**	**$ 38,690,009**	**$ 39,559,360**	**$ 40,458,672**	**$ 39,858,103**	**$ 39,366,459**
Net Cash Flow from Operations	**$ 18,011,838**	**$ 18,801,189**	**$ 19,611,893**	**$ 20,442,005**	**$ 21,294,747**	**$ 22,168,216**	**$ 23,065,675**	**$ 25,420,152**	**$ 22,060,505**	**$ 23,029,790**	**$ 24,024,761**	**$ 26,576,944**	**$ 29,079,269**
Equity Capital Invested (a)													
Total Net Cash Flow	**$ 18,011,838**	**$ 18,801,189**	**$ 19,611,893**	**$ 20,442,005**	**$ 21,294,747**	**$ 22,168,216**	**$ 23,065,675**	**$ 25,420,152**	**$ 22,060,505**	**$ 23,029,790**	**$ 24,024,761**	**$ 26,576,944**	**$ 29,079,269**
IRR													
NPV ($ million)													

(a) Construction costs are financed assuming debt fraction of

Low Temperature BLGCC - Mill Scale Cash Flows	Construction------------------------------------>			Operation--->											
	-2	**-1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Revenue															
Electricity Sales (export)				$ 6,301,416	$ 8,113,983	$ 8,361,646	$ 8,682,189	$ 8,982,867	$ 9,243,652	$ 9,505,558	$ 9,779,341	$ 10,042,430	$ 10,356,614	$ 10,678,920	$ 10,997,099
Renewable Energy Premium (on all incremental renewable)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues				**$ 6,301,416**	**$ 8,113,983**	**$ 8,361,646**	**$ 8,682,189**	**$ 8,982,867**	**$ 9,243,652**	**$ 9,505,558**	**$ 9,779,341**	**$ 10,042,430**	**$ 10,356,614**	**$ 10,678,920**	**$ 10,997,099**
Avoided Cost Savings															
Avoided Electricity Purchases				31,819,519	40,393,080	41,359,787	42,395,102	43,552,318	44,570,838	45,441,888	46,560,059	47,939,600	49,404,364	51,011,996	52,416,856
Avoided Wood Purchases				3,926,492	5,013,047	5,120,223	5,229,690	5,341,498	5,455,695	5,572,335	5,691,468	5,813,148	5,937,429	6,064,367	6,194,020
Subtotal - Avoided Cost Savings				**35,746,011**	**45,406,127**	**46,480,010**	**47,624,793**	**48,893,816**	**50,026,534**	**51,014,222**	**52,251,526**	**53,752,747**	**55,341,793**	**57,076,363**	**58,610,876**
Revenue+Avoided Cost Savings	**$ -**	**$ -**	**$ -**	**$ 42,047,428**	**$ 53,520,111**	**$ 54,841,656**	**$ 56,306,981**	**$ 57,876,683**	**$ 59,270,185**	**$ 60,519,780**	**$ 62,030,867**	**$ 63,795,178**	**$ 65,698,407**	**$ 67,755,283**	**$ 69,607,975**
Direct Operating Costs															
Natural Gas Purchases				$ 5,869,855	$ 7,604,076	$ 7,885,126	$ 8,280,114	$ 8,640,880	$ 8,935,386	$ 9,229,076	$ 9,539,069	$ 9,829,265	$ 10,198,277	$ 10,577,423	$ 10,947,081
Incremental Lime Kiln Fuel (#6 oil)				$ 1,437,806	$ 1,844,523	$ 1,892,515	$ 1,942,339	$ 1,994,543	$ 2,046,939	$ 2,101,889	$ 2,157,353	$ 2,214,696	$ 2,273,945	$ 2,334,731	$ 2,398,079
Hog Fuel Purchases				$ 1,292,540	$ 1,650,217	$ 1,685,498	$ 1,721,533	$ 1,758,338	$ 1,795,930	$ 1,834,326	$ 1,873,543	$ 1,913,598	$ 1,954,509	$ 1,996,296	$ 2,038,975
Operation and Maintenance				$ 10,611,000	$ 10,894,522	$ 11,185,621	$ 11,484,497	$ 11,791,359	$ 12,106,420	$ 12,429,900	$ 12,762,023	$ 13,103,020	$ 13,453,128	$ 13,812,592	$ 14,181,660
Subtotal - Operating Costs	**$ -**	**$ -**	**$ -**	**$ 19,211,201**	**$ 21,993,339**	**$ 22,648,760**	**$ 23,428,482**	**$ 24,185,120**	**$ 24,884,676**	**$ 25,595,192**	**$ 26,331,987**	**$ 27,060,578**	**$ 27,879,859**	**$ 28,721,041**	**$ 29,565,794**
Financing															
Interest	$ 1,798,234	$ 5,319,774	$ 8,691,462	$ 8,316,830	$ 7,942,198	$ 7,567,566	$ 7,192,934	$ 6,818,302	$ 6,443,670	$ 6,069,038	$ 5,694,406	$ 5,319,774	$ 4,945,142	$ 4,570,510	$ 4,195,878
Principal	$ 936,580	$ 2,809,740	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900
Subtotal - Financing	**$ 2,734,814**	**$ 8,129,514**	**$ 13,374,362**	**$ 12,999,730**	**$ 12,625,098**	**$ 12,250,466**	**$ 11,875,834**	**$ 11,501,202**	**$ 11,126,570**	**$ 10,751,938**	**$ 10,377,306**	**$ 10,002,674**	**$ 9,628,042**	**$ 9,253,410**	**$ 8,878,778**
Total Expenses Before Taxes	**$ 2,734,814**	**$ 8,129,514**	**$ 13,374,362**	**$ 32,210,931**	**$ 34,618,437**	**$ 34,899,226**	**$ 35,304,317**	**$ 35,686,323**	**$ 36,011,246**	**$ 36,347,130**	**$ 36,709,293**	**$ 37,063,252**	**$ 37,507,902**	**$ 37,974,452**	**$ 38,444,573**
Income Taxes	$ (719,293)	$ (2,127,910)	$ (3,476,585)	$ 2,295,584	$ 2,672,658	$ 3,596,587	$ 4,488,971	$ 5,398,623	$ 6,226,910	$ 6,964,217	$ 7,766,575	$ 8,386,910	$ 8,971,279	$ 9,606,472	$ 10,160,437
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 2,015,520**	**$ 6,001,605**	**$ 9,897,777**	**$ 34,506,515**	**$ 37,291,096**	**$ 38,495,813**	**$ 39,793,288**	**$ 41,084,945**	**$ 42,238,157**	**$ 43,311,347**	**$ 44,475,868**	**$ 45,450,162**	**$ 46,479,180**	**$ 47,580,924**	**$ 48,605,010**
Net Cash Flow from Operations	**$ (2,015,520)**	**$ (6,001,605)**	**$ (9,897,777)**	**$ 7,540,913**	**$ 16,229,015**	**$ 16,345,843**	**$ 16,513,693**	**$ 16,791,738**	**$ 17,032,029**	**$ 17,208,433**	**$ 17,554,999**	**$ 18,345,015**	**$ 19,219,226**	**$ 20,174,358**	**$ 21,002,964**
Equity Capital Invested	$ (23,414,500)	$ (46,829,000)	$ (46,829,000)												
Total Net Cash Flow	**$ (25,430,020)**	**$ (52,830,605)**	**$ (56,726,777)**	**$ 7,540,913**	**$ 16,229,015**	**$ 16,345,843**	**$ 16,513,693**	**$ 16,791,738**	**$ 17,032,029**	**$ 17,208,433**	**$ 17,554,999**	**$ 18,345,015**	**$ 19,219,226**	**$ 20,174,358**	**$ 21,002,964**
IRR	**11.61%**														
NPV ($ million)	**$ 21.94**														
(a) Construction costs are financed assuming debt fraction of	50%														

Low Temperature BLGCC - Mill Scale Cash Flows	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue													
Electricity Sales (export)	$ 11,339,140	$ 11,681,032	$ 12,033,751	$ 12,397,655	$ 12,773,110	$ 13,160,497	$ 13,560,210	$ 13,972,654	$ 14,398,251	$ 14,837,434	$ 15,290,653	$ 15,758,373	$ 16,241,073
Renewable Energy Premium (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ 11,339,140**	**$ 11,681,032**	**$ 12,033,751**	**$ 12,397,655**	**$ 12,773,110**	**$ 13,160,497**	**$ 13,560,210**	**$ 13,972,654**	**$ 14,398,251**	**$ 14,837,434**	**$ 15,290,653**	**$ 15,758,373**	**$ 16,241,073**
Avoided Cost Savings													
Avoided Electricity Purchases	54,057,002	55,693,057	57,378,627	59,115,212	60,904,355	62,747,647	64,646,727	66,603,283	68,619,055	70,695,836	72,835,471	75,039,862	77,310,971
Avoided Wood Purchases	6,326,444	6,625,826	6,935,118	7,254,607	7,584,586	7,925,359	8,277,236	8,640,537	9,015,589	9,402,728	9,802,299	10,214,658	10,640,169
Subtotal - Avoided Cost Savings	**60,383,446**	**62,318,883**	**64,313,745**	**66,369,818**	**68,488,941**	**70,673,006**	**72,923,963**	**75,243,820**	**77,634,644**	**80,098,563**	**82,637,770**	**85,254,520**	**87,951,139**
Revenue+Avoided Cost Savings	**$ 71,722,586**	**$ 73,999,915**	**$ 76,347,497**	**$ 78,767,473**	**$ 81,262,051**	**$ 83,833,503**	**$ 86,484,173**	**$ 89,216,474**	**$ 92,032,895**	**$ 94,935,997**	**$ 97,928,423**	**$ 101,012,893**	**$ 104,192,212**
Direct Operating Costs													
Natural Gas Purchases	$ 11,351,885	$ 11,753,427	$ 12,169,172	$ 12,599,623	$ 13,045,300	$ 13,506,742	$ 13,984,506	$ 14,479,169	$ 14,991,330	$ 15,521,607	$ 16,070,641	$ 16,639,096	$ 17,227,658
Incremental Lime Kiln Fuel (#6 oil)	$ 2,462,488	$ 2,528,510	$ 2,596,302	$ 2,665,912	$ 2,737,388	$ 2,810,781	$ 2,886,141	$ 2,963,522	$ 3,042,977	$ 3,124,563	$ 3,208,336	$ 3,294,355	$ 3,382,681
Hog Fuel Purchases	$ 2,082,567	$ 2,127,091	$ 2,172,567	$ 2,219,015	$ 2,266,456	$ 2,314,911	$ 2,364,403	$ 2,414,952	$ 2,466,582	$ 2,519,316	$ 2,573,178	$ 2,628,190	$ 2,684,379
Operation and Maintenance	$ 14,560,589	$ 14,949,643	$ 15,349,093	$ 15,759,216	$ 16,180,297	$ 16,612,629	$ 17,056,513	$ 17,512,258	$ 17,980,180	$ 18,460,604	$ 18,953,866	$ 19,460,307	$ 19,980,280
Subtotal - Operating Costs	**$ 30,457,528**	**$ 31,358,670**	**$ 32,287,133**	**$ 33,243,765**	**$ 34,229,441**	**$ 35,245,063**	**$ 36,291,562**	**$ 37,369,901**	**$ 38,481,069**	**$ 39,626,090**	**$ 40,806,020**	**$ 42,021,949**	**$ 43,274,999**
Financing													
Interest	$ 3,821,246	$ 3,446,614	$ 3,071,982	$ 2,697,350	$ 2,322,718	$ 1,948,086	$ 1,573,454	$ 1,198,822	$ 824,190	$ 449,558	$ 149,853	$ -	$ -
Principal	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 4,682,900	$ 3,746,320	$ 1,873,160	$ -
Subtotal - Financing	**$ 8,504,146**	**$ 8,129,514**	**$ 7,754,882**	**$ 7,380,250**	**$ 7,005,618**	**$ 6,630,986**	**$ 6,256,354**	**$ 5,881,722**	**$ 5,507,090**	**$ 5,132,458**	**$ 3,896,173**	**$ 1,873,160**	**$ -**
Total Expenses Before Taxes	**$ 38,961,675**	**$ 39,488,185**	**$ 40,042,016**	**$ 40,624,016**	**$ 41,235,059**	**$ 41,876,049**	**$ 42,547,917**	**$ 43,251,623**	**$ 43,988,159**	**$ 44,758,549**	**$ 44,702,193**	**$ 43,895,109**	**$ 43,274,999**
Income Taxes	$ 10,798,505	$ 11,499,769	$ 12,216,332	$ 12,952,460	$ 13,704,937	$ 14,478,058	$ 15,268,643	$ 13,991,507	$ 21,091,054	$ 21,944,139	$ 22,789,020	$ 23,596,378	$ 24,366,885
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 49,760,179**	**$ 50,987,953**	**$ 52,258,348**	**$ 53,576,475**	**$ 54,939,996**	**$ 56,354,107**	**$ 57,816,559**	**$ 57,243,130**	**$ 65,079,213**	**$ 66,702,688**	**$ 67,491,213**	**$ 67,491,486**	**$ 67,641,884**
Net Cash Flow from Operations	**$ 21,962,407**	**$ 23,011,961**	**$ 24,089,148**	**$ 25,190,998**	**$ 26,322,055**	**$ 27,479,396**	**$ 28,667,614**	**$ 31,973,344**	**$ 26,953,681**	**$ 28,233,309**	**$ 30,437,210**	**$ 33,521,407**	**$ 36,550,328**
Equity Capital Invested													
Total Net Cash Flow	**$ 21,962,407**	**$ 23,011,961**	**$ 24,089,148**	**$ 25,190,998**	**$ 26,322,055**	**$ 27,479,396**	**$ 28,667,614**	**$ 31,973,344**	**$ 26,953,681**	**$ 28,233,309**	**$ 30,437,210**	**$ 33,521,407**	**$ 36,550,328**
IRR													
NPV ($ million)													

(a) Construction costs are financed assuming debt fraction of

High Temperature BLGCC - Mill Scale Cash Flows	Construction----------------------------------->			Operation-->											
	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue															
Electricity Sales (export)				4,173,572	5,374,077	5,538,110	5,750,413	5,949,559	6,122,282	6,295,749	6,477,082	6,651,332	6,859,423	7,072,893	7,283,631
Renewable Energy Premium (on all incremental renewable)				-	-	-	-	-	-	-	-	-	-	-	-
Carbon Trading Credit (on net carbon reduction)				-	-	-	-	-	-	-	-	-	-	-	-
NOx Credit (on net NOx reduction)				-	-	-	-	-	-	-	-	-	-	-	-
Subtotal - Revenues				**4,173,572**	**5,374,077**	**5,538,110**	**5,750,413**	**5,949,559**	**6,122,282**	**6,295,749**	**6,477,082**	**6,651,332**	**6,859,423**	**7,072,893**	**7,283,631**
Avoided Cost Savings															
Avoided Electricity Purchases				31,819,519	40,393,080	41,359,787	42,395,102	43,552,318	44,570,838	45,441,888	46,560,059	47,939,600	49,404,364	51,011,996	52,416,856
Avoided Wood Purchases				3,926,492	5,013,047	5,120,223	5,229,690	5,341,498	5,455,695	5,572,335	5,691,468	5,813,148	5,937,429	6,064,367	6,194,020
Subtotal - Avoided Cost Savings				**35,746,011**	**45,406,127**	**46,480,010**	**47,624,793**	**48,893,816**	**50,026,534**	**51,014,222**	**52,251,526**	**53,752,747**	**55,341,793**	**57,076,363**	**58,610,876**
Revenue+Avoided Cost Savings	**-**	**-**	**-**	**39,919,584**	**50,780,205**	**52,018,120**	**53,375,205**	**54,843,375**	**56,148,816**	**57,309,971**	**58,728,608**	**60,404,079**	**62,201,215**	**64,149,256**	**65,894,506**
Direct Operating Costs															
Natural Gas Purchases				1,242,670	1,609,811	1,669,310	1,752,930	1,829,306	1,891,654	1,953,829	2,019,456	2,080,891	2,159,013	2,239,279	2,317,537
Incremental Lime Kiln Fuel (#6 oil)				511,872	656,667	673,753	691,490	710,075	728,729	748,292	768,037	788,452	809,545	831,185	853,738
Hog Fuel Purchases				1,292,540	1,650,217	1,685,498	1,721,533	1,758,338	1,795,930	1,834,326	1,873,543	1,913,598	1,954,509	1,996,296	2,038,975
Operation and Maintenance				10,611,000	10,894,522	11,185,621	11,484,497	11,791,359	12,106,420	12,429,900	12,762,023	13,103,020	13,453,128	13,812,592	14,181,660
Maintenance				-	-	-	-	-	-	-	-	-	-	-	-
Consumables				-	-	-	-	-	-	-	-	-	-	-	-
Subtotal - Operating Costs	**-**	**-**	**-**	**13,658,082**	**14,811,217**	**15,214,181**	**15,650,450**	**16,089,078**	**16,522,733**	**16,966,347**	**17,423,058**	**17,885,961**	**18,376,195**	**18,879,352**	**19,391,909**
Financing															
Interest	1,493,130	4,417,177	7,216,796	6,905,727	6,594,659	6,283,590	5,972,521	5,661,452	5,350,383	5,039,315	4,728,246	4,417,177	4,106,108	3,795,039	3,483,971
Principal	777,672	2,333,016	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360	3,888,360
Subtotal - Financing	**2,270,802**	**6,750,193**	**11,105,156**	**10,794,087**	**10,483,019**	**10,171,950**	**9,860,881**	**9,549,812**	**9,238,743**	**8,927,675**	**8,616,606**	**8,305,537**	**7,994,468**	**7,683,399**	**7,372,331**
Total Expenses Before Taxes	**2,270,802**	**6,750,193**	**11,105,156**	**24,452,169**	**25,294,236**	**25,386,131**	**25,511,331**	**25,638,890**	**25,761,477**	**25,894,021**	**26,039,664**	**26,191,498**	**26,370,663**	**26,562,751**	**26,764,240**
Income Taxes	(597,252)	(1,766,871)	(2,886,718)	4,826,040	6,135,717	7,015,624	7,897,214	8,794,298	9,600,283	10,320,463	11,114,289	11,770,404	12,418,370	13,119,974	13,738,256
Renewable Energy Production Tax Credit (on all incremental renewable)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expenses After Taxes	**1,673,550**	**4,983,322**	**8,218,438**	**29,278,209**	**31,429,953**	**32,401,755**	**33,408,545**	**34,433,188**	**35,361,760**	**36,214,485**	**37,153,953**	**37,961,902**	**38,789,033**	**39,682,725**	**40,502,496**
Net Cash Flow from Operations	**(1,673,550)**	**(4,983,322)**	**(8,218,438)**	**10,641,375**	**19,350,251**	**19,616,365**	**19,966,660**	**20,410,187**	**20,787,056**	**21,095,487**	**21,574,655**	**22,442,177**	**23,412,182**	**24,466,532**	**25,392,011**
Equity Capital Invested	(19,441,800)	(38,883,600)	(38,883,600)												
Total Net Cash Flow	**(21,115,350)**	**(43,866,922)**	**(47,102,038)**	**10,641,375**	**19,350,251**	**19,616,365**	**19,966,660**	**20,410,187**	**20,787,056**	**21,095,487**	**21,574,655**	**22,442,177**	**23,412,182**	**24,466,532**	**25,392,011**
IRR	**16.14%**														
NPV ($ million)	**$ 72.82**														

(a) Construction costs are financed assuming debt fraction of 50%

High Temperature BLGCC - Mill Scale Cash Flows	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue													
Electricity Sales (export)	$ 7,510,172	$ 7,736,615	$ 7,970,229	$ 8,211,251	$ 8,459,923	$ 8,716,499	$ 8,981,238	$ 9,254,409	$ 9,536,291	$ 9,827,173	$ 10,127,350	$ 10,437,131	$ 10,756,835
Renewable Energy Premium (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ 7,510,172**	**$ 7,736,615**	**$ 7,970,229**	**$ 8,211,251**	**$ 8,459,923**	**$ 8,716,499**	**$ 8,981,238**	**$ 9,254,409**	**$ 9,536,291**	**$ 9,827,173**	**$ 10,127,350**	**$ 10,437,131**	**$ 10,756,835**
Avoided Cost Savings													
Avoided Electricity Purchases	54,057,002	55,693,057	57,378,627	59,115,212	60,904,355	62,747,647	64,646,727	66,603,283	68,619,055	70,695,836	72,835,471	75,039,862	77,310,971
Avoided Wood Purchases	6,326,444	6,625,826	6,935,118	7,254,607	7,584,586	7,925,359	8,277,236	8,640,537	9,015,589	9,402,728	9,802,299	10,214,658	10,640,169
Subtotal - Avoided Cost Savings	**60,383,446**	**62,318,883**	**64,313,745**	**66,369,818**	**68,488,941**	**70,673,006**	**72,923,963**	**75,243,820**	**77,634,644**	**80,098,563**	**82,637,770**	**85,254,520**	**87,951,139**
Revenue+Avoided Cost Savings	**$ 67,893,618**	**$ 70,055,498**	**$ 72,283,975**	**$ 74,581,069**	**$ 76,948,864**	**$ 79,389,505**	**$ 81,905,201**	**$ 84,498,229**	**$ 87,170,936**	**$ 89,925,736**	**$ 92,765,120**	**$ 95,691,652**	**$ 98,707,974**
Direct Operating Costs													
Natural Gas Purchases	$ 2,403,235	$ 2,488,243	$ 2,576,258	$ 2,667,386	$ 2,761,738	$ 2,859,427	$ 2,960,571	$ 3,065,293	$ 3,173,719	$ 3,285,981	$ 3,402,213	$ 3,522,557	$ 3,647,158
Incremental Lime Kiln Fuel (#6 oil)	$ 876,668	$ 900,172	$ 924,307	$ 949,089	$ 974,535	$ 1,000,663	$ 1,027,492	$ 1,055,041	$ 1,083,327	$ 1,112,373	$ 1,142,197	$ 1,172,820	$ 1,204,265
Hog Fuel Purchases	$ 2,082,567	$ 2,127,091	$ 2,172,567	$ 2,219,015	$ 2,266,456	$ 2,314,911	$ 2,364,403	$ 2,414,952	$ 2,466,582	$ 2,519,316	$ 2,573,178	$ 2,628,190	$ 2,684,379
Operation and Maintenance	$ 14,560,589	$ 14,949,643	$ 15,349,093	$ 15,759,216	$ 16,180,297	$ 16,612,629	$ 17,056,513	$ 17,512,258	$ 17,980,180	$ 18,460,604	$ 18,953,866	$ 19,460,307	$ 19,980,280
Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Consumables	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Operating Costs	**$ 19,923,059**	**$ 20,465,150**	**$ 21,022,225**	**$ 21,594,705**	**$ 22,183,025**	**$ 22,787,630**	**$ 23,408,979**	**$ 24,047,543**	**$ 24,703,809**	**$ 25,378,274**	**$ 26,071,453**	**$ 26,783,875**	**$ 27,516,083**
Financing													
Interest	$ 3,172,902	$ 2,861,833	$ 2,550,764	$ 2,239,695	$ 1,928,627	$ 1,617,558	$ 1,306,489	$ 995,420	$ 684,351	$ 373,283	$ 124,428	$ -	$ -
Principal	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,888,360	$ 3,110,688	$ 1,555,344	$ -
Subtotal - Financing	**$ 7,061,262**	**$ 6,750,193**	**$ 6,439,124**	**$ 6,128,055**	**$ 5,816,987**	**$ 5,505,918**	**$ 5,194,849**	**$ 4,883,780**	**$ 4,572,711**	**$ 4,261,643**	**$ 3,235,116**	**$ 1,555,344**	**$ -**
Total Expenses Before Taxes	**$ 26,984,321**	**$ 27,215,343**	**$ 27,461,349**	**$ 27,722,761**	**$ 28,000,012**	**$ 28,293,548**	**$ 28,603,828**	**$ 28,931,324**	**$ 29,276,520**	**$ 29,639,917**	**$ 29,306,569**	**$ 28,339,219**	**$ 27,516,083**
Income Taxes	$ 14,449,090	$ 15,222,211	$ 16,014,422	$ 16,829,473	$ 17,664,912	$ 18,524,532	$ 19,405,921	$ 18,577,925	$ 24,713,110	$ 25,669,672	$ 26,627,696	$ 27,563,111	$ 28,476,757
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 41,433,412**	**$ 42,437,554**	**$ 43,475,771**	**$ 44,552,233**	**$ 45,664,924**	**$ 46,818,080**	**$ 48,009,749**	**$ 47,509,249**	**$ 53,989,630**	**$ 55,309,588**	**$ 55,934,264**	**$ 55,902,330**	**$ 55,992,839**
Net Cash Flow from Operations	**$ 26,460,207**	**$ 27,617,944**	**$ 28,808,204**	**$ 30,028,836**	**$ 31,283,940**	**$ 32,571,425**	**$ 33,895,452**	**$ 36,988,981**	**$ 33,181,305**	**$ 34,616,148**	**$ 36,830,855**	**$ 39,789,322**	**$ 42,715,135**
Equity Capital Invested													
Total Net Cash Flow	**$ 26,460,207**	**$ 27,617,944**	**$ 28,808,204**	**$ 30,028,836**	**$ 31,283,940**	**$ 32,571,425**	**$ 33,895,452**	**$ 36,988,981**	**$ 33,181,305**	**$ 34,616,148**	**$ 36,830,855**	**$ 39,789,322**	**$ 42,715,135**
IRR													
NPV ($ million)													

(a) Construction costs are financed assuming debt fraction of

High Temperature BLGCC - Utility Scale Cash Flows	Construction----------------------------------->			Operation-->											
	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue															
Electricity Sales (export)				$ 35,955,897	$ 46,298,409	$ 47,711,573	$ 49,540,590	$ 51,256,261	$ 52,744,300	$ 54,238,739	$ 55,800,943	$ 57,302,132	$ 59,094,864	$ 60,933,943	$ 62,749,474
Renewable Energy Premium (on all incremental renewable)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues				**$ 35,955,897**	**$ 46,298,409**	**$ 47,711,573**	**$ 49,540,590**	**$ 51,256,261**	**$ 52,744,300**	**$ 54,238,739**	**$ 55,800,943**	**$ 57,302,132**	**$ 59,094,864**	**$ 60,933,943**	**$ 62,749,474**
Avoided Cost Savings															
Avoided Electricity Purchases				31,819,519	40,393,080	41,359,787	42,395,102	43,552,318	44,570,838	45,441,888	46,560,059	47,939,600	49,404,364	51,011,996	52,416,856
Avoided Wood Purchases				3,926,492	5,013,047	5,120,223	5,229,690	5,341,498	5,455,695	5,572,335	5,691,468	5,813,148	5,937,429	6,064,367	6,194,020
Subtotal - Avoided Cost Savings				**35,746,011**	**45,406,127**	**46,480,010**	**47,624,793**	**48,893,816**	**50,026,534**	**51,014,222**	**52,251,526**	**53,752,747**	**55,341,793**	**57,076,363**	**58,610,876**
Revenue+Avoided Cost Savings	**$ -**	**$ -**	**$ -**	**$ 71,701,908**	**$ 91,704,537**	**$ 94,191,583**	**$ 97,165,383**	**$ 100,150,077**	**$ 102,770,834**	**$ 105,252,961**	**$ 108,052,470**	**$ 111,054,880**	**$ 114,436,657**	**$ 118,010,306**	**$ 121,360,349**
Direct Operating Costs															
Natural Gas Purchases				$ 22,820,550	$ 29,562,776	$ 30,655,427	$ 32,191,044	$ 33,593,615	$ 34,738,582	$ 35,880,376	$ 37,085,550	$ 38,213,760	$ 39,648,390	$ 41,122,416	$ 42,559,554
Incremental Lime Kiln Fuel (#6 oil)				$ 511,872	$ 656,667	$ 673,753	$ 691,490	$ 710,075	$ 728,729	$ 748,292	$ 768,037	$ 788,452	$ 809,545	$ 831,185	$ 853,738
Operation and Maintenance				$ 11,515,000	$ 11,822,677	$ 12,138,575	$ 12,462,914	$ 12,795,919	$ 13,137,822	$ 13,488,860	$ 13,849,278	$ 14,219,326	$ 14,599,262	$ 14,989,350	$ 15,389,860
Subtotal - Operating Costs	**$ -**	**$ -**	**$ -**	**$ 34,847,422**	**$ 42,042,120**	**$ 43,467,755**	**$ 45,345,448**	**$ 47,099,610**	**$ 48,605,133**	**$ 50,117,528**	**$ 51,702,865**	**$ 53,221,538**	**$ 55,057,197**	**$ 56,942,952**	**$ 58,803,152**
Financing															
Interest	$ 1,859,581	$ 5,501,262	$ 8,987,977	$ 8,600,564	$ 8,213,151	$ 7,825,739	$ 7,438,326	$ 7,050,913	$ 6,663,500	$ 6,276,087	$ 5,888,675	$ 5,501,262	$ 5,113,849	$ 4,726,436	$ 4,339,023
Principal	$ 968,532	$ 2,905,596	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660
Subtotal - Financing	**$ 2,828,113**	**$ 8,406,858**	**$ 13,830,637**	**$ 13,443,224**	**$ 13,055,811**	**$ 12,668,399**	**$ 12,280,986**	**$ 11,893,573**	**$ 11,506,160**	**$ 11,118,747**	**$ 10,731,335**	**$ 10,343,922**	**$ 9,956,509**	**$ 9,569,096**	**$ 9,181,683**
Total Expenses Before Taxes	**$ 2,828,113**	**$ 8,406,858**	**$ 13,830,637**	**$ 48,290,646**	**$ 55,097,931**	**$ 56,136,153**	**$ 57,626,434**	**$ 58,993,183**	**$ 60,111,293**	**$ 61,236,275**	**$ 62,434,200**	**$ 63,565,460**	**$ 65,013,706**	**$ 66,512,048**	**$ 67,984,835**
Income Taxes	$ (743,833)	$ (2,200,505)	$ (3,595,191)	$ 7,669,574	$ 9,587,874	$ 10,692,348	$ 11,770,021	$ 12,866,598	$ 13,882,189	$ 14,809,554	$ 15,804,670	$ 16,611,242	$ 17,385,623	$ 18,214,777	$ 18,966,648
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 2,084,281**	**$ 6,206,353**	**$ 10,235,446**	**$ 55,960,220**	**$ 64,685,805**	**$ 66,828,501**	**$ 69,396,455**	**$ 71,859,781**	**$ 73,993,482**	**$ 76,045,829**	**$ 78,238,870**	**$ 80,176,702**	**$ 82,399,329**	**$ 84,726,825**	**$ 86,951,484**
Net Cash Flow from Operations	**$ (2,084,281)**	**$ (6,206,353)**	**$ (10,235,446)**	**$ 15,741,688**	**$ 27,018,732**	**$ 27,363,082**	**$ 27,768,927**	**$ 28,290,296**	**$ 28,777,352**	**$ 29,207,132**	**$ 29,813,600**	**$ 30,878,178**	**$ 32,037,328**	**$ 33,283,481**	**$ 34,408,866**
Equity Capital Invested	$ (24,213,300)	$ (48,426,600)	$ (48,426,600)												
Total Net Cash Flow	**$ (26,297,581)**	**$ (54,632,953)**	**$ (58,662,046)**	**$ 15,741,688**	**$ 27,018,732**	**$ 27,363,082**	**$ 27,768,927**	**$ 28,290,296**	**$ 28,777,352**	**$ 29,207,132**	**$ 29,813,600**	**$ 30,878,178**	**$ 32,037,328**	**$ 33,283,481**	**$ 34,408,866**
IRR	**17.53%**														
NPV ($ million)	**$ 111.06**														

(a) Construction costs are financed assuming debt fraction of 50%

High Temperature BLGCC - Utility Scale Cash Flows	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue													
Electricity Sales (export)	$ 64,701,163	$ 66,651,998	$ 68,664,616	$ 70,741,050	$ 72,883,397	$ 75,093,830	$ 77,374,590	$ 79,728,000	$ 82,156,455	$ 84,662,436	$ 87,248,506	$ 89,917,314	$ 92,671,602
Renewable Energy Premium (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carbon Trading Credit (on net carbon reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOx Credit (on net NOx reduction)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Revenues	**$ 64,701,163**	**$ 66,651,998**	**$ 68,664,616**	**$ 70,741,050**	**$ 72,883,397**	**$ 75,093,830**	**$ 77,374,590**	**$ 79,728,000**	**$ 82,156,455**	**$ 84,662,436**	**$ 87,248,506**	**$ 89,917,314**	**$ 92,671,602**
Avoided Cost Savings													
Avoided Electricity Purchases	54,057,002	55,693,057	57,378,627	59,115,212	60,904,355	62,747,647	64,646,727	66,603,283	68,619,055	70,695,836	72,835,471	75,039,862	77,310,971
Avoided Wood Purchases	6,326,444	6,625,826	6,935,118	7,254,607	7,584,586	7,925,359	8,277,236	8,640,537	9,015,589	9,402,728	9,802,299	10,214,658	10,640,169
Subtotal - Avoided Cost Savings	**60,383,446**	**62,318,883**	**64,313,745**	**66,369,818**	**68,488,941**	**70,673,006**	**72,923,963**	**75,243,820**	**77,634,644**	**80,098,563**	**82,637,770**	**85,254,520**	**87,951,139**
Revenue+Avoided Cost Savings	**$ 125,084,609**	**$ 128,970,880**	**$ 132,978,361**	**$ 137,110,868**	**$ 141,372,338**	**$ 145,766,836**	**$ 150,298,554**	**$ 154,971,820**	**$ 159,791,099**	**$ 164,760,999**	**$ 169,886,275**	**$ 175,171,835**	**$ 180,622,741**
Direct Operating Costs													
Natural Gas Purchases	$ 44,133,333	$ 45,694,428	$ 47,310,743	$ 48,984,231	$ 50,716,914	$ 52,510,885	$ 54,368,314	$ 56,291,443	$ 58,282,599	$ 60,344,186	$ 62,478,696	$ 64,688,708	$ 66,976,894
Incremental Lime Kiln Fuel (#6 oil)	$ 876,668	$ 900,172	$ 924,307	$ 949,089	$ 974,535	$ 1,000,663	$ 1,027,492	$ 1,055,041	$ 1,083,327	$ 1,112,373	$ 1,142,197	$ 1,172,820	$ 1,204,265
Operation and Maintenance	$ 15,801,073	$ 16,223,272	$ 16,656,753	$ 17,101,816	$ 17,558,771	$ 18,027,935	$ 18,509,636	$ 19,004,208	$ 19,511,994	$ 20,033,348	$ 20,568,633	$ 21,118,220	$ 21,682,492
Subtotal - Operating Costs	**$ 60,811,073**	**$ 62,817,873**	**$ 64,891,803**	**$ 67,035,135**	**$ 69,250,219**	**$ 71,539,484**	**$ 73,905,442**	**$ 76,350,692**	**$ 78,877,920**	**$ 81,489,907**	**$ 84,189,525**	**$ 86,979,748**	**$ 89,863,650**
Financing													
Interest	$ 3,951,611	$ 3,564,198	$ 3,176,785	$ 2,789,372	$ 2,401,959	$ 2,014,547	$ 1,627,134	$ 1,239,721	$ 852,308	$ 464,895	$ 154,965	$ -	$ -
Principal	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 4,842,660	$ 3,874,128	$ 1,937,064	$ -
Subtotal - Financing	**$ 8,794,271**	**$ 8,406,858**	**$ 8,019,445**	**$ 7,632,032**	**$ 7,244,619**	**$ 6,857,207**	**$ 6,469,794**	**$ 6,082,381**	**$ 5,694,968**	**$ 5,307,555**	**$ 4,029,093**	**$ 1,937,064**	**$ -**
Total Expenses Before Taxes	**$ 69,605,344**	**$ 71,224,731**	**$ 72,911,248**	**$ 74,667,168**	**$ 76,494,839**	**$ 78,396,691**	**$ 80,375,236**	**$ 82,433,073**	**$ 84,572,888**	**$ 86,797,462**	**$ 88,218,618**	**$ 88,916,812**	**$ 89,863,650**
Income Taxes	$ 19,807,180	$ 20,714,903	$ 21,642,320	$ 22,593,923	$ 23,566,474	$ 24,564,501	$ 25,584,801	$ 24,471,147	$ 32,024,348	$ 33,122,479	$ 34,216,714	$ 35,276,835	$ 36,303,636
Renewable Energy Production Tax Credit (on all incremental renewable)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses After Taxes	**$ 89,412,524**	**$ 91,939,633**	**$ 94,553,568**	**$ 97,261,090**	**$ 100,061,313**	**$ 102,961,191**	**$ 105,960,037**	**$ 106,904,219**	**$ 116,597,237**	**$ 119,919,941**	**$ 122,435,332**	**$ 124,193,647**	**$ 126,167,287**
Net Cash Flow from Operations	**$ 35,672,085**	**$ 37,031,247**	**$ 38,424,794**	**$ 39,849,777**	**$ 41,311,025**	**$ 42,805,644**	**$ 44,338,517**	**$ 48,067,600**	**$ 43,193,862**	**$ 44,841,058**	**$ 47,450,943**	**$ 50,978,188**	**$ 54,455,454**
Equity Capital Invested													
Total Net Cash Flow	**$ 35,672,085**	**$ 37,031,247**	**$ 38,424,794**	**$ 39,849,777**	**$ 41,311,025**	**$ 42,805,644**	**$ 44,338,517**	**$ 48,067,600**	**$ 43,193,862**	**$ 44,841,058**	**$ 47,450,943**	**$ 50,978,188**	**$ 54,455,454**
IRR													
NPV ($ million)													

(a) Construction costs are financed assuming debt fraction of