November 2002 • NREL/SR-510-33000

Subcontractor Report

Bioethanol Co-Location Study

August 15, 2000—February 28, 2002

G. Morris
Green Power Institute
Berkeley, California

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

November 2002 • NREL/SR-510-33000

Bioethanol Co-Location Study

August 15, 2000—February 28, 2002

G. Morris
Green Power Institute
Berkeley, California

NREL Technical Monitor: Robert Wallace

Prepared under Subcontract No. XDH-0-30010-04

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: reports@adonis.osti.gov

Available for sale to the public, in paper, from:
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/ordering.htm

Contents

Tables

Figures

Introduction and Context

The California biomass power industry must find ways to become more competitive as it faces a continuously evolving electricity market. At the same time, California will soon need large quantities of ethanol fuels in order to phase out the use of the water-polluting fuel additive MTBE from motor vehicle fuels. Co-location of biomass ethanol plants with the existing biomass power plants in California has the potential to reduce the production costs for both facilities. Ethanol production facilities can also be co-located with coal-fired power plants in other regions of the country to gain some of the same benefits, as MTBE is phased out of use nationwide.

This report describes the results of an analysis of the generic economic feasibility of co-locating ethanol production facilities with California biomass power plants, and with coal-fired power plants in the Southeast. A proforma engineering and financial model was developed to analyze co-located ethanol production facilities and biomass or coal-fired power plants, both as separate, side-by-side commercial enterprises, and as integrated operations. Facility descriptions and specifications are developed for reference biomass and coal-fired power plants, and for both acid hydrolysis and enzymatic-hydrolysis ethanol production technologies. The reference facilities are then combined in a variety of configurations, and a series of economic studies are performed and described.

MTBE phaseout and the market for ethanol in California

The Clean Air Act Amendments of 1990 established a two-percent oxygenate standard in motor fuels for regions of the country that have persistent air pollution problems. Virtually all of California was subject to the requirements to use reformulated motor fuels (RMF), and RMFs have been used in the state for over a decade. This program, combined with a number of other measures aimed at a variety of air pollution sources, has produced noticeable air quality improvements in many parts of the state.

There are two principal fuel additive candidates that can provide the oxygenate content requirement of RMF: ethanol, and MTBE. Ethanol fuels are produced in large quantities in the US Midwest, which is the heart of the nation's grain belt. California gasoline blenders, who are located far away from the Midwest, chose MTBE as the low-cost oxygenate additive. No commercial ethanol fuel production facility has been built in California, and very little ethanol-blended fuel has been marketed in the state.

While RMF fuels containing MTBE have been an air-pollution success in California, MTBE has been discovered to be causing widespread contamination of groundwater resources. In response to this threat Governor Gray Davis, in one of his first major actions as the then new governor of California, issued an Executive Order in March 1999 to phase out the use of MTBE as a fuel additive in the state by the end of 2002 (the deadline has since been extended by one year to the end of 2003).

California has two options open to it in replacing MTBE. One option is to use ethanol to meet the oxygenate requirement of RMF. The other option is to obtain a waiver of the oxygenate requirement from the USEPA, allowing RMF to be produced with an oxygen content below 2 percent, but which otherwise provides equivalent environmental performance to oxygenated gasoline. In order to avoid the market shock that might result from total reliance on ethanol fuels, California applied for a waiver of the federal oxygenate requirement for RMF. At the same time, the state began preparing for the possibility that it would have to procure as much as 600 million gallons per year of ethanol fuels. That possibility became stronger when the EPA formally denied California's waiver request in June 2001.

California is considering an appeal of the EPA waiver denial. At the same time, federal legislation to ban MTBE nationwide is moving through the senate (S950) that would allow state governors to waive the oxygenate requirement as long as non-oxygenated fuels meet the same standards as oxygenated fuel. At the same time, a recent agreement in principle between farmers and oil producers would establish a national renewable fuel requirement for all motor fuels. The future of all of these efforts is highly uncertain, but in any event there is little doubt that California will soon become a major market for ethanol fuel.

California has two basic choices for the procurement of ethanol fuels, in-state production, or importation. At the present time ethanol fuels are not produced commercially in the state. Moreover, although the state is a major producer of agricultural products, its agricultural infrastructure is not oriented to the type of bulk grain production that provides the feedstock for alcohol fuel production in the Midwest. The state does have large amounts of biomass resources in the form of cellulosic residues that potentially could be converted into ethanol fuels, but the technology that is needed to convert cellulose into ethanol is not as advanced as that used for the conversion of grains.

Several project proposals are under development in California for new, commercial ethanol production facilities. Feedstocks under consideration for these projects include both wood residues, and agricultural residues such as rice straw. Ethanol production from biomass resources will have to compete with ethanol produced from grain in the Midwest and imported into California. Ethanol production from biomass is inherently more expensive than ethanol production from grain, because cellulose requires more extensive pretreatment prior to fermentation. On the other hand, biomass residue feedstocks are less expensive than commodity grains, and locally produced fuel does not have to be transported halfway across the country. In addition, the collection and use of biomass residues for ethanol production reduces the air pollution associated with the open burning of these materials that is the current disposal practice for most of them. Thus, a great deal of interest has been focused on ethanol fuels production in California.

The California biomass power dilemma

California has long been a catalyst and innovator in the development of renewable energy sources. Strong state incentives for renewable energy development were enacted during the early 1980s to match the then available federal incentives. These incentives, combined with favorable market conditions, led to the development of more than sixty biomass electricity-generating facilities in the state, as illustrated in Figure 1. Biomass fuels were produced from traditional sources such as residues from sawmills and food-processing plants, and from new sources such as urban wood residues diverted from landfill disposal, and orchard prunings diverted from open burning.

At its peak the California biomass energy industry produced almost 4.5 billion kWhs per year of electricity, and provided a beneficial use outlet for more than 10 million tons per year of the state's solid wastes. The peak, however, occurred during the early 1990s, as shown in Figure 2. During the second half of the decade a quarter of the biomass energy facilities agreed to buyouts of their power sales contracts and terminated operations. Many of the remaining facilities reduced their operations during off-peak hours when fuel costs exceeded power rates. By the end of the decade biomass fuel use had dropped by more than a third from peak levels reached early in the decade. Moreover, the long-term future of the industry in a newly deregulating marketplace was very much in doubt. Biomass facility operators were searching for new approaches that would allow them to continue to operate. The concept of ethanol facility co-location was one that several facilities began to pursue.

The California electricity market experienced a crisis of major proportions beginning in the summer of 2000. As shown in Figure 3, wholesale electricity prices went through the roof, and the state's operating biomass facilities began to ramp up their operations. Conditions began to look so promising for electricity generators that many of the biomass facilities that had been shut down during the 1990s began preparations to restart and resume operations. As 2001 began wholesale electricity prices were consistently in the mid-teens (cents per kWh), biomass fuel prices were at levels never before experienced, and generators were earning unprecedented profits. Thoughts of pursuing ethanol co-location projects were put on hold.

The system itself, however, was in a mode of rapid self-destruction. The utilities began to default on their payments to generators for purchased power. The California power exchange was shut down, and the state had to step in and become the major power purchaser in the state. By the middle of the year an unusually cool summer, combined with a variety of other circumstances, had combined to bring wholesale electricity prices back down to pre-crisis levels. Biomass power generators once again were in a pickle. They were owed large sums of money by a bankrupt utility, and once again they were being paid revenues that were not sufficient to cover their costs of operations. Many of the restarted facilities were in a particularly difficult position. They had invested significant sums of money in the process of refurbishment and restarting, while negotiating in good faith with the state for long-term power purchase agreements that were to provide them with fixed prices for periods of five to ten years. Many obtained letters of intent, but for a variety of reasons the state never finished the contracting process, leaving these facilities with full exposure to the risk of being limiting to selling in the short-term market. Once again, California's biomass power plants are interested in exploring the potential of ethanol production co-location as a means to provide a stable environment for their continued operations.

Ethanol production from cellulosic biomass

Yeast has been used since biblical times to ferment starch and sugars to ethanol. Most of the world's commercial fuel ethanol production is based on the fermentation of these types of materials. The production of fuel ethanol in the US is based on the fermentation of grains (starch), while fuel ethanol production in Brazil is based on the fermentation of sugars from sugarcane. In both cases the feedstocks are themselves major agricultural commodities, and the fuel-production process produces valuable agricultural co-products, the production of which is as fundamental to the enterprise as the production of ethanol fuel. Ethanol fuel production from corn, for example, is part of a greater enterprise that includes the co-production of agricultural products such as corn oil, sweeteners, and animal feeds. Ethanol production from sugarcane involves the co-production of molasses and bagasse, which is used as a fuel.

Grain and sugars are easy to prepare for fermentation. A fermentation broth is prepared, then inoculated with yeast. The yeast convert simple sugars in the broth into ethanol and carbon dioxide. Ethanol is recovered from the broth using distillation technology. Solids are recovered and used for animal feed and other products.

Yeast and most other fermentative organisms that convert sugars into ethanol are unable to act directly on cellulose, a common form of carbohydrate in most biomass residue materials. Cellulose and hemicellulose account for two-thirds to three-quarters of the carbon content of wood and agricultural residues. The remaining carbon in biomass is mainly in the form of lignin, which is highly resistant to hydrolysis and fermentation. In order to ferment cellulosic biomass into ethanol fuel, it first necessary to separate the cellulose and hemicellulose from the lignin, and to break the carbohydrates down into simple sugars. The lignin can be recovered and used as a fuel in the production process.

Two major approaches are being developed to covert cellulosic biomass residues into fermentable ethanol feedstocks. The approach that has been under development for the longest period of time is the use of acid hydrolysis to convert cellulose into sugars. The approach that appears to offer the highest conversion efficiencies and lowest production cost is enzymatic hydrolysis. Both approaches produce significant quantities of lignin as a byproduct of the production process. The major use for lignin is as a biomass fuel. However, biomass boilers are expensive pieces of equipment, and entail significant operating costs as well.

The confluence of a massive new demand for ethanol fuels in California, combined with the existence of a large and ailing biomass power production industry, have led many to surmise that co-locating ethanol production facilities with existing biomass power plants could provide significant benefits for each enterprise. Co-location would allow substantial capital cost savings for the ethanol production enterprise, which would not have to install its own steam and power generating equipment. Biomass handling and storage facilities, as well as other capital equipment, might also be able to be provided by the existing biomass power plant. In addition, the two facilities could share operating costs, resulting in additional savings. The biomass power generators are interested in the arrangement because they know that their future as stand-alone operations is highly uncertain, and they view the ethanol producer as a stable alternative market for some of the energy they produce.

Pro Forma engineering and financial model

In order to analyze the financial impacts of co-location on the economics of ethanol production, a detailed pro forma engineering/financial model was developed as a key part of this study. The model is built around a proprietary proforma model for a biomass cogeneration project that includes a heat balance optimization routine for the steam and power systems. Major additions and modifications were added to the model to adapt it to the co-location scenario, in which an ethanol production facility is co-located with either an existing biomass or coal-fired power plant. The ethanol operation obtains its steam and electricity requirements from the power plant, while the power plant obtains fuel, in the forms of lignin and biogas, from the ethanol production facility. Other connections between the co-located operations are also possible, such as shared facilities and operations.

The model includes separate pro forma balance sheets for the ethanol production enterprise and the host-facility power production enterprise. The model performs a full heat and materials balance for the power generation cycle, allowing the effects of a variety of fuel mixes to be analyzed, including biomass fuels, biogas, lignin, and coal. The model allows a variety of financial and technical variables to be studied, and project configurations to be explored.

The pro forma model is an excel-based spreadsheet model consisting of twelve interconnected worksheets. The first three pages present financial statements for the ethanol production enterprise, the power production enterprise, and the combined operations of the two. All of the input data needed to run the model are entered into the final nine pages. All of the cells in the model that contain input data are red. Only red-colored cells should be manipulated by a model user. Table 1 summarizes the twelve worksheet pages that constitute the model. The appendix to this report contains a complete printout of the model's output.

One of the special features of the model is that it allows the two enterprises that are included in the analysis, cogeneration and ethanol production, to be fully decoupled. Part of the motivation for performing this study is to explore the synergies of co-locating an ethanol production facility with existing biomass power plants. The model provides for the two enterprises to have separate start-up schedules and separate operating schedules. It also allows either of the facilities to be examined as standalone, non-coupled facilities. Dates and schedules for each enterprise are entered in the *Capital* worksheet.

One of the potentially interesting synergisms that may be obtained from co-location is that the lignin fuel that would be supplied from the ethanol process to the power plant boiler may be superior in quality to the power facility's regular biomass fuels. The pro forma model can handle a mixture of up to six different fuels, each with its own unique characteristics in terms of composition, heat content, and moisture content. Fuel-related data are entered in the model in two pages, *Biomass*, and *Ht Bal*. The way the model works is that the user enters annual fuel-use data for all fuels under consideration except for the first listed fuel. The user enters estimates for the annual quantity of this fuel that will be used both before and after co-location. As long as the estimate is within a factor of two of the actual amount needed, the model will be able to calculate that amount.

The final page of the model, titled heat balance, performs a complete heat and materials balance for the power-generation cycle of the combined operations. This worksheet is programmed to determine the fuel use requirements of the power cycle for a variety of time-of-use segments of the year (e.g. summer peak, winter off-peak). The heat balance calculation for each time period is an iterative process, which takes into effect the heat content and moisture value of each fuel that is in the mix. The model determines the amount of the first listed fuel that is needed to provide the boiler with the energy input necessary to serve the demand for steam, given the amounts of each of the other fuels that have been specified by the modeler.

Cellulosic Fermentation Technology

The technology for converting sugars into ethanol is well known, and commercially proven. Sugars are easily extracted from sugar and grain crops, and these types of feedstocks are the basis for virtually all of the world's fuel ethanol production. However, these types of feedstocks are important agricultural commodities, and carry a high price tag. Cellulose derived from waste and residue resources is available for much lower cost. Cellulose can be converted to ethanol by first converting the cellulose to sugars, and then applying conventional fermentation technology. Two different approaches are under consideration for cellulose conversion: acid hydrolysis, and enzymatic hydrolysis. Acid hydrolysis technology is a near-term commercial option, while the commercialization of enzymatic hydrolysis technology is further in the future.

Experience with ethanol production technology in the Midwest has demonstrated that the process benefits from significant economies of scale. Facilities producing fifty million gallons of ethanol annually from grain crops are not uncommon. However, this scale of operation would not be well suited for a cellulose-conversion facility using waste and residue sources of biomass. Producing fifty million gallons per year at a cellulose-based conversion facility using dilute acid technology would require 750,000 - 950,000 bdt per year of feedstock based on the technology specifications developed for this report (see below). Enzymatic conversion technologies would require 650,000 - 700,000 bdt per year of feedstock. Yet the largest biomass power facilities in the world, which also benefit from significant economies of scale, use less than 400,000 bdt per year of fuel.

Fuel-procurement considerations for waste and residue forms of biomass represent a distinct diseconomy of scale, and cellulosic residue-based ethanol production facilities are likely to be significantly smaller than grain-based ethanol facilities. For purposes of this report, we developed base-case and optimistic-case configurations for both dilute acid and enzymatic fermentation, for facilities sized to process 550 and 1,100 bdt per day of biomass. The amount of biomass feedstock needed to supply a 550 bdt per day ethanol facility, 180,000 bdt/yr, is approximately the same as the quantity needed to fuel a 25 MW standalone biomass power plant.

Current technology: acid hydrolysis

The use of acid to convert cellulose to extractable sugars has long been know and practiced. Classic industrial acid-hydrolysis technology uses dilute (one percent) sulfuric acid under high temperature and pressure to free cellulose from other biomass components such as lignin, and hydrolyze it into simple sugars. Dilute acid hydrolysis technology is the technology of choice for most of the commercial cellulose-to-ethanol projects that are under development in the U.S. today. Sulfuric acid remains the acid of choice, although a promising process based on dilute nitric acid is currently under development shows promise of achieving substantially reduced capital and operating costs.

One of the problems with dilute acid hydrolysis is that the process does not end with the production of the sugars. As the reaction continues, sugars degrade into smaller compounds, such as furfurals, which are not only unsuitable ethanol feedstocks, but may actually inhibit the subsequent fermentation process. Typical dilute acid technology produces sugar yields of approximately fifty percent of theoretical (Graf and Koehler, 2000).

Recent development of dilute-acid hydrolysis technology has led to a two-stage process in which hydrolysis of the cellulose and hemicellulose are largely separated, resulting in smaller losses to due to breakdown of the sugars. The separation of the process into two stages also facilities the subsequent fermentation process, because the fermentation of the pentoses, which are the product of the hydrolysis of hemicellulose, involves different organisms than the hydrolysis of the six-carbon sugars that are derived from cellulose. The base case acid-hydrolysis technology used in this report is based on the two-stage dilute acid hydrolysis process. Process yields are in the range of 50 - 60 gal/bdt of feedstock.

An alternative approach to acid hydrolysis involves the use of concentrated (e.g. seventy percent) sulfuric acid at lower temperature and pressure than used in the dilute-acid process to convert cellulose and hemicellulose to sugars. The process is carried out in a two-stage configuration, separating the hemicellulose and cellulose hydrolysis steps. Concentrated-acid hydrolysis produces higher yields of sugars due to much reduced rates of subsequent sugar degradation. The challenge is to find economical methods to recycle the acid, and neutralize the substrate prior to fermentation.

Future technology: enzymatic hydrolysis

An alternative to acid hydrolysis that has the potential for considerably higher sugar yields at lower production cost is enzymatic hydrolysis. In the enzymatic approach cellulase enzymes instead of acids are used to hydrolyze cellulose and hemicellulose into sugars. Recent innovations in molecular biology have opened up the field of enzymatic hydrolysis by increasing the range and productivity of cellulase enzymes. Enzyme production is a key component of the process, and has a major influence on process economics.

Pre-processing of the biomass feedstock is used to make the cellulose and hemicellulose parts of the feedstock accessible to the enzymes. This usually involves both mechanical processing and dilute acid hydrolysis (much less severe than the dilute acid hydrolysis used in non-enzymatic systems). The enzymatic hydrolysis and subsequent fermentation processes can be run simultaneously in a single reactor, or separately. Simultaneous saccharification and fermentation has the advantage of fewer steps and vessels, while the two-step approach allows optimization of each process under different conditions.

Enzymatic hydrolysis technology shows considerable promise, but its commercial application is further in the future than acid hydrolysis technology. NREL, a leading research center for the technology, estimates that it will be at least five years before enzymatic hydrolysis technology will begin to be available for commercial applications. Enzymatic hydrolysis is expected to be able to produce yields of 75 gallons or more of ethanol per bdt of biomass feedstock (Wooley et. al. 1999, Unnasch et. al. 2001).

Base case project configurations

Ethanol production involves several major processing operations, including:

- Biomass receiving, storage, and handling
- Feedstock preparation and hydrolysis
- Fermentation
- Separation and materials handling
- Distillation

Co-location of an ethanol production enterprise with an existing biomass or coal power plant allows the ethanol production operation to share some major capital facilities with the host operation, most importantly the boiler and power generating equipment. Co-location with a biomass plant also allows for shared materials procurement, as well as shared on-site storage and handling of biomass and lignin. The capital cost estimates developed for the base case ethanol production enterprises considered in this study assume that all energy production is done at the existing host facility, so new solid-fuels boilers and turbine generators are not included in the plans. Shared materials procurement and handling are also included for facilities co-located with biomass power plants. Other shared facilities such as water supply and water treatment are possible.

Table 2 summarizes the specifications that define the base-case ethanol production facility configurations considered in this study. The data for the base cases for each technology, and the optimistic case for ethanol, were supplied by NREL. The data for the optimistic acid-hydrolysis case were extracted from a study by Merrick and Associates (Merrick, 1999). For each case, a data set is constructed for facility sizes of 550 bdt/day, and 1,100 bdt/day. A 550 bdt/day facility consumes approximately the same amount of biomass as a 25 MW standalone power plant operating in base-load mode, and produces approximately 10.0 - 12.5 million gallons of ethanol annually.

The final line in the table, *ethanol price $/gal*, shows the calculated plant-gate selling price that is required for the ethanol facility to return a twenty-percent return on equity investment, for a facility funded with 75 percent commercial debt, and 25 percent equity. The values shown are based on sales of products between the enterprises at full avoided costs, based on market rates. In effect, this price can be interpreted as the total cost of ethanol production for the operation, including capital, feedstock, and operating cost components. Further details of the calculation of required ethanol selling price are discussed in the following sections.

Co-Location with Existing Biomass Facilities

California market context

Since this project was initially conceived almost two years ago the energy outlook in California and across the US has changed dramatically. At the time this project was conceived wholesale energy prices were low, and had been fairly constant for more than a decade. California's 600 MW of biomass power plants were able to operate only because of a temporary production credit of 1.5 ¢/kWh that was being funded by a public purpose assessment on utility bills. Biomass generators faced an uncertain future, and were actively searching for a long-term solution to their dilemma. At the same time the governor of California had announced a policy of phasing out MTBE from gasoline, which would create a huge new demand in the state for fuel ethanol. Many energy experts saw a potential opportunity to solve two problems at once by co-locating ethanol production facilities in California with existing biomass power-generating facilities. If co-location could enhance a biomass power plant's overall operations, then the biomass energy industry was actively interested.

California experienced an energy crisis that began in the summer of 2000. Due to a variety of factors, including natural gas shortages and supply bottlenecks, low reservoir levels in the Pacific Northwest, and a variety of possible market manipulations, wholesale electricity prices in the state suddenly shot through the roof (see Figure 3). By the end of 2000 biomass power generators were scrambling for fuel supplies and firing at full throttle. Short-run avoided costs had reached unimaginable levels, and prices on the state's power exchange were higher still. This impossible situation led to the rapid demise of the state's investor-owned electric utility companies, and left California in the middle of a full-fledged energy crisis. To add further fuel to the fire, the federal EPA denied California's request for a waiver from the federal oxygenate standards for motor fuel, virtually ensuring future ethanol shortages in the state if the MTBE phase-out program goes forward on schedule.

The result of all of these dynamics as it relates to this study is that the entire outlook for the future of energy markets in California has gone through almost unimaginable machinations since this study began. At the present time wholesale electricity prices have returned to pre-crisis levels, and once again many of the state's biomass generators are looking for new approaches, such as co-location, to support their operations. Indeed, the situation is worse in some ways than it was before the onset of the energy crisis, because now approximately 100 MWs of previously idle biomass power generating capacity have resumed operations, but have no stable market for their power. At the same time California is trying to figure out how to cope with the recent EPA waiver denial, and the development of an in-state ethanol production industry is a high priority. Ethanol co-location continues to be a very pertinent opportunity for the state of California.

Reference biomass facility configurations

California's fleet of 45 existing biomass power plants includes facilities sized from less than one MW to three that are 50 MW. Thirty-five of the facilities currently are operating, while ten are shut down. Ethanol co-location opportunities will be limited to the larger biomass facilities in order to take advantage of the economies of scale that are necessary to make for a commercially successful ethanol production enterprise. The host facility must be large enough to be able to handle the large quantities of lignin fuel that will be produced during the ethanol production process, and to supply the amounts of steam and electricity that are required for ethanol production. For purposes of this study, we have selected two reference biomass facility sizes: 25 MW and 50 MW. The 25 MW facility is large enough to host a 550 bdt per day ethanol production facility, while the 50 MW facility is large enough to host a 1,100 bdt per day ethanol production facility.[1] Fourteen of California's biomass power plants are in the relevant size range to be considered reasonable potential co-location host sites (> 20 MW), while another nine are marginally big enough (15 - 20 MW) to merit consideration.

Table 3 shows the specifications that define the reference 25 and 50 MW biomass power plants. For analytical purposes it is assumed that the facilities are fully amortized and approximately ten to fifteen years old, and that their capital recovery requirements are approximately sixty percent of the amount that would be associated with a new facility of the same specifications. The biomass facilities are assumed to burn a fifty-fifty mixture of sawmill residues and in-forest residues, and currently operate as standalone electricity generators, selling their output to the grid, either through an old standard offer power purchase agreement, or into the short-term energy market.

Co-location hosts must meet two key criteria. First, they must have steam turbines with suitable extraction points, or turbines that can be equipped with suitable extraction points, in order to be able to operate in the combined heat and power mode that will provide steam to the ethanol production operation. Second, they must have combustors that can handle a high percentage of their fuel input in the form of lignin, which is lower in bulk density than conventional biomass fuels. California has a number of potentially suitable host sites for ethanol co-location project, several of which have already begun to explore the potential for co-location hosting on their own. NREL supported an engineering study for a co-location project at the Martell biomass plant in Amador County (). BCI has been pursuing ethanol projects in conjunction with two California biomass facilities, Collins Pine, in Plumas County, and Pacific Oroville Power, in Butte County. The Collins Pine project would convert in-forest residues to ethanol, while the Gridley project with Pacific Oroville would use rice straw as a feedstock.

---

[1] These pairings lead to a boiler fuel mix for the existing combustor that is more than 60% lignin. This may present technical challenges for existing equipment, but that is beyond the scope of this study.

Financial Performance of Biomass Reference Facilities

Under normal circumstances, electricity generation in standalone biomass power plants is expensive compared to conventional alternatives such as fossil-fuel-fired generators. This unfortunate but inherent property of biomass power production presents a perpetual challenge to the industry. Biomass power production also provides valuable, demonstrated environmental benefits to society (Morris, 1999, Morris 2000). These benefits, which have a greater value than the electricity itself, make the preservation of the biomass industry a legitimate mater of concern for public policy. If co-location of ethanol production facilities with existing biomass power plants offers even a part of a long-term solution to the economic dilemma faced by the biomass power industry, then the industry is interested in participating.

In order to determine the extent of the co-location benefits for a potential host-site facility, it is necessary to establish a baseline for the power plant's expected future operations as a standalone facility. For analytical purposes we have established baseline economic performance data for the two reference biomass power plants, under several different wholesale electricity price scenarios for sales of electricity into the grid. California currently has 35 operating biomass power plants, of which 19 are standalone generators, and 16 already operate in a combined heat and power mode. The facilities have a variety of types of power sales arrangements, ranging from standard-offer power-purchase agreements written in the 1980s to facilities that are operating as merchant plants, selling power into the short-term energy market.

Most of the California biomass facilities that are operating under old standard-offer power-purchase agreements before the electricity crisis hit the state in the summer of 2000 were selling electricity at short-run avoided cost rates (SRAC) that were in the range of 2.0 - 3.0 ¢/kWh. As prices at the California Power Exchange (PX) soared above posted utility SRAC rates, most of the biomass facilities exercised their option to convert their payment basis from SRAC to PX, a switchover that in any case was mandated by the state's electric utility restructuring law to take effect by the end of 2002. However, the energy crisis became so severe by the end of 2000 that the utility companies suspended payments of their bills to the power generators, and the PX itself collapsed in January 2001. That left the status of the standard offer (SO) contracts in distinct doubt. Eventually an agreement was worked out to offer biomass generators holding SO contracts an option to accept a five-year fixed SRAC rate of 5.37 ¢/kWh. This agreement went into effect in the middle of 2001, so the fixed-price period for the affected facilities will last into mid-2006.

Most of the merchant plants have been trying to negotiate long-term power purchase agreements with the state since the beginning of 2001, but so far only two facilities have succeeded in obtaining long-term agreements. Most of the remaining merchant facilities have signed interim agreements with the state, which are intended to carry them until longer-term contracts can be negotiated. These facilities cannot continue to operate if they have to sell power into the short-term market, where prices recently have been in the range of 2 - 3 ¢/kWh. The interim contracts provide the generators with a total price of 6.5 ¢/kWh for their electricity, which covers both energy and capacity.

The average cost of electricity production in an existing, amortized, standalone California biomass power plant is approximately 7 ¢/kWh, almost equally divided among three cost categories:

- Capital
- Fuel
- Non-fuel operations and maintenance

Facilities that are operating under standard-offer PPAs with the five-year fixed SRAC rate are earning revenues that are comparable to their cost of production (~2 ¢/kWh capacity plus 5.37 ¢/kWh energy), and thus can be expected to operate reliably for at least the next five years. The facilities that have signed the interim agreements for rates of 6.5 ¢/kWh will be able operate successfully for the term of the contracts, and are hoping that long-term contracts patterned on the terms in the interim agreements can be successfully negotiated. Biomass power plants that are dependent on merchant power sales at current market prices, even with the CEC production credit program that is in place, are having considerable trouble covering just their fuel and operating costs, and are in imminent danger of having to shut down.

Fuel and non-fuel operating costs for biomass power plants can be estimated with a high degree of accuracy based on real world experience. Fuel-cost data are based on extensive annual surveys of the biomass fuels market in California that have contributed to the development of a reliable database on California biomass fuel use (Morris 2000). Non-fuel O&M costs are based on extensive survey work of the North American biomass energy industry (Morris 1994, Morris 2000).

California's biomass fuel supply is derived from four broad categories of material: sawmill residues, in-forest residues, agricultural residues, and urban wood residues. Each of these types of biomass has different characteristics and costs. Most facilities use two or three of the categories of material, depending on what is available in their procurement region. For purposes of conducting this study, it is assumed that the reference biomass facilities use a mixture of sawmill and in-forest residues, and that each facility has available to it a fixed quantity (90,000 bdt/yr) of sawmill residues, the cheaper of the two fuel types, and an unlimited quantity of in-forest residues ($25.00 / bdt for sawmill residues, vs. $36.00 / bdt for in-forest residues). In-forest fuels are more expensive to produce than sawmill residues because of extra collection and transportation costs.

The base-case 25 MW reference facility derives 50 percent of its fuel supply from sawmill residues, while the 50 MW reference facility derives 25 percent of its fuel supply from sawmill residues. This assumption set has two benefits for the study. First, the marginal fuel is more expensive than the average fuel for each facility configuration, guaranteeing that the larger the amount of biomass required at a site, the greater the average cost of fuel procurement. Second, the marginal fuel source considered for the study is in-forest material, which is the least tapped, but most expensive of the four categories of biomass fuels used in the state.

The capital cost of new biomass generating facilities using conventional technology are well known. The EPC cost of a new facility is generally in the range of $1,250 - 1,750 per kW of capacity, with the all-in costs in the range of $1,600 - 2,300 per kW (Morris 1994, Morris 2000). In contrast, capital cost values are difficult to estimate on a generic basis for existing, amortized facilities. Most of the biomass facilities in California were placed into service during the period 1985 - 1990. Thus, the typical existing biomass facility in California that is a candidate for a co-location project is 10 - 15 years old. Conventional biomass facilities have an expected physical lifetime of at least 30 years (some biomass facilities have operated continuously for more than 80 years). Straight-line accounting would estimate these facilities to have lost between one-third and one-half of their original capital value. Experience with restarts of idle biomass facilities in California over the past couple of years shows that the facilities typically need capital up-grades of $750,000 - 1.5 million, mainly in the areas of controls and instrumentation, in order to be brought up to current standards. Full overhauls costing a few million dollars could bring the equipment to near-new condition, where it would be suitable for pairing with a new ethanol production enterprise.

For purposes of analysis, we assume a capital value of $28 million for the 25 MW base-case facility, and $45 million for the 50 MW base-case facility. The facilities are assumed to be financed with seventy percent debt, and thirty percent equity. The debt is assumed to be seven years, at 10 percent interest. Equity return on investment is based on a ten-year return, with no assumed residual value for the facilities.

Table 4 shows a pro forma financial statement for the 25 MW reference biomass facility operating under a SO contract (2 ¢/kWh capacity plus 5.37 ¢/kWh energy fixed). The facility receives the fixed revenue price through the middle of 2006, then revenues are assumed to revert to the then prevailing market price. For purposes of analysis, it is assumed that the prevailing market price in 2006 is based on a current market price of 3.5 ¢/kWh, escalated at one percent annually to 3.68 ¢/kWh in 2006. Table 5 shows a pro forma financial statement for the 25 MW reference biomass facility operating under an assumed long-term power contract with the state for a price of 6.5 ¢/kWh in 2002, then escalating at one percent annually (labeled CPA, which stands for the California Power Authority, which is the presumptive buyer). This assumed escalation rate is half of the assumed overall inflation rate of two percent per year. Tables 6 and 7 show proformas for the base case 50 MW facility, for both an SO#4 contract, and an assumed long-term contract with the state.

The 25 MW biomass power plant operating under a SO contract with the 5.37 ¢/kWh five-year fixed revenue option is able to operate comfortably, generating a 21 percent IRR using the financing assumptions adopted for this study. Operating under the conditions assumed for the long-term state contracts, 6.5 ¢/kWh no capacity, the 25 MW biomass facility has a positive operating margin of approximately \$3.15 million per year, which is insufficient to cover its capital-recovery requirements. These facilities would appear to be prime candidates as co-location sites. Although not shown, it is obvious that facilities operating as merchant plants at current market rates would not be able to show a positive operating margin, even if they receive a state supplement of 1.0 or 1.5 ¢/kWh.

The larger facilities enjoy substantial economies of scale, leading to enhanced operating margins as compared with the 25 MW facilities operating with comparable power contracts. Tables 6 and 7 show the proformas for the reference 50 MW biomass power plant operating under the SO4 and CPA power purchase agreements. It is important to note that there are only three 50 MW facilities in California, two of which have standard offer PPAs, and one that has one of the interim contracts with the DWR, and is seeking a long-term agreement. Outside of these three, the next largest facility in the state is 31 MW. Thus, 50 MW facilities are special cases in the biomass realm. While these facilities are appealing co-location hosts because they offer the ethanol operation an opportunity to take advantage of economies of scale, this factor must be balanced by the fact that the host site on its own already supports a huge materials handling operation. Adding an ethanol production operation increases the amount of biomass that must be brought to the site by thirty percent or more.

Co-location benefits to existing biomass facilities

In order to become a co-location host, a biomass power plant will have to reduce the amount of electricity it sells to the power grid in order to provide steam and electricity to the ethanol production operation. Ethanol production is an energy-intensive process, and requires significant quantities of both steam and electricity. In theory the ethanol production facility can obtain its energy requirements from the biomass power plant at a price below avoided retail, while providing enhanced revenues to the power plant compared to the current situation in which the power plant sells all of its output to the grid at wholesale rates. Co-location projects that provide enhanced operating margins to biomass power plants will attract interest from most potential host sites.

Table 8 shows technical specifications for co-locating a 550 bdt per day ethanol facility with a 25 MW biomass facility. Data are shown for four ethanol configurations: acid and enzymatic hydrolysis, with a base case and optimistic case for each technology. Providing the steam for a 550 bdt per day ethanol facility costs the reference 25 MW biomass power plant approximately 5 MW of its output. Providing the electrical requirements of the ethanol operation reduces the amount of electricity that can be supplied to the grid by another 2.5 - 4.0 MW, with the result that the power plant's sales of electricity to the grid is reduced by approximately 30 - 35 percent as compared with the existing standalone biomass power plant. The lost revenues are offset by the sale of electricity (2.5 - 4.0 MW) and steam (71,600 - 87,500 lbs. per hour) to the ethanol production enterprise at avoided retail rates.

Biomass power facilities operating under the old standard offer power purchase agreements have provisions in their capacity agreements that require them to meet certain performance requirements during the peak hours of the year (weekdays noon to six, June, July, and August). The minimum performance factor cannot be achieved if the power facility is turned down by 30 percent or more during the defined peak hours. A co-location host with a SO contract would have two major options available to meet its performance requirement. It could turn down the amount of steam and electricity provided to the ethanol operation during the crucial peak hours (approximately 375 hours per year), and/or it could over-fire its boiler during these hours, assuming that it has the physical capacity and regulatory authority to do so, thus increasing the amount of export power produced. Without over-firing, the facilities operating under SO contracts would have to reduce their sales of utilities (steam and electricity) to the ethanol operation during peak hours of electricity usage by at least 45 percent in order to comply with the requirements of the capacity provisions in their contracts.

Facilities that are operating at market rates, or under CPA contracts, do not have to meet the kind of peak-period performance factor requirement that is part of the SO contracts. However, due to the nature of electricity, all power plants find that their output is more valuable during the peak hours of the year. Thus, virtually all power plants that have the capability to do so will find it beneficial to over-fire their boilers during peak hours, and all co-located operations will benefit from design and operating protocols that allow them to adjust their own operations to accommodate the electric market needs of the host cogeneration facility.

Avoided retail electric rates in California today are very high, a carryover effect of the energy crisis that hit the state in 2000-2001. Pre-crisis rates for large industrial energy users in California averaged approximately 5.5 - 6.0 ¢/kWh, but jumped to an average of 10.5 - 11.0 ¢/kWh in July of 2001. These high rates were enacted in order to repay the state for its purchases of energy when prices were very high and the utilities were broke. For analytical purposes, we are assuming that the current rates will be in place through the end of 2006, then drop by thirty percent and remain fixed at that level for the following ten years.

Avoided retail rates for industrial steam are based on the avoided cost of natural gas, and the avoided costs of operations and maintenance for the steam-generation equipment. Avoided natural gas costs are assumed to be 30 ¢ per therm (2002), escalating at one percent annually. The initial avoided cost for high-pressure steam is $4.30 / mmbtu, and for low-pressure steam is $3.75 / mmbtu. These rates provide the same revenue as sales of the equivalent amount of electricity at approximately 6.5 ¢/kWh.

At first blush, trading wholesale electrical sales for electrical sales to a co-location facility at 10.7 ¢/kWh, and steam sales at the equivalent of 6.5 ¢/kWh (weighted average of approximately 7.9 ¢/kWh), would appear to be a good deal for a host power plant that sells its electrical output at wholesale rates. However, the California biomass facilities that have SO contracts sell their electricity at an average rate of almost 8.0 ¢/kWh, and those with the current interim CPA contracts sell their electricity at an average rate of 6.5 ¢/kWh. As a result, the facilities with SO contracts, in the absence of over-firing, would see only about a $270,000 to $380,000 revenue gain in 2005 with co-location. The acid optimistic case, which has much greater electricity use than the other defined technologies, benefits to a greater extent, with a $800,000 revenue gain in 2005. Over-firing improves the situation considerably, due to the particular nature of the capacity provisions in the SO contracts.

Cogeneration facilities that are operating under CPA-type contracts would benefit from co-location to a greater extent than those operating under SO contracts. Without over-firing, the benefits to facilities operating under CPA-type contracts are at least twice as great as the benefits to those operating under SO contracts. Over-firing can increase the benefits by approximately twenty percent.

Co-location hosts can augment the benefits derived from co-location by over-firing their boilers during the peak hours of the year, thus increasing their sales to the grid during these crucial hours. In addition, a facility operating under an SO contract that over-fires its boiler by ten percent during peak hours would only have to reduce utility deliveries to the ethanol facility by 15 percent during these hours (vs. 45 percent without over-firing) in order to meet its capacity performance requirements. On the other hand, due to provisions in the SO contracts that generously reward grid sales during peak hours, if the ethanol facility were able to accept the 45 percent reduction in utilities during peak hours, the advantage to the cogen facility of overfiring during peak hours increases considerably as compared to the power-only configuration.

All of the numbers above assume that the biomass power plant sells steam and electricity to the ethanol facility at full avoided retail prices, and that the biomass power plant purchases lignin from the ethanol facility at equivalent value to the fuel it was purchasing prior to the development of the co-located ethanol production operation. The assumption is that the reference 25 MW biomass power plant purchases a 50/50 mixture of sawmill residues ($25 /bdt) and in-forest residues ($36 /bdt). In the co-location mode, the power plant's biomass purchases continue to be a 50/50 mixture of sawmill residues and in-forest residues, with lignin and biogas purchased at an equivalent btu value. The overall operation continues to procure the same total amount of lower-cost biomass (sawmill residues) as the power plant did before co-location, with all of the additional biomass coming from more costly (in-forest) sources. The co-located combined operation has to procure 30 - 45 percent more biomass than the host site facility did prior to co-location.

Co-location would appear to offer modest benefits to potential co-location host biomass power plants in California, particularly for facilities that do not have SO contracts. This results from the fact that the operating biomass power plants in California receive revenues for wholesale electrical sales that are themselves rather high. If the biomass plants received revenues at the current average wholesale market rate of 2.5 - 3.5 ¢/kWh, then co-location would be much more beneficial for them. However, under these circumstances, the co-location benefits would not be enough to make the host facility a viable commercial enterprise, so biomass power plants selling their electricity at current wholesale rates would not be a suitable co-location site.

The analyses above assume that a co-located ethanol facility in California would use essentially the same kinds of feedstocks that the host facility already uses for fuel. Procuring additional quantities of biomass at an existing site would mean bringing in supplies of increasingly costly material, based on the simple premise that the existing power plant, prior to co-location, has already been striving to minimize its fuel cost. Based on the approach used in this study, the host site would have its overall fuel cost remain constant after co-location, with the ethanol operation picking up the cost of the higher-priced marginal biomass that is procured.

There is one way to avoid this conundrum, which would be for the ethanol production operation to use a cellulosic feedstock that is not currently part of the fuel mix of the host site, or of the state biomass fuel market in general. The obvious biomass candidate in this category is agricultural field straws, which are inferior power plant fuels and almost never used for that application, but may actually be relatively desirable feedstocks for ethanol fermentation.

Rice straw, in particular, presents a difficult disposal problem in California. Rice is grown extensively in the Sacramento Delta area north of the San Francisco Bay, and rice straw burning, the traditional disposal practice for the material, is a major source of air pollution in the state's Central Valley region during the fall. The California Air Resources Board has spent millions of dollars trying to develop alternative uses for rice straw, with little result. Open burning has now been banned, and growers are being forced to landfill their straw, at considerable cost and risk to succeeding crops (straw not removed in a timely fashion harbors a deadly fungus).

Ethanol facilities that are co-located at sites with reasonable access to adequate quantities of rice straw or similar materials would be able to procure their feedstock at considerably lower cost than facilities that use the same types of biomass as their co-location hosts. In the specific case of rice straw, California even offers a tax credit for beneficial use of the material, and ethanol production qualifies as a beneficial use. This would further reduce the procurement cost for the feedstock, although we do not take it into account in this analysis.

In addition, the host facility itself can see its cost of fuel procurement decline in this type of co-location scenario. In the 25 MW / 550 bdt/day co-location configuration, the power plant derives 60 - 67 percent of its fuel from the lignin co-product of the ethanol production process. This means that its procurement from the conventional biomass fuels market would be reduced by more than half, and the average cost of fuel procured would be reduced accordingly.

For modeling purposes, we assume that a co-location scenario with the 25 MW / 550 bdt/day configuration converting rice straw into ethanol would allow the host facility to procure only sawmill residues for its outside fuel requirements, instead of the 50/50 mixture of sawmill residues and in-forest residues. This allows the power plant to reduce its average fuel procurement cost from $30.50 /bdt for the pre-co-location fuel mix to $25.00 /bdt with co-location, an 18 percent decrease. At the same time, with rice straw priced at $19 /ton ($22.35 /bdt) (Uhland 2001), the cost of feedstock procurement for the ethanol operation is reduced by more than 30 percent compared with the cases considered above where in-forest residues were the marginal biomass source. Thus, both enterprises benefit in this configuration.

The rice straw feedstock co-location scenario provides considerably greater benefits to a potential host site facility than the conventional biomass feedstock scenario. This assumes that the particular characteristics of the rice straw do not present problems for either the ethanol or cogeneration operations. The host cogeneration facility obtains the same revenue enhancements regardless of the type of feedstock used by the ethanol production operation. However, in the conventional biomass feedstock scenario the cogeneration facility's fuel procurement cost is unaffected by co-location, whereas in the rice straw feedstock scenario the host facility receives a greater than $1 million per year fuel savings in addition to the revenue enhancement from retail sales of steam and electricity.

Co-location benefits for ethanol production operations

The major co-product of ethanol production from cellulose is lignin, which is produced in large quantities. For example, the four 550 bdt per day ethanol plant configurations considered in this study convert 180,000 bdt per year of biomass into 9.3 - 13.6 million gallons of ethanol, and 98,500 - 126,500 dry tons of lignin. The lignin co-product is enough fuel to produce 14 - 18 MW of electricity in an efficient standalone power plant, or more than enough to supply all of the steam and electrical needs of the ethanol production operation, and still produce a surplus of 5 - 10 MW of electricity. Doing this, however, requires the installation and operation of very expensive equipment in the form of a solid-fuel boiler and steam turbine-generator. In the Merrick study, for example, which provided design details for standalone and co-located facilities of the same production capacity, the co-located facility was thirty percent less costly to build than the standalone ethanol production plant. Avoiding the need for this expensive equipment is one of the primary motivations for co-location.

The technology required for producing ethanol from cellulose is still in the pre-commercial stage of development. This factor, combined with the fact that the facilities will be limited in size due to resource considerations, lead to projections of rather high costs for producing ethanol. For analytical purposes, the figure of merit that is computed for each ethanol production configuration considered in this study is the required selling price for ethanol at the plant gate, without regard to available state and federal tax credits. Private capital financing is assumed for the reference case, with a 75:25 debt-to-equity ratio, debt based on a fifteen year loan term at ten percent interest, and equity earning a twenty percent internal rate of return over a ten-year period. These are rigorous investment criteria, suitable for a commercially mature industry. Cheaper financing options, which may be available in the near-to-middle term, are also considered in this report.

The required ethanol selling price is unaffected by the type of power sales arrangement that the host facility is operating under, nor by whether the host facility is over-firing its boiler or otherwise manipulating output during peak hours of electricity demand. The required ethanol-selling price is mainly a function of two factors, the choice of ethanol technology employed, and the type (cost) of feedstock used. In the rice-straw scenarios the ethanol production facilities sell their lignin to the power plants at a lower cost than in the conventional biomass feedstock scenarios, due to the fact that the host facilities fuel procurement costs are reduced. Nevertheless, the reduction in ethanol feedstock costs in the rice straw scenarios (~ $10 / bdt) more than makes up for the loss in lignin values, allowing ethanol to be sold for about 10 ¢ less per gallon for each ethanol production technology considered.

Table 8 shows the required ethanol selling price for the various 550 bdt/day ethanol / 25 MW biomass co-location configurations considered previously. In all cases the data shown in the table are based on an assumption that the two co-located facilities are run as separate operations, with sales of energy products between the two entities based in all cases on full avoided costs from prevailing commercial market rates. Steam and electricity are sold by the power plant to the ethanol producer at prices based on the avoided cost of natural gas, and retail electricity prices for large industrial energy users. Lignin and biogas are sold by the ethanol production operation to the power plant based on the power plant's avoided cost of procurement of biomass fuel.

The cost of producing ethanol from cellulosic feedstocks can be broken down into three major components: feedstock acquisition cost, operations and maintenance (O&M) cost (not including feedstock), and capital cost. Figure 4 shows plots of the relative contributions of the production cost components for 550 and 1,100 bdt/d ethanol production facilities. Due to economies of scale with regard to capital and O&M costs, the relative importance of feedstock cost compared to the other two cost components becomes amplified as the size of the ethanol production facility increases.

The cost of the feedstock used for the conversion process accounts for one-quarter to one-third of the total cost of production. The feedstock cost differential is the main difference between the selling prices for each ethanol production technology shown in Table 8 based on biomass vs. rice straw feedstocks. Figure 5 shows a plot of required ethanol selling price vs. feedstock cost for acid-hydrolysis and enzymatic-hydrolysis ethanol production technologies. The bandwidth for each technology is bounded by the base-case configuration and the optimistic configuration.

The required ethanol selling prices discussed so far have been based on meeting commercial project-finance requirements, which for purposes of analysis are defined as interest rates of 10 percent on debt, and 20 percent rates of return on equity capital. In recognition of the significant public benefits of energy production from residue forms of biomass (Morris 1999), it may be possible to obtain lower cost financing for co-located ethanol projects. For example, if highly concessionary rates of 5 percent for interest and 12 percent for equity rates of return are assumed (vs. 10% & 20% respectively), the required selling price for each of the configurations shown in Table 8 are reduced by about 20 cents per gallon (range of 18 - 21 ¢/gal).

The host facilities in the various 550 / 25 co-location configurations shown in Table 8 see their annual operating margins (ebitda--earnings before interest, taxes, depreciation, and amortization) increase in the range of $300,000 - 2,700,000. Since these ebitda enhancements are due entirely to the presence of the co-located ethanol facility, it is reasonable to consider the possibility of some sharing of the benefits between the two entities. A simple way to do this in the model is by discounting the price of energy products (steam and electricity) sold by the host power plant to the ethanol production operation. The required ethanol prices shown in the table can be considered to be the prices when one-hundred percent of the co-location benefits accrue to the biomass power plants. If the special co-location benefits are completely transferred to the ethanol production operations, the required ethanol selling price can be reduced by as much as 18 ¢/gal.

Figure 6 illustrates the range of required ethanol selling prices that are possible as a function of feedstock cost (conventional biomass vs. rice straw in the figure) and degree of sharing of the special co-location benefits between the two co-located enterprises. With fairly equal benefit sharing and medium feedstock prices, ethanol can be produced for a plant-gate selling price in the neighborhood of $1.70 /gal using acid-hydrolysis technology, and $1.50 /gal using enzymatic-hydrolysis technology. The values in the figure are based on commercial financial return expectations (10% debt, 20% equity). The required selling-price spaces shown in the figure would fall vertically by as much as 20 ¢/gal if extremely favorable concessionary financing terms can be arranged.

Co-location presents a number of possibilities for sharing of physical facilities and operations that could lead to reductions in the required selling price for ethanol. These include:

- Avoidance of new boiler and power generating equipment for the ethanol production operation
- Joint biomass procurement, storage, and handling facilities and operations
- Joint water processing and water treatment facilities and operations
- Sharing of key maintenance personnel
- Joint administrative and management services

The various opportunities for synergism can produce capital cost savings, operating cost savings, or a combination of the two. The most compelling reason for co-location, avoiding the need to include a boiler and turbine generator in the design of the ethanol production process, produces both capital cost savings and operating cost savings for the ethanol producer, but at the expense of a major new operating cost item, utility purchases (steam and electricity). Moreover, in a standalone configuration, an ethanol production facility equipped with efficient power generating equipment would be able to produce surplus power for the grid, taking advantage of which ads a whole layer of additional complexity to the ethanol production enterprise. Comparing co-located ethanol production facilities to standalone facilities is beyond the scope of this report, but preliminary calculations suggest significant net benefits for co-location.

In order to analyze the results of capital and operating cost savings on the required plant-gate selling price for ethanol, a series of sensitivity analyses on these two variables were performed. Figure 7 shows the sensitivity of required ethanol selling prices to changes in capital costs from the base case values presented in this analysis. Figure 8 shows the sensitivity of required ethanol selling prices to changes in operating costs from the base case values. Based on the data shown in the figures, the required ethanol selling price for the various ethanol production technologies changes by 1.2 - 1.7 ¢/gal per million dollars change in project capital cost, and by 7.5 - 10.5 ¢/gal per million dollars change in annual operating costs.

One of the significant factors leading to the high cost of production for ethanol fuels from cellulosic feedstocks is the relatively small size of the production units envisioned. The limiting factor on unit size is the nature of the resources that are used as feedstock. The reference 550 bdt/day ethanol facilities use the same amount of biomass as a 25 MW standalone biomass power plant. In the 550 bdt/day / 25 MW co-location configurations, the total operation uses as much biomass as a 35 MW standalone biomass facility, which is very large by industry standards. Yet these facilities produce only about 10.0 - 12.5 million gallons per year of ethanol, which compares with 40 million gallons per year or more for state-of-the art grain-to-ethanol operations. Cellulose-to-ethanol facilities will not be able to achieve the kinds of economies of scale that grain converters can.

For purposes of analysis, we have defined specifications for reference 1,100 bdt per day ethanol facilities for each of the ethanol production technologies under consideration (Table 2). The 1,100 bdt/day facilities cannot be paired with a 25 MW power plant, because they produce too much lignin for the facility to consume. For analytical purposes, we pair the 1,100 bdt/d ethanol facilities with the reference 50 MW biomass power plant configurations. Such combinations would consume more biomass at a single location than any standalone biomass power plant in the world. This means that some of the biomass would have to be procured from relatively costly sources, counteracting the positive effects of the economies of scale achieved in a larger operation. Nevertheless, each of the three 50 MW biomass facilities in California would be capable of procuring the amount of additional biomass needed if conditions warranted.

The cost savings achievable with larger production facilities are impressive. Doubling the size of the ethanol facilities to 1,100 bdt/day allows the required selling price of ethanol to drop by as much as 25 ¢/gal, if one assumes that the additional feedstock required for such facilities can be obtained at the same marginal cost as is assumed for the 550 bdt/d - 25 MW configuration. In the more likely event that the marginal feedstock acquisition cost will be higher, the advantage of doubling the size of the ethanol production operation is to decrease the required selling price of ethanol by about 15 - 20 ¢/gal for each technology.

Co-Location with Coal-Fired Power Plants

Market context

Cellulose-to-ethanol production facilities can be co-located with coal-fired power plants in order to achieve many of the same synergies as co-locating with biomass power plants, the notable exception being that completely separate materials storage and handling facilities will be required. In fact, co-location with coal plants offers several significant advantages for the ethanol production operation in comparison with biomass co-location. Some of these advantages include:

- Coal plants are typically much larger than biomass power plants. As a result, coal facilities can support larger ethanol operations with fewer technical challenges for the host facility, such as limitations on the percent of lignin in the fuel mix.

- All biomass procured in a coal co-location configuration is for conversion to ethanol. There is no competition for biomass resources with the host facility. Moreover, many regions that have substantial numbers of coal-fired power plants do not have well developed biomass power industries, because avoided costs are too low to allow biomass power plant development to take place. The result is that there is little competition for biomass resources in these regions.

- Co-locating an ethanol production facility with an existing coal-fired power plant provides significant environmental improvements at the host site. Environmental performance is a significant issue for many old coal facilities in the U.S. Ethanol production does not "green" a host biomass facility, which is already one-hundred percent renewable and green.

- Coal-fired electricity production is a lower-cost process than making electricity from biomass. As a result, most coal-fired power plants receive lower unit values for electricity supplied to the grid than biomass facilities, which need to receive above market rates in order to survive. Exchanging some of the coal plant's electricity sales for sales of steam and electricity to an ethanol operation, therefore, gives the host facility a greater boost in product value than is the case with a biomass power plant. This means that there may be greater co-location benefits to be shared between the two operations.

The southeastern region of the U.S., in particular, would appear to offer fertile ground for ethanol co-location with existing coal-fired power plants. The Southeast has a large number of old, and in many cases quite dirty, coal facilities. This region is also endowed with significant biomass resources, and produces large quantities of under or unutilized cellulosic residues in the forms of wood residues at sawmills and from in-forest operations, and agricultural residues such as straws from grain crops. The collection and use of these materials would provide steady jobs in many economically depressed areas, as well as promoting significant environmental improvement.

Most of the dirtiest of the existing coal facilities in the Southeast are exempted under the Clean Air Act, and the owners of these facilities are extremely resistant to doing anything to modify them for fear of triggering significantly more stringent environmental regulations. Nevertheless, these facilities are under strong political pressure to clean up, and may not be able to maintain their grandfathered status indefinitely. Ethanol co-location offers significant environmental values to a coal facility. It allows the coal plant to substitute a clean-burning renewable fuel for a portion of its fuel mix, which is a significant benefit in itself, particularly with regards to reduced sulfur and particulate loading in the system. In addition, lignin fuels may have a positive effect in scavenging coal sulfur in the combustor, as well as in suppressing NOx formation. Lignin fuels should be easier to co-fire with coal than conventional biomass fuels, especially in the PC boilers that the majority of old coal-fired units have.

Reference coal facility configuration

For purposes of analysis we define a reference coal-fired power plant that can serve as a host facility for a co-located ethanol production facility. Analyst Jacqueline Broder and associates at the TVA assisted in producing realistic specifications for the reference facility. The reference coal plant is a typical 300 MW coal-fired power plant in the Southeast, burning locally-produced coal in a PC boiler. This coal plant is large enough to support any of the ethanol production facility configurations that are considered in this study (Table 2).

Table 9 shows the base-case specifications that define the reference 300 MW coal-fired power plant. For analytical purposes it is assumed that the facility is fully amortized and approximately twenty to thirty years old, and that its capital recovery requirements are approximately thirty percent of the amount that would be associated with a new facility of the same specifications. The coal facility is utility owned, and operates as a standalone electricity generator. The average value of the electricity that it supplies to the grid is assumed to be 2.5 ¢/kWh.

Cellulose feedstock availability at any given potential co-location project site is site specific. In some locations in the Southeast there is an existing, established market for biomass fuels, while in other parts of the region there is little current demand for residue biomass. For analytical purposes, we assume that the first 225,000 bdt per year of biomass at a given site is available for a price of $22.50 per bdt, which would correspond to wood processing residues, while additional biomass at the site would be available at a price of $36 per bdt, which would be primarily in-forest residues or agricultural straws.

Co-location benefits to the existing coal facility

Existing coal-fired power plants like the defined reference facility form the backbone of the power grid supply infrastructure in the Southeast. A proforma model run on the reference coal facility without co-location is shown in Table 10. The power plant produces an operating margin (ebitda) of some $17 million per year, which makes it a performing utility asset. Based on the various assumptions built into the specification of the reference facility, the model calculates an irr of 18 percent for this asset.

The reference 300 MW coal facility can host any of the eight reference ethanol technology configurations that are described in Table 2. In order to take advantage of economies of scale, it is likely that developers will build facilities that are as large as possible at any given co-location site, subject to the availability of biomass at that location. An 1,100 bdt/day facility uses as much biomass as the largest biomass power plants in the world. It is unlikely that more than a handful of sites with suitable existing coal-fired power plants will be able to support this level of production. For purposes of analysis, we consider co-locating both the 550 and 1,100 ton/day reference ethanol production facilities at the reference 300 MW coal-fired power plant.

Table 11 shows the specifications and results from co-locating the various reference ethanol plants at the reference coal-fired power plant. Co-locating a 550 bdt/d ethanol facility at the reference coal plant reduces the coal plant's delivery of power to the grid by approximately 8 - 10 MW, substituting far more valuable sales of steam and electricity to the ethanol production operation. The host facility's coal use is reduced by 5 - 9 percent, and the value of its output increases by $1.4 - 2.7 million annually.

Co-locating a 1,100 bdt/d ethanol facility at the reference coal plant reduces the coal plant's delivery of power to the grid by approximately 15 - 18 MW, substituting far more valuable sales of steam and electricity to the ethanol production operation. The host facility's coal use is reduced by 11 - 18 percent, and the value of its output increases by $2.9 - 4.7 million annually.

In addition to the financial benefits, the co-location host facility receives significant environmental benefits from co-location. While quantifying these benefits is beyond the scope of this study, it should be noted that gaining the environmental benefits of co-location may be of greater interest to the owners of existing coal-fired power plants than any increased value in their energy production. This depends to a great extent on the future course of air pollution regulation and efforts to reduce greenhouse gas emissions. The pro forma co-location model could be used to study the relative cost-effectiveness of compliance with tougher air-pollution standards for a grandfathered coal plants using the co-location approach with an ethanol facility, vs. installing and operating various pollution control technologies (or a mix of both).

Co-location benefits for ethanol production operations

The ethanol production operations considered for co-location with coal facilities are the same configurations that were considered for co-location with biomass power plants in California, and their production economics are very similar. The major differences between the two scenarios are the expected prices for various energy products, especially the wholesale and retail prices for electricity, the price of biomass feedstock, and the value of the lignin sold by the ethanol facility to the power plant. Table 11 shows the required plant-gate price for ethanol fuel from the various ethanol configurations, based on the base case set of assumptions used for this analysis. These prices are based on the use of full avoided cost pricing for each product traded between the two co-located enterprises.

The required plant-gate selling prices shown in Table 11 for ethanol production facilities co-located with coal power plants in the Southeast are comparable to the prices shown in Table 8 for ethanol production facilities co-located with biomass power plants in California operating on rice straw residues as feedstock, and about a dime cheaper than for California facilities operating on conventional biomass. The larger facilities for each technology have production costs that are 15 - 30 ¢/gal cheaper than the smaller facilities, even taking into account their higher average cost for feedstock. Larger facilities are assumed to have higher average feedstock acquisition costs because they must collect biomass from a larger area, and feedstock transportation is expensive.

Figure 9 shows a plot of the required selling price for ethanol vs. the cost of feedstock for acid and enzymatic hydrolysis technologies, with consideration given to ethanol production enterprise size. The required selling price for acid hydrolysis has a stronger response to feedstock cost than for enzymatic hydrolysis, because acid hydrolysis is less efficient in terms of converting feedstock into ethanol. This means that it uses more feedstock per gallon produced, making feedstock cost a greater determinant of total production cost. With advanced conversion technologies at sites with plentiful supplies of feedstock, ethanol fuels could be produced for plant-gate selling prices of $1.50 per gallon with acid hydrolysis techniques, and $1.30 per gallon with enzymatic hydrolysis techniques.

One of the problems with co-locating an ethanol production facility with an existing biomass power plant is that power production using biomass fuels is expensive, and, as a result, biomass power plants either receive revenues in the neighborhood of seven cents per kWh, or they cannot operate. This means that diverting a portion of their output to a co-located ethanol facility at avoided retail rates is not as great a bump as it is for a coal-fired power plant, whose electrical output to the grid is much lower valued. In other words, co-location with coal facilities produces a greater co-location benefit to the host facility, measured in terms of increased operating margin, than is the case for co-location with a biomass facility. In addition, co-location with a coal facility provides large environmental benefits to the coal facility, which is not the case for co-location with already "green" biomass power plants. Thus there is more ebitda benefit to share with co-location at a coal-fired power plant, and more incentive for the host facility to be willing to share a greater proportion of the benefit.

Figure 10 shows a plot of the required selling price for ethanol vs. the degree of sharing of the benefits of co-location between the host facility and the ethanol production enterprise, for acid and enzymatic hydrolysis technologies, with consideration given to ethanol-production enterprise size. Fairly equal benefit sharing would lead to plant-gate ethanol selling prices in the neighborhood of $1.55 /gal for acid hydrolysis technologies, and $1.35 /gal for enzymatic hydrolysis technologies. If the coal plant is willing to share most or all of the economic benefits of co-location in return for the environmental benefits, required selling prices fall to the neighborhood of $1.50 /gal for acid hydrolysis, and $1.30 /gal for enzymatic hydrolysis technologies. With advanced technologies and prime resource sites, these prices can be driven down by another dime.

The production economics for ethanol facilities co-located with coal power plants show the same sensitivities to concessionary financing terms, and to changes in capital and operating costs as were found in the case of co-location with biomass power plants (see previous section: *Co-Location with Existing Biomass Facilities*).

Conclusion and Recommendations

The precarious future of the California biomass power industry, coupled with the state's plans to phase MTBE out of its fuel mix, have focused considerable attention on the concept of co-locating cellulose-to-ethanol facilities with existing biomass power plants in the state. Co-locating cellulose-to-ethanol facilities with existing biomass power plants has a number of advantages over developing standalone ethanol production operations, particularly in the areas of shared facilities and operations. However, biomass co-location faces some difficult challenges that may limit its future development. Some of these issues are avoided in co-locating cellulose-to-ethanol facilities with coal-fired power plants, which may turn out to be a greater opportunity for the U.S. ethanol industry in the long run.

One important technical issue that will have to be addressed in moving forward on real co-location projects involves the ability of existing solid-fuel boilers to accept lignin as a significant portion of the fuel mix. In the biomass power plant co-location configurations considered in this study, lignin provides some sixty percent or more of the power plant's fuel mix. Lignin fuels are different than conventional biomass and coal fuels, and existing boilers may be limited in terms of their abilities to accept high percentages of lignin in their fuel mix. In general, biomass power plants that have fluidized-bed combustors may be able to burn higher percentages of lignin in their fuel mix than grate-type boilers, although each potential host site has to be evaluated for its own unique characteristics and limitations. Eleven of the 35 operating biomass power plants in California have fluidized-bed combustors. Nine of the 14 facilities in the size range of interest for co-location projects (greater than 20 MW) in California have fluidized-bed boilers.

When this study was initially conceived, it was thought that lignin fuels might provide certain advantages to biomass boilers, including possibly allowing them to operate at higher output rates. These hopes were based on the fact that lignin has a higher energy density, in terms of btus per bdt, than conventional biomass fuels. However, based on the ethanol facility production specifications provided by NREL for this study, the product that is commonly referred to as “lignin” is really a mixture of lignin, hemicelluloses, yeast, and other matter. Its heating value and moisture content are similar to that of conventional biomass fuels, and energy mixes containing high percentages of this type of lignin do not provide for increased combustion efficiencies. The exception is the acid-hydrolysis optimistic configuration, for which data were derived from a different source. In this design it is assumed that the fuel product produced in the ethanol production process is fairly pure lignin, with a correspondingly higher energy density. For this technology the model does compute a higher boiler efficiency for fuel mixtures with high percentages of lignin.

The scale economies that appear to be an inherent characteristic of the ethanol production industry dictate that only rather large biomass power plants should be considered as potential host sites for ethanol co-location projects. The 25 MW reference biomass power plant considered in this study, for example, is hard strapped to accommodate the smallest ethanol production configurations under consideration. California has fourteen operating biomass power plants that are 20 MW or larger, and another seven in the size range of 15 - 20 MW. If all of these 21 facilities were utilized as co-location sites, and all could take a very high proportion of their fuel in the form of lignin (e.g. 80%), the combined ethanol production capacity in the state would be approximately 265 million gal/yr using acid hydrolysis technology, and 415 million gal/yr using enzymatic hydrolysis technology. This represents the absolute upper limit on the co-location potential for ethanol production in California. Seventy-five percent of the total is from plants associated with host sites that are larger than 20 MW in size.

It is unlikely that all of the biomass power plants that are large enough to host co-located ethanol facilities will do so. It is also unlikely that all of the facilities that would host a co-located ethanol facility would be able to use fuel mixes with eighty percent lignin content. If eight 550 bdt/d ethanol production facilities were developed in California, the industry would have a production potential of approximately 100 million gallons per year, which is about 15 percent of the potential California market for ethanol fuels of 600 million gallons per year.

The biomass co-location configurations considered in this study all require the amount of total biomass procurement at the host site to increase by thirty percent or more, as compared with the situation before the initiation of the ethanol co-location project. In general, if the feedstock utilized by the ethanol production operation is essentially the same kind of material that is used by the host power plant, it is inevitable that the extra increment of biomass procured for the joint operations will have a higher unit cost than the average cost of the biomass procured by the host facility prior to co-location. If the ethanol facility can use a feedstock, such as rice straw, that is not a desirable boiler fuel, then this problem can be avoided. However, while California does produce large quantities of straws and other agricultural residues that are not of great interest to the biomass power plants, the bulk of the under-utilized biomass residue resource base in California is in-forest residues, and these materials tend to have relatively high production costs.

Biomass power generation in California is more expensive than many of the conventional alternative generating sources available to the state's grid. This fact leaves the state's biomass producers in a precarious position, dependent on public policy measures to compensate them for the valuable environmental services that are the ancillary products of biomass power production. This has led to a hope that co-location of an ethanol facility on their site would provide a higher-valued outlet for some of their energy output, and have a stabilizing influence on the business. In other words biomass power generators, who are the potential host sites for co-location projects, are hoping that a co-located ethanol facility could improve their own situation.

Ethanol production is itself an expensive process, especially using cellulose as a feedstock. The motivation among ethanol producers to pursue co-location opportunities is to avoid the necessity to include expensive steam and power generating equipment in their designs, and the possibility that other cost-savings arrangements might be possible. In other words each of the two enterprises is looking to the other for help, because each finds itself in an above-market production cost position. The reality is that each is limited in its capacity to help support the other's operations.

Based on all of the available information, it must be concluded that ethanol production from cellulosic resources in California will be expensive. In the best of circumstances, using advanced technology and low-cost feedstocks such as rice straw, it may be able to produce ethanol from cellulose in co-located facilities in California for a plant-gate selling price below \$1.40 per gallon. However, getting to this point will require progressing through a commercialization process that will involve producing ethanol that requires a plant-gate selling price of \$1.75 per gallon or more. In the long run, it appears that in order to approach California's ethanol from cellulose potential, long-term plant-gate prices in the neighborhood of \$1.50 per gallon will be required. Supporting such an enterprise will require significant public policy support.

Co-location of ethanol production facilities with existing coal-fired power plants may overcome some of the complications and issues involved with co-locating with existing biomass power plants. Coal facilities tend to be much larger than biomass facilities, which means that for a given sized ethanol production operation the host coal facility will burn a lower percentage of lignin in its fuel mix than a host biomass power plant, which may lead to fewer technical problems. On the other hand, lignin is more similar to conventional biomass fuels than it is to coal, so technical issues might still arise, even at lower percentages of lignin in the mixture. Site-specific considerations will have to be taken into account for any potential co-location project.

One advantage that co-location with coal-fired power plants may have over co-location with biomass facilities is that there is never any potential for the two co-located operations to be in competition with each other for the acquisition of biomass resources. All of the biomass procured at a given site will be used for the production of ethanol. Moreover, many coal co-location opportunities are in regions that have abundant biomass resources, but lack a competitive market for biomass residues. These areas are prime candidates for ethanol facility co-location.

Many potential coal-fired host-site candidates for ethanol co-location are economically stable operations, but have serious environmental issues. These operations could afford to share most or all of the economic benefits of co-location with the ethanol enterprise in return for receiving the environmental benefits that co-location provides. Co-location with coal facilities, however, still faces the most difficult issue that confronts co-location with biomass power plants. That is, due to the inherent characteristics of cellulosic biomass resources, cellulose-to-ethanol production operations will be smaller than grain-to-ethanol operations, and consequently will have higher unit production costs. Thus, even using advanced technologies, cellulose-to-ethanol facilities co-located with coal-fired power plants will require plant-gate selling prices in the neighborhood of $1.30 per gallon.

A possible approach to overcoming the limitation on facility size imposed on ethanol production operations utilizing biomass residues as a feedstock would be to develop conversion facilities that could convert a mixture of starch commodities or biomass crops such as fast-growing grasses, and conventional biomass residues. While evaluating the technical or economic feasibility of such operations is beyond the scope of this study, it is reasonable to assume, for example, that coal-fired power plants in the Southeast could act as host sites for forty million gallon per year ethanol production operations that utilize locally available wood products and forestry residues, and grain that arrives via rail from the Midwest.

Ethanol production from cellulosic biomass appears to be an expensive undertaking. Like electricity production from biomass, ethanol production from biomass residue resources will provide valuable environmental services that are not compensated in the commercial marketplace. This is a fertile area for public policy to address. Public support for the enterprise, both in terms of R&D and commercialization support to move the technology for ethanol production from cellulose into the marketplace, and some form of compensation for the environmental services and oil displacement benefits provided by converting wasted residues into a beneficial product, would make an enormous difference in developing the country's cellulose-to-ethanol potential.

References

Broder, Jacqueline, TVA, personal communications and written submissions prepared for this study concerning the specifications of the reference coal-fired power plant, January 2002.

Graf, A. and Koehler, T., *Oregon Cellulose-Ethanol Study*, Report to the Oregon Office of Energy, June 2000.

Merrick & Co., *Softwood Biomass to Ethanol Feasibility Study*, Merrick Project No. 19013104, Report to NREL, June 14, 1999.

Morris, G., *Fuel Use and other Characteristics of Biomass Power Plants in the U.S. and Canada*, FRA report for Hydro-Québec, December, 1994.

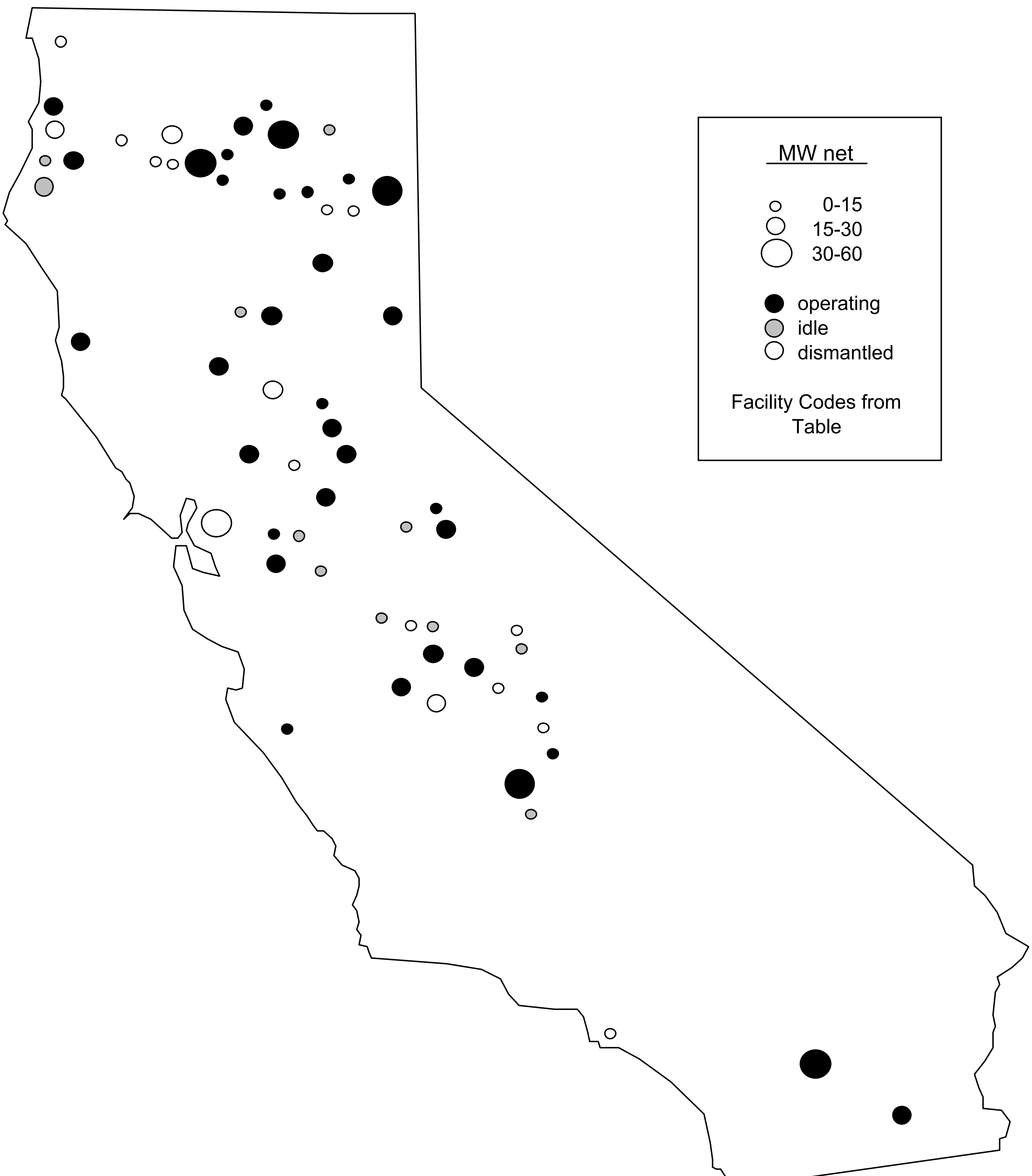
Morris, G., *The Value of the Benefits of U.S. Biomass Power*, NREL Report No. NREL/SR-570-27541, November 1999.

Morris, G., *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*, NREL Report No. NREL/SR-570-28805, November 2000.

Uhland, Jerry, California Rice Commission, personal communication, June 2001.

Unnasch, S., Kaahaaina, N., Kassoy, E., Vehkatesh, S., Rury, P., Counts, R., *Costs and Benefits of a Biomass-to-Ethanol Production Industry in California*, California Energy Commission Report No. P500-01-002, 2001.

Figure 1
California Biomass Power Plants, 1980-2002



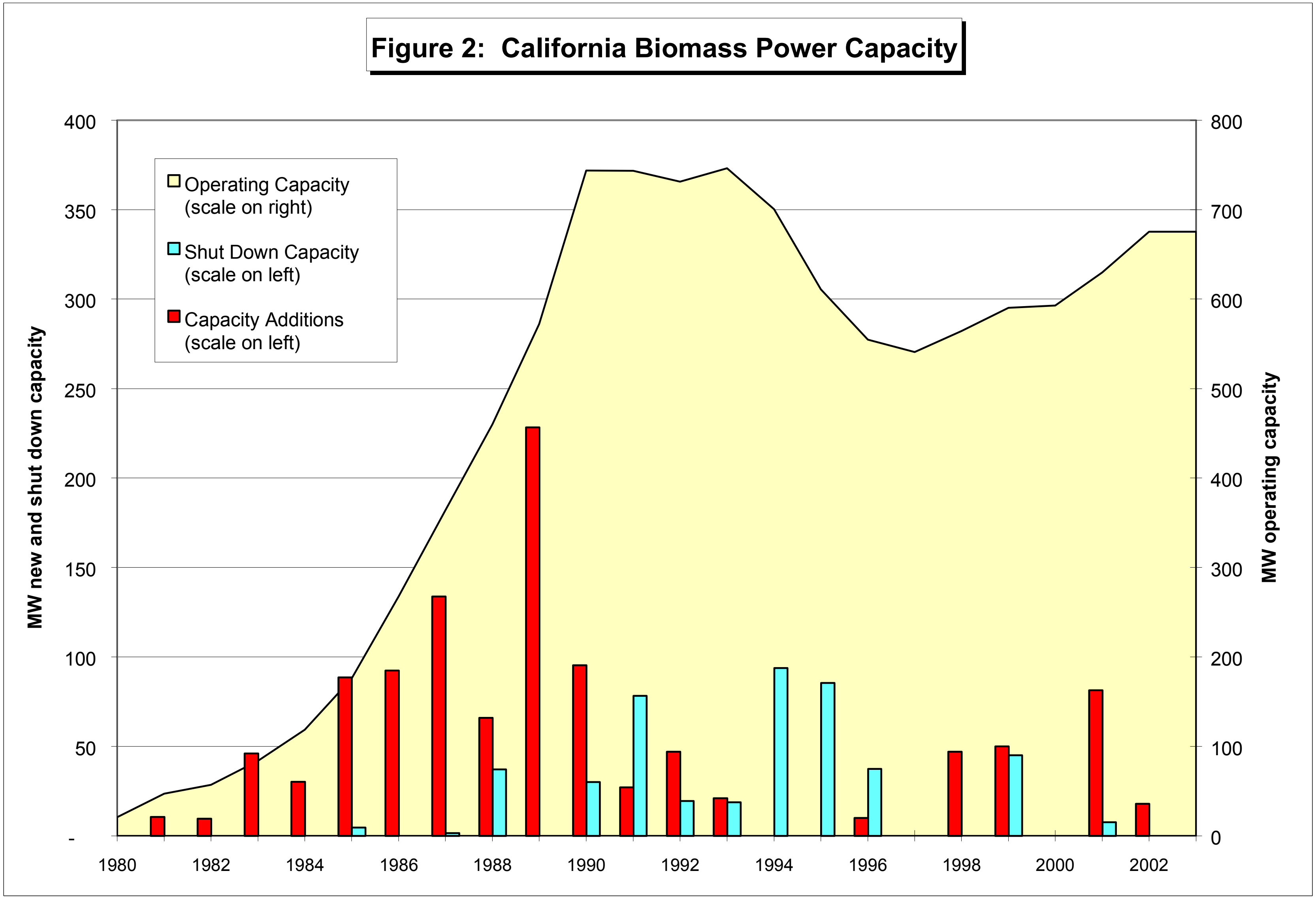
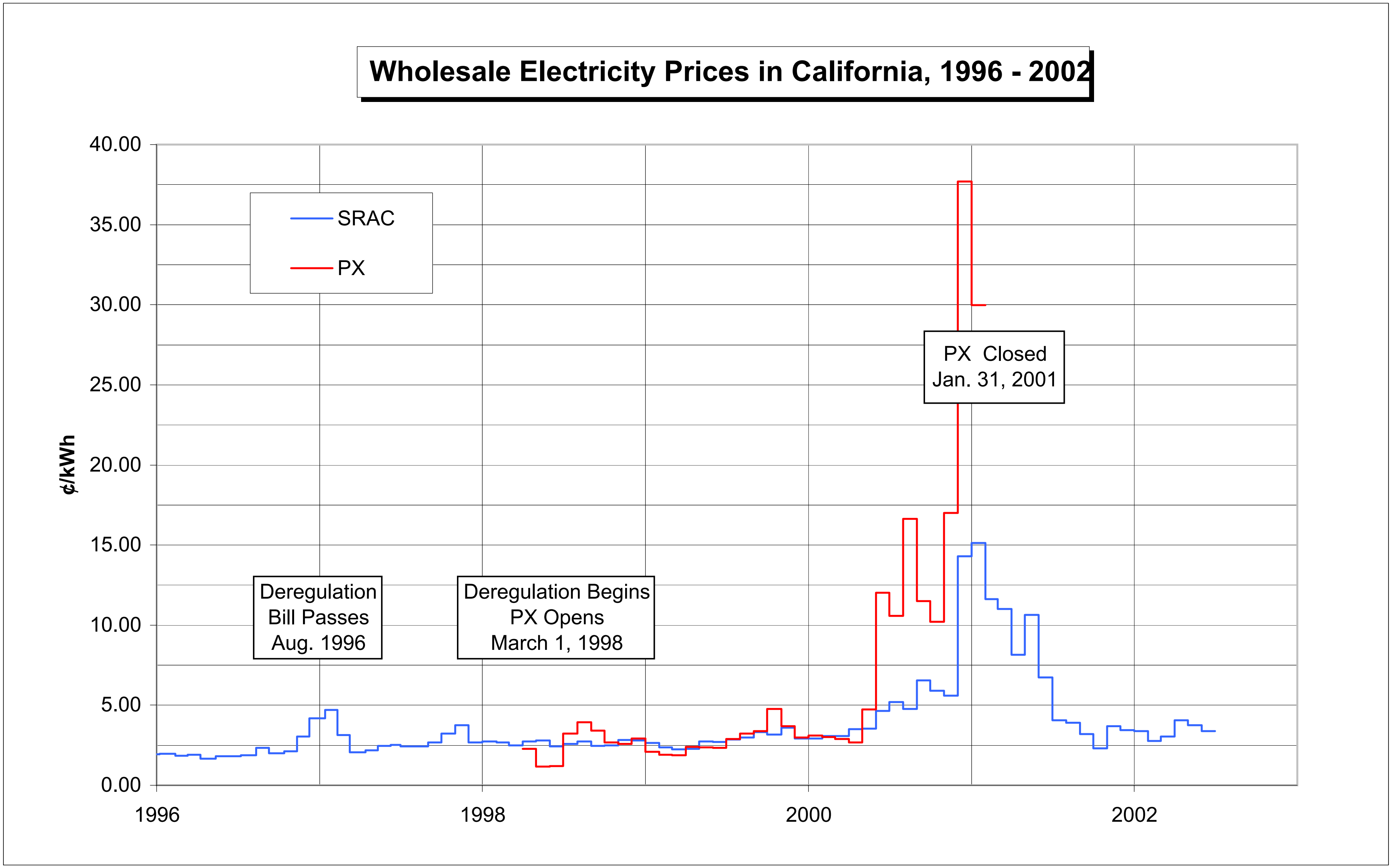


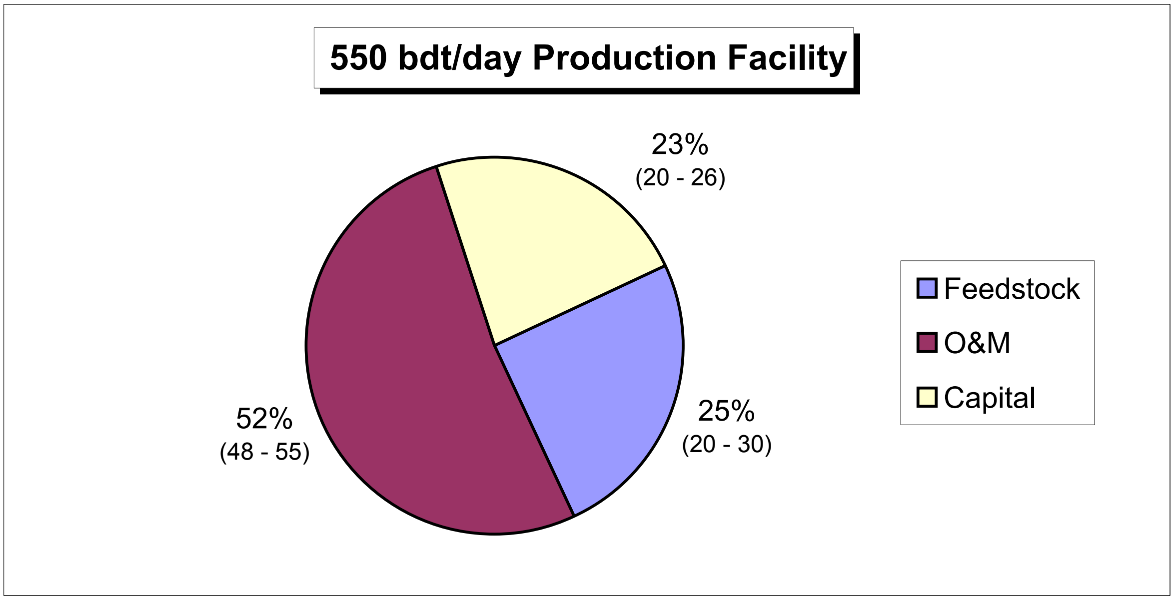
Figure 2: California Biomass Power Capacity
Operating Capacity (scale on right)
Shut Down Capacity (scale on left)
Capacity Additions (scale on left)
MW new and shut down capacity
MW operating capacity
400
350
300
250
200
150
100
50
-
800
700
600
500
400
300
200
100
0
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002

Figure 3



Wholesale Electricity Prices in California, 1996 - 2002
SRAC
PX
PX Closed
Jan. 31, 2001
Deregulation
Bill Passes
Aug. 1996
Deregulation Begins
PX Opens
March 1, 1998
¢/kWh
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1996
1998
2000
2002

Figure 4
Cost of Ethanol Production



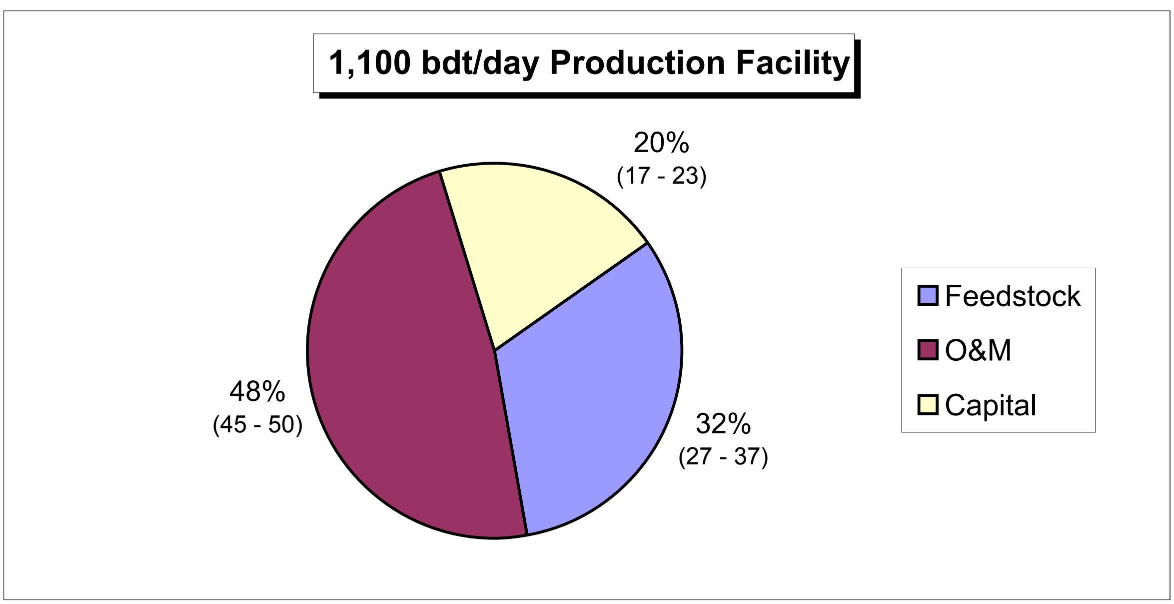


Figure 5: Ethanol Price vs. Feedstock Cost

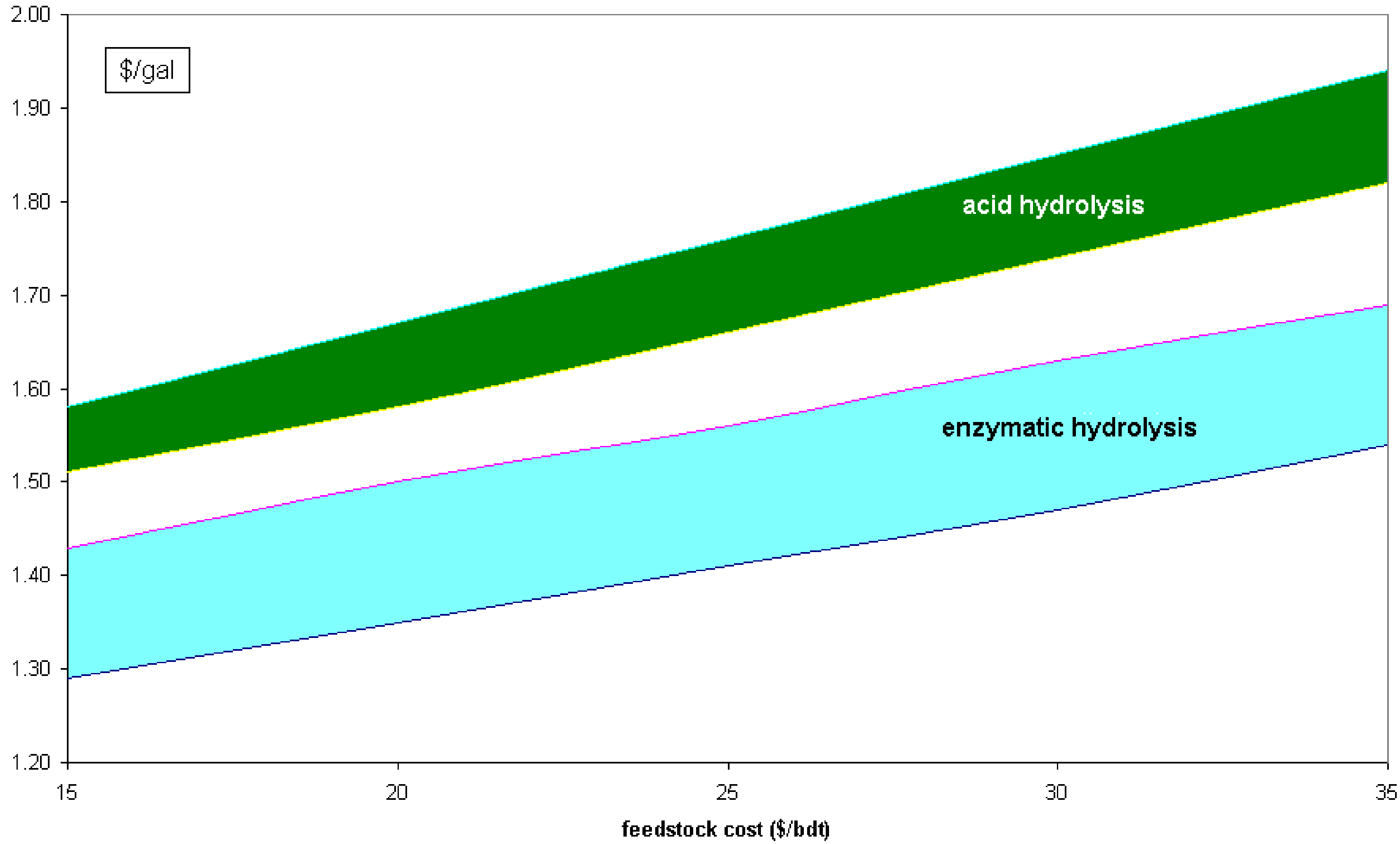


Figure 6

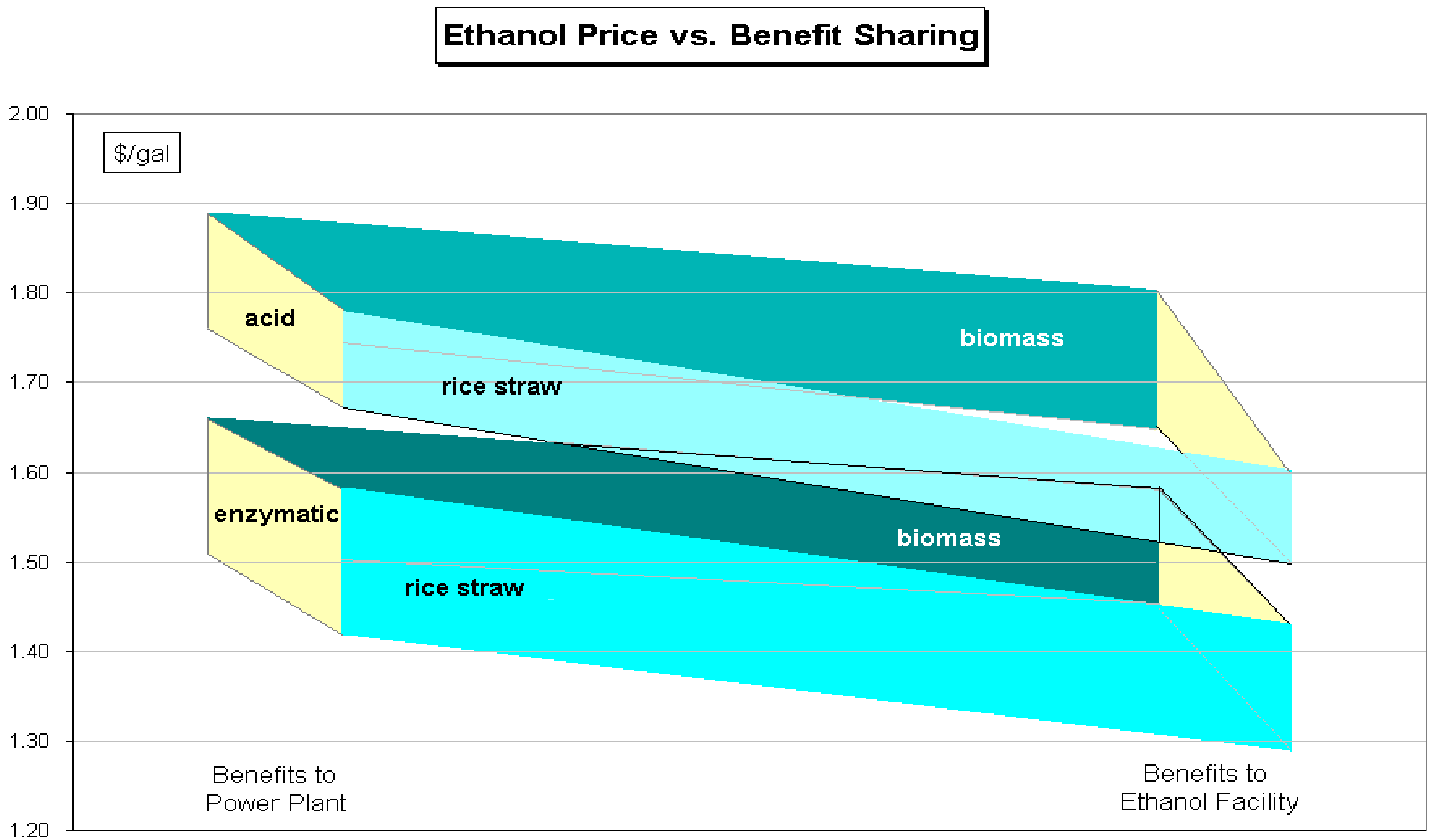

Ethanol Price vs. Benefit Sharing
$/gal
2.00
1.90
1.80
1.70
1.60
1.50
1.40
1.30
1.20
acid
biomass
rice straw
enzymatic
biomass
rice straw
Benefits to Power Plant
Benefits to Ethanol Facility

Figure 7

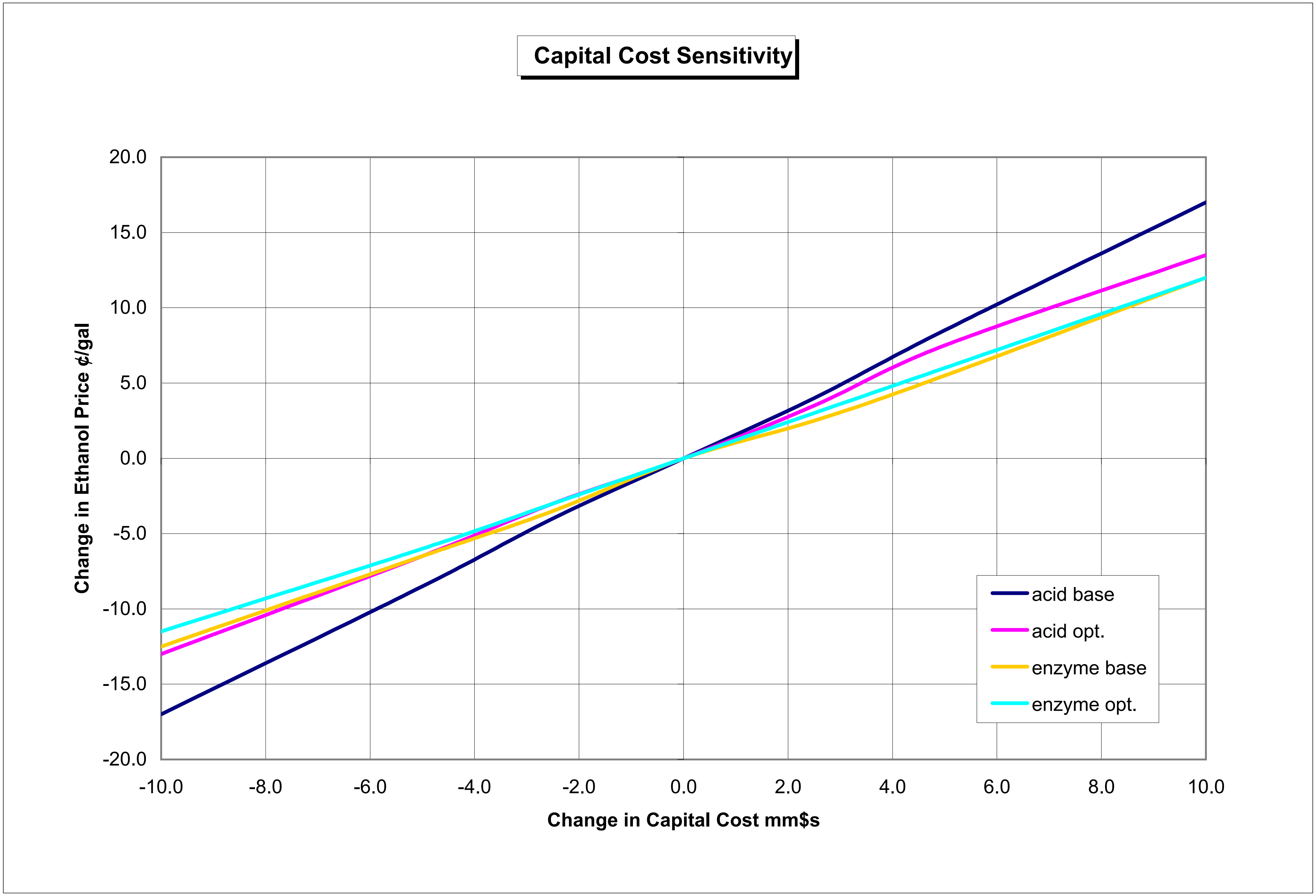
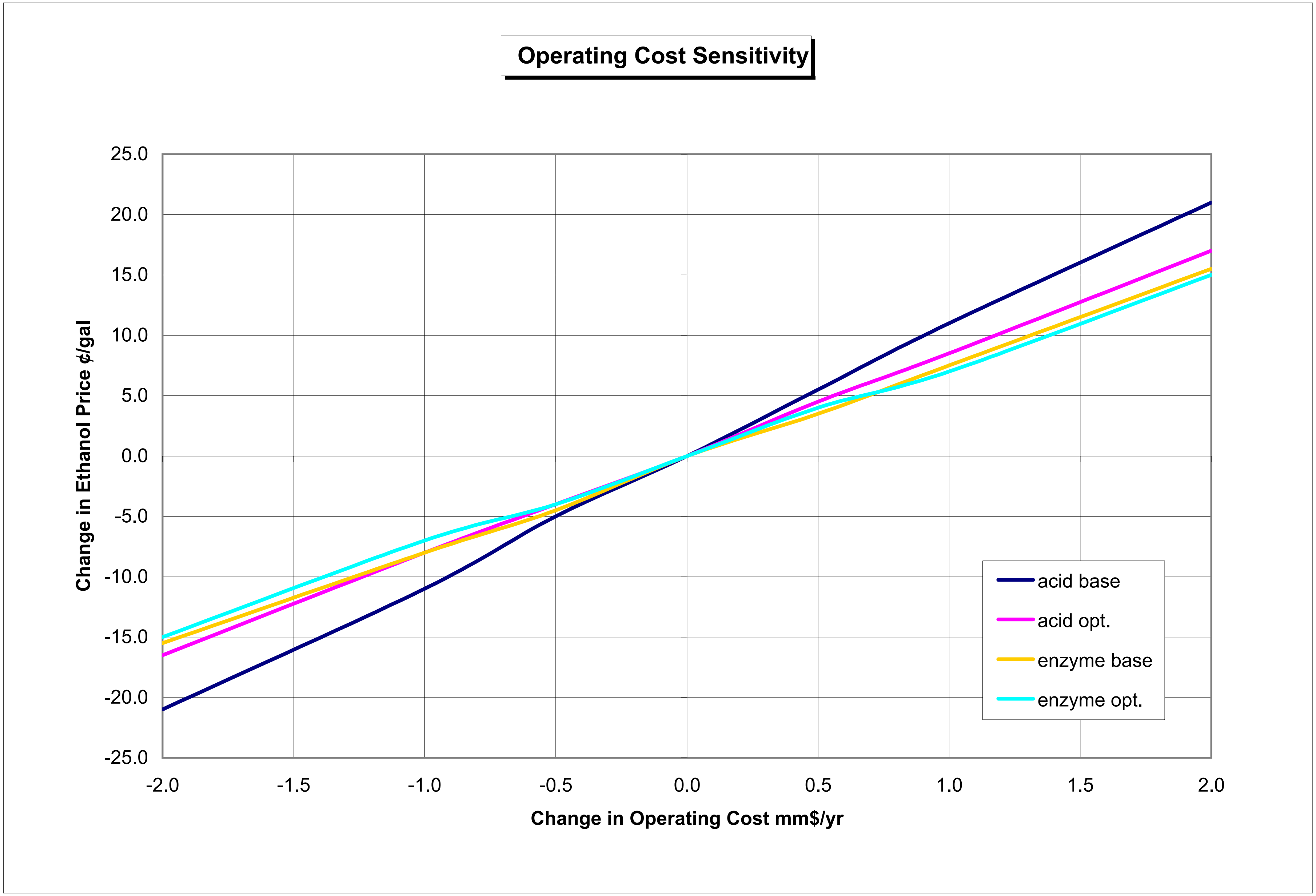
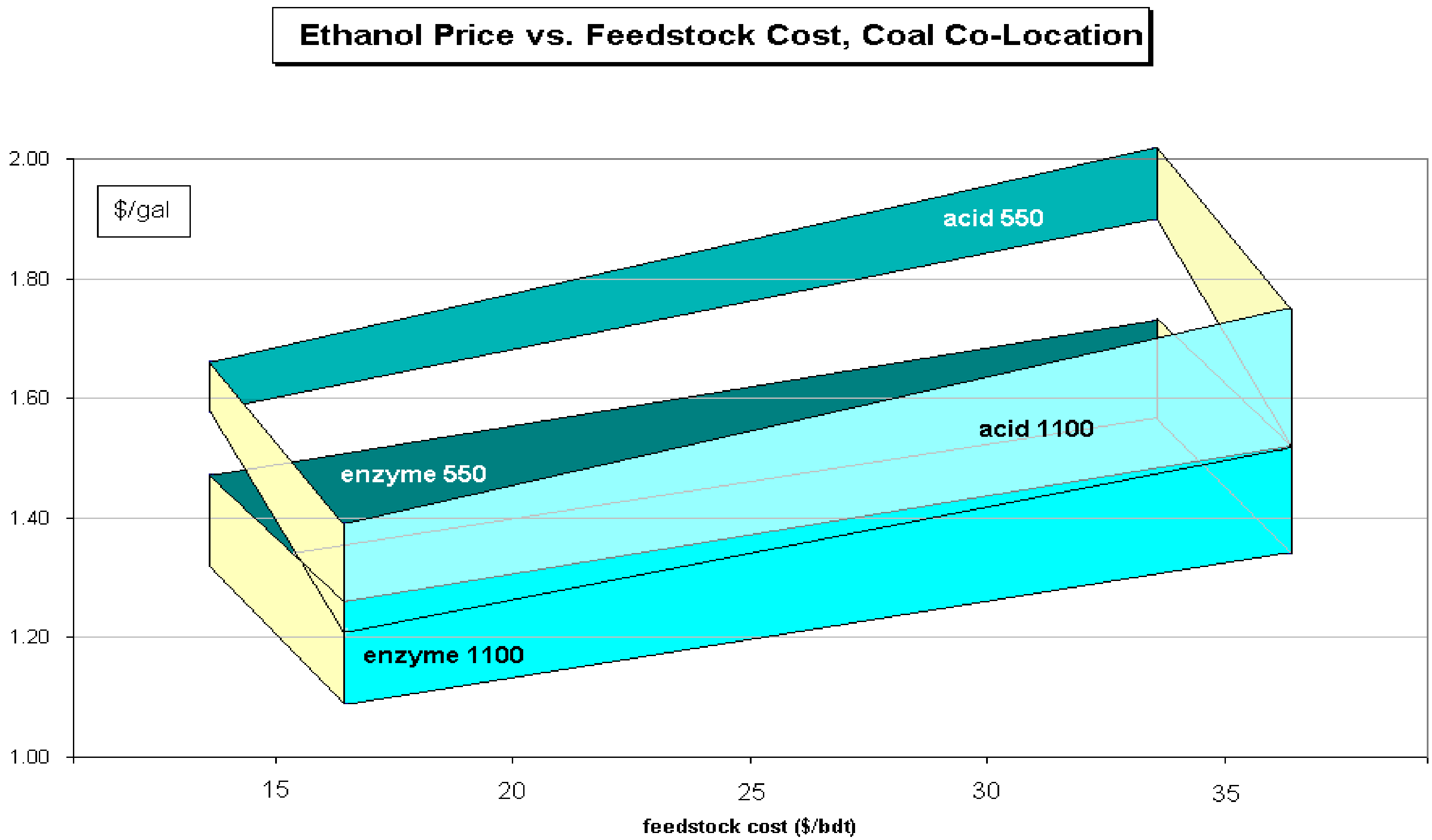

Capital Cost Sensitivity
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
Change in Ethanol Price ¢/gal
-10.0
-8.0
-6.0
-4.0
-2.0
0.0
2.0
4.0
6.0
8.0
10.0
Change in Capital Cost mm$s
acid base
acid opt.
enzyme base
enzyme opt.

Figure 8



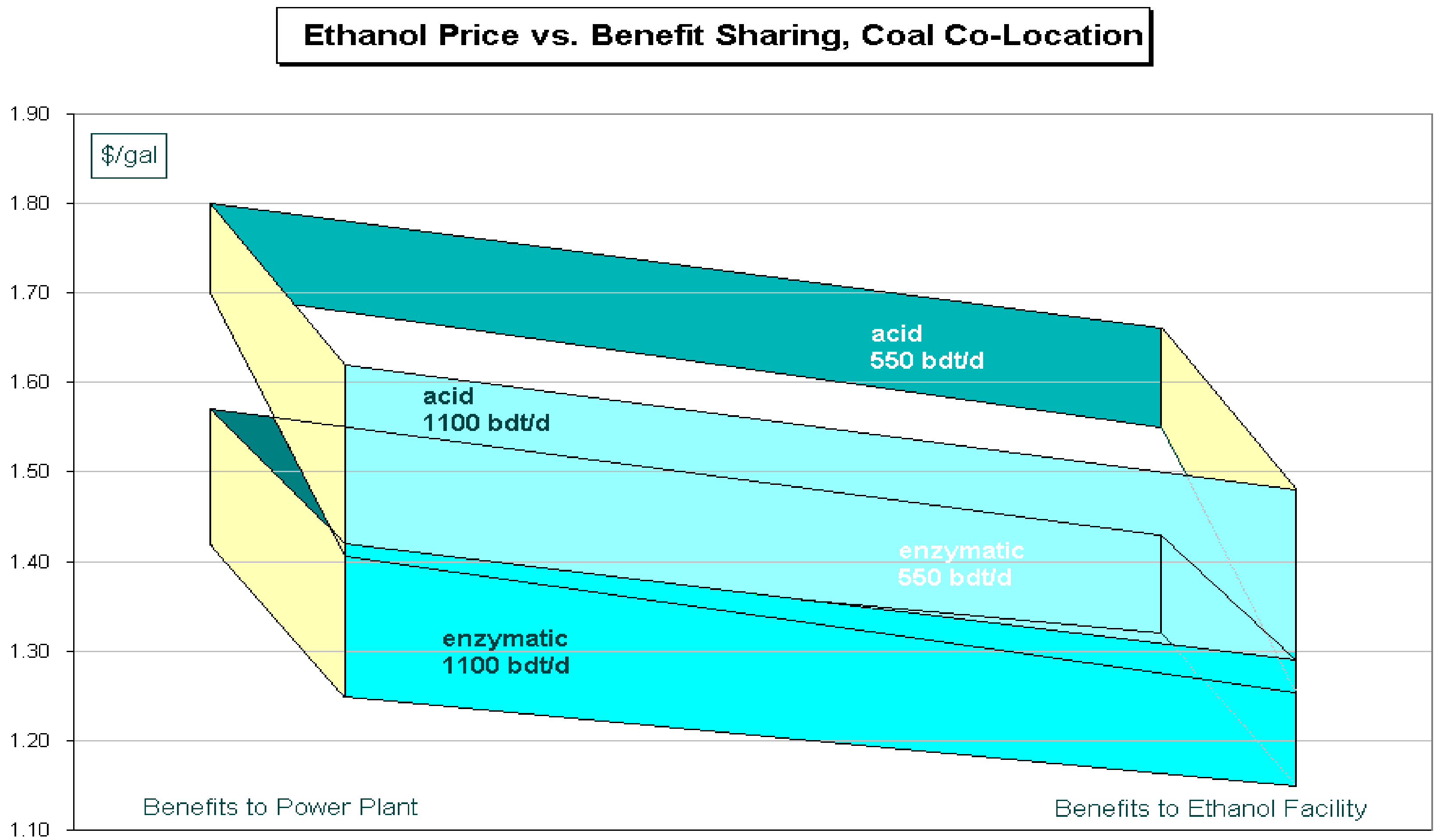
Operating Cost Sensitivity
Change in Ethanol Price ¢/gal
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
-2.0
-1.5
-1.0
-0.5
0.0
0.5
1.0
1.5
2.0
Change in Operating Cost mm$/yr
acid base
acid opt.
enzyme base
enzyme opt.

Figure 9



Ethanol Price vs. Feedstock Cost, Coal Co-Location
$/gal
2.00
1.80
1.60
1.40
1.20
1.00
acid 550
acid 1100
enzyme 550
enzyme 1100
15
20
25
30
35
feedstock cost ($/bdt)

Figure 10



Ethanol Price vs. Benefit Sharing, Coal Co-Location
$/gal
1.90
1.80
1.70
1.60
1.50
1.40
1.30
1.20
1.10
acid
550 bdt/d
acid
1100 bdt/d
enzymatic
550 bdt/d
enzymatic
1100 bdt/d
Benefits to Power Plant
Benefits to Ethanol Facility

Table 1
Worksheets in Pro Forma Engineering / Financial Model

PF Comb: Combined Pro Forma financial statement for the power and ethanol production operations.

PF Cogen: Pro Forma financial statement for the cogeneration operation.

PF Etoh: Pro Forma financial statement for the ethanol production operation.

Capital: Statement of capital accounts for both the cogeneration and ethanol production operations. Input data relating to capital costs, financing terms, and depreciation are entered on this page. Some of the key financial results for a model run are presented on this page.

Scenarios: This page shows a series of inflation factors used in the model for out-year calculations. All of the series are input in this page, and can be manipulated in a variety of ways.

Ops Power: This page presents the operating specifications and cost factors for the cogeneration facility for periods when the ethanol facility is not operational (e.g., during the planning and development of the ethanol facility). A variety of operating parameters and unit costs are entered on this page.

Ops Comb: This page presents the operating specifications and cost factors for the cogeneration facility for periods when the ethanol facility is operational. A variety of operating parameters and unit costs are entered on this page.

O&M: This page is used for inputs and calculations relating to the operations of both the power production and the ethanol production facilities.

Labor: This page is used for inputs and calculations relating to the labor component of operations for both enterprises.

Biomass: This page is used for inputs and calculations relating to the biomass use component of operations for both enterprises.

E-20: This page is used to calculate the retail electric rate component pertaining to the purchase of electricity by the ethanol production enterprise. PG&E tariff schedule E-20 is entered on this page.

Ht Bal: This page is used to calculate the boiler fuel requirement for the cogeneration facility under a variety of operating conditions. Various inputs are entered on this page.

Table 2
Specifications for Co-Located Ethanol Production Facilities

	Dilute Acid Hydrolysis				Enzymatic Hydrolysis			
	550 bdt/d		1100 bdt/d		550 bdt/d		1100 bdt/d	
	base	optimistic	base	optimistic	base	optimistic	base	optimistic
Feedstock use bdt/yr	180,000	180,000	360,000	360,000	180,000	180,000	360,000	360,000
Ethanol Production gal/bdt	51.5	60.0	51.5	60.0	71.6	75.1	71.6	75.1
Ethanol production mil.gal/yr	9.3	11.8	18.6	23.6	12.9	13.6	25.8	27.2
Electric use kW	2,500	4,063	4,730	8,125	2,980	2,906	5,410	4,954
HP steam use lb/h	42,500	41,250	85,090	82,500	41,540	14,725	82,760	29,450
LP steam use lb/h	30,240	30,315	61,190	60,625	45,970	60,000	92,240	121,000
Lignin Production dry ton/bdt	0.70	0.52	0.70	0.52	0.55	0.64	0.55	0.64
Lignin Production dry ton/yr	126,500	102,000	253,000	204,000	98,100	115,700	196,200	231,400
lignin moisture %	55%	50%	55%	50%	50%	50%	50%	50%
lignin heat value btu/dry lb	8,580	10,043	8,580	10,043	8,775	7,588	8,775	7,589
Digester Gas mmbtu/hr	4.0	32.5	8.0	65.0	18.0	4.0	36.0	7.0
Labor # full-time	28.0	44.0	35.0	68.0	28.0	28.0	35.0	35.0
EPC Cost m$s	37.0	48.1	60.0	72.9	49.0	47.7	80.0	73.4
Capital Cost mil.$s	44.0	56.5	69.9	84.4	57.5	56.0	92.3	85.0
O&M Cost mil.$s/yr	8.7	9.9	15.4	17.3	10.0	9.1	17.9	15.7
Ethanol Price $/gal	1.80	1.67	1.56	1.40	1.58	1.43	1.36	1.19

Table 3

Defined Biomass Reference Plants

	25 MW	50 MW
Rated Output kW	25,000	50,000
Capacity Factor	90%	90%
Fuel Use bdt/yr	180,000	360,000
Boiler Output lb/hr	260,000	510,000
Labor # Full Time	30	48
Capital Cost (new) mil.$s	45	70
O&M Cost mil.$/yr	4.4	6.8

Pro Forma Statement, Cogeneration Facility

Table 4

(all values in thousands of Dollars, except as noted)

25 MW Biomass Plant base case, SO#4, 5 year fixed option, then SRAC

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Revenues												
	Off-Site Sales of Electricity	10,561	16,069	16,069	16,069	14,366	12,735	12,808	12,881	12,955	13,030	13,105
	AB 995 Supplement	245	294	294	294	1,138	1,981	1,981	1,981	1,981	1,981	1,981
	Electricity to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Steam to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Total Revenues	10,806	16,363	16,363	16,363	15,504	14,717	14,789	14,862	14,936	15,011	15,086
Expenses												
	Fuel	3,247	5,477	5,518	5,560	5,602	5,644	5,686	5,729	5,772	5,815	5,858
	Personnel	1,147	2,006	2,046	2,087	2,129	2,172	2,215	2,259	2,305	2,351	2,398
	Operations & Maintenance	1,158	2,025	2,065	2,106	2,149	2,192	2,235	2,280	2,326	2,372	2,420
	Taxes, G & A	248	434	442	451	460	469	479	488	498	508	518
	Total Expenses	5,801	9,942	10,072	10,205	10,339	10,476	10,615	10,756	10,900	11,046	11,194
Operating Margin		5,006	6,422	6,291	6,159	5,165	4,240	4,174	4,106	4,036	3,965	3,893
Capital Accounts												
	Payments of Principal	996	2,145	2,368	2,614	2,885	3,185	3,515	1,892	-	-	-
	Interest Payments	968	1,782	1,559	1,313	1,042	742	412	71	-	-	-
	Depreciation	3,370	5,857	4,332	3,220	2,409	2,280	2,223	1,411	599	599	369
	Coverage Ratio	*2.55*	*1.64*	*1.60*	*1.57*	*1.32*	*1.08*	*1.06*	*2.09*	*NA*	*NA*	*NA*
Cash Flows												
	Taxable Income	668	-	-	809	1,714	1,218	1,539	2,624	3,438	3,367	3,523
	Pre-Tax Cash Flow	3,042	2,495	2,364	2,232	1,238	314	247	2,143	4,036	3,965	3,893
	Income Tax	200	-	-	243	514	365	462	787	1,031	1,010	1,057
	After-Tax Cash Flow	2,842	2,495	2,364	1,989	724	(52)	(215)	1,355	3,005	2,955	2,836
Balance Sheet												
	Assets	28,000	26,600	25,200	23,800	22,400	21,000	19,600	18,200	16,800	15,400	14,000
	Liabilities	18,604	16,459	14,091	11,477	8,592	5,407	1,892	(0)	(0)	(0)	(0)
	Distributions	2,842	2,495	2,364	1,989	724	-	-	1,355	3,005	2,955	2,836

Pro Forma Statement, Cogeneration Facility

Table 5

(all values in thousands of Dollars, except as noted)

25 MW Biomass Plant base case, CPA Contract @ 6.56 ¢/kWh

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Revenues											
	Off-Site Sales of Electricity	8,021	13,128	13,260	13,392	13,526	13,661	13,798	13,936	14,075	14,216
	AB 995 Supplement	-	-	-	-	-	-	-	-	-	-
	Electricity to Ethanol	-	-	-	-	-	-	-	-	-	-
	Steam to Ethanol	-	-	-	-	-	-	-	-	-	-
	Total Revenues	8,021	13,128	13,260	13,392	13,526	13,661	13,798	13,936	14,075	14,216
Expenses											
	Fuel	3,247	5,477	5,518	5,560	5,602	5,644	5,686	5,729	5,772	5,815
	Personnel	1,147	2,006	2,046	2,087	2,129	2,172	2,215	2,259	2,305	2,351
	Operations & Maintenance	1,158	2,025	2,065	2,106	2,149	2,192	2,235	2,280	2,326	2,372
	Taxes, G & A	248	434	442	451	460	469	479	488	498	508
	Total Expenses	5,801	9,942	10,072	10,205	10,339	10,476	10,615	10,756	10,900	11,046
Operating Margin		2,220	3,186	3,187	3,188	3,187	3,185	3,183	3,180	3,176	3,170
Capital Accounts											
	Payments of Principal	996	2,145	2,368	2,614	2,885	3,185	3,515	1,892	-	-
	Interest Payments	968	1,782	1,559	1,313	1,042	742	412	71	-	-
	Depreciation	3,370	5,857	4,332	3,220	2,409	2,280	2,223	1,411	599	599
	Coverage Ratio	*1.13*	*0.81*	*0.81*	*0.81*	*0.81*	*0.81*	*0.81*	*1.62*	*NA*	*NA*
Cash Flows											
	Taxable Income	-	-	-	-	-	-	-	-	-	-
	Pre-Tax Cash Flow	257	(740)	(739)	(739)	(740)	(742)	(744)	1,216	3,176	3,170
	Income Tax	-	-	-	-	-	-	-	-	-	-
	After-Tax Cash Flow	257	(740)	(739)	(739)	(740)	(742)	(744)	1,216	3,176	3,170
Balance Sheet											
	Assets	28,000	26,600	25,200	23,800	22,400	21,000	19,600	18,200	16,800	15,400
	Liabilities	18,604	16,459	14,091	11,477	8,592	5,407	1,892	(0)	(0)	(0)
	Distributions	257	-	-	-	-	-	-	1,216	3,176	3,170

Pro Forma Statement, Cogeneration Facility — Table 6

(all values in thousands of Dollars, except as noted)

50 MW Biomass Plant base case, SO#4, 5 year fixed option, then SRAC

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Revenues												
	Off-Site Sales of Electricity	17,653	32,139	32,139	32,139	28,733	25,471	25,616	25,762	25,910	26,059	26,210
	AB 995 Supplement	392	588	588	588	2,276	3,963	3,963	3,963	3,963	3,963	3,963
	Electricity to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Steam to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Total Revenues	18,045	32,727	32,727	32,727	31,008	29,433	29,578	29,725	29,873	30,022	30,173
Expenses												
	Fuel	5,905	11,681	11,769	11,857	11,946	12,035	12,126	12,216	12,308	12,400	12,493
	Personnel	1,796	3,140	3,203	3,267	3,332	3,399	3,467	3,536	3,607	3,679	3,753
	Operations & Maintenance	1,823	3,188	3,251	3,316	3,383	3,450	3,519	3,590	3,661	3,735	3,809
	Taxes, G & A	365	638	650	663	677	690	704	718	732	747	762
	Total Expenses	9,889	18,646	18,873	19,103	19,337	19,575	19,816	20,061	20,309	20,561	20,818
Operating Margin		8,156	14,081	13,854	13,624	11,671	9,859	9,763	9,664	9,564	9,461	9,355
Capital Accounts												
	Payments of Principal	1,600	3,448	3,806	4,201	4,637	5,118	5,650	3,041	-	-	-
	Interest Payments	1,555	2,863	2,505	2,110	1,674	1,193	662	115	-	-	-
	Depreciation	5,416	9,413	6,962	5,176	3,872	3,665	3,573	2,268	962	962	594
	Coverage Ratio	*2.58*	*2.23*	*2.20*	*2.16*	*1.85*	*1.56*	*1.55*	*3.06*	*NA*	*NA*	*NA*
Cash Flows												
	Taxable Income	1,185	1,804	4,387	6,338	6,125	5,001	5,528	7,282	8,601	8,498	8,762
	Pre-Tax Cash Flow	5,001	7,770	7,543	7,313	5,360	3,547	3,451	6,509	9,564	9,461	9,355
	Income Tax	356	541	1,316	1,901	1,837	1,500	1,658	2,185	2,580	2,550	2,629
	After-Tax Cash Flow	4,645	7,229	6,227	5,411	3,523	2,047	1,793	4,324	6,983	6,911	6,727
Balance Sheet												
	Assets	45,000	42,750	40,500	38,250	36,000	33,750	31,500	29,250	27,000	24,750	22,500
	Liabilities	29,900	26,452	22,646	18,446	13,809	8,691	3,041	0	0	0	0
	Distributions	4,645	7,229	6,227	5,411	3,523	2,047	1,793	4,324	6,983	6,911	6,727

Pro Forma Statement, Cogeneration Facility — Table 7

(all values in thousands of Dollars, except as noted)

50 MW Biomass Plant base case, CPA Contract @ 6.56 ¢/kWh

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Revenues												
	Off-Site Sales of Electricity	16,409	26,271	26,534	26,799	27,067	27,338	27,612	27,888	28,167	28,448	28,733
	AB 995 Supplement	-	-	-	-	-	-	-	-	-	-	-
	Electricity to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Steam to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Total Revenues	16,409	26,271	26,534	26,799	27,067	27,338	27,612	27,888	28,167	28,448	28,733
Expenses												
	Fuel	6,925	11,681	11,769	11,857	11,946	12,035	12,126	12,216	12,308	12,400	12,493
	Personnel	1,796	3,140	3,203	3,267	3,332	3,399	3,467	3,536	3,607	3,679	3,753
	Operations & Maintenance	1,823	3,188	3,251	3,316	3,383	3,450	3,519	3,590	3,661	3,735	3,809
	Taxes, G & A	365	638	650	663	677	690	704	718	732	747	762
	Total Expenses	10,909	18,646	18,873	19,103	19,337	19,575	19,816	20,061	20,309	20,561	20,818
Operating Margin		5,500	7,625	7,661	7,696	7,730	7,763	7,796	7,827	7,857	7,887	7,915
Capital Accounts												
	Payments of Principal	1,600	3,448	3,806	4,201	4,637	5,118	5,650	3,041	-	-	-
	Interest Payments	1,555	2,863	2,505	2,110	1,674	1,193	662	115	-	-	-
	Depreciation	5,416	9,413	6,962	5,176	3,872	3,665	3,573	2,268	962	962	594
	Coverage Ratio	*1.74*	*1.21*	*1.21*	*1.22*	*1.22*	*1.23*	*1.24*	*2.48*	*NA*	*NA*	*NA*
Cash Flows												
	Taxable Income	-	-	-	-	-	-	1,132	5,445	6,895	6,925	7,321
	Pre-Tax Cash Flow	2,344	1,314	1,350	1,385	1,419	1,452	1,485	4,672	7,857	7,887	7,915
	Income Tax	-	-	-	-	-	-	340	1,634	2,069	2,077	2,196
	After-Tax Cash Flow	2,344	1,314	1,350	1,385	1,419	1,452	1,145	3,038	5,789	5,809	5,719
Balance Sheet												
	Assets	45,000	42,750	40,500	38,250	36,000	33,750	31,500	29,250	27,000	24,750	22,500
	Liabilities	29,900	26,452	22,646	18,446	13,809	8,691	3,041	-	-	-	-
	Distributions	2,344	1,314	1,350	1,385	1,419	1,452	1,145	3,038	5,789	5,809	5,719

Table 8
Co-Location of 550 bdt/d Ethanol @ 25 MW Cogen

	Acid		Enzyme	
	Base	**Optimistic**	**Base**	**Optimistic**
Cogen Only				
Biomass bdt/yr	178,500	178,500	178,500	178,500
Grid Sales kW	25,000	25,000	25,000	25,000
Cogen Op. Mar. 2005 th.$s SO#4	6,159	6,159	6,159	6,159
Cogen Op. Mar. 2005 th.$s CPA	3,188	3,188	3,188	3,188
Combined Operation				
Total Biomass bdt/yr	236,000	230,000	247,200	259,900
Net Electric kW	20,100	20,200	19,300	20,400
Lignin Fuel to Boiler bdt/yr	127,100	103,000	99,000	116,000
Biomass Fuel to Boiler bdt/yr	54,600	31,900	65,600	78,300
Grid Sales kW	17,600	16,100	16,300	17,500
Change in 2005 Op.Mar. for Cogen (th.$s)				
Cogen with SO#4, no overfire, 45/15	267	803	382	318
Cogen with SO#4, 10% overfire, 45/15	927	1,282	878	963
Cogen with SO#4, 10% overfire, 15/5	509	1,069	608	572
Cogen with CPA, no overfire	754	1,519	1,021	838
Cogen with CPA, 10% overfire	960	1,725	1,227	1,042
Change in 2005 Op.Mar. for Cogen with Rice Straw Feedstock (th.$s)				
Cogen with SO#4, no overfire, 45/15	1,292	1,790	1,387	1,361
Cogen with SO#4, 10% overfire, 45/15	1,962	2,280	1,893	2,017
Cogen with SO#4, 10% overfire, 15/5	1,545	2,065	1,624	1,626
Cogen with CPA, no overfire	1,779	2,507	2,027	1,882
Cogen with CPA, 10% overfire	1,994	2,722	2,241	2,097
Required Price for Ethanol $/gal				
Wood Residue Feedstock	1.89	1.76	1.66	1.51
Rice Straw Feedstock	1.78	1.67	1.58	1.42

Table 9

Defined Coal Reference Plant

Rated Output kW	300,000
Capacity Factor	80%
Boiler Output lb/hr	2,185,000
Product Value ¢/kWh	2.5
Coal Use ton/yr	900,000
Coal $/mmbtu	1.00
Coal $/ton	22.00
Biomass $/bdt	
First 225,000 bdt/y	22.50
Additional bdt/y	36.00
Labor # Full Time	115
Capital Cost (new) mil.$s	330
O&M Cost mil.$/yr	14.3

Pro Forma Statement, Cogeneration Facility — Table 10

(all values in thousands of Dollars, except as noted)

300 MW Coal Plant base case, 2.5 ¢ average wholesale price

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Revenues												
	Off-Site Sales of Electricity	31,870	53,080	53,611	54,147	54,689	55,236	55,788	56,346	56,909	57,479	58,053
	AB 995 Supplement	-	-	-	-	-	-	-	-	-	-	-
	Electricity to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Steam to Ethanol	-	-	-	-	-	-	-	-	-	-	-
	Total Revenues	31,870	53,080	53,611	54,147	54,689	55,236	55,788	56,346	56,909	57,479	58,053
Expenses												
	Fuel	12,654	21,778	21,942	22,106	22,272	22,439	22,607	22,777	22,948	23,120	23,293
	Personnel	4,117	7,199	7,343	7,489	7,639	7,792	7,948	8,107	8,269	8,434	8,603
	Operations & Maintenance	3,558	6,222	6,346	6,473	6,603	6,735	6,870	7,007	7,147	7,290	7,436
	Taxes, G & A	525	918	936	955	974	994	1,014	1,034	1,054	1,076	1,097
	Total Expenses	20,854	36,117	36,567	37,024	37,488	37,960	38,438	38,925	39,418	39,920	40,429
Operating Margin		11,016	16,964	17,044	17,123	17,201	17,276	17,350	17,421	17,491	17,559	17,624
Capital Accounts												
	Payments of Principal	3,201	6,895	7,611	8,401	9,274	10,236	11,299	6,082	-	-	-
	Interest Payments	3,110	5,727	5,011	4,221	3,349	2,386	1,323	229	-	-	-
	Depreciation	10,832	18,827	13,923	10,351	7,745	7,330	7,146	4,535	1,925	1,925	1,187
	Coverage Ratio	*1.75*	*1.34*	*1.35*	*1.36*	*1.36*	*1.37*	*1.37*	*2.76*	*NA*	*NA*	*NA*
Cash Flows												
	Taxable Income	-	-	-	-	-	3,813	8,881	12,657	15,567	15,634	16,437
	Pre-Tax Cash Flow	4,705	4,341	4,422	4,501	4,578	4,654	4,728	11,110	17,491	17,559	17,624
	Income Tax	-	-	-	-	-	1,144	2,664	3,797	4,670	4,690	4,931
	After-Tax Cash Flow	4,705	4,341	4,422	4,501	4,578	3,510	2,063	7,313	12,821	12,868	12,693
Balance Sheet												
	Assets	90,000	85,500	81,000	76,500	72,000	67,500	63,000	58,500	54,000	49,500	45,000
	Liabilities	59,799	52,904	45,293	36,891	27,617	17,381	6,082	-	-	-	-
	Distributions	4,705	4,341	4,422	4,501	4,578	3,510	2,063	7,313	12,821	12,868	12,693

Table 11
Ethanol Co-Location @ 300 MW Coal Power Plant

	Acid		Enzyme	
	Base	Optimistic	Base	Optimistic
Cogen Only				
Coal ton/yr	901,000	901,000	901,000	901,000
Grid Sales kW	300,000	300,000	300,000	300,000
Cogen Op. Mar. 2005 th.$s	17,123	17,123	17,123	17,123
Combined Operation, 550 bdt/d Ethanol				
Net Electric kW	294,700	294,800	293,800	295,000
Grid Sales kW	292,200	290,800	290,800	292,100
Ethanol Production mil. gal/yr	9.3	11.8	12.9	13.6
Biomass Feedstock bdt/yr	181,000	197,000	181,000	181,000
Lignin Fuel to Boiler bdt/yr	126,000	102,000	98,000	116,000
Coal Fuel to Boiler ton/yr	838,000	821,000	842,000	852,000
Coal Savings %	7.0%	8.9%	6.5%	5.4%
dCogen Op. Mar. 2005 th.$s, no overfire	1,362	1,979	1,929	1,469
dCogen Op. Mar. 2005 th.$s, 10% overfire	2,103	2,719	2,669	2,210
Required Ethanol Selling Price $/gal	1.80	1.70	1.57	1.42
Combined Operation, 1100 bdt/d Ethanol				
Net Electric kW	289,400	289,700	287,600	290,000
Grid Sales kW	284,700	281,600	282,200	285,000
Ethanol Production mil. gal/yr	18.6	23.7	25.9	27.1
Biomass Feedstock bdt/yr	361,000	394,000	361,000	361,000
Lignin Fuel to Boiler bdt/yr	253,000	205,000	197,000	231,000
Coal Fuel to Boiler ton/yr	750,000	740,000	782,000	802,000
Coal Savings %	16.8%	17.9%	13.2%	11.0%
dCogen Op. Mar. 2005 th.$s, no overfire	2,884	3,973	3,758	2,793
dCogen Op. Mar. 2005 th.$s, 10% overfire	3,624	4,712	4,497	3,532
Required Ethanol Selling Price $/gal	1.62	1.41	1.42	1.25

REPORT DOCUMENTATION PAGE			*Form Approved* *OMB NO. 0704-0188*
Public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0188), Washington, DC 20503.			
1. AGENCY USE ONLY (Leave blank)	2. REPORT DATE November 2002	3. REPORT TYPE AND DATES COVERED Subcontract Report, August 15, 2000—February 28, 2002	
4. TITLE AND SUBTITLE Bioethanol Co-Location Study			5. FUNDING NUMBERS XDH-0-30010-04 TA: BBA34300
6. AUTHOR(S) G. Morris			
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) Green Power Institute 2039 Shattuck Ave., Suite 402 Berkeley, CA 94704			8. PERFORMING ORGANIZATION REPORT NUMBER
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory 1617 Cole Blvd. Golden, CO 80401-3393			10. SPONSORING/MONITORING AGENCY REPORT NUMBER NREL/SR-510-33000
11. SUPPLEMENTARY NOTES NREL Technical Monitor: Robert Wallace			
12a. DISTRIBUTION/AVAILABILITY STATEMENT National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161			12b. DISTRIBUTION CODE
13. ABSTRACT *(Maximum 200 words)* This report describes the results of an analysis of the generic economic feasibility of co-locating ethanol production facilities with California biomass power plants, and with coal-fired power plants in the Southwest.			
14. SUBJECT TERMS ethanol; co-location; California			15. NUMBER OF PAGES
			16. PRICE CODE
17. SECURITY CLASSIFICATION OF REPORT Unclassified	18. SECURITY CLASSIFICATION OF THIS PAGE Unclassified	19. SECURITY CLASSIFICATION OF ABSTRACT Unclassified	20. LIMITATION OF ABSTRACT UL

NSN 7540-01-280-5500

Standard Form 298 (Rev. 2-89)
Prescribed by ANSI Std. Z39-18
298-102