December 2002 • NREL/SR-510-33001

Subcontractor Report

AES Greenidge Bioethanol Co-Location Assessment: Final Report

13 November 2001—31 August 2002

Easterly Consulting
Fairfax, Virginia

NREL

National Renewable Energy Laboratory

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Golden, Colorado 80401-3393

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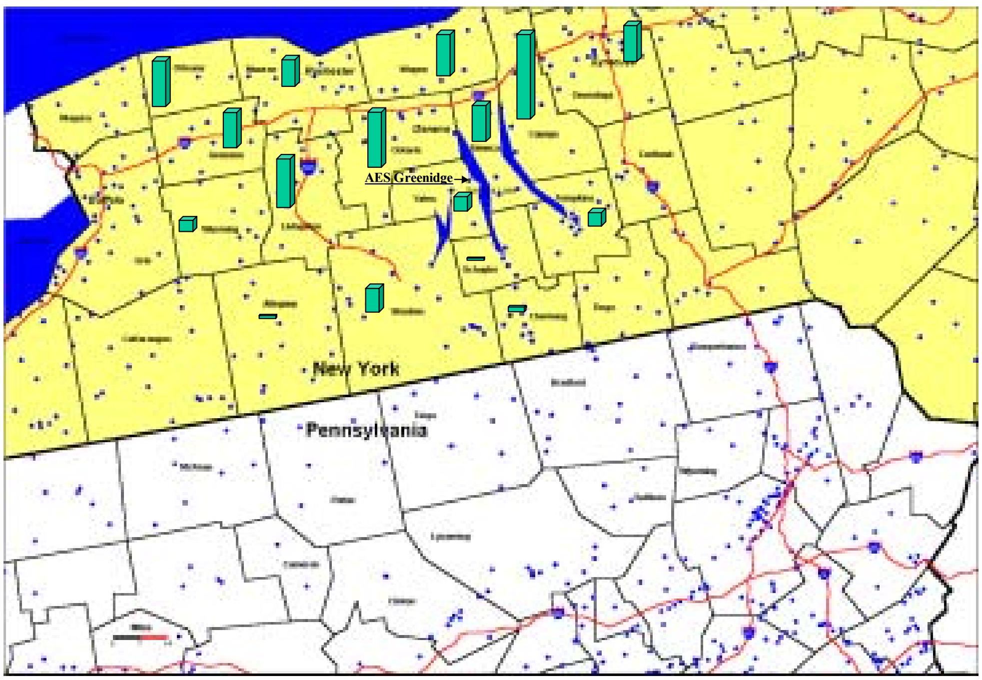

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Executive Summary

The feasibility of co-locating a cellulose-to-ethanol (bioethanol) facility at the existing AES Greenidge coal-fired electric power plant near Dresden, New York, has been evaluated in this study. The AES Greenidge facility currently obtains 8 to 10% of its energy by cofiring biomass, in the form of particleboard chips. The study evaluated the feasibility of developing a new bioethanol plant that would obtain steam for process heat (as well as electricity) from the Greenidge plant. In exchange, the bioethanol facility would provide biomass residues, primarily in the form of lignin, from the ethanol manufacturing process that would be either cofired with coal in the Greenidge boilers (in lieu of wood), or burned exclusively as the dedicated fuel in lieu of coal in one of the existing coal boilers (by converting an existing coal boiler to dedicated use of "lignin mix" fuel). The co-production approach could reduce costs for the bio-ethanol facility by approximately 35%, by avoiding the need for the ethanol facility to purchase and install its own boiler and turbine generator for process energy needs and lignin utilization. In addition, sharing personnel between the power and ethanol plants could reduce O&M costs for bio-ethanol production.

Since the Greenidge power plant is in the corn production region of New York State (NYS), the potential availability of corn stover as an ethanol feedstock was evaluated for this site. Annual corn stover availability for the AES Greenidge site was estimated to be approximately 330,000 dry tons per year at a delivered price of about $35.70 per dry ton, assuming that 30% of the total available corn stover from the local counties surrounding the AES Greenidge site is utilized. Assuming a relatively conservative yield of 60 gallons of ethanol per dry ton of feedstock for a 20 million gallon bioethanol facility using a two-stage dilute-sulfuric acid hydrolysis system, the amount of feedstock required would be 333,000 dry tons per year, or about 950 dry tons per day if the facility operates 350 days per year.

In addition to corn stover, a preliminary assessment was made of other potential bioethanol feedstocks in order to provide a more complete picture of resource options, with the idea that some degree of diversity in the feedstock supply could help reduce project risks and potentially help reduce average feedstock costs. Sawmill residues from Pennsylvania could supply roughly 100,000 dry tons per year at a delivered cost of about $36 per dry ton. Additional miscellaneous sources of wood waste are available in NYS, including waste wood that could be separated from waste streams in major urban centers in the broad New York region and delivered to the AES Greenidge site via truck or rail. Under the Conservation Reserve Program (CRP) Pilot Project for bioenergy crops that USDA has awarded New York State, energy crops (willow trees and switchgrass) could potentially provide about 200,000 dry tons per year of feedstock for a bioethanol facility at the AES Greenidge site.

Two basic configurations were evaluated for the co-located bioethanol facility:

1) An ethanol facility with co-current dilute acid prehydrolysis and enzymatic hydrolysis, based on cost and performance parameters anticipated to be achievable by the year 2010; and
2) An ethanol facility with two-stage dilute acid hydrolysis, based on cost and performance parameters anticipated being achievable in the 2004 timeframe.

Design and cost estimates were developed for a number of key variables for each of these system configurations. In each case it was assumed that a quantity of 1,000 dry tons per day of corn stover would be used for the feedstock supply. Easterly Consulting collaborated closely with NREL in efforts to model the design and cost parameters under this task – NREL modified and ran their latest 2-stage dilute acid and enzymatic models with inputs provided by Easterly Consulting and AES Greenidge staff. In particular, AES Greenidge staff provided input on a variety of design and cost parameters related to the integration of their facility and operations with those of a potential bioethanol facility. These issues include factors such as steam availability and conditions, boiler and fuel feed parameters and limits, duty/dispatch cycles for the power plant that could impact steam availability and demand for lignin fuel, and acceptable cost parameters for steam sales and lignin purchases.

The evaluation included an assessment of opportunities to reduce O&M costs by sharing some personnel/functions between the coal power plant and the ethanol facility. It also addressed the potential to use methane from the bioethanol wastewater treatment plant as a potential fuel for the AES Greenidge "reburn" injectors. The reduction in NO_x emissions that the "reburn" system provides could allow the bioethanol facility to provide monetized value for this benefit (NO_x emission credits are traded in the Northeast). The design and cost evaluation also addressed a variety of other factors that could generate additional credits and revenue, including potential gypsum sales ($3/ton), carbon dioxide sales (for beverages, etc., $9/ton), SO_2 credits ($172/ton), and greenhouse gas credits ($1/ton of CO_2 equivalent). The results of the "base case" financial analysis for both the two-stage dilute acid and the enzymatic hydrolysis systems are summarized in Table ES-1, with the primary assumptions listed below the table.

Table ES-1. "Base Case" Financial Analysis Results

	Anticipated Commercial Availability	**Ethanol Yield**	**Ethanol Production**	**Total Installed Cost**	**Net Production Cost**	**Internal Rate of Return**
Ethanol Technology:	Year	gal/dry ton	gal/year	$	$/gal	%
2-Stage Dilute Acid	2004	64.4	23,600,000	$61,400,000	$0.93	23.3%
Enzymatic Hydrolysis	2010	89.7	31,400,000	$65,000,000	$0.82	38.0%

"Base Case" assumptions for both systems:
Ethanol Selling Price: $1.30/gallon in New York State
Feedstock Use: 1,000 dry tons/day of corn stover
Feedstock Cost: $35.70 per dry ton (delivered)
Equity Financing: 25%
Debt Financing: 75% at 8% interest for 15 years
Project Life: 20 years
$$: In Year 2000 dollars
Hours of Facility Operation Per Year: 8,406 hours

The sensitivity of profitability (internal rate of return (IRR)) for the AES Greenidge site was calculated for a number of variables, including feedstock cost, plant size (feed rate), ethanol selling price, owner equity, capital cost (total project investment), lignin selling price, steam costs, electricity costs, greenhouse gas credits, and labor costs. Substantial sensitivity/changes in IRR were found for feedstock cost, plant size, ethanol selling price, owner equity, and capital cost. Whereas the IRR was only modestly sensitive to changes in the selling price for lignin, steam costs, electricity costs, greenhouse gas credits, and labor costs.

The environmental impacts of siting and operating a commercial-scale bioethanol facility at the AES Greenidge site were also addressed. Lignin should typically have much lower sulfur content than coal, which will help reduce SO_2 emissions, when the lignin by-product stream from the ethanol process is used to replace coal use in the AES Greenidge boilers. Since lignin is a renewable fuel, it will reduce CO_2 emissions by offsetting fossil fuel/coal combustion; methane from the bioethanol wastewater treatment system offsets natural gas use for the reburn system used for NO_x control; and the ethanol fuel produced by the facility will reduce CO_2 emissions as it displaces gasoline/petroleum used for transportation. The bioethanol facility will have a wastewater treatment system that includes an anaerobic digester to treat the organic waste stream from the process. The design target is to have a facility with zero discharge of wastewater, where treated water is recycled for use in the bioethanol process. The gypsum produced as a by-product of the acid neutralization stage of a bioethanol facility could potentially be marketed as a soil amendment product, assuming that tests of gypsum verify that it has acceptable characteristics for this use. Depending on site-specific topography (e.g., land slope) and soil characteristics, a number of farms in the AES Greenidge area that currently use conventional tillage practices will need to switch to conservation tillage practices in order to allow for corn stover removal while maintaining acceptable protection for erosion.

The construction and operation of a bioethanol facility co-located at the AES Greenidge site will result in the creation of a significant number of jobs and a substantial amount of income in the region surrounding the site. An input-output analysis was performed to estimate direct and indirect jobs and income (as well as state and local tax revenues) that could result from the construction and operation of a bioethanol facility at the AES Greenidge site. The indirect impacts assessed included those resulting from functions that support the operation of the facility, and also included induced impacts due to ripple (multiplier) effects as direct and indirect income is re-spent through the regional/state economy. For the "base case" scenarios, it was found that the annual operation of the bioethanol facility would support/create \$39 million in income, 25 direct jobs, and 363 indirect jobs for the two-stage dilute acid system, and \$48 million in income, 25 direct jobs and 486 indirect jobs for the enzymatic hydrolysis system.

After January 1, 2004, New York State (NYS) has announced that it will no longer allow MTBE to be used as a fuel additive in gasoline. Ethanol fuel could play a significant role in replacing this MTBE (from an octane, oxygen, and fuel volume perspective), and could also reduce New York's 100 percent dependence on external fuel supplies. If reformulated gasoline (RFG) continues to require 2 percent oxygen content (per the U.S. Clean Air Act Amendment), the amount of ethanol needed in New York State to replace MTBE and its associated oxygen content, will be about 175 million gallons per year.

Task 1. Feedstock Supply Assessment

1.0 Overview

Available biomass resources for the AES Greenidge site were identified and quantified, with a primary focus on potential corn stover supplies, and a secondary focus on potential wood resources and energy crop supplies. The potential use of corn stover and waste wood in different seasons of the year could provide flexibility to deal with seasonal availability and storage issues for stover. Energy crops such as switchgrass can probably be blended with corn stover as an acceptable mix for bioethanol production. A dual (or multiple) feedstock approach could reduce the potential for suppliers of a particular feedstock to take advantage of captive demand perceptions in pricing their feedstock once a large bioethanol facility is constructed. In addition, the dual feedstock approach could add an element of diversity to the feedstock supply outlook, potentially helping to reduce barriers to project financing by reducing risks/uncertainties with regard to feedstock supplies and costs.

The target was to evaluate the availability and cost for obtaining enough biomass feedstock to supply a 20-million gallon per year or larger bioethanol facility. The criteria for evaluating feedstock supplies included:

- Feedstock availability
- Feedstock cost – including farmer payments, harvest costs, and transportation costs,
- Potential ethanol yields from the feedstock,
- The potential for co-products such as lignin fuel,
- Competitive uses for the feedstock
- Infrastructure barriers and opportunities, and
- Farmer education and acceptance issues.

1.1 Feedstock Supply Requirements vs. Facility Scale

Capital cost savings associated with the co-location approach should allow the bioethanol facility to be developed at a smaller scale than a stand-alone facility, from an economic competitiveness standpoint. Based on prior NREL analyses, it appears that a co-located bioethanol facility is likely to need a capacity of 20 million gallons per year or larger to be economically viable. Assuming a relatively conservative yield of 60 gallons of ethanol per dry ton of feedstock for a bioethanol facility using a two-stage dilute-sulfuric acid hydrolysis system, the amount of feedstock required would be 333,000 dry tons per year, or about 950 dry tons per day if the facility operates 350 days per year. Based on these assumptions, a key element of the feedstock analysis was to determine whether a supply of 950 dry tons (i.e., close to 1000 dry tons) or more of corn stover and/or wood could be available as feedstock for a bioethanol facility co-located at the AES Greenidge site.

1.2 Corn Stover Availability

Table 1.1 provides a summary of the amount of corn produced in the 16-county area surrounding the AES Greenidge site (out to a radius of approximately 75-miles from the site), as well as estimates of the potential supply of corn stover that could be available for bioethanol production. There is an average of 109 bushels of corn harvested per acre in these 16 counties. The estimates for corn stover availability are based on the assumption that approximately 1 dry ton of corn stover remains in the field for every ton of corn grain harvested (and that one bushel of corn weighs 56 pounds). Table 1.1 indicates that there could be a total of approximately 1.1 billion dry tons of corn stover from the 16 counties surrounding the AES Greenidge site. In general, it is likely that a portion of the corn stover will need to be left on the land to protect against soil erosion and to satisfy soil carbon requirements. In most cases 30% of the stover can safely be removed – the remaining 70% of the stover left in the field will generally be adequate to satisfy erosion and soil carbon requirements. (Issues regarding allowable stover removal are explored in greater detail later in this chapter.) Assuming that 30% of the stover is removed for use as feedstock for a bioethanol facility, approximately 330,000 dry tons of corn stover could be available in the 16 counties surrounding the AES Greenidge site. This would satisfy the target for feedstock availability needed for a 20 million gallon bioethanol facility.

Figure 1.1 illustrates the geographic distribution and magnitude of corn stover availability for the 16 counties listed in Table 1.1 (using the data for 30% stover utilization). The map illustrates that of the 16 counties in Table 1.1, those that lie generally to the south of the AES Greenidge site contribute fairly little to the potential corn stover supply. The counties that could supply the bulk of the stover to the Greenidge site are generally located along the east/west I-90 (New York Thruway) corridor, somewhat to the north of the site. While it is roughly 75 miles to the eastern- and western-most counties along this corridor from AES Greenidge, the strong transportation linkage offered by I-90 should help reduce the stover transportation costs for the counties that are further away.

Table 1.2 illustrates the amount of corn silage that is harvested in the counties surrounding AES Greenidge. While silage is not a likely to contribute to the supply of stover available for ethanol production, quantifying the amount of silage produced helps to fully illustrate the aggregate corn production activities in the region.

Table 1.1. Annual Corn Production and Stover Availability in the AES Greenidge Area

County	No. of Farms*	Acres of Corn*	Bu. of Corn per Year*	Total Tons of Stover per Year	30% of Total Stover (Tons) per Year	Ave. Bu. of Corn per Acre per Year	Ave. Acres per Farm
Cayuga	396	56,993	6,433,149	180,128	54,038	113	144
Ontario	289	39,289	4,324,098	121,075	36,322	110	136
Livingston	234	34,549	3,838,938	107,490	32,247	111	148
Orleans	139	31,335	3,606,152	100,972	30,292	115	225
Wayne	246	31,786	3,301,580	92,444	27,733	104	129
Onondaga	200	28,930	2,969,209	83,138	24,941	103	145
Seneca	176	26,722	2,940,061	82,322	24,697	110	152
Genesee	192	27,231	2,889,770	80,914	24,274	106	142
Monroe	117	21,614	2,270,703	63,580	19,074	105	185
Steuben	258	19,047	2,020,358	56,570	16,971	106	74
Yates	257	12,441	1,362,644	38,154	11,446	110	48
Tompkins	124	12,944	1,297,543	36,331	10,899	100	104
Wyoming	137	9,351	1,057,785	29,618	8,885	113	68
Chemung	48	3,751	426,943	11,954	3,586	114	78
Allegany	86	2,739	287,085	8,038	2,412	105	32
Schuyler	49	2,537	250,575	7,016	2,105	99	52
Total:	2,948	361,259	39,276,593	1,099,745	329,923	109	123

Total tons of Stover needed/year = 333,333
(assuming 20 million gal/yr capacity & 60 gal ethanol/dry ton)

*Corn grown for grain or seed
(does not include corn grown for silage or chop)

One bushel of corn = 56 lbs.
Approx. one ton of corn stover is produced for each ton of corn (grain) produced.

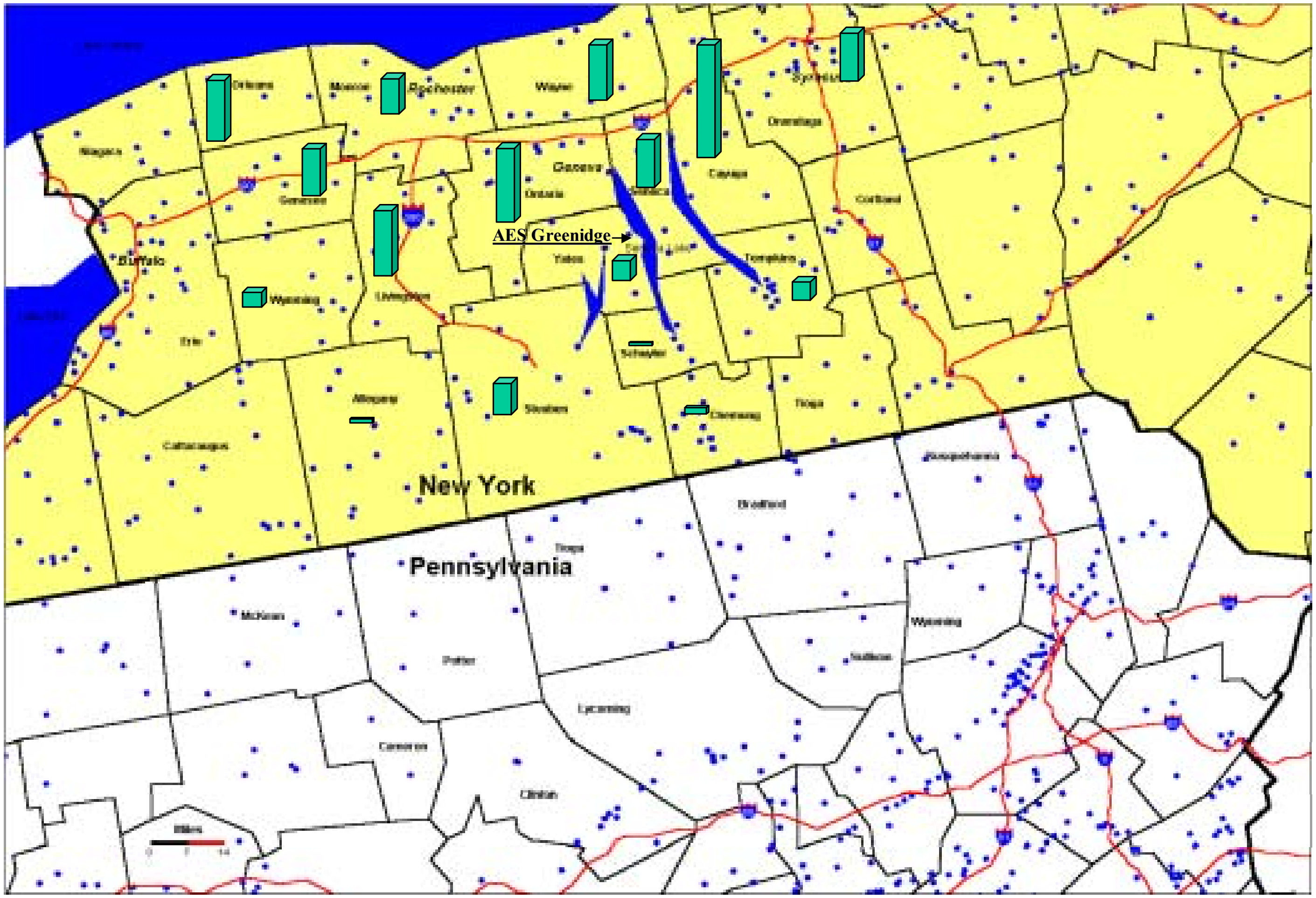

Figure 1.1. Corn Stover Availability by County

Table 1.2. Annual Tons of Corn Silage Harvested in the AES Greenidge Area

County	No. of Farms	Acres of Corn for Silage	Green Tons of Silage	Dry Tons of Silage[1]		Total Tons of Stover (from Table 1)
Cayuga	233	19,240	330,771	165,386		180,128
Ontario	133	11,412	186,583	93,292		121,075
Livingston	136	15,282	258,523	129,262		107,490
Orleans	68	3,737	56,085	28,043		100,972
Wayne	112	5,658	87,706	43,853		92,444
Onondaga	159	12,306	192,833	96,417		83,138
Seneca	91	5,347	81,474	40,737		82,322
Genesee	133	16,816	275,228	137,614		80,914
Monroe	44	2,655	40,441	20,221		63,580
Steuben	352	19,244	277,620	138,810		56,570
Yates	204	6,021	90,859	45,430		38,154
Tompkins	101	6,216	92,514	46,257		36,331
Wyoming	324	38,731	640,781	320,391		29,618
Chemung	56	2,786	38,660	19,330		11,954
Allegany	86	10,685	161,479	80,740		8,038
Schuyler	59	3,507	52,892	26,446		7,016
Total:	2,291	179,643	2,864,449	1,432,225		1,099,745

[1] - Assumed moisture content of green silage = 50%

A recent NREL report provided the following representative pricing structure for corn stover delivered to a processor – Great Lakes Chemicals [see Hettenhaus & Wooley, Oct. 2000].

Table 1.3. Corn Stover Pricing, Delivered to Processor

	Payments ($/dry ton)			
Radius (miles)	0 - 15	16 - 30	31 - 50	51 – 100
Producers Revenue	$15.00	$12.33	$9.66	$7.00
Baler's Revenue	$14.60	$14.60	$14.60	$14.60
Hauler's Revenue	$6.10	$8.77	$11.44	$14.10
Total Delivered Cost	$35.70	$35.70	$35.70	$35.70

There are many variables that will impact actual corn stover pricing for the AES Greenidge site. It appears that the pricing structure shown in Table 1.3 could be a reasonable approximation for the situation at AES Greenidge, assuming that optimal harvesting techniques/systems are employed and that an effective outreach/education program for local farmers is implemented. In order to reduce transportation costs it is likely that large square bales would be preferable over round bales. Large square bales (e.g., 4x4x8 foot bales) will also facilitate storage, since they are easier to stack. Since square bales are more susceptible to deterioration from precipitation than round bales, they would need to be covered with tarps or under roof-covered structures to keep them dry. Given the large number of relatively small farms in the area, it is likely that one or more 3rd party stover harvester/supplier entities would need to be established to help achieve economy-of-scale benefits and maximize utilization of stover harvesting/baling equipment. One option that could offer significant cost and logistics advantages would be for these biomass suppliers to use "one pass" harvesting equipment that harvests (and separates) corn and stalks at the same time – this equipment now exists in Europe [per Hettenhaus & Wooley, 2000].

In order to obtain site-specific information on corn stover supply issues, Mr. Easterly conducted meetings with farmers and toured corn farms in the AES Greenidge vicinity in December 2001. On Dec. 12, 2001, J. Easterly met with Kevin Swartley, President of the NYS Corn Growers Association (and Tim Chambers from the AES Greenidge plant), to discuss corn stover issues. Mr. Swartley farms about 1,500 acres of corn in the Seneca County area, including land that he owns and leases, as well as corn acreage he is paid to harvest by other corn growers. He uses no-till practices on much of the land he farms. On Dec. 13, 2001, Mr. Easterly met with Fred DeWick, President of the Yates County Farm Bureau. Mr. DeWick is a corn farmer who grows about 800 acres of corn in Yates County. He owns some of the acres he farms and leases the remaining acres. He uses a mix of conservation tillage and conventional tillage on the acres he farms. Mr. DeWick provided a tour of his farm operations. Mr. Easterly and Mr. DeWick met with another corn farmer in Yates County, Dale Hallings (at Mr. Hallings farm), to discuss corn stover harvesting issues. Mr. Hallings recently purchased a square baler, which makes 3x3x8 foot bales (the bales are automatically wrapped in a white plastic covers by the baler). Mr. Hallings uses the baler to do custom/contract baling for other farmers.

These three farmers generally raised similar issues/concerns regarding corn stover harvesting, including concerns regarding nutrient loss and possible adverse impacts on soil tilth from stover removal; concerns regarding compaction and rutting of soil from added tractor traffic to harvest the stover; and concerns regarding logistics issues for corn grain harvesting and subsequent stover harvesting/baling operations. These natural concerns of farmers are reasonable to expect and highlight the need to have trusted local agricultural advisors, such as USDA Extension Service agents, involved in an outreach process to address farmer concerns and to help implement acceptable stover harvesting practices. It seems advisable that an early step in the process of developing a stover supply system should include efforts to educate Extension Agents regarding the impacts, benefits, and desired practices for corn stover harvesting, so that they can work effectively to help achieve the widespread participation of corn farmers desired for the project.

Mr. Swartley felt that the window of time to harvest corn (and stover) in New York State (NYS) might be only half as long as it is in Midwestern states such as Nebraska. Although he noted that these midwestern states generally have a much greater variation in weather and crop yields than New York. As a result, crop insurance is a critical component of corn farming in these Midwestern states, whereas it is not a common practice or requirement in New York State. Corn harvesting in NYS begins in October, typically mid-October, and is completed by late November (Thanksgiving).

As indicated in Table 1.1, the average size corn farm in the 16 counties surrounding ASE Greenidge is 123 acres. Mr. DeWick noted that in Yates County, where the AES Greenidge plant is located, there has been a large influx of Mennonite farmers over the last 10 years who have bought land and are now growing corn on a number of smaller acreage farms. This is reflected in Table 1, which indicates that the average corn farm in Yates County is only about 48 acres in size. As illustrated in Table 1.1, Yates County would not be expected to provide a large portion of the stover supplies for a bioethanol facility at the AES Greenidge site.

The rule-of-thumb that 30% of the stover can safely be removed, from a soil quality/erosion protection perspective, is a simplified means to address a number of factors that relate primarily to tillage practices and soil slopes. No-till farming allows the maximum amount of corn stover to be removed per acre; mulch-till practices allow a moderate amount of stover to be removed; and conventional tillage practices allow for the least amount of stover removal (since more stover must be left in place for erosion protection on sloped land, if a cover crop such as clover is not planted at the end of the season). Crop rotation practices also impact the amount of stover that can be removed. If corn is planted year after year on a given acreage, more stover can be safely removed than in situations were non-corn crops such as soybeans are rotated with corn production in alternate years. Table 1.4 provides a summary of the tillage practices for the acres planted in corn in New York State in 1998 (note that this data combines corn produced for both grain and silage). For the 16 counties surrounding the AES Greenidge site, 41% of the total corn acreage was planted using a conservation tillage method. Depending on site-specific topography (e.g., land slope) and soil characteristics, a number of farms in the AES Greenidge area that currently use conventional tillage practices will need to switch to conservation tillage practices in order to allow for corn stover removal while maintaining acceptable protection for erosion. (With respect to Table 1.4, it is interesting to note that the 543,000 acres of corn planted in these 16 counties represents close to half (47%) of the total corn acreage planted in New York State.)

Table 1.4. Conservation Tillage Practices in the Counties Surrounding AES Greenidge

		Conservation Tillage			Conventional Tillage	
County	**Total Planted Acres Corn**	**No-Till acres**	**Ridge Till acres**	**Mulch Till acres**	**15-30% Residue acres**	**0-15% Residue acres**
Cayuga	75,000	350	400	30,000	32,000	12,250
Ontario	50,900	3,000	0	25,000	13,400	9,500
Livingston	50,000	5,000	0	10,000	15,000	20,000
Wyoming	46,000	1,700	0	19,800	10,000	14,500
Steuben	42,600	1,600	0	200	10,000	30,800
Wayne	42,500	4,000	0	29,000	3,500	6,000
Genesee	41,550	2,550	0	6,500	16,500	16,000
Onondaga	37,200	1,200	300	9,200	16,500	10,000
Seneca	36,000	15,000	0	16,000	0	5,000
Orleans	31,500	2,700	0	7,500	13,300	8,000
Tompkins	24,000	1,200	100	4,000	2,000	16,700
Monroe	21,600	3,500	0	11,000	4,000	3,100
Yates	20,000	800	0	6,500	0	12,700
Allegany	12,100	0	0	250	1,200	10,650
Schuyler	7,500	500	0	2,500	1,500	3,000
Chemung	4,800	0	0	0	0	4,800
Total:	543,250	43,100	800	177,450	138,900	183,000
NY State	1,159,268	88,252	7,536	274,286	249,359	539,835

% Conservation Tillage in 16 counties: 40.7%

Source: Conservation Technical Information Center, *1998 National Crop Residue Management Survey*, web page: http://www.ctic.purdue.edu/.

In General, increasing the percentage of land where conservation tillage is practiced will increase the amount of stover that can be removed. The demand created for stover by a bioethanol facility could actually help facilitate this process. For example, in cases where conventional tillage is practiced and land is too susceptible to erosion to allow for removal of stover, the opportunity to sell stover could be an incentive to farmers to switch to conservation tillage, where they would then be able to offer stover for sale. Similarly, farmers who currently use mulch till practices could be encouraged to switch to no-till practices, which would allow them to offer more stover for sale, while also reducing erosion on their farm land.

Comparing the acres of corn farm land per county in Table 1.1 with the tons of stover available (using the rule-of-thumb that 30% of the stover could be removed), it can be seen that about 1 ton of stover per acre per year would be provided, on average, for the corn farms surrounding the AES Greenidge site. At a minimum, it is likely that the farmers would want to be paid at least \$10 per acre for their corn stover if a third party bales and removes the stover. At about 1 dry ton of stover per acre, and \$10 per ton, the farmer would receive \$10 in revenue per acre per year for the stover removed from their farms. (Note that if farmers increase their use of conservation tillage practices, the amount of stover could potentially be increased above 1 dry ton per acre. This would increase farmer revenues per acre of corn land cultivated and increase the total supply of stover available for bioethanol production.) There are two transportation infrastructure considerations/options that might help keep stover transportation costs low enough for the more distant counties and still allow payments of \$10 per ton to the farmers: 1) as indicated above, the strong east/west highway infrastructure (e.g., Interstate 90) may help keep transportation costs lower for the more distant counties; and/or 2) use of the existing railroad infrastructure may help limit the transportation costs for stover delivery to the Greenidge site to about \$11.50 per dry ton, as discussed below, allowing the total delivered cost to remain near the target level of \$35.70 per dry ton.

Assuming that large square bales are used, approximately 70 trucks per day would be needed to deliver 1000 tons per day of stover when operating seven days per week [Hettenhaus & Wooley, 2000]. In order to avoid weekend and nighttime deliveries, a modified delivery schedule of five-days per week, 12-hours per day would require an average of 8.2 truck deliveries per hour.

An alternative for reducing the large volume of truck deliveries to the Greenidge site could be to deliver a significant portion, or all of the stover, via rail. The power plant's existing coal delivery infrastructure includes rail lines that go directly to the power plant and literally into the power plant building. The existing tracks on the AES Greenidge site can accommodate storage of 55 rail cars, plus 100 additional cars can be stored at the adjacent Dresden siding. Figure 1.2 shows a map with the local railway lines, including two sites where rail loading of stover bales could occur. As illustrated on Figure 1.2, one eastern site could be at Auburn, in Cayuga County; a second western site could be at Churchville, in western Monroe County. The map shows 20-mile radius circles at each of these locations. One option for transporting the bales from the fields to the Auburn or Churchville rail loading sites could be to use "load-and-go" wagons and high-speed tractors. The cost for this highway leg of the transportation would be about \$6 per ton (similar to the 15 mile radius situation indicated in Table 1.1). This would leave about \$5.50 per ton allowable for rail transport, in order to achieve the overall target for total transportation costs of about \$11.50 per dry ton.

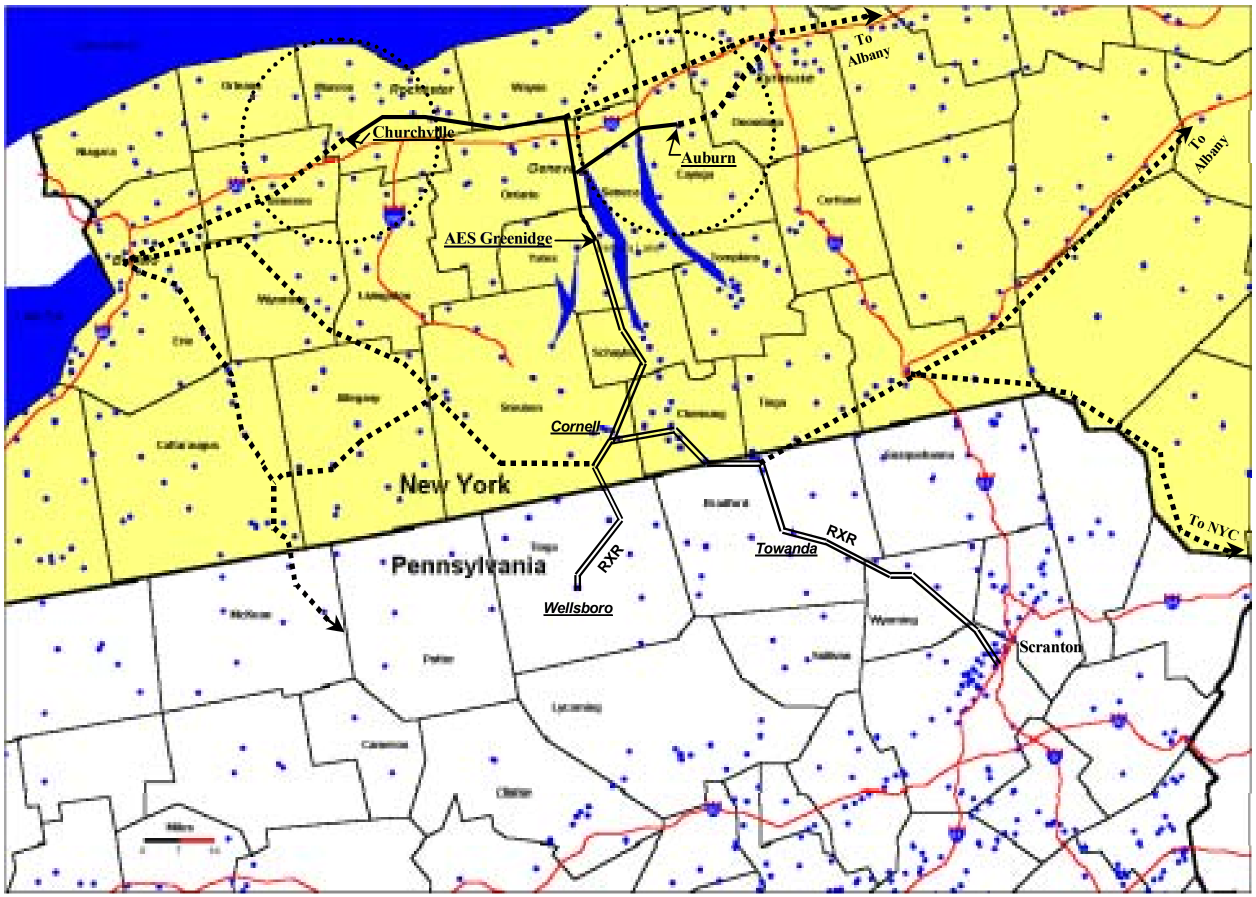

Figure 1.2. Railway Infrastructure for Corn Stover Transportation

There is a biomass power plant in Burlington, Vermont (McNeil Station), which receives 75% of its 1,000 dry tons per day of wood fuel via rail delivery. In order to keep costs down, McNeil Station purchased 20 rail cars as part of their overall plant-financing package. They have a rail yard about 35 miles from their power plant where trucks deliver wood chips that are loaded into the rail cars. McNeil pays a local railroad company $5,800 per round trip for a locomotive (and engineer) to pull the train cars to their power plant – this is a fixed cost that does not change with the number of cars that are pulled. Overall, it costs McNeil Station about $6.80 per ton to deliver wood chips from their rail yard to their power plant via rail, including the various costs associated with their remote rail yard [Irving, Sept. 2002].

A variety of rail car types and sizes are available that might be suitable for transporting large 4x4x8 foot bales of stover. For example, one type of car that could be suitable is a "center beam" car that is 73 feet long, with a 12-foot 6-inch high beam that runs down the full length of the car's centerline [Florian, 2002]. These cars are often used to transport 4x4x8 foot bundles of lumber. The cars have built-in steel cables that are used for tying down the bundled lumber – these cables could be convenient for tying down stacks of corn stover bales. The rail cars are 9 feet wide, so they could accommodate stacks of stover bales that are 2 bales wide, 3 bales high, and 9 bales long, for a total of 54 bales per rail car. At about 1400 pounds per bale, and 54 bales per car, each rail car would carry about 75,000 pounds of stover. Assuming an average moisture content of 20%, a bioethanol facility that requires 1,000 dry tons per day of stover would use 2.5 million pounds per day of stover (as received), requiring deliveries by about 33 "center beam" rail cars per day. This is a little less than half the number of trucks that would be required to deliver this amount of stover.

In a discussion with the Finger Lakes Railroad, another rail car that could be an option is a "high cube" double-door boxcar [Sullivan, 2002]. These enclosed cars offer the advantage of keeping the stover dry drying transport. Also, if there are concerns regarding flammability and fire risks with the transport of stover in open rail cars, use of these enclosed boxcars would address this concern. These cars are 50-feet 6-inches long, 9-feet 6-inches wide, and 12-feet 10-inches high. Thus they could carry stacks of 4x4x8 foot stover bales that are 2 bales wide, 3 bales high, and 4 bales long, for a total of 24 bales per rail car. With an average moisture content of 20% and 1,400 pounds per bale, each car would deliver 33,600 pounds of stover (as received). Thus a 1,000 dry ton per day bioethanol facility would require about 75 cars per day if high-cube, double-door boxcars are used, slightly more than the number of trucks required. The double doors on these trailers are 16-feet wide, thus the logistics of loading bales into the enclosed ends of the cars would need to be evaluated to determine if the cars could be efficiently loaded and unloaded. One advantage is that the bales probably would not need to be tied down inside the enclosed cars, as they would for a rail car with open sides.

The cubic weight of corn stover is about 11 pounds per cubic foot – which equates to about 8.8 dry pounds per cubic foot of stover, assuming a 4x4x8 foot bale of corn stover, as received (at 20% moisture) weighs about 1,400 pounds. The cubic weight of green hardwood chips is about 25 pounds per cubic foot, or approximately 12.5 pounds per cubic foot on a dry basis (assuming that green wood has a 50% moisture content). Using these values, the cubic weight of stover is about 70.3% that of wood chips, on a comparative dry weight basis. Using bulk density (on an adjusted dry weight basis), it appears reasonable to assume that the cost of rail transport should be adjusted to about $9.67 per ton of stover delivered (i.e., using the $6.80 per ton cost at McNeil Station, noted earlier, divided by a bulk density adjustment factor of 70.3%). With these assumptions, the combined transportation costs for delivering corn stover from the Auburn or Churchville sites would be about $6 per ton for highway transportation to the rail loading sites, plus about $9.67 per ton for rail transport to Greenidge, for a total stover transportation cost of $15.67 per ton for the combined truck and rail approach. For those areas that are within 30 miles of the Greenidge site, one option could be to have direct deliveries of stover to Greenidge via "load-and-go" wagons with high-speed tractors.

It is desirable to bale stover when its moisture content is 20% or less to allow for long-term storage of the bales with minimal decomposition. However, if one-pass harvesting of grain and stover is implemented, the stover collected at the beginning of the harvest season will have high moisture content. One approach would be to harvest the area closest to the Greenidge site in the early phase of the harvest season using a silage form of storage for the wet stover. Since it is expensive to transport wet stover long distances, the close-in areas are most suitable for this approach. Tractors could readily be used to transport the forage-type stover to silos for storage. There are 142 acres of agriculturally zoned property on the southeast side of Route 14 owned by AES Greenidge (across the street from their power plant site), which could be a logical place to locate silos for storage of early-season green stover.

1.3 Potential Hardwood Supply Availability

The counties in Pennsylvania directly south of the AES Greenidge site are predominantly forested areas, with mostly hardwood tree species. There is a substantial hardwood lumber industry active in this area of Pennsylvania. Over the last two years, two large pulp and paper mills stopped using local hardwood pulp chips in Pennsylvania. The Proctor and Gamble paper mill near Towanda (in the northwestern corner of Wyoming County) switched to imported Brazilian Eucalyptus pulp chips two years ago. At the end of 2001 a paper mill owned by International Paper, near Erie, Pennsylvania, also shut down. Both of these paper mills drew heavily on north central Pennsylvania to supply hardwood pulp chips for their mills. According to the Pennsylvania Bureau of Forestry (Lester, 2002), these two paper mills used over 500,000 green tons of wood chips per year (about 40% came from sawmill residues, with the remaining pulpwood supplied from roundwood thinning of forests). This amount of wood supply is now potentially available for bioethanol production and would be adequate to supply the annual biomass feedstock requirements of a 20 million gallon per year bioethanol facility (assuming a yield of 60 gallons of ethanol per dry ton of wood chips).

There are a few particleboard manufacturers in the area who provide a demand for a portion of the available sawmill residues. Sawmills debark their logs first and sell the bark for mulch. The resulting wood waste from sawmills is thus free of bark and is superior for manufacturing particleboard than roundwood chips, which contain some amount of bark. In contacting sawmills and wood industry contacts in the area, it appears that sawmills currently receive $10 to $12.50 per ton for their wood residues (these residues are primarily green wood). However, with the loss in demand for wood to paper mills, many sawmills are known to be having problems finding a market for their wood residues [Elder, February 2002].

As indicated in Figure 1.3, rail transportation from the northeastern Pennsylvania counties to AES Greenidge is quite direct and could offer an attractive means for wood chip delivery to a bioethanol facility co-located at the power plant site. A radius of 20 miles is shown for two sites on the rail lines in Pennsylvania to illustrate a possible distance for trucks to haul wood chips to the railroad loading sites (near the communities of Wellsboro in Tioga County and Towanda in Bradford County, Pennsylvania).

The shaded area in Pennsylvania, on Figure 1.3, indicates the counties that could potentially supply hardwood chips for ethanol production to the AES Greenidge site at Dresden. The New York State counties listed in Table 1.1 as potential suppliers of stover for an AES Greenidge-based ethanol facility are indicated as shaded areas on Figure 1.3.

J. Easterly contacted Norfolk Southern (and the Wellsboro & Corning Railroad) and got a quote of about $8.25 per ton for the cost to deliver wood chips via railroad from Wellsboro, Pennsylvania to Dresden, New York, a distance of about 80 miles. [Florian, 2002; and Hunter, 2002]. This quote is based on the use of Norfolk Southern-supplied rail cars. Norfolk Southern (NS) is the rail company that delivers coal to the AES Greenidge power plant (NS owns the rail track in the vicinity of AES Greenidge). NS has a large supply of underutilized railcars suitable for this job. One type of car is called a "woodchip hoper." It has a bottom dump design with a carrying capacity of 7,500 cubic feet, or about 90 tons of wood chips. NS also has bigger gondola style cars that can hold 8,200 cubic feet, or about 100 tons of wood chips per car. The gondola style cars require a rather expensive rotary car dumper to unload. These rotary dumpers cost about $2.5 million to purchase and install [Sullivan, 2002]. While it would appear that the woodchip hoppers are a much less expensive option, since they would not require a rotary dumper for unloading, there are some pros and cons to consider. AES Greenidge would like to have a rotary dumper to unload their coal cars. A rotary dumper could unload coal from gondola-style coal cars ten times (or more) faster than the bottom-dump coal cars that AES Greenidge currently uses. In addition, wintertime unloading of bottom-dump cars can be a problem for both coal and wood chips, since the solid fuel can often freeze together in these open-top bottom-dump rail cars, presenting a significant time delay in unloading the fuel. A rotary dumper could facilitate improved rail traffic if both coal and wood chips are delivered to the AES Greenidge site via rail. It is possible that the cost for a rail car dumper could be shared by AES Greenidge (for its coal-based power operations) and by the bioethanol facility.

The delivered price for pulpwood paid by the two Pennsylvania paper mills that have stopped using local wood chips was typically in the range of $20 to $28 per green ton [Lester, 2002; and Sherwood, 2002]. Even though there is currently a large amount of wood available from the forests, the cost for harvesting and transporting this wood to a bioethanol facility located at the AES Greenidge site is anticipated to be too high to be competitive as a feedstock for bioethanol production (probably in the range of $45 to $60 per dry ton), even if the stumpage prices paid for standing trees in the forest are zero or close to zero. However, it appears that sawmill residues exceed local demand and could be available at a more competitive price, possibly in the range of $36 per dry ton delivered to the Greenidge site (i.e., at a price that is similar to corn stover), as discussed below. A detailed survey of the existing sawmills would be necessary to accurately determine the amount and price of sawmill residues that could be available for bioethanol facility at AES Greenidge. Table 1.5 provides a summary of the mill residues produced in the counties

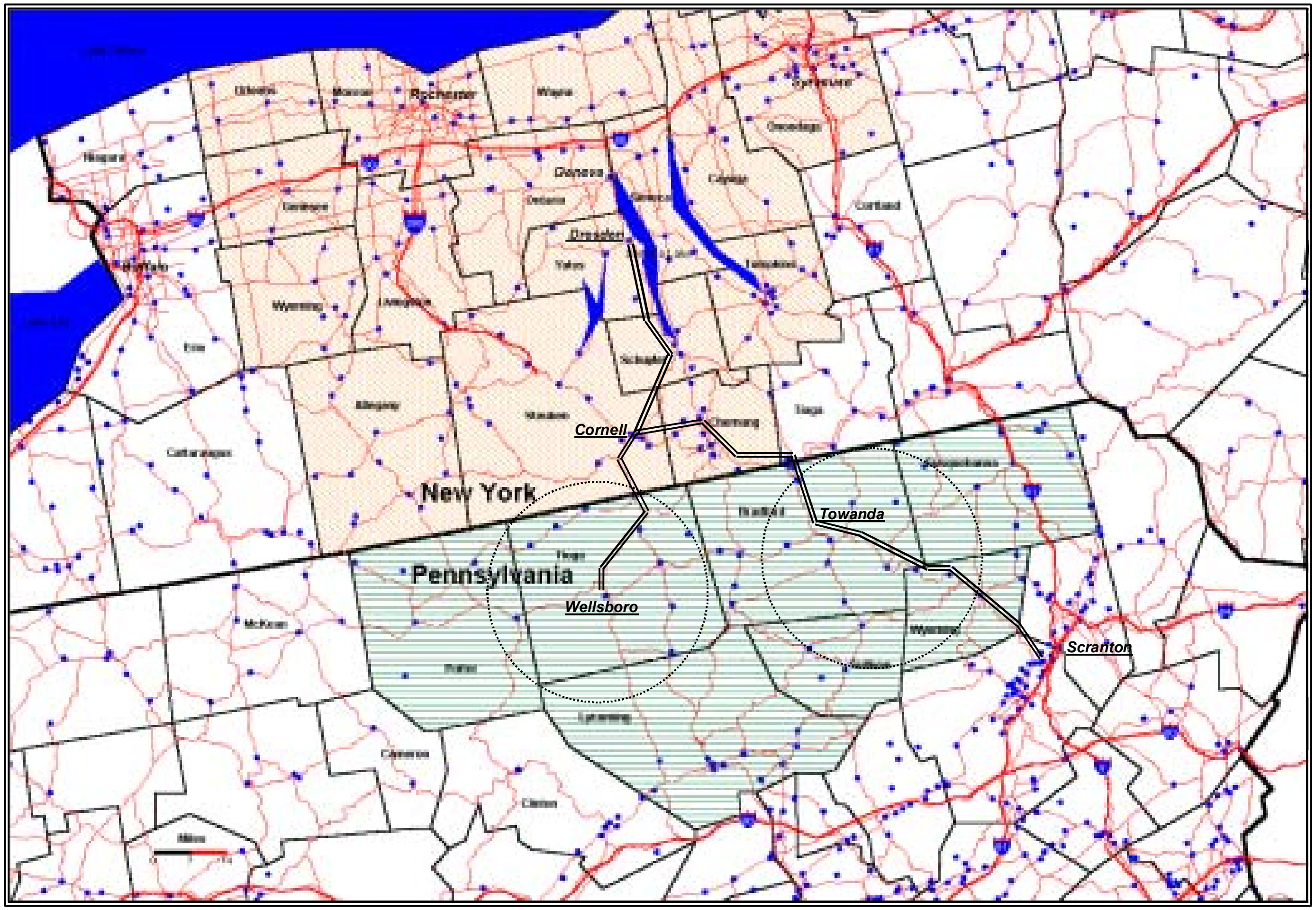

Figure 1.3. Potential NY Corn Stover and PA Wood Supply Areas for a Bioethanol Facility at AES Greenidge

around Towanda, Pennsylvania in 1996; and Table 1.6 provides a summary of the mill residues available in the counties surrounding Wellsboro, Pennsylvania. The total quantity of wood residues in these two areas exceeded 400,000 dry tons per year. As a rough approximation, if one-forth of the residues in this area do not have a market, this would represent a potential supply of 100,000 dry tons per year. Given the significant loss of paper mill demand for wood residues in Pennsylvania this could be a reasonable approximation. Most of these sawmill residues are greenwood, with moisture content near 50% [DeCamp, 2002]. From Tables 1.5 and 1.6 it can be seen that the majority of mill residues are available near Wellsboro rather than Towanda. Assuming that sawmill residues from Pennsylvania come via rail from Wellsboro to AES Greenidge, that the mills are paid $10 per ton when they deliver their mill residues to the Wellsboro rail loading site (basically covering little more than their transportation costs), and that the cost for rail delivery from Wellsboro to AES Greenidge is $8.25 per ton (assuming the rail cars are provided by NS), then the delivered cost of the mill residues would be approximately $18 per green ton or about $36 per dry ton. If the rail cars are owned by the bioethanol facility (similar to the McNeil power plant in Vermont, as discussed earlier), the rail delivery costs could be closer to $7.00 per ton, which could allow payments of $11.00 per ton for the mill residues, and still allow for a cost of about $18 per green ton or about $36 per dry ton to deliver the woodchips to AES Greenidge.

Table 1.5. Mill Residues Produced in the Counties Around Wellsboro, Pennsylvania in 1996*

		Wood Residues			
County	Bark Residues	Coarse Material	Fine Material	All Material	All Residue
Bradford	4	12	7	19	24
Sullivan	1	3	1	4	5
Susquehanna	2	6	4	10	12
Wyoming	2	7	4	11	13
Total:	9	28	16	44	54

Table 1.6. Mill Residues Produced in the Counties Around Towanda, Pennsylvania in 1996*

		Wood Residues			
County	Bark Residues	Coarse Material	Fine Material	All Material	All Residue
Cameron	4	12	7	19	23
Clinton	2	6	3	9	11
Lycoming	12	33	21	54	66
McKean	8	23	14	37	45
Potter	32	101	59	161	193
Tioga	3	9	6	15	18
Total:	61	184	110	295	356

* Data source: US Forest Service web page: http://www.srsfia.usfs.msstate.edu/; units: 1,000's dry tons/year

Additional miscellaneous sources of wood waste are available in New York State, including waste wood that could be separated from waste streams in major urban centers in the broad region of the state surrounding AES Greenidge and delivered to the plant site via truck or rail. However a significant amount of wood recycling occurs in the state (for production of particleboard, mulch, etc.) and quantifying this potential resource requires detailed surveys and site visits that are beyond the scope of work for this project. Table 1.7 lists the amounts of bark and mill residues generated in the same counties that were listed for corn stover residues in NYS. Much of this residue is currently used and an in-depth analysis would be needed to determine how much of it could be available or sold at a price below that which a bioethanol facility at AES Greenidge could afford to pay for the feedstock.

Table 1.7. Annual Mill Residues Produced in Counties Near AES Greenidge

County	Bark Residue (dry tons)	Wood Residue (dry tons)	Total Wood Residue (dry tons)
Onondaga	7,000	54,000	61,000
Wyoming	8,000	28,000	36,000
Cayuga**	2,000	18,000	20,000
Allegany	3,000	11,000	14,000
Chemung**	3,000	11,000	14,000
Livingston	3,000	9,000	12,000
Steuben	2,000	8,000	10,000
Wayne	2,000	7,000	10,000
Monroe**	2,000	6,000	8,000
Ontario	1,000	3,000	5,000
Genesee*	0	0	0
Orleans*	0	0	0
Schuyler*	0	0	0
Seneca*	0	0	0
Tompkins*	0	0	0
Yates*	0	0	0
Total:	33,000	155,000	190,000

Total tons of biomass needed/year = 333,333
(assuming 20 million gal/yr capacity & 60 gal ethanol/dry ton)

* Data for this county is combined with another county (by USFS).
** Data for this county includes data from other counties (by USFS)

Data Source: US Forest Service web page: srsfia.usfs.msstate.edu

1.4 Energy Crop Supply Options

In addition to corn stover and wood chips from Pennsylvania, energy crops grown in central and western NYS could offer another interesting option for providing biomass feedstocks for a bioethanol facility co-located at the AES Greenidge site. In March 2001, New York State was one of four states that the United States Department of Agriculture (USDA) awarded "Biomass Pilot Projects" under the Conservation Reserve Program (CRP) [USDA Farm Service Agency, 2001, 2000, and 1999]. Under this program, farmers in New York State can grow willow or switchgrass as energy crops that can be harvested on CRP land. Under CRP, farmers are paid 50% of the costs to establish the crops, plus annual rental payments for restricting their use of the land. Under the terms of the Biomass Pilot Project, a number of conditions must be met:

- Acreage may not be harvested more than once every other year;
- No commercial use may be made of harvested crops other than energy production;
- Annual rental payments will be reduced by 25% during the year the acreage is harvested; and
- Pilot projects must be conducted for a minimum of 10 years.

In the NYS pilot project, 16,000 acres were approved for production of energy crops. However, under the overall terms of USDA's pilot project program, each state was allowed to propose up to 50,000 acres of CRP land. It is quite possible that the NYS project could be modified to increase the allowable area up to 50,000 acres [Dickerson, 2002].

In their proposal to USDA, NYS indicated that they planned to have about 2/3 of the acreage planted with willow crops and 1/3 with switchgrass. The intent under the NYS proposal was to cofire some of the harvested willow crops at the AES Greenidge power plant. AES Greenidge has done cofiring tests with both willow woodchips and switchgrass. The tests were generally successful, however AES Greenidge found the amount of water in the willow to be undesirable and they currently do not plan to use willow for cofiring. While they did not have any significant problem cofiring the switchgrass, the low bulk density of switchgrass (compared to woodchips or coal) required a distinctly larger volume of material to produce each megawatt of additional power. Although AES Greenidge is not currently interested in cofiring willow or switchgrass, they have confirmed that these fuels can be burned in their boilers. In order to create a market for these feedstocks, to facilitate a ramp-up in their production so they could be available in sufficient quantity for future use as bioethanol feedstock, AES Greenidge indicated a willingness to consider cofiring these materials as a transitional strategy.

The restriction that the energy crops can only be harvested every other year under the CRP program is a drawback for switchgrass, since the yearly growth is not stored above ground, as it is with woody crops. Switchgrass was the sole energy crop planned under the CRP Biomass Pilot Projects awarded to the states of Pennsylvania and Iowa. J. Easterly contacted the respective project contacts in each of these states and in each case they acknowledged that the every-other-year harvest cycle would probably double the acreage needed to provide a certain desired quantity of switchgrass, but that this was not an insurmountable barrier [Sellers, 2002; Elder, 2002]. After establishing the crops, annual crop maintenance costs are expected to be low, and harvesting/baling/transportation costs are obviously incurred only in the year of harvest. Also, the farmers receive their full CRP annual rental payments in the years that the switchgrass is not harvested. Based on field trials in Iowa and Pennsylvania, Iowa expects to have yields of about 4 dry tons per year and Pennsylvania expects to have yields of about 6 to 8 dry tons per year (switchgrass is a warm season grass, and Pennsylvania has somewhat warmer/longer growing seasons than Iowa). In NYS the USDA Natural Resource Conservation Service (NRCS) has had about 18 years of experience in growing switchgrass for habitat uses [Dickerson, 2002]. They have found that switchgrass produces about 4.5 dry tons per year in NYS. However, these yield levels reflect conditions where no effort was made to manage the switchgrass for higher yields. In the central southern NYS counties near AES Greenidge, where there is a significant amount of land that could be a target for sign-ups under the NYS CRP Biomass Pilot Project, switchgrass yields are likely to be in the range of 5 dry tons per year.

The South Central New York RC&D had a lead role in writing the proposal for the NYS CRP Biomass Pilot Project and they have been actively involved in willow energy crop development efforts in NYS for a number of years [Edick, 2002]. Based on field trials of willow crops they expect the annual yield to be close to 5 dry tons per acre. The South Central New York RC&D covers a multi-county area that includes many of the counties just to the west of AES Greenidge that would be suitable for production of energy crops under the CRP pilot project. Based on their experience with willow crop yields and related cost estimates, it is anticipated that willow-based woodchips could be delivered to the AES Greenidge site for under $30 per dry ton, with the CRP payments helping to bring the cost down to this level [Edick, 2002].

It is interesting to note that in Pennsylvania, the state game commission is expected to contribute the 50% in switchgrass establishments costs that are not covered under the biomass CRP pilot project, due to benefits in habitat created for ground-nesting bird species (such as pheasant and quail) by the switchgrass acreage [Elder, 2002]. In Iowa, negations with USDA look quite favorable to reduce the reduction in CRP rental payments to 10% instead of 25% in the years that switchgrass is harvested, in recognition of the strong erosion protection benefits that the harvested switchgrass acreage will still provide in those years [Sellers, 2002]. These types of actions could also be pursued under the New York State Biomass CRP Pilot Project to further improve the economics of energy crop production in that state.

One barrier for the CRP Biomass Pilot Project in NYS is that there is rather little land in the state currently enrolled under standard CRP contracts. There are only 59,000 acres of CRP land in NYS, whereas there are over a million acres of CRP land in many Midwestern and Western states [USDA-FSA, Dec. 2001]. Table 1.8 provides a summary of the active CRP acres and contracts in NYS for the 1988–2002 timeframe. As illustrated in Table 1.8, there are close to 31,000 acres of CRP land in the counties surrounding the AES Greenidge site (for the same counties listed in the earlier discussion regarding corn stover resources). Average annual rental payments are $41 per acre for the CRP contracts in these counties. New CRP sign-ups were not offered in year 2001 or 2002, however it is anticipated that USDA will call for new sign-ups in 2003 or 2004. While there are limits on a national basis regarding the total number of acres that can be enrolled under CRP, it is anticipated that NYS could be very likely to receive all the acres they request under the CRP Biomass Pilot Project, up to the full 16,000 acres approved under their current pilot project [Edick, 2002]. Assuming that 50,000 acres of energy crops are eventually developed in NYS under their CRP Biomass Pilot Project (per the discussion above), with perhaps 2/3 as willow crops and 1/3 as switchgrass, this could provide a little over 200,000 dry tons of biomass for bioethanol production at a cost in the vicinity of $30 per dry ton.

Table 1.8. Active CRP Contracts and Acreage for Counties in the Vicinity of AES Greenidge

County	Average Annual CRP Rental Rate per Acre	CRP Acres	No. of Contracts	Average Acres per Contract
Allegany	$39.13	3,035	131	23.2
Cayuga	$48.45	4887	121	40.4
Chemung	$32.35	709	25	28.4
Genesee	$43.14	1332	63	21.1
Livingston	$44.58	5256	133	39.5
Monroe	$46.40	734	19	38.6
Onondaga	$36.23	656	33	19.9
Ontario	$46.00	2175	67	32.5
Orleans	$44.23	670	43	15.6
Schuyler	$28.69	326	9	36.2
Seneca	$47.61	328	7	46.9
Steuben	$37.09	5232	141	37.1
Tompkins	$46.64	341	18	18.9
Wayne	$40.66	1,849	75	24.7
Wyoming	$40.04	1,886	64	29.5
Yates	$48.75	1,579	44	35.9
Total:	$41.87	30,995	993	31.2

Source: USDA, Farm Service Agency, Dec. 31, 2001

1.5 Summary Observations

Considering the range of factors discussed in the overall feedstock assessment, it appears that the most viable approach would be to use more than one type of feedstock for supplying a bioethanol facility co-located at the AES Greenidge site. While the total quantity of corn stover available is generally adequate, complete participation of all corn farmers in the region is probably unlikely to occur, particularly in the early years of ethanol facility operation. It is likely to take a number of years of educating farmers and demonstrating the acceptability and success of corn stover removal practices (by "early adopter" farmers) in order to convince the bulk of the corn farmers that they would benefit from supplying corn stover to the bioethanol facility. At the outset, when the bioethanol facility begins operating, waste wood supplies are likely to be the most viable feedstock option. A parallel effort could be pursued to enlist farmers in supplying corn stover for the bioethanol facility. Seasonal switching between the two feedstocks could be implemented, allowing the bioethanol process conditions to be optimized for the duration of a "season" based on the characteristics of the feedstock being converted. Given the CRP energy crop pilot project in New York State, it may make sense to work with farmers to also supply switchgrass and willow wood chips for the ethanol facility. It may be possible to use (blend) corn stover and switchgrass during one season of operation, and then use waste wood and willow wood chips in another season of operation. Further research and/or testing will be needed to assess feedstock handling issues and conversion optimization issues regarding strategies for using multiple feedstocks.

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Task 2. Site Characterization

2.0 Overview

The AES Greenidge coal-fired power plant is located in a corn production region on the western side of New York State. The power plant is situated on the western shore of Seneca Lake, just south of Dresden, New York, in Yates County (see Figure 2.1). The following chapter provides a characterization of the AES Greenidge site with respect to the suitability of this site for co-locating a bioethanol facility that could use corn stover (and potentially waste wood, on a seasonal basis) as the feedstock for producing 20-million gallons per year or more of ethanol fuel.

The Greenidge coal-fired power plant has successfully cofired waste wood for seven years -- there are only five commercial coal plants with ongoing cofiring operations in the U.S. Over the last few years, the Greenidge power plant has been looking for an industrial steam host willing to co-locate on their 300-acre site.

The following issues are addressed in this site characterization report:

1) Existing on-site infrastructure and utilities
2) Site layout and features
3) Transportation infrastructure
4) Feedstock proximity and abundance
5) Accessibility to end-use markets, and
6) Compatibility of current surrounding land-uses.

2.1 Existing On-Site Infrastructure and Utilities

The AES Greenidge coal-fired power plant was originally constructed in the 1930's with its first generator (Unit 1) going into service in 1938. Additional units were added in 1942 (Unit 2), 1950 (Unit 3), and 1953 (Unit 4). Units 1 and 2 were retired from service in 1985. The two remaining generating units, units 3 and 4, have a combined generating output of 161 megawatts.

Unit 3 utilizes two Babcock and Wilcox pulverized coal wall-fired steam generators (no. 4 and 5 boilers), supplying steam to a non-reheat turbine generator manufactured by General Electric, with a net generating capacity of 56 MW. These boilers are each rated at 288,000 lb./hr., with a design pressure of 1000 psi at 910 degrees. Unit 3 was placed into service in 1950.

Unit 4 utilizes a single Combustion Engineering pulverized coal, tangentially-fired steam generator, supplying steam to a reheat steam turbine generator manufactured by General Electric, with a net generating capacity of 105 MW. This No. 6 boiler is rated at 665,000 lb./hr. with a design pressure of 1465 psi and 1005 degrees F at the superheater outlet. As noted earlier, Unit 4 went into service in 1953.

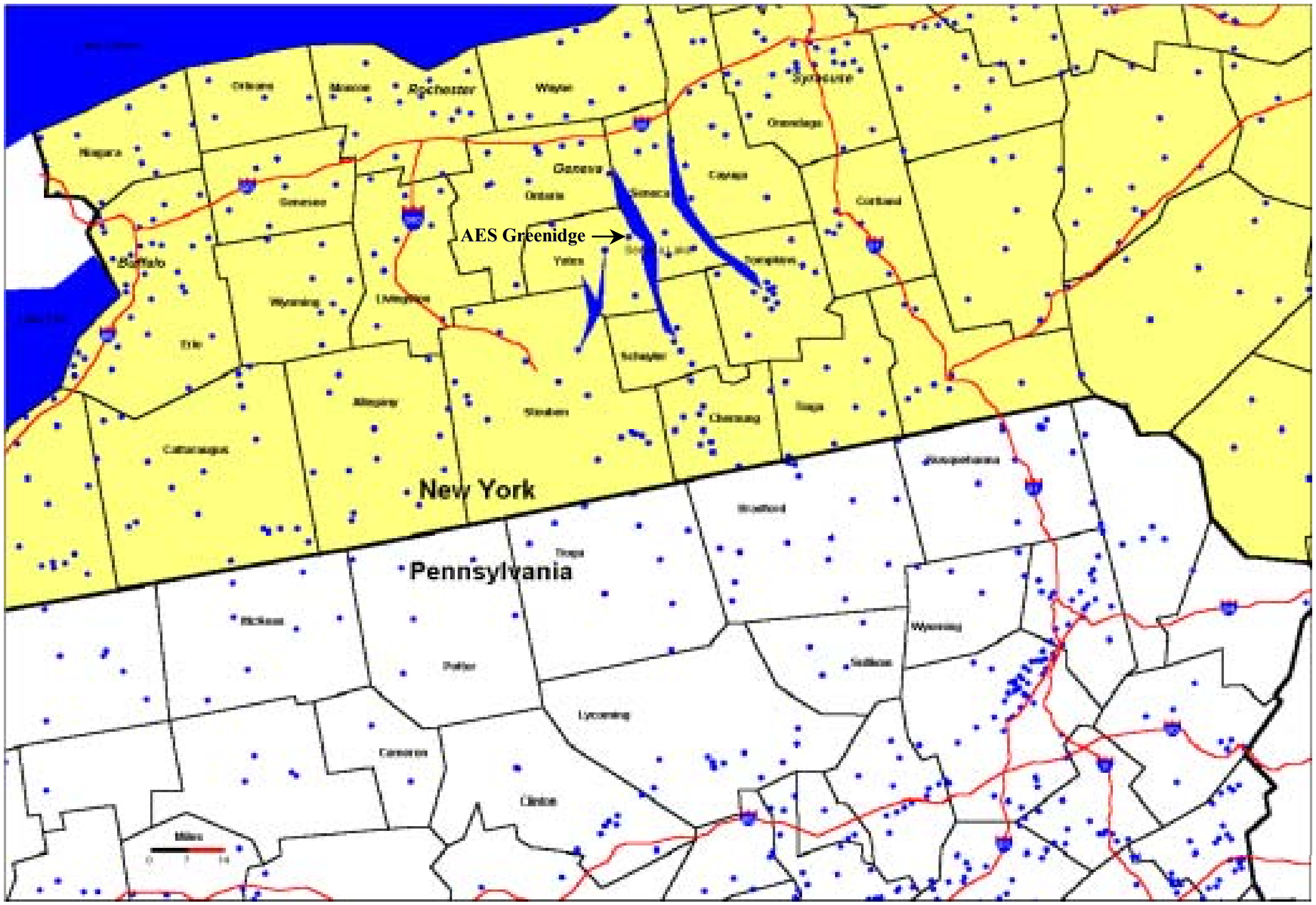

Figure 2.1 County Boundaries and Major Interstate Highways in the AES Greenidge Area

When units 1 and 2 were retired from service, their turbines and associated boilers were removed. As a result, the AES Greenidge power plant building is essentially half empty. This raises the possibility of locating much of the components for a bioethanol production facility inside of the existing power plant building. With this scenario, there may be a potential to achieve further capital cost savings (beyond avoided boiler and turbine costs) through this co-location project, by utilizing the existing power plant building to house a significant portion of the bioenergy production system.

The bituminous (soft) coal used for fuel at the AES Greenidge Station is mined in Southwestern Pennsylvania and delivered to the plant by rail. The plant also has the capacity to receive coal by truck, but has not utilized this capacity for a number of years. The typical as-fired coal quality for Greenidge Station is as follows: 6.3% moisture content, 8.8% ash, 34% volatile matter, 2.3% sulfur, 50.9% fixed carbon, and 12,800 BTU/lb., with a density of 55 lbs/cu. ft. The power plant has coal car storage capacity on site that can accommodate 55 cars. The nearby Dresden rail siding can accommodate a train with 100 cars.

Utility Services Available

Greenidge Station's existing infrastructure offers valuable attributes for co-locating a bioethanol facility at their site, including steam, water, electricity, waste disposal capabilities, compressed air, and natural gas supplies. The following is a closer look at each of these physical attributes available at the site.

- STEAM is available either as saturated or superheated steam and can be supplied as process heat from 10 psig to 1450 psig. AES Greenidge Station is capable of supplying this steam at rates of hundreds of thousands of pounds per hour, and should readily be able to meet the process steam requirements of a bioethanol facility.

- WATER supplies are abundant, including potable water and industrial grade water. A demineralizer was installed in 1985 and provides quality water to the boiler feedwater systems and is monitored with a modern monitoring system. The demineralizer is capable of 110,000 gallons at about 90 gallons per minute (gpm). Potable water is purchased from the Village of Dresden. The plant uses water from Seneca Lake for power plant cooling water – circulating pumps provide about 34,000 gpm for Unit 3 and about 68,000 for Unit 4. Their warm water discharge can provide a source of warm water with a discharge rate of 135.4 million gallons per day. The plant has house service water pumps and hydrojet water pump systems that pump from Seneca Lake.

- ELECTRICAL requirements: AES Greenidge Station has the capacity to supply all of the electrical needs of a bioethanol facility. Provisions are available to supply 120 volts to 115,000-volt systems. The plant can supply 208/220 volts 3-phase, 408/880 volts 3-phase, 2400 volts 3-phase, 13,800 volts 3-phase, or 115,000 volts 3-phase electricity with existing equipment. This also eliminates the necessity to purchase and install transformers or other switching devices. AES Greenidge is connected to the power grid through three 115 KV lines and three 34.5 KV lines.

- LIGNIN UTILZATION capabilities: AES Greenidge Station has the capacity to utilize the lignin by-product resulting from a bioethanol facility. Greenidge Station routinely cofires wood in its coal boilers. They have burned up to 172 tons of wood per day (including particle board and wood pellets), and are currently permitted to burn up to 30 percent (by weight) of biomass in their boilers. Lignin could be cofired with coal in boiler number 4, 5 and/or 6; or boiler number 4 (and/or 5) could be modified to be a dedicated lignin-fueled boiler(s).

- SOLID WASTE DISPOSAL facilities: AES Greenidge owns a 142 parcel of land on the southwest side of Route 14 that is used in part as a solid waste disposal site for fly ash or other permitted materials. Bottom ash is collected in a settling pond at the east end of the plant. The ash is sometimes sold to highway departments and is otherwise landfilled at their ash disposal site.

- WASTEWATER TREATMENT facilities: AES Greenidge has a wastewater treatment facility that is used to treat various plant wastes, particularly the coal pile run-off water, air pre-heater washing water, and boiler chemical cleaning rinse water. The system utilizes lime, polymer, and sulfuric acid in the treatment process.

- COMPRESSED AIR is available at the site, including oil and moisture free instrument air up to 25 psig. The compressed air system is currently being upgraded.

- NATURAL GAS is provided to the site via an eight-inch pipeline. A natural gas re-burn system is installed on boiler number 6 (i.e., for "Unit 4") for NO_x and SO_x reduction. (With this system, boiler no. 6 can utilize natural gas for up to 25 percent of its heat input requirements.)

- LABOR/PERSONNEL RESOURCES: there are 50 people employed at the AES Greenidge plant, representing a diverse and skilled work force that includes engineers, industrial electricians, mechanical maintenance, machinists, as well as staff for administrative, technical, environmental, and operational assistance. (The staff has received all OSHA-required training.) The power plant manager, Doug Roll, is a chemical engineer.

2.2 Site Layout and Features

The power plant site consists of two somewhat irregular shaped plots of land, with a total area of 304 acres (see Figure 2.2). There are 162 acres on the northeast side of Route 14 (where the power plant is located, next to Seneca Lake) that is zoned as industrial property. As noted earlier, AES Greenidge owns 142 acres of property on the southeast side of Route 14; this land is currently zoned as agricultural/ residential. Part of this parcel of land is used for ash disposal. Additional acres may be available on adjoining off-site properties.

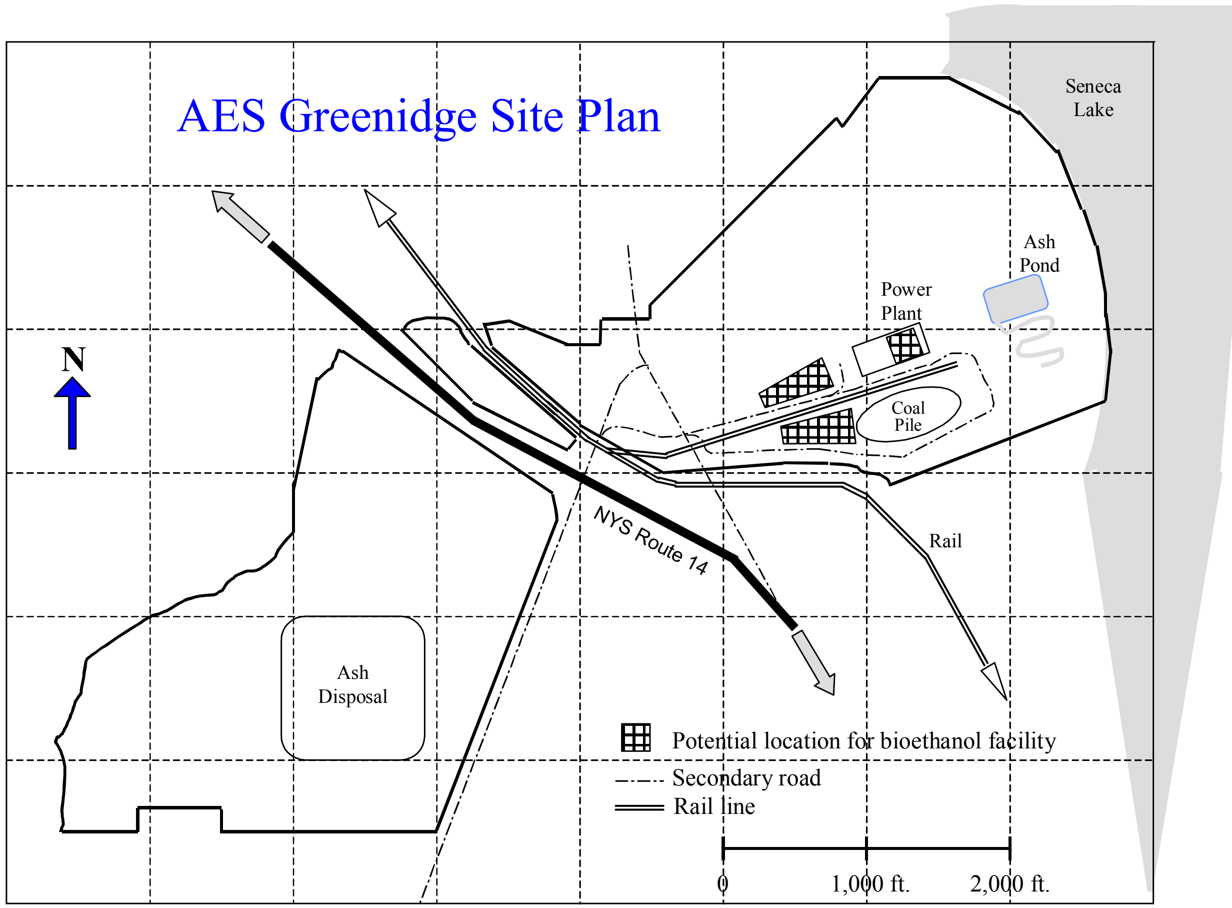

Figure 2.2. AES Greenidge Site Description

The character of the site is generally rural, however the small community of Dresden is just above the northeast boundary of the 162-acre plot of land owned by AES Greenidge, with residential units essentially just across the northeast property line. A stream, canal, and wooded land are located on the far northeast portion of the 162-acre plot of land, which provide a buffer with the Dresden community.

The far northeast corner of the 162-acre plot of land, adjacent to the lake, was previously used as a fly ash sluicing pond (this land is currently unused). In the distant past this corner of land may have been marshy in character. (The AES Greenidge staff has provided an old site plan drawing that shows gravel, sand, and clay in this corner of the plot. This drawing also provides useful information regarding the depth to bedrock at various locations across the site).

Ferro Corporation is located below the south side of the 162-acre plot of land, along the Seneca Lake shoreline. Ferro is a manufacturer of electronic materials and grinding/polishing compounds.

The Greenidge site includes numerous easements for high voltage power transmission lines, a power line substation, railroad tracks, and existing access roads that will impact options for siting a bioethanol facility.

A large coal storage area is located on the south side of the Greenidge power plant building. As indicated in Figure 2.2, the rail lines are located between the coal storage area and the power plant. AES Greenidge staff believes that the west end of the current coal pile storage area could be used for biomass feedstock storage (there is a rubber liner and runoff collection and treatment system for the coal pile, which could be a helpful feature for avoiding concerns regarding potential runoff from a biomass feedstock storage pile/area). If a larger reserve of biomass feedstock storage is desired than can be accommodated at the coal pile site, the 142-acre parcel of land on the other side of Route 14 could potentially be used.

Figure 2.2 illustrates areas on the AES Greenidge site where a bioethanol facility could be located, based on preliminary assessments of land availability, transportation infrastructure, power line easements, process steam piping, as well as input from the power plant staff. As discussed earlier, one area where much of the ethanol facility could be located is inside the existing power plant building, as indicated on Figure 2.2.

2.3 Transportation Infrastructure

The power plant is located on State Route 14, a major north-south access highway, which links New York State's two main east-west highways; the NYS Thruway (Route 90) and State Route 17. Rail access is already in place with a north-south main route, and siding and switching capabilities on site. Additionally, the rail siding at AES Greenidge allows access to certified rail scales. Air transportation is available with major airports in Rochester, Syracuse, Elmira, and Buffalo offering commercial service. Figure 2.3 provides a broad regional perspective with respect to rail transportation infrastructure surrounding the ASE Greenidge site.

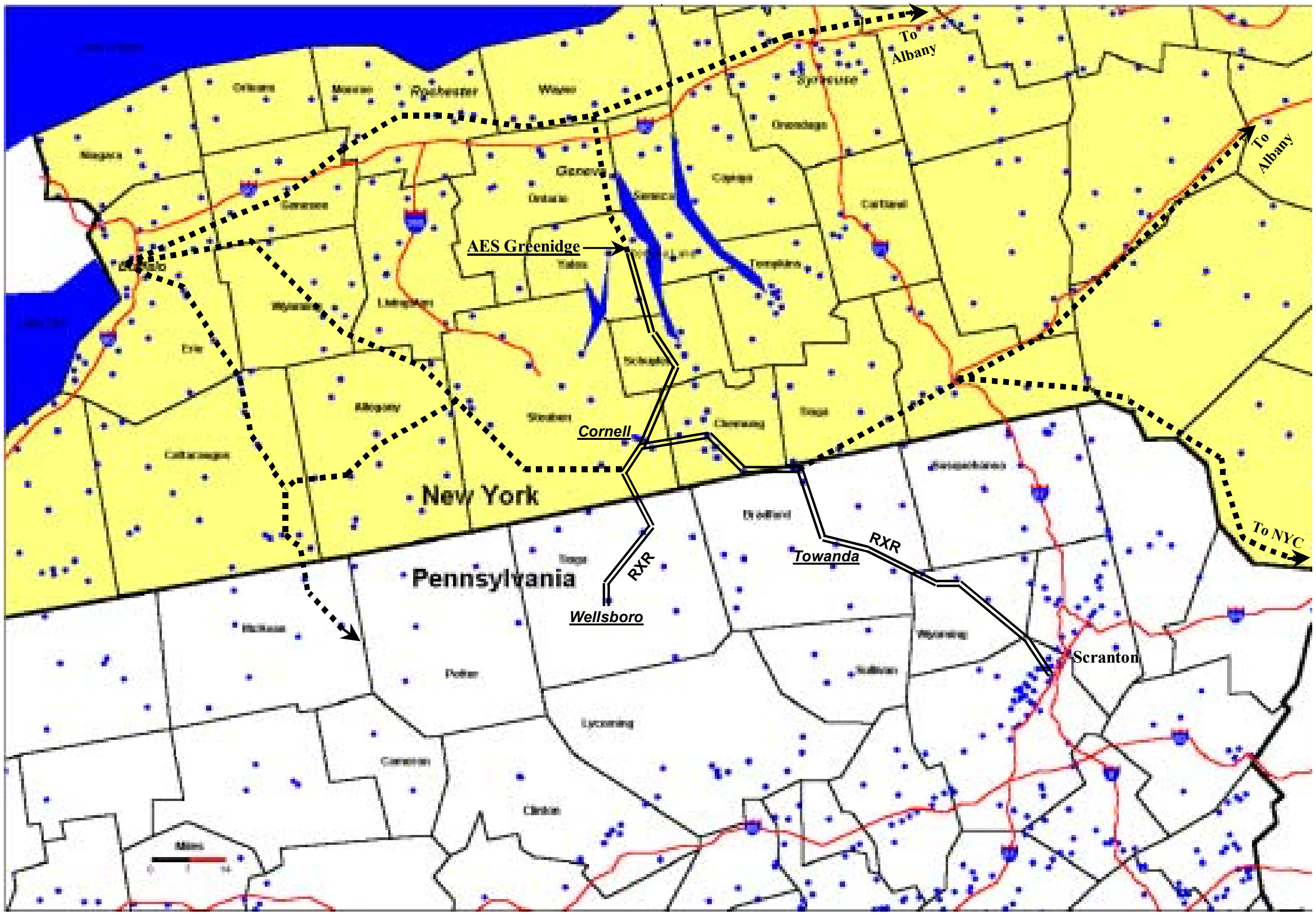

Figure 2.3. Railroad Infrastructure in the AES Greenidge Area

The doted lines on Figure 3 are rail lines in the region. The rail line that goes directly south from the AES Greenidge site, branching into Pennsylvania, is shown as a double line. It is shown with a different symbol to highlight its potential value for delivering wood from northern Pennsylvania, as discussed further in Section 2.4, below. Figure 2.4 shows the highways surrounding the AES Greenidge site. These are generally well-maintained two-lane asphalt roads suitable for truck traffic, as well as heavy agricultural equipment that is operated in much of the area. (Note that the black dots scattered on Figures 2.1, 2.3 and 2.4 indicate the location of villages and cities in the surrounding region. The names and boundaries of the counties surrounding the power plant site are also shown on Figures 2.1, 2.3 and 2.4.)

Figure 2.4 includes circles at 25-mile increments to illustrate the distance to points surrounding the AES Greenidge site. The cities of Rochester and Syracuse are both about 50 miles from the AES Greenidge site and Buffalo is about 100 miles from the site.

2.4 Feedstock Proximity and Abundance

The amount of corn produced, and potential corn stover residues available for a bioethanol facility at the AES Greenidge site, is summarized in Table 2.1 for the counties surrounding the site, out to approximately a 75-mile radius. Note that Interstate 90 (the New York Thruway) provides a strong east-west transportation corridor that could improve the feasibility of transporting corn stover from some of the more distant northwestern counties (such as Genesee and Wyoming counties). The rail lines that lead toward Buffalo could also provide an option for transporting stover from the outermost western counties. Table 2.1 illustrates that there could be approximately 1.1 million tons per year of stover produced in the region surrounding the AES Greenidge facility. Thirty percent of this amount would be approximately enough to produce 20 million gallons of ethanol per year. (Feedstock supply issues are addressed in greater detail in Task 2.1 of this project.)

Table 2.2 illustrates the amount of corn silage that is harvested in the counties surrounding AES Greenidge. While silage is not a likely to contribute to the supply of stover available for ethanol production, quantifying the amount of silage produced helps to fully illustrate the aggregate corn production activities in the region.

The counties in Pennsylvania directly south of the AES Greenidge site are predominantly forested areas, with mostly hardwood tree species. There is a substantial hardwood lumber industry active in this area of Pennsylvania. A large pulp and paper mill recently stopped using local hardwood pulp chips in this area (in the northwestern corner of Wyoming County) and switched to imported Brazilian Eucalyptus pulp chips. With an active lumber mill industry and lost pulp chip demand, supplies of low cost hardwood are abundant in this area. As indicated in Figure 2.5, rail transportation from the northeastern Pennsylvania counties to AES Greenidge (at Dresden) is quite direct and could offer an attractive means for wood chip delivery to a bioethanol facility co-located at the power plant site. A radius of 20 miles is shown for two sites on the rail lines in Pennsylvania to illustrate a possible distance for trucks to haul wood chips to

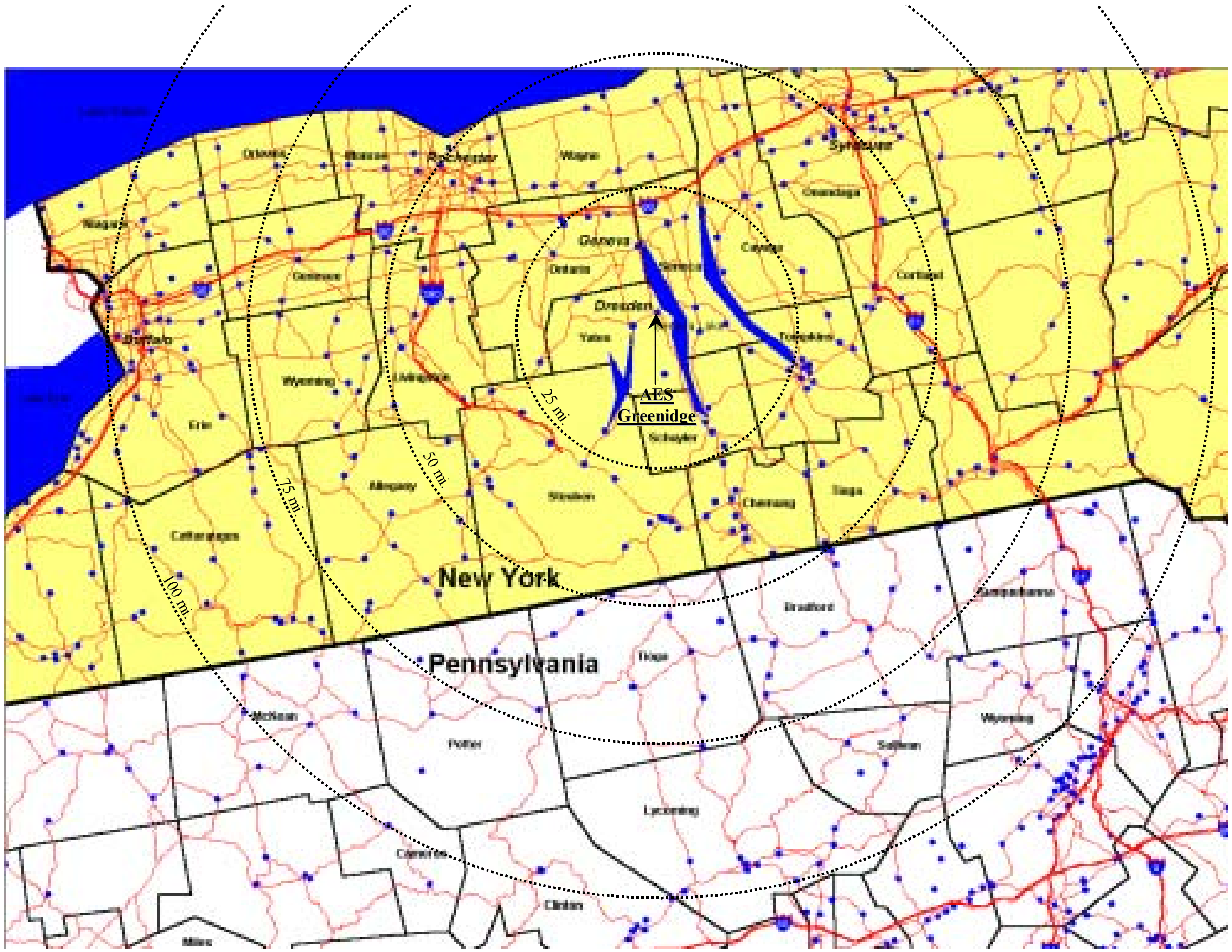

Figure 2.4. Highways and Distances to Counties and Major Cities in the AES Greenidge Area (in 25-mile increments)

Table 2.1. Annual Corn Production and Stover Availability in the AES Greenidge Area

County	No. of Farms*	Acres of Corn*	Bu. Of Corn*	Total Tons of Stover	30% of Total Stover (Tons)
Cayuga	396	56,993	6,433,149	180,128	54,038
Ontario	289	39,289	4,324,098	121,075	36,322
Livingston	234	34,549	3,838,938	107,490	32,247
Orleans	139	31,335	3,606,152	100,972	30,292
Wayne	246	31,786	3,301,580	92,444	27,733
Onondaga	200	28,930	2,969,209	83,138	24,941
Seneca	176	26,722	2,940,061	82,322	24,697
Genesee	192	27,231	2,889,770	80,914	24,274
Monroe	117	21,614	2,270,703	63,580	19,074
Steuben	258	19,047	2,020,358	56,570	16,971
Yates	257	12,441	1,362,644	38,154	11,446
Tompkins	124	12,944	1,297,543	36,331	10,899
Wyoming	137	9,351	1,057,785	29,618	8,885
Chemung	48	3,751	426,943	11,954	3,586
Allegany	86	2,739	287,085	8,038	2,412
Schuyler	49	2,537	250,575	7,016	2,105
Total:	2,948	361,259	39,276,593	1,099,745	329,923

*Corn grown for grain or seed
(does not include corn grown for silage or chop)

One bushel of corn = 56 lbs.
Approx. one ton of corn stover is produced for each ton of corn (grain) produced.

Table 2.2. Annual Tons of Corn Silage Harvested in the AES Greenidge Area

County	No. of Farms	Acres of Corn for Silage	Green Tons of Silage	Dry Tons of Silage[1]		Total Tons of Stover (from Table 1)
Cayuga	233	19,240	330,771	165,386		180,128
Ontario	133	11,412	186,583	93,292		121,075
Livingston	136	15,282	258,523	129,262		107,490
Orleans	68	3,737	56,085	28,043		100,972
Wayne	112	5,658	87,706	43,853		92,444
Onondaga	159	12,306	192,833	96,417		83,138
Seneca	91	5,347	81,474	40,737		82,322
Genesee	133	16,816	275,228	137,614		80,914
Monroe	44	2,655	40,441	20,221		63,580
Steuben	352	19,244	277,620	138,810		56,570
Yates	204	6,021	90,859	45,430		38,154
Tompkins	101	6,216	92,514	46,257		36,331
Wyoming	324	38,731	640,781	320,391		29,618
Chemung	56	2,786	38,660	19,330		11,954
Allegany	86	10,685	161,479	80,740		8,038
Schuyler	59	3,507	52,892	26,446		7,016
Total:	2,291	179,643	2,864,449	1,432,225		1,099,745

[1] - Assumed moisture content of green silage = 50%

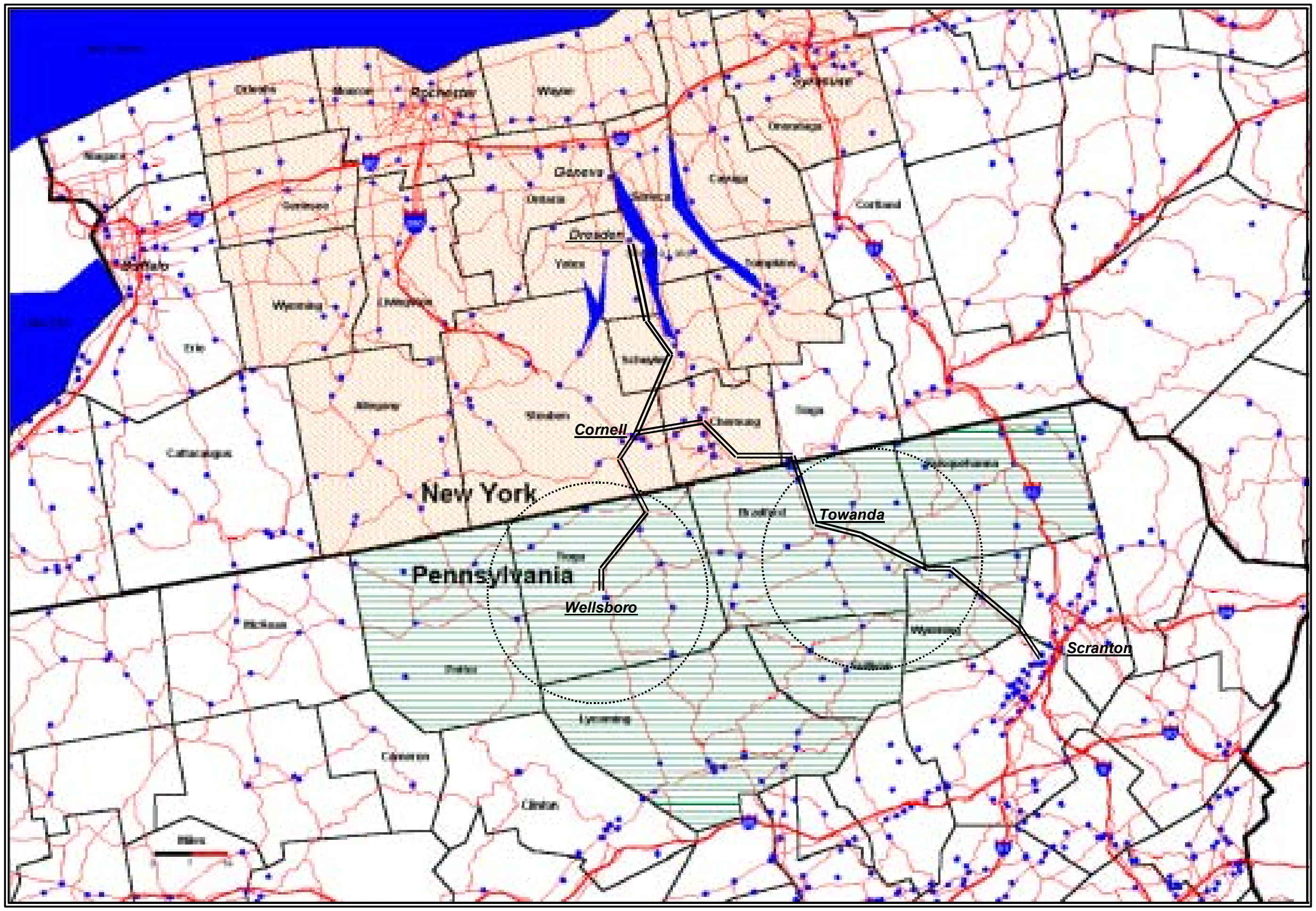

Figure 2.5. Potential NY Corn Stover and PA Wood Supply Areas for a Bioethanol Facility at AES Greenidge

the railroad loading sites (near the communities of Wellsboro in Tioga County and Towanda in Bradford County, Pennsylvania).

The New York counties listed in Table 2.1 as potential suppliers of stover for an AES Greenidge-based ethanol facility are indicated as shaded areas on Figure 2.5. The shaded area in Pennsylvania, on Figure 2.5, indicates the counties that could potentially supply hardwood chips for ethanol production at the AES Greenidge site. (As noted earlier, feedstock supply issues are addressed in greater detail in the Task 1 chapter of this report.)

2.5 Accessibility to End-Use Markets

After January 1, 2004, New York State (NYS) has announced that it will no longer allow MTBE to be used as a fuel additive in gasoline. Ethanol fuel could play a significant role in replacing this MTBE (from an octane, oxygen, and fuel volume perspective), and could also reduce New York State's 100 percent dependence on external fuel supplies. If reformulated gasoline (RFG) continues to require 2 percent oxygen content (per the U.S. Clean Air Act Amendment), the amount of ethanol needed in New York State to replace MTBE and its associated oxygen content will be about 175 million gallons per year (about half of the gasoline used in New York State is RFG, requiring about 350 million gallons per year of MTBE; since ethanol has about twice as much oxygen per gallon as MTBE, half as many gallons of ethanol would be required as MTBE gallons). A bioethanol facility located at the AES Greenidge site would be well situated to take advantage of the large market for ethanol that should soon exist in New York State. The AES Greenidge site is centrally located between Syracuse, Rochester, Buffalo, and could readily supply ethanol to New York City and Albany via truck or rail transport.

2.6 Compatibility of Current Surrounding Land-Uses

As an industrially zoned site in a predominantly rural setting, the AES Greenidge location should offer good compatibility with surrounding land uses for constructing a bioethanol facility at this site. The power plant staff does not believe that truck transportation of biomass feedstock will be a significant local concern – they have delivered coal to their power plant in past years with no complaints, and the local village of Dresden is well away from the main highway (Route 14) that would be used for truck transportation of biomass feedstock. As noted earlier, the property immediately south of the AES Greenidge site is also zoned for industrial uses (with a manufacturer of grinding/ polishing compounds located at this site). Potential environmental sensitivities include possible concerns with respect to odors from a bioethanol facility due to the proximity of the Dresden village north of the AES Greenidge property line, and possible concerns from a tourism point of view related to the visibility of a steam/vapor plume from bioethanol operations in cool weather. These potential concerns are addressed in greater detail under the Task 5 chapter on environmental issues.

Task 3. Design and Cost Estimates

3.0 Overview

Design and cost estimates have been developed for the AES Greenidge bioethanol co-location project for a number of key variables. Two basic configurations were evaluated for the bioethanol facility:

1) An ethanol facility with co-current dilute acid prehydrolysis and enzymatic hydrolysis, based on cost and performance parameters anticipated to be achievable by the year 2010; and

2) An ethanol facility with two-stage dilute acid hydrolysis, based on cost and performance parameters anticipated being achievable in the 2004 timeframe.

For each configuration it was assumed that a quantity of 1,000 dry tons per day of corn stover would be used for the feedstock supply. Easterly Consulting collaborated closely with NREL in efforts to model the design and cost parameters under this task – NREL modified and ran their latest 2-stage dilute acid and enzymatic models with inputs provided by Easterly Consulting and AES Greenidge staff. In particular, AES Greenidge staff have provided highly valuable input on a variety of design and cost parameters related to the integration of their facility and operations with those of a potential bioethanol facility. These issues include factors such as steam availability and conditions, boiler and fuel feed parameters and limits, duty/dispatch cycles for the power plant that could impact steam availability and demand for lignin fuel, and acceptable cost parameters for steam sales and lignin purchases.

The evaluation included an assessment of opportunities to reduce operation and maintenance costs by sharing some personnel/functions between the coal power plant and the ethanol facility. It also addressed the potential to use methane from the bioethanol wastewater treatment plant as a potential fuel for the AES Greenidge "reburn" injectors. (The reduction in NO_x emissions that the "reburn" system provides could allow the bioethanol facility to provide monetized value for this benefit, since NO_x emission credits are traded in the Northeast). The design and cost evaluation also addressed a variety of other factors that could generate additional credits and revenue, including potential gypsum sales, carbon dioxide sales, SO_2 credits, and greenhouse gas credits.

3.1 Introduction

NREL recently published an updated, detailed process design report for stand-alone enzymatic hydrolysis facilities using corn stover feedstock (NREL, May 30, 2002), and will soon publish a similar report for two-stage dilute acid plant designs. The following task report is based on very similar process design conditions to those described in detail in these two NREL reports. The primary difference between these two NREL analyses and the AES Greenidge analysis relates to co-location considerations and the scale of the facility. The two NREL analyses of stand-alone facilities assume that 2,000 dry metric tons (2,200 short tons) per day of feedstock is processed at the facilities, whereas the AES Greenidge co-location analysis assumes 1,000 short tons per day of feedstock utilization, based on the anticipated quantities of corn stover supplies available in the AES Greenidge area. The anticipated cost for the corn stover is $35.70 per dry ton. (See the Task 1 report for this project for further details regarding feedstock supply and cost considerations). The following report focuses on those design factors that are unique/specific with respect to co-location considerations for an AES Greenidge bioethanol plant. For other detailed process design and subsystem descriptions, refer to NREL's enzymatic and two-stage dilute acid design reports noted above.

Appendix A provides a summary table of process and economic parameters and results found for two co-located enzymatic hydrolysis scenarios, and Appendix B provides a similar summary for two 2-stage dilute acid scenarios. The first scenario in both Appendix A and in Appendix B (in the center column) is for a bioethanol facility that has 25 percent equity financing, with the rate of return (after taxes) calculated based on an ethanol selling price of $1.30 (this is 10 cents per gallon above the anticipated selling price of ethanol in Midwest markets; for a justification regarding this assumption see the discussion on regional ethanol transportation cost factors in the Task 7 Market Issues chapter). The second scenario in both Appendix A and Appendix B (in the right hand column) is for 100 percent equity financing, with the ethanol selling price calculated based on an assumed 10 percent internal rate of return after taxes.

3.2 Co-Location Design Factors

There are a number of benefits or impacts that result from co-locating the bioethanol facility next to the coal plant that were factored into the design and cost analysis in completing this task:

- Credits for avoided boiler and turbine/generator costs

Capital costs for boiler and turbine/generator equipment are avoided as a result of the co-location approach and were assumed to be zero. While there will be costs to modify various components of the existing AES Greenidge boiler and fuel handling equipment to accommodate the lignin and other by-product fuels from the bioethanol process, some or all of these costs may be paid by the power plant operation, rather than the ethanol operation (as discussed below). One option would be to use the older boilers – boilers 4 and/or 5 – to combust the lignin. At present, it appears that these boilers could very possibly be placed permanently out of service over the next few years if the bioethanol project does not occur. However, if these boilers are used to combust lignin and provide process steam for the bioethanol facility, this could provide new longer-term use for these boilers. AES has indicated that if boilers 4 and 5 were used, it would plan to follow through with a number of modifications (such as adding low-NO_x burners) to these boilers in efforts to upgrade their performance. The boiler upgrades and potential modifications needed to burn lignin could be an investment that AES Greenidge would make on their own (separate from the bioethanol financing package), since they would be obtaining substantially extended use of their boiler and turbine assets as a result of the bioethanol project. (This provides a rationale for not adding/including boiler modification costs in the bioethanol project costs/economics.)

- Use of existing space in the power plant building

Existing unused space inside the AES Greenidge power plant could be available for installing a significant portion of the bioethanol equipment/system, which should help reduce installation costs for the bioethanol facility (see the Task 2 "Site Characterization" chapter for further discussion/descriptions regarding available space inside the AES Greenidge power plant building). Based on this expectation, indirect costs for field expenses were reduced by 5 percent (lowered from 20 percent to 15 percent of total installed costs (TIC) for the equipment). In addition, the fee for home office and construction was lowered by 15 percent (lowered from 25 percent to 10 percent). These two adjustments for installation costs lowered the total project investment (TPI) for the enzymatic system by $9.23 million, and lowered the TPI for the two-stage dilute system by $8.72 million.

- Electricity pricing

The value of the electricity sold "across the fence" for use by the bioethanol plant was assumed to be $0.04 per kWh. (Note that for the year 2003, the price anticipated for electricity sold to the grid by power plants in western NYS is anticipated to be $0.03 per kWh on a wholesale, average round-the-clock basis, including on-peak and off-peak rates.)

- Process Steam Use and Pricing

Boilers 4 and 5 produce steam at 865 psig and 905 degrees F, and boiler 6 produces steam at 1,465 psig and 1005 degrees F. The steam turbines ("3 Unit," fed by boilers 4 and 5; and "4 Unit" fed by boiler 6) have various extraction ports that have been used in the past to provide process heat. With the assumption that AES is a major or primary owner of the bioethanol facility and that steam used for process heat in the bioethanol facility is extracted only after it has provided significant useful electric power generation after cascading from higher pressures through the turbine, the steam pricing was determined as follows – steam extracted from the turbine at 300 psig was assumed to have a value approximately equal to the cost of coal on a Btu basis, thus the price of 300 psig steam would be about $1.95 per 1,000 lbs of steam. For lower pressure steam at about 50 psig, where most of the energy available for electric power production has already been extracted, it was assumed that the value of the steam was about $0.56 per 1,000 lbs of steam. These two steam prices were used to create a linear steam cost "curve" for extrapolating steam prices at various pressures. For example, steam is extracted at three pressures for use in the enzymatic hydrolysis process – the steam pressures and corresponding prices determined from the steam cost curve are as follows: 191 psig (13 atmospheres) steam is priced at $1.34 per 1,000 lbs of steam; 65 psig (4.42 atm) steam is priced at $0.64 per 1,000 lbs of steam; and steam at 25 psig (1.68 atm) is priced at $0.42 per 1,000 lbs of steam. Table 3.1 provides a summary of process steam requirements and suggested steam costs for the enzymatic and the 2-stage dilute acid scenarios evaluated under Task 3. (From a broader corporate perspective there is another economic benefit to the production of process heat that could help justify keeping the steam prices reasonable. Since the older "3 Unit" turbine/generator is less efficient than "4 Unit," the operation of "3 Unit" has become increasingly intermittent. The cost in energy and other costs to start up "3 Unit" from a cold condition has meant that it has not been economical in some cases to fire up boilers 4 and 5 to produce electricity when peak electric rates/payments from the grid occur. By maintaining boilers 4 and/or 5 in continuous operation to provide process heat (and electricity) for the bioethanol facility, AES Greenidge might be able to avoid incurring cold start-up costs for these boilers and could more readily take advantage of opportunities to sell electric power to the grid from "3 Unit."

Table 3.1. Process Steam & Electricity Requirements & Costs

	Enzymatic Option					2-Stage Dilute Option			
Steam Category:	Psia	Temp (F)	lbs/hr steam	$/lb		psia	Temp (F)	lbs/hr steam	$/lb
"Hi" pressure	191	515	37,242	$1.34		250	567	48,731	$1.67
"Medium" pressure	65	326	95,550	$0.64		65	326	91,840	$0.64
"Lo" Pressure	25	239	4,021	$0.42		25	239	18,908	$0.42
Total Steam:			136,813					159,479	
			KW	$/kWh				KW	$/kWh
Electricity Needs:			8,018	$0.04				6,844	0.04

- Requirements for fuel combustion in suspension

A key consideration for the co-location project is that the lignin (and other bioethanol by-product) fuel will need to burn in suspension in the existing pulverized coal boilers at AES Greenidge. Bioethanol process evaluations done by NREL and others in the past have assumed that the lignin would be burned in a boiler designed to burn biomass fuel. These biomass boilers generally have either grates or fluid beds that allow for slower combustion of relatively high-moisture-content biomass fuels (in the range of 50 percent moisture). It is anticipated that ethanol by-products available for combustion in the boiler will have the following moisture content:

- Lignin stream: primarily lignin, with other significant fractions such as cellulose that has not been hydrolyzed in the process, sugars, ash, etc.; water content will be 48% (dewatered to this level via the use of a filter press);
- Anaerobic digester solids from the wastewater treatment system: water content will be about 70% (note that these solids represent less than 0.3% of the mass flow rate in comparison to the lignin stream);
- Evaporator syrup: water content of about 60%, dissolved solids content of about 26%, and insoluble solids content of about 2.5% (note that ignoring the water content of the evaporator syrup and the lignin streams, the energy value of the evaporator syrup stream would be about 62% as large as the energy content of the lignin stream); and
- Methane from the wastewater treatment system's anaerobic digester: water content in this stream is negligible (the methane stream contains about 52% methane, 44% CO_2, and 4.5% water; note that the energy content in the methane is a little less than 4% of the energy content in the lignin stream).

It is likely that lignin with a 48% moisture content can be cofired with coal in the AES Greenidge boilers at relatively low percentage levels – for example, if there is a mix of 95% coal and 5% lignin (on a Btu basis). However, if boilers 4 and/or 5 were used to combust the lignin, it would be necessary to combust relatively higher percentages of this biomass feedstock, considering the flow rate of lignin from the ethanol process versus the fuel requirements of the boilers. In order to cofire lignin at levels above approximately 10% biomass, it is likely that the moisture content of the lignin will need to be lower than 50% in order for complete combustion to occur in suspension. Considering that sub-bituminous coal with 30% moisture can be burned in suspension in pulverized coal (PC) boilers, this seems like a reasonable target for the lignin moisture content in order to facilitate proper combustion. Thus a second stage of drying is likely to be needed for the lignin following the filter-press dewatering stage, to achieve 30% moisture content for the lignin (drying technology issues are discussed in greater detail below). Combustion of the evaporator syrup also raises similar issues regarding combustion in the existing PC boilers at AES Greenidge, as discussed below.

- Thermal drying

There are limits on the extent to which mechanical drying techniques can reduce the water content of the lignin stream. Tests by NREL to date have shown that it is possible to obtain a solids content of about 52% using filter press technology. Further refinements may allow somewhat greater reductions in the moisture content of the lignin stream with this mechanical technology; however, it seems likely that a thermal drying stage will be needed if the moisture content is to be reduced to 30%. In evaluating thermal drying options, it appears that a type of pneumatic or "flash" dryer known as a ring dryer offers a fairly attractive approach. According to a representative from Barr-Rosin Company (which sells a wide variety of thermal drying equipment such as flash dryers, ring dryers, and rotary driers), a ring dryer would be a logical choice for drying the lignin stream from both a performance and cost standpoint (a rotary dryer would cost 30 to 40% more than a ring dryer). (As a side note – Barr- Rosin flash dryers are installed or being installed at five corn-to-ethanol facilities in the U.S. for drying distillers grain solids).

One option for thermal drying is to use the hot flue gases from the boiler(s) as a source of waste heat to dry the lignin stream. Boilers 4 and 5 each produce about 59,000 cubic feet/minute of exhaust gases at about 325 degrees F. Boiler 6 produces 178,000 cubic feet/minute of exhaust gases at about 310 degrees F. The exhaust gases from boilers 4 and 5 are combined together and pass through their own electrostatic precipitator (ESP) and stack. Similarly, boiler 6 has its own ESP and stack to handle its exhaust gases. The dew point temperature for all the exhaust gas streams is 160 degrees F. A ring dryer can use the exhaust gases for drying the lignin, and can also readily be designed with burners (such as natural gas burners) that can provide supplemental heat if the heat in the flue gases is not adequate.

Preliminary sizing and cost information was obtained from Barr-Rosin for installation of a ring dryer adequate to handle the quantity of lignin and digester solids streams associated with an enzymatic hydrolysis system processing 1,000 dry tons per day of stover; this information is summarized below.

<u>Use of a ring dryer and flue gas (only) for drying the lignin and digester solids:</u>

- Assuming a combined lignin and digester solids flow rate of 290 tons per day (on a dry basis);
- Moisture content of the combined incoming stream at 48% water;
- Moisture content of the dried outgoing stream at 30% water;
- Dryer inlet temperature of 325 deg. F (i.e., equal to the boiler flue gas temperature);
- Dryer outlet temperature of 190 deg. F (i.e., above the dew point of the flue gas);
- The ring dryer air flow required would be 544,000 lb/hr of air at 325 deg. F equal to 162,000 cu. ft/min (cfm) at atmospheric pressure

The flue-gas flow rate for boiler 6 alone is 178,000 cfm (when operated at full capacity), which is more than adequate to meet the 162,000 cfm requirement noted above. However the combined flue gas streams from boilers 3 and 4 (at 118,000 cfm when operated at full capacity) would not satisfy the 162,000 cfm requirement. If most of the by-product fuel streams from the ethanol operation were combusted in boilers 4 and/or 5, the operation of these boilers would need to coordinated with the operation of the ethanol facility (allowing operation of boiler 6 and the "4 Unit" turbine-generator) to be independent of the bioethanol operation. However, as indicated above, the flue gas flow rate from boilers 4 and 5 would not be adequate as the sole source of heat for drying. In order to take this approach, one option would be to use a supplemental heater in the ring dryer to boost the temperature of the flue gases from boilers 4 and 5, or to modify the boiler(s) to allow for extraction of flue gases at a higher temperature. However, even if this extraction is physically possible, it will result in de-rating the capacity of the boiler(s). After preliminary discussions with the boiler manufacture's engineering staff, this seems like a doubtful approach (Houser, 2002). Thus the option of using supplemental fuel was evaluated further, as summarized below.

<u>Use of a ring dryer with flue gas plus supplemental heat to dry the lignin and digester solids:</u>

- Assumed combined lignin and digester solids flow rate -- 290 tons per day (on a dry basis);
- Moisture content of the combined incoming stream at 48% water;
- Moisture content of the dried outgoing stream at 30% water;
- Dryer inlet temperature of 750 deg. F – where the boiler flue gas temperature is boosted by a heater (e.g., using natural gas and/or a solid fuel burner that combusts dried lignin);
- Dryer outlet temperature of 190 deg. F (i.e., above the dew point of the flue gas);
- The air flow required would be 149,000 lb/hr of air at 750 deg. F, equal to 42,000 cfm at atmospheric pressure
- Supplemental air heater input required – 14.2 million Btu/hr
- Ring dryer capital cost of approx. \$600,000 or a total installed cost of approx. \$1.2 million.

It is useful to note that the net cost of supplemental heat for a dryer (beyond the heat available in the flue gas) is rather low, since the energy/fuel used to vaporize the water will directly increase the energy value of the lignin stream (i.e., there is an energy penalty to vaporize the water, whether it occurs in the boiler, or upstream of the boiler via the use of supplemental fuel).

- By-product fuel pricing

The by-product streams of lignin, evaporator syrup, and digester solids were assigned a fuel value equal to the cost of coal (delivered), where the energy value of the by-product streams were adjusted to account for their water content as delivered to the boiler (i.e., accounting for any drying that is done prior to their delivery to the boiler). The price of coal obviously will vary somewhat over time – the value used in the current analysis assumed a delivered cost of coal at $1.95 per million Btu.

Biogas (methane) from the wastewater treatment system was assigned a fuel value equal to the price of natural gas on a per Btu basis, adjusting the energy value of the biogas to account for the effect of its carbon dioxide (non-methane) content. The biogas would be used to replace natural gas in the boiler reburn system to help reduce NO_x emissions and to help produce steam. The price assumed for natural gas was $2.95 per million Btu.

- Other by-product credits and pricing
  - NO_x credits

The cost of NO_x emission credits was recently $850 per ton for year 2002, and $5,100 per ton in 2003 and 2004 when federal and regional regulations require significant reductions in NO_x emissions [Evolution Markets, 2002]. The nitrogen content of boiler fuel (referred to as fuel-bound nitrogen) contributes to the formation of NO_x emissions during combustion of the fuel. Tests sponsored by the Electric Power Research Institute (EPRI) have found that the nitrogen in coal fuel contributes about 20% of the NO_x emissions; and nitrogen from combustion air contributes about 80% of the nitrogen in the NO_x flue gas emissions [Hughes, 2002]. With anticipation of high prices for NO_x credits over the next few years, the potential impacts of fuel changes on NO_x emissions will clearly be an important consideration.

The average nitrogen content of Eastern Bituminous (Pittsburgh) coal is 1.5 percent [EPRI, 1989], whereas tests by NREL found lignin samples to have a nitrogen content ranging from 0.16 to 1.04 percent for softwood-derived lignin [Elam, 2000], and 2.55 percent nitrogen for corn stover-derived lignin [Wallace, May 2002]. This would indicate a possible tendency for corn-stover-based lignin to increase NO_x emissions compared to coal. However, in addition to the effects of fuel bound nitrogen, tests sponsored by the Electric Power Research Institute and DOE have found that the high volatility of biomass compared to coal seems to help reduce NO_x emissions when biomass is cofired with coal, by changing the stoichiometry of the combustion conditions [Tillman, 2002; and Hughes, 2002]. At the present time, the interaction of fuel-bound nitrogen and biomass fuel volatility on NO_x emissions related to cofiring lignin (and the other bioethanol by-product streams) is quite difficult to predict. While it is important to note that the impact of costs/credits with regard to NO_x emissions could be quite significant, it is premature to predict what the impact of cofiring these biomass streams/materials will be on total NO_x emissions from a coal-fired power plant that cofires these materials. Thus with the exception of digester biogas, the cost impacts of cofiring the solid combustible residues from the bioethanol process have not been quantified in the analysis done for this task/project.

The impacts of cofiring methane (in the form of natural gas) are actually well known for power plants. Natural gas is currently used in the "reburn" system installed in boiler 6 for NO_x control/reduction. The combustion of methane in the reburn system reduces NO_x emissions by about 0.17 pounds per million Btu of methane. This factor was used to calculate a credit per gallon of ethanol produced per million Btu of digester methane available from the bioethanol facility

- SO_2 Emissions Credits

Lignin should typically have much lower sulfur content than coal, which will help reduce SO_2 emissions. The sulfur content of coal used at AES Greenidge is typically around 2.2 percent [Chambers, April 15, 2002]; whereas the sulfur content of lignin residues has been measured by NREL to be in the range of 0.07 to 0.10 percent for softwood-derived lignin [Elam, 2001] and 0.25 percent for corn stover-derived lignin [Wallace, May 2002]. The cost to purchase SO_2 credits is currently around $172 per ton [Evolution Markets, 2002]. Boiler 4 at AES Greenidge typically produces 3.32 pounds of SO_2 per million Btu of coal burned. Combining the heating value of the lignin per Btu with its sulfur content value, it can be calculated that combusting the lignin will produce of 1.03 pounds of SO_2 emissions per million Btu of lignin burned. Thus for every million Btu of coal displaced by lignin fuel, SO_2 emissions will by reduced by 2.29 pounds.

- Carbon dioxide sales

Recovery and sale of CO_2 resulting from fermentation is another potential source of revenue from the bioethanol process. The estimated market value of CO_2 in New York State is in the range of $9.00 per ton of CO_2 [New York Corn Growers Association, 2000]. NREL's process engineering analysis indicated that the enzymatic hydrolysis process would produce 11.7 tons per hour of CO_2 that would be available for sale.

- Gypsum sales

Gypsum is currently sold to farmers in the AES Greenidge area for $16.50 per ton, delivered [Horst, 2002]. A local gypsum supplier has said he would be willing to pay $3 per ton (at the plant gate) for gypsum produced by a bioethanol facility at AES Greenidge, assuming that tests of gypsum verify that it is acceptable as a soil amendment. NREL's process engineering analysis indicated that the enzymatic hydrolysis process would produce 3.6 tons per hour of gypsum that would be available for sale.

- Ash disposal

As noted earlier, AES Greenidge disposes its coal ash on site. While this allows for relatively low ash disposal costs, there are still some costs associated with handling the ash, property taxes for the land used for disposal, etc. Coal used at AES Greenidge typically has an ash content of approximately 7.9 percent. Tests done by NREL on lignin produced from stover found the ash content to be around 17.2 percent [Schell, 2001]. Thus on a Btu-adjusted basis, ash disposal costs could increase somewhat if corn stover is used as the feedstock for ethanol production, where the lignin derived from stover is used to displace coal.

- Greenhouse gas credits

Since lignin is a renewable fuel, it reduces CO_2 emissions by offsetting fossil fuel/coal combustion; methane from the bioethanol wastewater treatment system offsets natural gas use for the reburn system used for NO_x control; and the ethanol fuel produced by the facility will reduce CO_2 emissions as it displaces gasoline/petroleum used for transportation. According to the DOE Energy Information Administration, combustion of bituminous coal produces 205.3 pounds of CO_2 emissions per million Btu; gasoline combustion produces 156.4 pounds of CO_2 emissions per million Btu; and natural gas combustion produces 117.1 pounds of CO_2 emissions per million Btu [EIA, 2002]. In addition to reducing CO_2 emissions from fossil fuel combustion, there could also be additional sequestration of carbon due to increased conservation tillage practices associated with corn stover harvesting/utilization. However, for the modeling runs done to date, only the CO_2 emissions avoided at the power plant (i.e., coal and natural gas offsets) were used in determining credits for greenhouse gas reductions.

In the newly emerging market for trading CO_2 emission credits in North America, at least one marketer believes that it is possible to find buyers who would commit to paying $1 per ton of avoided CO_2 emissions [Elms, 2002]. Using this value, the preliminary process engineering analysis indicated that sales of CO_2 emissions credits could produce $350,000 per year for a bioethanol facility co-located at the AES Greenidge power plant.

- Cooling water equipment and costs

It is possible that lake water available at the AES Greenidge site could be used in lieu of a cooling tower for the bioethanol facility's cooling water system. This would reduce capital costs for the bioethanol facility by avoiding the need for a cooling tower, and would significantly cut makeup water consumption and related costs (the majority of makeup water required for a bioethanol system that uses a cooling tower to chill cooling water is due to water losses from evaporation associated with the cooling tower operation). There are a variety of environmental issues that would need to be evaluated in greater depth to determine whether the NYS Department of Environmental Protection (DEP) would allow Seneca Lake water to be used for the cooling water system (the AES Greenidge power plant is currently allowed to use a significant amount of Seneca Lake water for the power plant condenser operation). With this uncertainty, the current analysis (summarized in this task) assumes that cooling water is provided by means of a cooling tower, rather than the lower cost approach of using lake water for the cooling water system.

- Make-up water costs

For the modeling runs done to date, NREL's default value was used for the cost of make-up water at $0.0001 per pound, or $0.00083 per gallon.

- Labor cost savings via co-location

Table 3.2 provides a summary of the anticipated number of employees needed to operate a 1,000 dry ton per day bioethanol facility co-located at the AES Greenidge power plant. This estimate of employee requirements is based on the assumption that AES is at least a partial owner of the bioethanol facility, thus facilitating employee roles/functions that can engage in both ethanol and power plant operations. (Note that this is close to the number of employees (27) estimated for a similarly sized co-located bioethanol facility that was evaluated in a 1999 study by Merrick & Company [Merrick, 1999].)

Table 3.2. Estimated Number of Employees to Operate a 1,000 Dry Ton/Day Bioethanol Facility Co-Located at the AES Greenidge Power Plant

Job Title	Employees per day
Operators	12
Technicians	2
Yard Employees	9
Supervisors	2
Total:	25

By comparison, NREL estimates that 40 employees per day would be needed to operate a stand-alone two-stage dilute acid bioethanol facility at a similar scale, and that 77 employees would be needed to operate a stand-alone enzymatic hydrolysis bioethanol facility (while the 77 employees would be for a facility processing 2,200 (short) tons of biomass per day, NREL anticipates that the number of employees required would not drop significantly for a smaller-scale stand-alone bioethanol facility).

3.3 Options for Combusting the Bioethanol By-Product Streams in AES Boilers

Figure 3.1 provides a comparison of the energy flows available in the four combustible by-product streams for the bioethanol facility compared to the amount of fuel that the three AES Greenidge boilers can burn when operated at full capacity (based on the Btu's of coal that these boilers can burn). The Btu values shown for the four bioethanol streams are for the base-case two-stage dilute acid hydrolysis facility processing 1,000 dry tons per day of corn stover. In Figure 3.1 the capacities of boilers 3 and 4 (307 million Btu per hour each), are based on the situation where both of these boilers are operated together to provide steam at the maximum design capacity of the "3 Unit" turbine generator, which is 52-megawatts. When operated alone, either boiler 4 or boiler 5 can provide enough steam for "3 Unit" to generate 30 megawatts, or 58% of the steam needed for full capacity operation. Thus when operated alone, either boiler 4 or 5 could burn 354 million Btu per hour, whereas they are limited to using no more than 307 million Btu per hour of fuel when operated together for electricity production, due to the capacity limits of "3 Unit." (Note: if there are circumstances when the value/price paid for electricity sold to the grid is high, it might be possible to run both boilers at the higher 354 million Btu/hr level, if piping is installed that will allow the option of diverting process steam to the bioethanol process prior to the "3 Unit" turbine, rather than removing the steam via extraction ports on the turbine.)

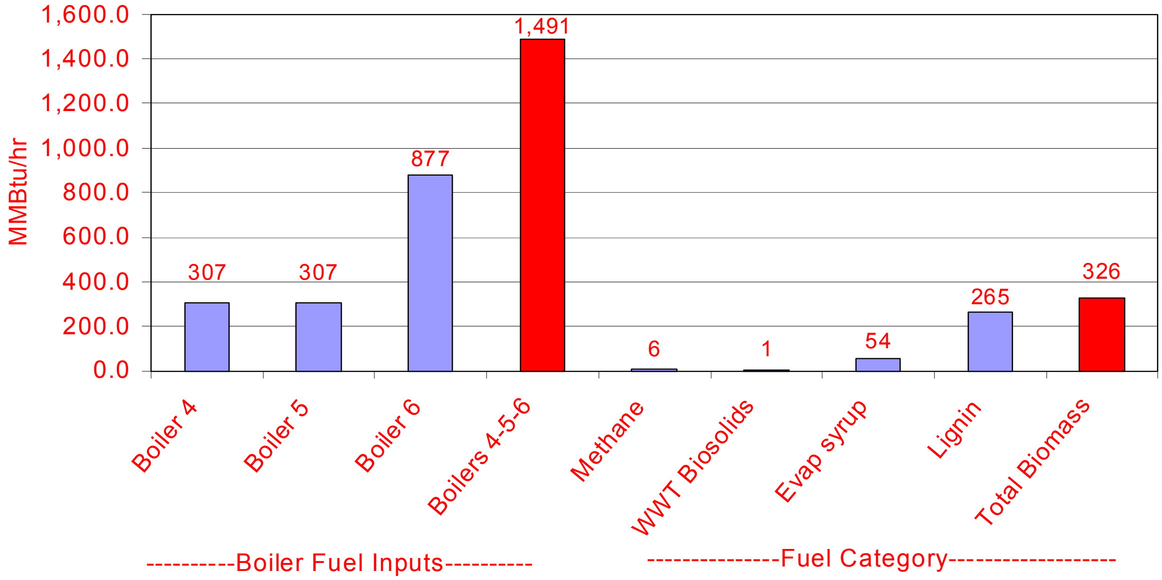

Figure 3.1. Fuel required for the AES Greenidge boilers to operate at full capacity vs. by-product fuel available from the base-case two-stage acid hydrolysis facility processing 1,000 dry tons/day of corn stover

There are a number of different combinations or approaches for combusting the four bioethanol by-product streams in the three boilers. Table 3.3 (on the following page) illustrates some the different combinations that could be used in matching/feeding the by-product streams to the three boilers.

All four biomass fuel streams as a % of the total combined boiler capacity at AES Greenidge (i.e., for boilers 4, 5, & 6 combined)	21.9%
All four biomass fuel streams supplying boilers 4 & 5 run together	53.1%
All four biomass fuel streams supplying boiler 6	37.2%
Lignin + biosolids as a % of boiler 4 capacity	75.1%
Lignin + biosolids + methane as a % of boiler 4 capacity	76.8%
Lignin + biosolids + evaporator syrup as % of boiler 4 capacity	90.4%
Lignin + biosolids as a % of boilers 4 & 5 capacity if run together	43.3%
Lignin + biosolids + evap syr as a % of boilers 4 & 5 run together	52.1%
Evaporator syrup as a % of boiler 6 capacity	6.2%
Evaporator syrup as a % of boiler 5 (or 4) capacity	15.3%
Lignin + biosolids as a % of boiler 6 capacity	30.3%
Lignin + biosolids + evaporator syrup as % of boiler 6 capacity	36.5%

Table 3.3. Percentage of boiler fuel provided when grouping/supplying various biomass fuel streams to different boiler combinations (for the base-case two-stage dilute acid hydrolysis facility processing 1,000 dry tons/day of corn stover)

Considering the various configurations or combinations for delivering the biomass fuel streams to the coal boilers, there are a number of scenarios that could make sense:

<u>Scenario One for Boiler/Fuel Flow Configurations:</u>

- Lignin and digester solids dried to 30% moisture using boiler flue gases (plus supplemental heat or fuel, such as natural gas, if necessary), then blended with coal and fed into boiler 4 (or 5) through the existing pulverizer/coal feed system. Note that the mills in the coal pulverizers for boilers 4 and 5 have direct metal-to-metal contact, unlike the mills for the pulverizers in boiler 6. AES Greenidge staff believe the direct metal contact in the boiler 4 and 5 mills could be advantageous in avoiding gumming problems with the mills when feeding a somewhat wetter fuel than pure coal.

- Digester biogas would be combusted in "reburn" nozzles installed in boiler 4 (or 5) for NO_x control/ reduction, as well as for additional steam production by the boiler; and

- Evaporator syrup would be spray-injected into boiler 6 and cofired with coal, providing NO_x reduction benefits, in part due to the water in the syrup cooling the combustion flame temperature somewhat. Based on tests of combusting coal/water slurries in coal PC boilers, it is also possible that this injected stream will alter the stoichiometry of the combustion zone such that NO_x emissions will be reduced more than predicted by simple cooling of the combustion flame temperatures [Miller, 1997]. The large capacity of boiler 6 can probably best accommodate cofiring of the high moisture evaporator syrup stream.

<u>Scenario Two:</u>

- Identical to scenario one, except the dried lignin and digester solids would be burned in both boilers 4 and 5 (rather than in only one of these boilers). The potential advantage of this approach is that it would increase the ratio of coal burned compared to biomass fuel in each of the boilers – lower percentage cofiring of biomass probably has less risks involved for assuring that the 30% moisture biomass fuel burns properly in these suspension boilers.

<u>Scenario Three:</u>

- Lignin, digester solids, and evaporator syrup mixed together and dried to 30% moisture using boiler flue gases (with supplemental heat/fuel, if needed), then blended with coal and feed into boilers 4 and 5 through the existing pulverizer/coal feed system. The advantage of this approach is that it avoids the technical uncertainties of burning the evaporator syrup as a slurry in boiler 6. The drawbacks of this scenario are that it will increase the likelihood that additional supplemental heat will be needed for the thermal drying step in order to accommodate the high moisture syrup, and the amount of biomass cofired in relation to coal use will be rather high (the boiler is designed to burn coal, whereas there are uncertainties regarding the combustion of high percentages of biomass; this issues is discussed in greater detail below). There may also be some handling and drying questions regarding the wet mix of biomass materials to be dried (e.g., would it be a sticky problematic mix?).

- Digester biogas would be combusted in "reburn" nozzles to be installed in boiler 4 for NO_x reduction, as well as for additional steam production by the boiler.

<u>Scenario Four:</u>

- Scenario four is similar to scenario three, however, under scenario four the mix of dried biomass fuel would all be burned in boiler 6. The lignin, digester solids, and evaporator syrup are mixed together and dried to 30% moisture using boiler flue gases (with supplemental heat/fuel, as needed). A potential advantage of this approach is that it would increase the ratio of coal compared to biomass fuel burned in the boiler (relative to scenarios 1, 2 or 3), which entails less risks in terms of assuring that the 30% moisture biomass fuel burns properly in the suspension-style, pulverized coal boilers. As in scenario 3, this approach would avoid the technical uncertainties of cofiring a liquid stream in boiler 6. As indicated in Table 3.3, the combustion of all four of the biomass streams would represent 36.5% of the capacity of boiler 6. (A selective catalytic NO_x reduction system (SCNR) is to be installed for boiler 6 in the near future, thus one issue that would need to be explored is the impact of the scenario 4 approach on performance and warranties for the SCNR.)

- Digester biogas would be combusted in the existing "reburn" nozzles in boiler 6 for NO_x reduction, as well as for additional steam production by the boiler.

<u>Scenario Five:</u>

- Scenario five is similar to scenario four, where the lignin stream and the digester solids would be sent to boiler 6, however the evaporator syrup would be sent to the wastewater treatment system. This would result in an increase in the size, installation cost, and operating cost of the wastewater treatment system, as well as increased production of methane fuel in the digester (about 3.5 times as much methane) and increased digester/biosolids residues for use in boiler 6 (almost 7 times as much energy in the digester biosolids compared to the other scenarios). The lignin and digester solids would be mixed together and dried to 30% moisture using boiler flue gases, providing about 33% of the fuel required for boiler 6 to run at full capacity. Note that with the absence of the evaporator syrup to boiler 6, the energy value of the combined lignin and digester solids fuel stream in scenario 5 is about 15.5% less than the solids fuel stream for scenario 4. Even though there is an increase in the amount of biogas fuel provided to boiler 6 in scenario 5, the total combined biomass-derived fuel delivered to boiler 6 (including biogas) would be about 12.7% less for scenario 5 than in scenario 4. As in scenarios 3 and 4, the approach in scenario 5 would avoid the technical uncertainties of cofiring a liquid stream in boiler 6. (Again, as noted under scenario 4, a selective catalytic NO_x reduction system (SCNR) is to be installed for boiler 6 in the near future, thus one issue that would need to be explored is the impact of the scenario 5 approach on performance and warranties for the SCNR.)

  With the higher capital and operating costs for a larger wastewater treatment system in scenario 5 and the reduced amount of net energy/fuel supplied to boiler 6, the rate-of-return (profitability) for scenario 5 would be about 2% lower than for scenario 4. (Rate-of-return analyses are discussed in detail in the next chapter). One potential advantage of the scenario 5 approach, which might make it of interest compared to the scenario 4 approach, is that it would avoid uncertainties regarding the drying characteristics of evaporator syrup.

- Digester biogas could be combusted in the existing "reburn" nozzles in boiler 6 for NO_x reduction, as well as for additional steam production by the boiler.

After reflecting on the five scenarios described above, AES Greenidge staff believe that either scenario 4 or scenario 5 is likely to offer the most attractive approach, where boiler 6 would be relied on to combust the by-product fuels from the bioethanol process. A primary reason for this decision is the fact that the ethanol facility is likely to operate for 20 years, and the age and poorer condition of boilers 4 and 5 make them less attractive with respect to their long-term reliability for use with the ethanol facility.

A potential benefit of scenario 5 is that the lower ratio of biomass fuel compared to coal use in boiler 6 should help reduce potential risks and uncertainties regarding biomass cofiring. Most of the experience to date in cofiring biomass with coal has shown that 10% or less biomass can work acceptably in pulverized coal boilers, with a few instances showing the potential to go up to 20% biomass cofiring. The biomass particle size has been found to be a key limiting factor in prior cofiring experience, where smaller biomass particle sizes result in better cofiring results. For the case of a bioethanol facility, the lignin (and other biomass) particles will be quite small. The small particle sizes, combined with the ability to dry the lignin to essentially any moisture level desired/needed (i.e., with the planned drying system), should mean that the lignin/biomass material would be a good quality fuel for use in a pulverized coal boiler (i.e., the small biomass particle sizes, combined with the drying system, should allow for distinctly higher percentages of biomass cofiring with coal for the co-location approach.) However, since this has not been fully tested, the lower the percentage of biomass to be cofired the less the perceived risk will be with regard to boiler performance. Since scenario 5 has the lowest proportion of biomass to be cofired, it may offer reduced uncertainties (and risks) in comparison to the four other scenarios.

For either scenario 4 or scenario 5, one issue is whether significant modifications will be needed to boiler 6 in order to combust the dried biomass fuel that will be supplied from the ethanol operation. With the small particle size of the dried biomass resulting from the bioethanol process, it is possible that this biomass material can be blended with the coal and fed to boiler 6 through the existing coal pulverizer system. Another possibility would be to use the fuel delivery system currently in place to deliver biomass/wood chips to boiler 6 for cofiring. The existing coal/biomass cofiring approach uses a separate pneumatic system to supply wood chips to boiler 6 through a dedicated biomass fuel feed port in the side of the boiler. It may be possible to use this pneumatic delivery system to supply the dried lignin/biomass fuel to boiler 6. Alternatively, a combined approach may offer a workable solution, where some of the lignin/biomass is delivered via the existing coal pulverizers (if it is found that the amount of biomass fuel that can be accommodated by the coal pulverizer system is limited), with the remainder of the dried lignin/biomass supplied to boiler 6 through the existing pneumatic biomass supply system. Some amount of testing and experimentation will be needed to determine whether the existing coal pulverizer feed system or pneumatic biomass supply system will work, or whether additional modifications are necessary to the boiler.

3.4 Summary Observations

The combustion (and drying) characteristics of the lignin stream, as well as the evaporator syrup and digester solids streams, are critical factors with respect to the viability of co-locating a bioethanol facility at a coal-fired power plant. Most power plant operators require extensive test data on the combustion characteristics of any alternative fuel that they would consider cofiring in their existing boilers. The AES Greenidge staff/owners have demonstrated a willingness to be innovative in experimenting with the combustion/co-firing of alternative fuels, including six years of successful cofiring of wood in their pulverized coal boilers. However, even with this willingness to try new fuels, it would be desirable to have better information and test data on the drying and combustion characteristics of the lignin and related streams to be combusted in the AES Greenidge boiler(s). At present, the fact that a commercial scale bioethanol facility has not yet been built and operated means that the characteristics of the lignin and related streams must be based on pilot scale tests, combined with analytical extrapolations of the anticipated fuel characteristics.

In reality, any "early adopter" or demonstration facility must include de-bugging and "on the fly" development work to make a new system or technology work as planned. This represents an added risk factor that would logically justify government participation/funding of some aspects of the co-location facility, especially given the potential for the technology to be widely replicated, with significant energy security and employment benefits beyond the immediate benefits to the ethanol facility owners.

The issue of NO_x emissions in relation to cofiring lignin/biomass fuel also needs further study. A life cycle analysis on fuel-bound nitrogen is needed, as well as further combustion testing, to clarify how lignin/biomass cofiring will impact NO_x emissions from the power plant. Given the stringent new NO_x emissions regulations that are being implemented in the Northeast U.S. (including NO_x emissions trading/credits), the nitrogen issue could be important with regard to the profitability of the bioethanol facility and the overall co-location approach.

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Task 4. Financial Evaluation

4.0 Overview

Easterly Consulting and NREL worked closely in performing the following financial evaluation subtasks. To conduct this evaluation, NREL modified their latest two-stage dilute acid and enzymatic production process engineering models to evaluate the option of co-locating a bioethanol facility at the AES Greenidge coal-fired power plant. AES Greenidge staff provided valuable input regarding factors that impact project financing, such as steam and lignin pricing, labor costs, etc.

4.1 Project Financing

The internal rate of return (IRR) was determined for the AES Greenidge co-location project based on two-stage dilute acid and enzymatic hydrolysis technologies. For the base-case design scenarios (as described in greater detail in the Task 3 report), it was assumed that 1,000 dry tons per day of corn stover is processed for both the two-stage dilute acid and the enzymatic conversion system. The two-stage dilute acid system would produce 23.6 million gallons of ethanol per year and the enzymatic system would produce 31.4 million gallons per year (assuming that the facility operates 8,400 hours per year). Key economic assumptions used to calculate the IRR for the base case scenarios included the following:

1) Project life – 20 years,
2) Reference year – 2000,
3) Construction period – 1.5 years,
4) Owner equity – 25%,
5) Financing terms – interest rate of 8%, with a loan term of 15 years,
6) Cost of feedstock – $35.70,
7) Ethanol market price – $1.30,
8) Electricity price – $0.04 per kWh,
9) Methane/natural gas price – $2.95 per million Btu,
10) Steam prices – $1.95 per lb at 300 psia and $0.056 per lb at 50 psia (with linear/proportional scaling for pricing other steam conditions),
11) "Lignin" co-product price – $1.95 per million Btu,
12) SO_x credits – $172 per ton avoided,
13) Greenhouse gas credits -- $1.00 per ton of avoided CO_2 emissions,
14) Carbon dioxide sales (beverage and industrial uses) – $9.00 per ton,
15) Gypsum sales -- $3.00 per ton,
16) Income tax rates – 39%, and
17) Total project investment: $61.4 million for the two-stage dilute acid system, and $65.0 million for the enzymatic system.

4.2 Cash Cost of Production and Net Production Cost

The cash cost of production and the net production cost were determined for both a two-stage dilute acid hydrolysis system and an enzymatic hydrolysis system using the base-case assumptions listed under Task 4A. Appendix C provides a detailed side-by-side comparison of the cash cost of production and net production cost for both system configurations. Appendix D provides a summary of the results for the engineering process analysis for the two-stage dilute acid system (with capital and operating costs), and Appendix E provides a similar summary for the enzymatic system (see the two spreadsheets from R. Wallace in the References list for detailed economic analyses regarding the two systems.) For the base case analyses, the IRR for the two-stage dilute acid system was 23.3.8% and the IRR for the enzymatic system was 38.0%.

4.3. Maximum Feedstock Cost

As illustrated in the results summarized in Appendices C, D and E, feedstock supply represented the largest single cost component for bioethanol production at AES Greenidge. Thus, changes in feedstock costs will have a large impact on the rate of return for the bioethanol project. Figure 4.1 provides the results of sensitivity analyses for feedstock costs versus rates of return for the two-stage dilute acid and the enzymatic systems (using the base case assumptions listed in Task 4A, above). As discussed in the Task 1 report on feedstock supplies, it is anticipated that corn stover might cost about $35.70 per dry ton delivered, wood chips from Pennsylvania might cost $45 to $50 per dry ton, and energy crops from Western NYS might cost roughly $25 to $30 per dry ton (with the help of incentives under USDA's Conservation Reserve Program).

Feedstock Cost ($/ton)	2-Stage IRR	Enzymatic IRR
$25.00	18.40%	32.50%
$35.70	23.25%	38.00%
$50.00	27.30%	41.10%

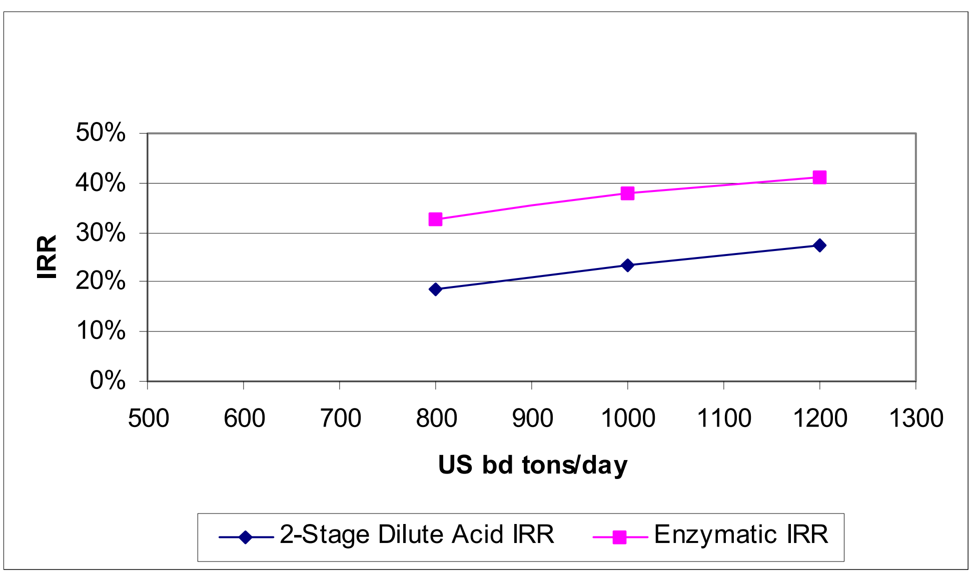

Figure 4.1. IRR vs. Feedstock Costs for 2-Stage Dilute Acid and Enzymatic Conversion

4.4 Sensitivity Analysis

In addition to evaluating the impact of feedstock costs on profitability (IRR), the sensitivity of profitability for the AES Greenidge site was also calculated for a number of variables, including:

1) Plant size (feed rate),
2) Ethanol selling price,
3) Owner equity,
4) Capital cost (total project investment)
5) Lignin selling price
6) Steam costs,
7) Electricity costs,
8) Greenhouse gas credits, and
9) Labor costs.

The sensitivity analyses/results for the nine variables listed above are provided on the following pages. It is interesting to observe where changes in the variables have the greatest and least impact on the IRR. Substantial sensitivity/changes in IRR can be seen for the first four variables listed above: plant size, ethanol selling price, owner equity, and capital cost (as well as feedstock cost, as noted earlier). Whereas the IRR is only modestly sensitive to changes in the selling price for lignin, steam costs, electricity costs, greenhouse gas credits, and labor costs.

Plant Size (Feed Rate) U.S. tons/day	2-Stage Dilute Acid IRR	Enzymatic IRR
800	18.40%	32.50%
1000	23.25%	38.00%
1200	27.30%	41.10%

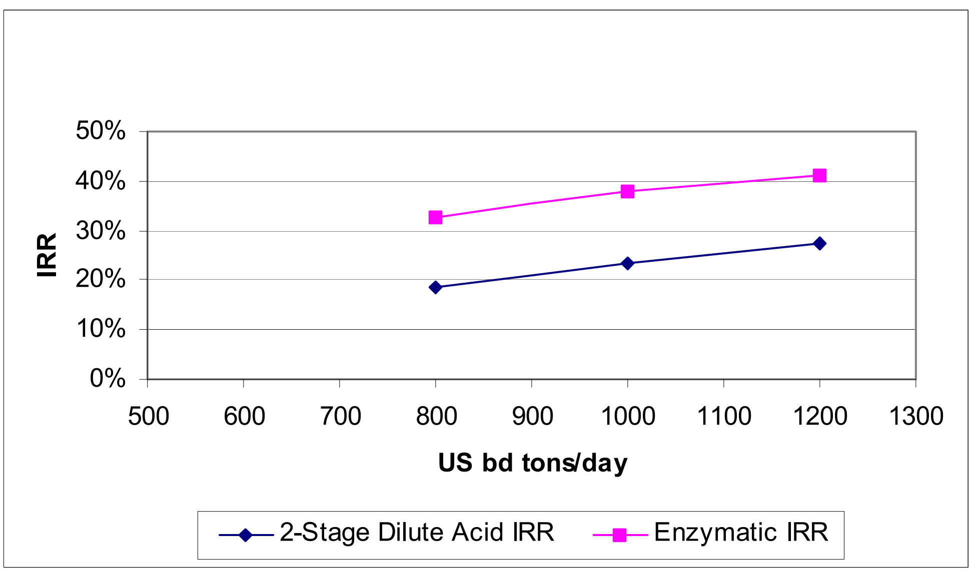

Figure 4.2. Plant Size (Feed Rate) vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

Ethanol Selling Price	2-Stage IRR	Enzymatic IRR
$1.10	9.2%	24.7%
$1.20	16.4%	31.8%
$1.30	23.3%	38.0%
$1.40	29.5%	43.5%

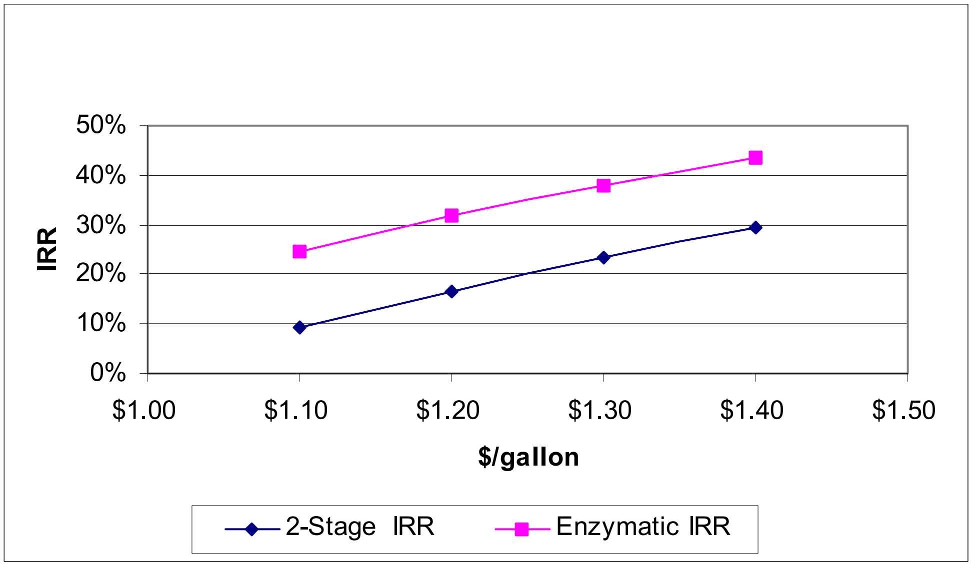

Figure 4.3. Ethanol Selling Price vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

Equity Financing %	2-Stage IRR	Enzymatic IRR
25%	23.3%	38.0%
50%	17.6%	27.7%
100%	13.3%	19.7%

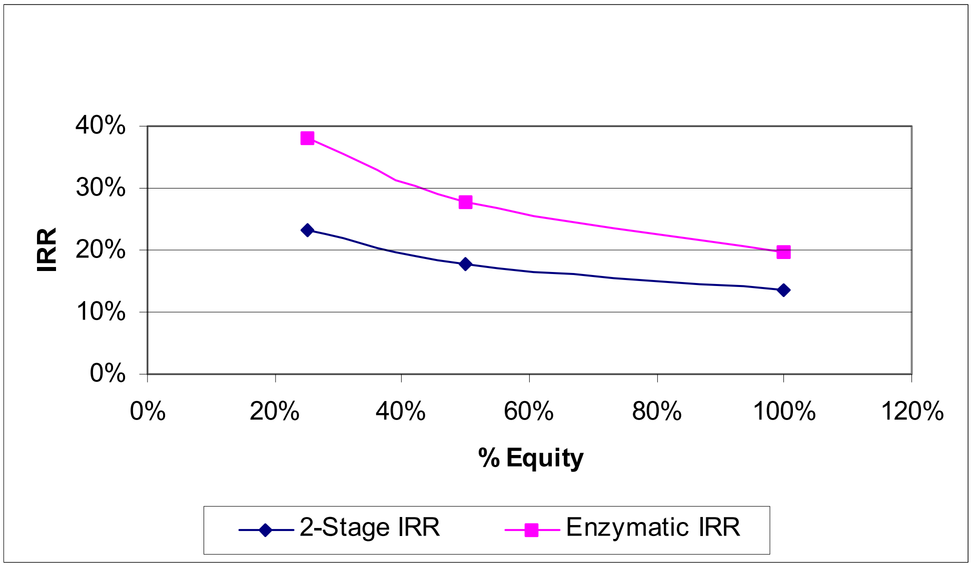

Figure 4.4. Owner Equity vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

Capital Cost	2-Stage IRR	Enzymatic IRR
80%	31.80%	46.80%
90%	27.20%	42.10%
100% of base case	23.3%	38.0%
110%	19.8%	34.3%
120%	16.8%	31.1%

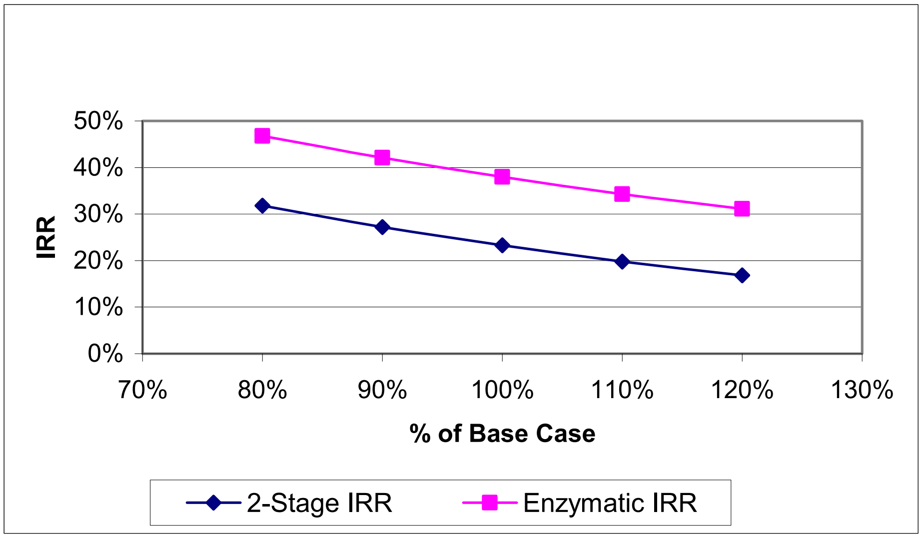

Figure 4.5. Capital Cost (total project investment) vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

Lignin Price ($/MMBtu)	2-Stage IRR	Enzymatic IRR
$1.46	19.24%	36.10%
$1.76	21.72%	37.3%
$1.95	23.3%	38.0%
$2.15	24.8%	38.7%
$2.44	27.00%	39.75%

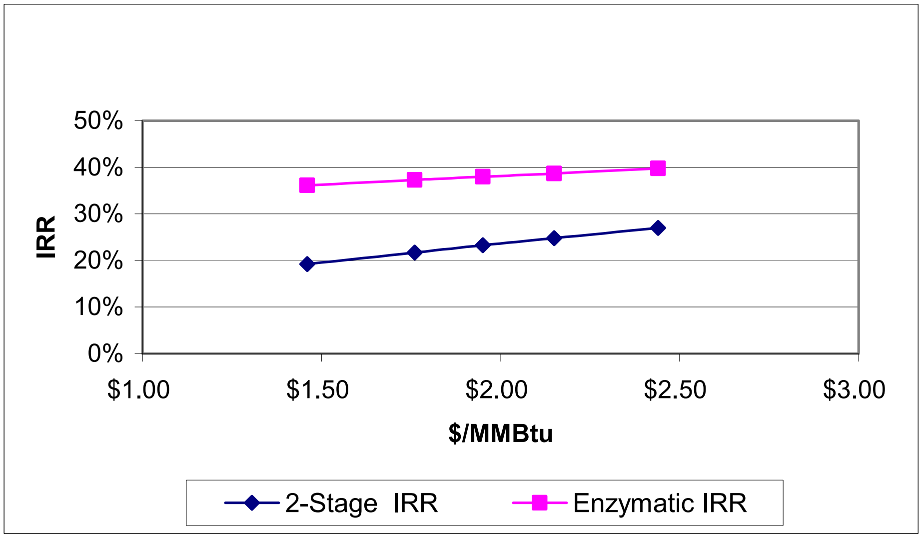

Figure 4.6. Lignin Selling Price vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

Steam Price	2-Stage IRR	Enzymatic IRR
90%	23.5%	38.1%
100% (of base case)	23.3%	38.0%
110%	23.0%	37.9%
200%	20.7%	36.8%

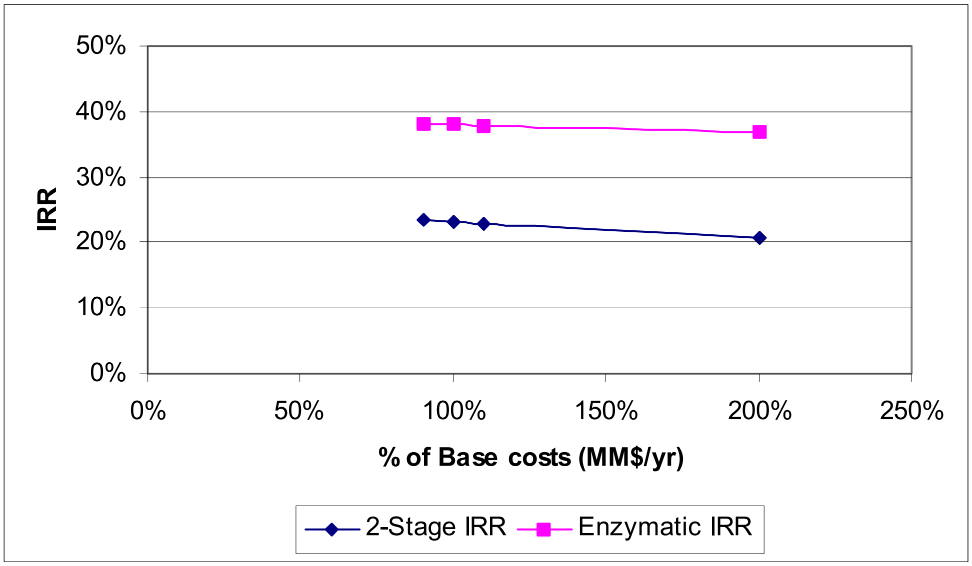

Figure 4.7. Steam Costs vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

Electricity Price ($/kWh)	2-Stage IRR	Enzymatic IRR
0.036	24.02%	38.4%
0.040	23.3%	38.0%
0.044	22.5%	37.5%

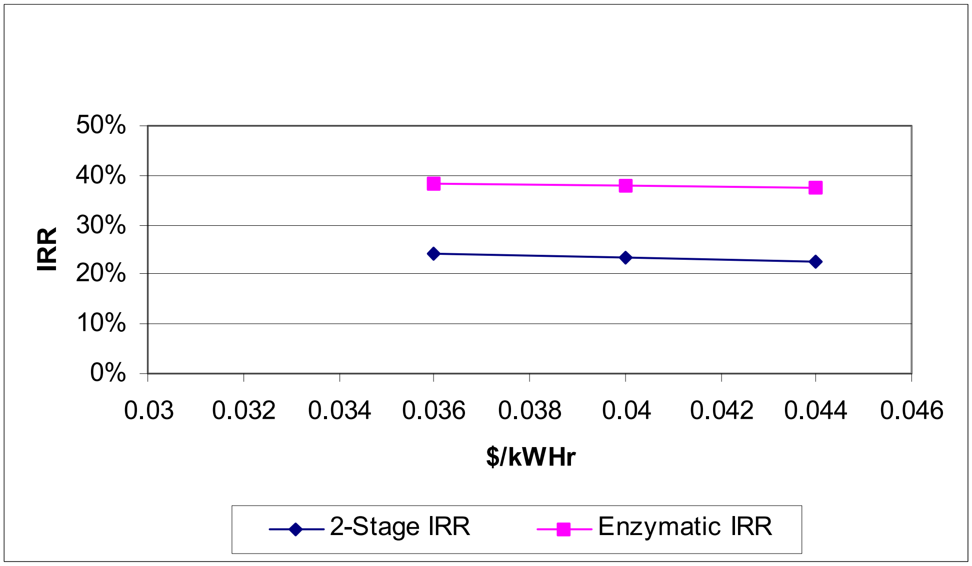

Figure 4.8. Electricity Costs vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

GHG Credits ($/ton)	2-Stage IRR	Enzymatic IRR
$1.00	23.3%	38.0%
$3.00	24.9%	38.7%
$5.00	26.5%	39.5%
$7.00	28.0%	40.3%
$10.00	30.2%	41.4%

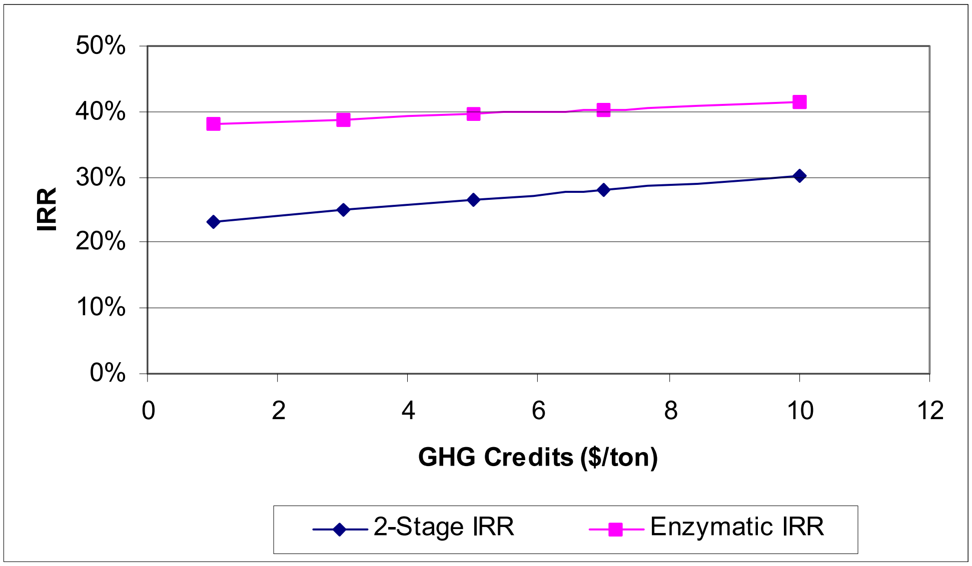

Figure 4.9. Greenhouse Gas Credits vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

As discussed in the Task 3 Design and Cost Report, there is at least one organization that has indicated that it could market greenhouse gas (CO_2) credits from an AES Greenidge bioethanol co-location project for $1.00 per ton. A recent press release noted that trading of emission credits under the new United Kingdom carbon (CO_2) emissions market has seen recent trades of $10.48 per metric ton [Planet Ark, 2002].

Labor Costs ($/MMBtu)	2-Stage IRR	Enzymatic IRR
$1.18	23.3%	38.0%
$1.48	22.4%	37.2%
$1.77	21.5%	36.5%

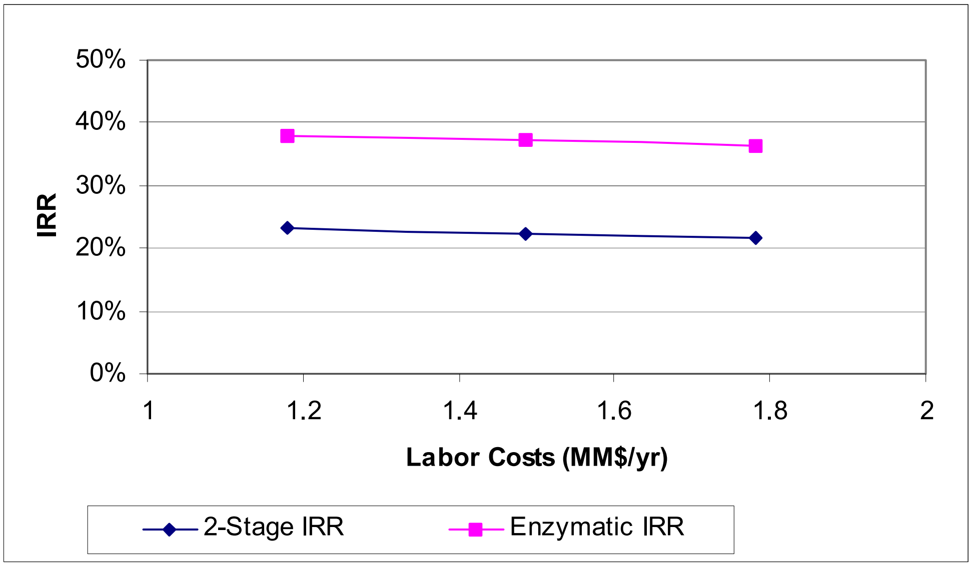

Figure 4.10. Labor Costs vs. IRR for 2-Stage Dilute Acid and Enzymatic Conversion

4.5 Summary Observations

The values used for the variables in the base case scenario appear to be reasonable/defensible assumptions, based on information and analyses done in the other tasks for this project. The projected rate of return of 38% for the enzymatic system generally represents a very attractive investment. However, it is important to note that the performance and cost values assumed for this system are based on an "nth" plant in the year 2010, where learning curve refinements in design and cost elements contribute to a more competitive system.

For the two-stage dilute acid system, a projected rate of return of 23% is still reasonably attractive. The performance and cost factors used in the base case analysis for this system are expected to be achievable in the 2004 time frame. However, since a system of this type has not yet been commercially developed, there are clearly important engineering and cost factors that will require more in depth evaluation to increase the level of confidence that the anticipated performance and cost targets can be achieved.

One of the most important observation that can be made regarding the financial analysis is the extent to which co-location at an existing power plant improves the profitability of a bioethanol facility compared to a stand-alone facility. A sensitivity analysis done to assess the benefit of co-locating at the AES Greenidge site found that the IRR increased by 15%, compared to a similar a stand-alone system, by avoiding the costs for boiler and turbine-generator equipment. It can clearly be argued that co-location offers an attractive strategy for accelerating the commercialization of bioethanol technology -- substantially lowering capital costs and improving profitability compared to stand-alone approaches for facility development.

References

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Wallace, Robert, NREL, draft ethanol production process engineering analysis for a co-located two-stage acid hydrolysis bioethanol facility processing 1000 dry tons per day of corn stover, with a yield of 64.4 gallons of ethanol per dry ton of corn stover feedstock (at a cost of $35.70 per dry ton), producing 23.6 million gallons of ethanol per year. Received July 29, 2002, spreadsheet file “bw0602a_JE_da5.xls”.

Task 5. Environmental Issues

5.0 Introduction

The environmental impacts of siting and operating a commercial-scale bioethanol facility at the AES Greenidge site are addressed in this chapter, including on-site and off-site impacts. Since environmental impacts are integral to a number of the tasks/chapters in this report, including feedstock supply analysis (Task 1), facility siting (Task 2), and the evaluation of market factors (Task 7), many environmental considerations are addressed in the chapters addressing those tasks. Since Task 5 focuses specifically on environmental impacts, the following chapter draws together and includes various sections on environmental impacts that were addressed in those related tasks.

5.1 Boiler Emissions

There are a number of environmental benefits/impacts that would result from displacing coal with lignin fuel in the exiting pulverized coal boilers at AES Greenidge, as discussed below.

- SO_2 Emissions

Lignin should typically have much lower sulfur content than coal, which will help reduce SO_2 emissions. The sulfur content of coal used at AES Greenidge is typically around 2.2 percent [Chambers, April 15, 2002]; whereas the sulfur content of lignin residues has been measured by NREL to be in the range of 0.07 to 0.10 percent for softwood-derived lignin [Elam, 2001] and 0.25 percent for corn stover-derived lignin [Wallace, May 2002]. The cost for AES Greenidge to purchase SO_2 credits is currently around \$172 per ton [Evolution Markets, 2002].

- NO_x emissions

The nitrogen content of boiler fuel (referred to as fuel-bound nitrogen) contributes to the formation of NO_x emissions during combustion of the fuel. Use of lignin to replace coal in a boiler could help reduce NO_x emissions if the lignin has lower nitrogen content than coal; conversely, if lignin has higher nitrogen content than coal, it could cause an increase in NO_x emissions in boiler flue gases. The average nitrogen content of Eastern Bituminous (Pittsburgh) coal is 1.5 percent [EPRI, 1989], whereas tests by NREL found lignin samples to have a nitrogen content ranging from 0.16 to 1.04 percent for softwood-derived lignin [Elam, 2000], and 2.55 percent nitrogen for corn stover-derived lignin [Wallace, May 2002]. It should be noted that the nitrogen content of lignin would depend in part on specific process factors, as well as the type of biomass feedstock being processed; for example, the amount of residual fermentation organisms in lignin could increase its overall nitrogen content. The cost of NO_x emission credits was recently \$850 per ton for 2002, and \$5,100 per ton in 2003 and 2004 when federal and regional regulations require significant reductions in NO_x emissions [Evolution Markets, 2002].

Methane from the bioethanol facility's wastewater treatment system can be cofired in the AES Greenidge boiler(s) and may be able to replace the natural gas currently used in the "reburn" system installed in the main AES Greenidge boiler (no. 6) for NO_x control/reduction. It should be noted that AES Greenidge plans to install a selective catalytic NO_x reduction system on their main boiler (boiler number 6, which supplies steam to turbine unit 4) in the relatively near future. If boilers 4 and/or 5 (for turbine unit 3) are dedicated for burning lignin, AES Greenidge plans to install low-NO_x burners in these boilers, as well as reburn nozzles in the boilers (only boiler 6 currently has reburn nozzles installed at present).

- Particulate Emission Control

AES Greenidge has separate electrostatic precipitators installed for generating unit 3 and for generating unit 4 to control particulate emissions in the exhaust gas from the boilers. If a lignin dryer is installed using boiler flue gas for thermal drying, it is possible that the gases exiting the dryer could be routed back into the duct going to the electrostatic precipitator(s), thus avoiding expenses for additional particulate control from the lignin drying system.

- Opacity Control for Flue Gases

To avoid being fined or shut down due to opacity violations (i.e., to avoid having a visible plume that is blackish or brownish in color), AES Greenidge must keep the opacity of their stack plume below 20 percent. Sulfur is a major contributor to opacity problems. Thus in addition to SO_2 benefits associated with the low sulfur content of lignin used to displace coal, AES Greenidge would also gain environmental benefits by virtue of being able to comply with opacity requirements more readily with the use of lignin fuel.

AES Greenidge has installed humidification systems upstream of the electrostatic precipitators for units 3 and 4 as a technique for reducing flue gas opacity. If a lignin dryer is installed upstream from the precipitators, it is possible that moisture added to the boiler flue gas as a result of the lignin drying action could help increase the humidity of the flue gas, thereby also helping to reduce flue gas opacity (and/or help reduce the amount of water needed for flue gas humidification).

- Greenhouse Gas (GHG) Emissions

Since lignin is a renewable fuel, it reduces CO_2 emissions by offsetting fossil fuel/coal combustion; methane from the bioethanol wastewater treatment system offsets natural gas use for the reburn system used for NO_x control; and the ethanol fuel produced by the facility will reduce CO_2 emissions as it displaces gasoline/petroleum used for transportation. According to the DOE Energy Information Administration, combustion of bituminous coal produces 205.3 pounds of CO_2 emissions per million Btu; gasoline combustion produces 156.4 pounds of CO_2 emissions per million Btu; and natural gas combustion produces 117.1 pounds of CO_2 emissions per million Btu [EIA, 2002].

Use of corn stover for bioethanol production can increase carbon sequestration in the soil where farmers switch to less tillage or no-till practices to facilitate stover harvesting (due to higher levels of organic matter retained in the soil with conservation tillage). In areas where corn production is roughly 130 bushels per acre, a switch to less tillage or no-till practices could result in 540 pounds per acre per year of carbon sequestration [Lal, 1998]. Using a conversion factor of 3.67 pounds of CO_2 equivalent per pound of carbon sequestration (on a molecular weight basis), this would correspond to 1,980 pounds of CO_2 offset per acre of land switched to less tillage or no-till practices to facilitate stover harvesting.

The net GHG contributions from combusting lignin and the other non-fermented biomass components will be near zero, since biomass is derived from solar energy and atmospheric carbon stored by the leaves of plants/trees.

Using a simplified approach to evaluate the GHG benefits associated with each ton of corn stover used for bioethanol production, the following estimates can be made:

- For an enzymatic hydrolysis-based facility, lignin fuel could provide about 0.85 tons of reduced CO_2 emissions per dry ton of corn stover feedstock by offsetting coal used as boiler fuel, based on the Btu's of coal combustion avoided [derived from NREL process flow diagrams; see the reference NREL, March 17, 2002]. The "lignin" fuel in this estimate includes all of the solids from the lignin stream, as well as solids from the evaporator syrup and the digester for the wastewater treatment system. A heating value of 8,543 Btu/lb of biomass solids is assumed, and net zero CO_2 emissions are assumed for the biomass fuel.

- Ethanol fuel provides about 0.53 tons of reduced CO_2 emissions per dry ton of corn stover, based on the Btu's of gasoline combustion avoided (assuming 76,000 Btu's per gallon of ethanol, and 89.4 gallons of ethanol per dry ton of stover from an enzymatic hydrolysis facility).

- Methane fuel from the wastewater treatment system provides about 0.01 tons of reduced CO_2 emissions per dry ton of corn stover [derived from NREL process flow diagrams; see the reference NREL, March 17, 2002].

- Switching to less tillage or no-till practices would provide the equivalent of about 0.99 tons of reduced CO_2 emissions per dry ton of corn stover feedstock use (assuming that one ton of stover is removed per acre, as discussed later in this report) [based on soil carbon sequestration factors from the reference Lal, 1998].

- In total, adding the estimates for avoided combustion of coal, gasoline, and natural gas, plus carbon sequestration in soil, there would be a total of approximately 2.38 tons of reduced CO_2 emissions per dry ton of corn stover feedstock use.

5.2 Wastewater Treatment

- AES Greenidge Power Plant Wastewater Treatment System

The AES Greenidge power plant has a wastewater treatment facility that is used to treat various plant wastes, particularly the coal pile run-off water, air pre-heater washing water, and boiler chemical cleaning rinse water. The system utilizes lime, polymer, and sulfuric acid in the treatment process. Note that the AES Greenidge power plant currently uses Seneca Lake for the supply and disposal of water for the power plant condenser – it is anticipated this system will continue to operate in its current permitted configuration if a bioethanol facility is built at the site.

- Bioethanol Facility Wastewater Treatment System

The bioethanol facility will have a wastewater treatment system that includes an anaerobic digester to treat the organic waste stream from the process. The design target is to have a facility with zero discharge of wastewater, where treated water is recycled for use in the bioethanol process.

5.3 Fresh Water/Make-up Water Requirements

Based on preliminary estimates, a 20 million gallon per year bioethanol facility would require about 344 gallons per minute of make-up water from Seneca Lake or from well water. This assumes an enzymatic hydrolysis-based bioethanol facility, with directly proportional scaling of make-up water requirements from process flow evaluations done by NREL for a bioethanol facility with a capacity of 69 million gallons per year [NREL, March 17, 2002].

5.4 Solid Waste Disposal

- Boiler Ash Disposal

AES Greenidge owns a 142-acre parcel of land on the southwest side of Route 14 that is used in part as a solid waste disposal site for fly ash or other permitted materials. Bottom ash is collected in a settling pond at the east end of the plant. The ash is sometimes sold to highway departments and is otherwise landfilled at their ash disposal site.

Lignin may have a lower ash content than coal. The coal used at AES Greenidge typically has an ash content of approximately 7.9 percent. Tests of lignin done by NREL found the ash content to be in a range from 0.26 to 0.84 percent when produced from softwood [Elam, 2000]; however, tests of lignin produced from stover found the ash content to be 17.2 percent [Schell, 2001]. Thus, depending on the type of biomass from which the lignin is derived, it may result in reduced or increased ash disposal costs per Btu of fuel use when displacing coal.

- Gypsum Disposal/Use

Many farmers in the vicinity of the AES Greenidge site currently use gypsum as a soil amendment to improve the quality of their soil (e.g., in situations where additional calcium is desired). The gypsum produced as a by-product of the acid neutralization stage of a bioethanol facility could potentially be marketed as a soil amendment product, assuming that tests of gypsum verify that it has acceptable characteristics for this use. Unlike the situation with wallboard production, where there are fairly stringent specifications for gypsum purity, it is possible that the gypsum from a bioethanol process (which will contain various fractions of organic substances) could actually make for a more valuable soil amendment product, since the organics in the gypsum could potentially provide beneficial organic content to the soil. The moisture content of gypsum from the bioethanol facility may be another important factor – some problems have occurred when unloading wet gypsum from dump trucks [Horst, 2002]. However, equipment for handling and applying wet gypsum is available from companies such as AGCO [Perry, 2002].

5.5 Site Issues

The character of the site is generally rural, however the small community of Dresden is just above the northeast boundary of the 162-acre plot of land owned by AES Greenidge, with residential units essentially just across the northeast property line. A stream, canal, and wooded land are located on the far northeast portion of the 162-acre plot of land, which provide a buffer with the Dresden community.

The far northeast corner of the 162-acre plot of land, adjacent to the lake, was previously used as a fly ash sluicing pond (this land is currently unused). In the distant past this corner of land may have been marshy in character.

- Fuel Storage

A large coal storage area is located on the south side of the Greenidge power plant building. AES Greenidge staff believes that the west end of the current coal pile storage area could be used for biomass feedstock storage (there is a rubber liner and runoff collection and treatment system for the coal pile, which could be a helpful feature for avoiding concerns regarding potential runoff from a biomass feedstock storage pile/area). If a larger reserve of biomass feedstock storage is desired than can be accommodated at the coal pile site, the 142-acre parcel of land on the other side of Route 14 could be used.

- Compatibility of Current Surrounding Land-Uses

As an industrially zoned site in a predominantly rural setting, the AES Greenidge location should offer good compatibility with surrounding land uses for constructing a bioethanol facility at this site. The power plant staff does not believe that truck transportation of biomass feedstock will be a significant local concern – they have delivered coal to their power plant in past years with no complaints, and the local village of Dresden is well away from the main highway (Route 14) that would be used for truck transportation of biomass feedstock. The property immediately south of the AES Greenidge site is also zoned for industrial uses (with a manufacturer of grinding/ polishing compounds located at this site).

- Odor Concerns

Due to the proximity of the Dresden village just north of the AES Greenidge property line (approximately 1/3rd of a mile from the plant), there are potential concerns with respect to odors from a bioethanol facility, particularly odors that may emanate from process vents. It may be necessary to install equipment to control vent odors, such as thermal oxidizer equipment. (Note: a brewery in downtown St. Paul, Minnesota that was converted to a grain-to-ethanol plant

(Gopher State Ethanol) had to install thermal oxidizer equipment to address complaints from neighbors regarding odors – the odors were primarily from drying of distillers grain mash [Grochen, 2002]. They also found that adding a carbon dioxide recovery system on the fermentation system reduced odor problems.)

- Steam Plume Aesthetics

The vicinity around the AES Greenidge facility is considered a tourist area due to amenities such as the Finger Lakes and numerous wineries in the region. From an aesthetics/tourism point of view, one possible concern could be the visibility of a steam/vapor plume related to operations of a bioethanol facility at the site, particularly in cooler weather. While this may not be a major concern, it is worth considering when designing a bioethanol facility at this site. For example, if there are choices between mechanical dewatering and thermal dewatering of various flow streams, mechanical approaches could be preferable from an overall site aesthetics perspective, due to the potential for water vapor plumes from thermal or evaporative drying operations.

5.6 Corn Stover Utilization Impacts/Issues

- Farmer Concerns

In discussions with farmers in the AES Greenidge plant, they generally raised similar issues/concerns regarding corn stover harvesting, including concerns regarding nutrient loss and possible adverse impacts on soil tilth from stover removal; concerns regarding compaction and rutting of soil from added tractor traffic to harvest the stover; and concerns regarding logistics issues for corn grain harvesting and subsequent stover harvesting/baling operations. These natural concerns of farmers are reasonable to expect and highlight the need to have trusted local agricultural advisors, such as USDA Extension Service agents, involved in an outreach process to address farmer concerns and to help implement acceptable stover harvesting practices.

- Impacts of Tillage Practices

As discussed in the Task 1 report, there could be a total of approximately 1.1 billion dry tons per year of corn stover supplied from the 16 counties surrounding the AES Greenidge site for use as a feedstock for bioethanol production. In general, it is likely that a portion of the corn stover will need to be left on the land to protect against soil erosion and to satisfy soil carbon requirements. In most cases 30% of the stover can safely be removed – the remaining 70% of the stover left in the field will generally be adequate to satisfy erosion and soil carbon requirements. This rule-of-thumb that 30% of the stover can safely be removed, from a soil quality/erosion protection perspective, is a simplified means to address a number of factors that relate primarily to tillage practices and soil slopes. No-till farming allows the maximum amount of corn stover to be removed per acre; mulch-till practices allow a moderate amount of stover to be removed; and conventional tillage practices allow for the least amount of stover removal (since more stover must be left in place for erosion protection on sloped land, if a cover crop such as clover is not planted at the end of the season). Crop rotation practices also impact the amount of stover that can be removed. If corn is planted year after year on a given acreage, more stover can be safely removed than in situations were non-corn crops such as soybeans are rotated with corn production in alternate years.

Table 5.1 provides a summary of the tillage practices for the acres planted in corn in New York State in 1998 (note that this data combines corn produced for both grain and silage). For the 16 counties surrounding the AES Greenidge site, 41% of the total corn acreage was planted using a

Table 5.1. Conservation Tillage Practices in the Counties Surrounding AES Greenidge

		Conservation Tillage			Conventional Tillage	
County	**Total Planted Acres Corn**	**No-Till acres**	**Ridge Till acres**	**Mulch Till acres**	**15-30% Residue Acres**	**0-15% Residue acres**
Cayuga	75,000	350	400	30,000	32,000	12,250
Ontario	50,900	3,000	0	25,000	13,400	9,500
Livingston	50,000	5,000	0	10,000	15,000	20,000
Wyoming	46,000	1,700	0	19,800	10,000	14,500
Steuben	42,600	1,600	0	200	10,000	30,800
Wayne	42,500	4,000	0	29,000	3,500	6,000
Genesee	41,550	2,550	0	6,500	16,500	16,000
Onondaga	37,200	1,200	300	9,200	16,500	10,000
Seneca	36,000	15,000	0	16,000	0	5,000
Orleans	31,500	2,700	0	7,500	13,300	8,000
Tompkins	24,000	1,200	100	4,000	2,000	16,700
Monroe	21,600	3,500	0	11,000	4,000	3,100
Yates	20,000	800	0	6,500	0	12,700
Allegany	12,100	0	0	250	1,200	10,650
Schuyler	7,500	500	0	2,500	1,500	3,000
Chemung	4,800	0	0	0	0	4,800
Total:	543,250	43,100	800	177,450	138,900	183,000
NY State	1,159,268	88,252	7,536	274,286	249,359	539,835

% Conservation Tillage in 16 counties: 40.7%

Source: Conservation Technical Information Center, *1998 National Crop Residue Management Survey*, web page: http://www.ctic.purdue.edu/.

conservation tillage method. Depending on site-specific topography (e.g., land slope) and soil characteristics, a number of farms in the AES Greenidge area that currently use conventional tillage practices will need to switch to conservation tillage practices in order to allow for corn stover removal while maintaining acceptable protection for erosion. (With respect to Table 5.1, it is interesting to note that the 543,000 acres of corn planted in these 16 counties represents close to half (47%) of the total corn acreage planted in New York State.)

5.7 New York State and Region-wide Gasoline Impacts/Issues

- MTBE

The State of New York has announced that it will no longer allow MTBE to be used as a fuel additive in gasoline after January 1, 2004, due to concerns regarding groundwater pollution from leaking underground gasoline storage tanks. Ethanol fuel could play a significant role in replacing this MTBE (from an octane, oxygen, and fuel volume perspective). If EPA continues to require 2 percent oxygen content in reformulated gasoline (RFG), per the requirements under the U.S. Clean Air Act Amendment, ethanol is a primary candidate to replace the oxygen content currently provided by MTBE. Ethanol fuel contains about twice as much oxygen per gallon as MTBE, as a result gasoline would require 5.7 percent ethanol to meet the required 2 percent

- One concern is that "backsliding" of air quality could occur. Since only 5.7 percent by volume of ethanol is needed, compared to 11 percent MTBE by volume to provide the same amount of oxygenate for gasoline, there is a concern that the 5 or 6% of gasoline components used to make up this difference in fuel supply volume (and octane value) could include toxic components such as benzene or toluene, which could result in increases in toxic air emissions.

- Another concern is the potential that tailpipe emissions of acetaldehyde will increase with ethanol blends. Although a study in California indicated that ambient acetaldehyde emissions did not increase due to ethanol blends, NESCAUM is concerned that California airsheds are different from those in the Northeast, particularly in "microenvironments where elevated exposures are more likely."

- The NESCAUM report also notes that "…environmental transport properties of ethanol are cause for some concern: 1) at high concentrations, ethanol can make other gasoline constituents more soluble in groundwater; 2) when present in a gasoline spill, ethanol can delay the degradation of other, more toxic components in gasoline; and 3) ethanol can cause greater lateral spread of the layer of gasoline on top of the water table."

In general, the environmental concerns NESCAUM raises tend to be presented as potential causes for concern, rather than absolutely unacceptable characteristics of ethanol blends.

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Task 6. Socioeconomic Issues

6.0 Overview

The anticipated socioeconomic impacts for co-locating a bioethanol facility at the AES Greenidge site were evaluated under this task. An input-output analysis was performed to estimate direct and indirect jobs and income (as well as state and local tax revenues) that could result from the construction and operation of a bioethanol facility at the AES Greenidge site. The project's probable effects on local infrastructure (particularly roads, schools, and utilities), is also addressed.

6.1 Overview of Economic Impact Models

The construction and operation of a bioethanol facility co-located at the AES Greenidge site will result in the creation of a significant number of jobs and a substantial amount of income in the region surrounding the site. This is particularly evident when considering the indirect impacts resulting from functions that support the operation of the facility, as well as induced impacts due to ripple (multiplier) effects as direct and indirect income is re-spent through the regional/state economy.

In an effort to estimate the income and job impacts from a bioethanol facility at AES Greenidge, two previous studies where used as key resources. The first study, entitled "Corn Stover to Ethanol: Macroeconomic Impacts Resulting from Industry Establishment," was completed by Oak Ridge National Lab, the University of Tennessee, and NREL in year 2000, with revisions/refinements done in 2001 [Walsh, 2001]. This highly relevant study estimated direct, indirect, and induced impacts that would result from the construction and operation of the first bioethanol plant to be developed in each of ten midwestern states, specifically for situations where corn stover would be used as the feedstock. (As a simplified abbreviation, this study is referred to as the "ORNL report" in the following discussion.)

A second study used as a key resource for this Task 6 report was titled "The Economic Impacts of Fuel Ethanol Facilities in the Northeast States," done by the Resource Systems Group (RSG) for the DOE Northeast Regional Biomass Program in December 2000. This study used NREL's analysis and report on ethanol production via lignocellulosic biomass conversion using enzymatic hydrolysis [Wooley, et al, 1999] as the basis for determining facility cost factors for evaluating the economic impact of specific projects in northeastern states. The RSG report evaluated direct, indirect, and induced impacts of bioethanol projects and included a publicly available spreadsheet model for calculating the economic impacts of specific projects. The model includes state-specific input/output factors (multipliers) for New York State (NYS) and four other Northeastern states. For Task 6, this spreadsheet model was modified and used to estimate direct and indirect economic impacts that would occur for a bioethanol facility co-located at the AES Greenidge site (referred to below as the "AES model").

The ORNL report and the AES model evaluated economic impacts using IMPLAN, a regional input-output model that estimates the economic flows to and from industries and institutions in a region – the model is available from the Minnesota IMPLAN Group [Minnesota IMPLAN Group, 1999].

"AES Model" Results

Two scenarios were evaluated using the AES Model:

1) An ethanol facility with co-current dilute acid prehydrolysis and enzymatic hydrolysis, based on cost and performance parameters anticipated to be achievable by the year 2010; and.

2) An ethanol facility with two-stage dilute acid hydrolysis, based on cost and performance parameters anticipated being achievable in the 2004 timeframe.

In both scenarios, the following common assumptions were used:

- The bioethanol facility was co-located at the AES Greenidge power plant;
- The facility was sized to process a quantity of 1,000 dry tons of corn stover per day;
- Twenty-five employees are required to operate the co-located bioethanol facility;
- The bioethanol facility was financed with 25 percent equity, and;
- The ethanol selling price was $1.30 per gallon.

Cost factors for the construction and operation of the facilities were based on modeling/analyses done by NREL, with inputs provided by Easterly Consulting and AES Greenidge staff [see Wallace, June 14, 2002; and Wallace, June 17, 2002]. (For a more detailed list of the design, cost, and operational parameters see the Task 3 chapter.) Table 6.1 provides a summary of the estimated jobs and income found with the AES Model runs done for the enzymatic and 2-stage dilute scenarios.

In comparing the results for the two scenarios it is useful to note that, while in both cases the facilities process 1,000 dry tons of stover per day, in comparison to the 2-stage dilute scenario, the enzymatic scenario has a 33% higher yield of ethanol per ton of stover processed, a 5.4% higher construction cost, and a 10.5% higher operating cost (due primarily to the cost for enzymes). The "bottom line" is that the enzymatic scenario creates more jobs and income due to its higher ethanol yields, as well as its higher installation and operating costs.

The construction phase impacts are one-time impacts, whereas the operational phase impacts reoccur each year for the life of the facility. Note that the employment impacts shown in Table 6.1 reflect full-time-equivalent jobs – the model initially calculates both full and part-time jobs, and then adjusts the estimate of part-time jobs to full-time-equivalent jobs in determining the total number of jobs created. The income shown for the construction phase includes indirect and induced income categories. For the estimates of income resulting from the operations phase, both direct and indirect income estimates are shown (where the indirect category includes indirect income for the facility's suppliers, as well as induced income as money is re-spent throughout the economy). The estimate of local taxes paid is a rough estimate of property taxes and other local taxes and fees paid each year. The estimate of state taxes paid is simply the state income tax rate times the total income shown for the year. Appendix F provides the inputs used for the AES Model runs for the enzymatic and 2-stage dilute scenarios.

It should be noted that the indirect income and jobs estimates reflect the indirect and induced impacts of respending dollars throughout the New York State economy, with the assumption that all of the goods and services are made or provided from within the state. Clearly some supplies and services for the bioethanol facility at AES Greenidge (as well as those encompassed by the ripple effect of respending dollars) will come from areas outside of the New York State boundary. Thus while the indirect jobs and income impacts summarized in Table 6.1 will occur primarily in New York State, some of the impacts will spill out beyond the state boundaries.

6.2 Farm Sector Impacts

New York corn growers have struggled to be profitable over the last few years, in large part due to continuing low market prices for the corn they produce. The use of large quantities of corn stover by a bioethanol facility co-located at the AES Greenidge plant would help provide an economic stimulus to the agricultural sector in the local region, and, in particular, would help provide new revenue from corn production in central-western New York State. The bioethanol facility would use an average of 1,000 dry tons per day of stover 350 days per year, or a total of 350,000 dry tons per year of stover. At an anticipated delivered price of $37.50 per ton, corn stover payments would total $12.5 million per year. It was assumed that farmers would be paid a minimum of $10 per ton for stover removed from their land, assuming that a third party comes in to do the harvesting, baling, and transportation of the stover to the AES Greenidge site. Those farmers who have the time and/or interest in harvesting, baling, and/or transporting the stover, could receive payments up to the full $37.50 per ton for the delivered stover.

Table 6.1. Economic impact of bioethanol production at AES Greenidge

	2-Stage Dilute Acid		Enzymatic	
Ethanol Capacity	23.6 million gal/yr.		31.4 million gal/yr	
Feedstock Use – corn stover	1,000 dry tons/day		1,000 dry tons/day	
CONSTRUCTION PHASE IMPACTS	**Income**	**Jobs**	**Income**	**Jobs**
	(Yr 2000 $)		(Yr 2000 $)	
Total Construction expenditure	$61,415,841		$64,734,237	
Total Income	$53,648,229		$56,611,610	
Total Jobs		1,138		1,201
Local Taxes Paid	$581,597		$621,000	
State Taxes Paid	$3,433,487		$3,623,143	
Total Taxes Paid	$4,015,083		$4,244,143	
OPERATIONS PHASE (ANNUAL IMPACTS)				
Total Operation expenditure	$25,426,545		$28,099,758	
Direct Income	$14,435,048		$18,046,145	
Indirect Income	$24,741,190		$29,928,374	
Total Income	$39,176,238		$47,974,519	
Direct Jobs		25		25
Indirect Jobs		363		486
Total Jobs		388		511
Local Taxes Paid	$581,597		$621,000	
State Taxes Paid	$2,507,279		$3,070,369	
Total Taxes Paid	$3,088,876		$3,691,369	

6.3 Comparing the ORNL Report with the AES Model Results

The results from the ORNL report provide interesting benchmark or "ballpark" estimates for comparison to the results from the AES model, even though there are some key differences in the methodologies and assumptions used for the two assessments.

Key similarities between the ORNL and AES model results – both are:

- Based on the use of the IMPLAN input /output model for estimating direct and indirect impacts,
- Both are based on NREL's process design evaluation for enzymatic hydrolysis technology,
- Both reports evaluate the economic impacts of constructing and operating a single bioethanol facility, and
- Both are based on the use of corn stover as the feedstock for ethanol production.

Key differences between the ORNL and AES model results are that:

- The AES model is based on a bioethanol facility co-located at a coal-fired power plant, while the ORNL report is for stand-alone facilities – thus the capital costs are higher and rates of return are lower for the ORNL study.
- Another difference is that the ORNL report addresses five Midwestern states, and does not include New York State, and
- The ORNL report assumes the construction of larger facilities in each state – 2,000 metric dry tons/day of corn stover are processed at each facility in the ORNL report, vs. 1000 short tons/day of corn stover used as feedstock in the AES model runs. Thus while the ORNL facilities do not benefit from cost reductions due to the co-location approach, the facilities modeled in the ORNL study have economy-of-scale-benefits since they are over twice as large as the facilities assumed in the AES model runs.

Table 6.2 provides a comparison between the ORNL results and the AES model results. In order to facilitate comparisons between the results for the two assessments, the jobs and incomes from the ORNL report have been proportionally adjusted downward to a similar level of feedstock use as those assumed for the AES model – the ORNL results were simply divided by a factor of 2.205 to reflect/adjust to 1,000 short tons of feedstock use, rather than the 2,000 metric tons actually modeled in the ORNL report. (Note that Appendix G has a copy of the actual ORNL results, without the scale adjustment used in Table 6.2.) Comparing the results shown in Table 6.2 for the AES model runs regarding the NYS scenario, versus the ORNL runs for the midwestern states, it can be seen that somewhat fewer jobs were created in the construct phase for the New York scenario. This could be explained by the reduced scope of construction required for the co-located plant in the NYS scenario, versus the stand-alone plants modeled for the midwestern states. A similar observation (or argument) could be made for the jobs resulting from the annual combined industrial, agricultural, and transportation impacts for operating the facilities – co-location reduces the required jobs for the NYS scenario. For the total value added estimate, the NYS case is higher, which could be explained by the higher rate-of-return facilitated by the co-located scenario.

Table 6.2. Comparison of the ORNL Study Results to the AES Model Runs

	One-Time Only Construction			**Annual Combined Industrial, Agricultural, and Transportation**		
	Total Industry Output (MM $)	**Employ-ment (jobs)**	**Total Value Added (MM $)**	**Total Industry Output (MM $)**	**Employ-ment (jobs)**	**Total Value Added (MM $)**
Illinois	158.3	1,388	81.6	78.6	584	36.7
Indiana	142.9	1,396	64.0	72.7	599	31.6
Iowa	137.8	1,416	64.1	65.3	527	25.4
Kansas	145.8	1,510	67.5	92.1	848	40.7
Minnesota	151.6	1,458	72.1	71.2	573	28.6
Missouri	155.9	1,580	72.7	95.7	954	46.9
Nebraska	141.9	1,509	63.4	68.2	571	26.9
Ohio	136.0	1,277	62.1	74.8	612	31.8
South Dakota	134.6	1,460	57.0	63.8	500	20.6
Wisconsin	149.3	1,520	57.0	74.3	683	30.1
New York		1,201	56.6		511	48.0

Midwestern state impacts are adjusted to a 1000 short tons/day facility size (same as NY)

Enzymatic hydrolysis technology and corn stover feedstock for all cases

Midwestern state impacts for a stand-alone facility; NY impacts for a co-located facility

6.4 Economic Impacts of a Conventional Corn-to-Ethanol Plant vs. the AES Greenidge Co-located Bioethanol Plant

In addition to the two corn-stover-to-ethanol analyses discussed above, a recent report estimated the direct and indirect economic impacts of constructing and operating a 40 million gallon per year dry-mill corn-to-ethanol facility [Urbanchuk 2002]. This report provides an interesting point of comparison with respect to the impacts estimated for the bioethanol facilities.

As summarized in Table 6.3, the cost to build and equip a typical new 40 million gallon per year dry-mill ethanol plant would be about $60 million. It was estimated that 41 jobs would be created by the operation of the corn-to-ethanol facility, which compares to an estimate of 25 jobs to operate a 31-million gallon co-located bioethanol facility at AES Greenidge. Operating expenses for the corn-to-ethanol plant were estimated at $56 million annually, which scales to about $43.4 million for a 31-million gallon facility, if the costs are adjusted on a simplistic proportional basis. This compares to an estimated operating expense of $28 million for a corn-stover based bioethanol facility. The corn-to-ethanol study noted that corn costs represented 71 percent of the operating costs. Since corn stover will be less expensive than corn, this helps explain why operating expenses are higher for the dry mill plant, since the price of corn used in the Urbanchuk study was $85.71 per ton ($2.40 per bushel) compared to a price of $35.70 per dry ton of corn stover used in the AES model. Table 6.3 provides a summary comparison of the costs and impacts of a dry-mill facility vs. a co-located bioethanol plant. Values for a dry mill facility are shown for both a 40-million gal/yr plant (as reported in the Urbanchuk study), and for an adjusted dry-mill plant size of 31 million gallons, using simple proportional scaling in order to facilitate comparisons between values for the two facility types. The total jobs estimates in Table 6.3 reflect direct, as well as indirect jobs resulting from the annual operation of the facilities. (Note that the average annual return on investment assumes an ethanol selling price of $1.16/gal for the scenarios shown in Table 6.3; however, if ethanol commands a more attractive price of $1.30/gal in New York State, the rate of return would be 44% for the enzymatic facility). The estimate that a greater number of jobs would be supported with an enzymatic plant (based on comparably sized facilities) could be explained by the distinctly higher rate of return anticipated for the bioethanol plant.

Table 6.3. Comparison of Costs & Job Impacts for a Dry Mill Corn-to-Ethanol Plant vs. a Co-located Bio-ethanol Plant using Corn-Stover Feedstock

Facility Description:	Construction Costs (millions $)	Direct Jobs to Operate	Annual Operating Expenses (millions $)	Average Annual Return on Investment	Total Jobs
Dry Mill - 40 million gal/yr ethanol plant	$60	41	$56	13.3%	593
Dry Mill - 31 million gal/yr ethanol plant*	$47	32	$43	13.3%	460
Enzymatic 31 million gal/yr co-located plant	$65	25	$28	37.0%	511

*Dry mill factors adjusted to a 31 MM gal/yr scale based on a simple proportion sizing calculation.

6.5 Local Infrastructure Impacts

Given the number of communities and the population base in the vicinity of the AES Greenidge power plant, there should not be a significant concern with regard to the capacity and availability of schools or the availability of new employees to operate a bioethanol facility at the site. As noted earlier, there will be a need for about 25 new employees to operate the bioethanol facility, including a mix of skilled, semi-skilled, and unskilled labor. There are about 340 people who live in the Village of Dresden, NY, which is located immediately north of the AES Greenidge power plant. The town of Penn Yan is located a little less than 6 miles west-southwest of Dresden. It has a population of 5,300. The town of Geneva is 14 miles north of Dresden and has a population of 14,200. Rochester is about 57 miles northwest of Dresden, and Syracuse is about 68 miles northeast of Dresden. Ithaca, NY (and Cornell University) is located 64 miles southeast of Dresden.

Genencor International has offices in Rochester, including manufacturing, sales, and marketing functions. With the fairly close proximity of Genencor facilities and staff with respect to the AES Greenidge site, Genencor could be a useful resource in providing enzymes and related expertise for an enzymatic hydrolysis facility at AES Greenidge.

Another interesting consideration is the extent of fermentation expertise in the local area – there are 41 wineries in the Finger Lakes region, including 15 near the western shore of Seneca Lake where the AES Greenidge power plant is located. While this expertise is obviously centered on production of ethanol for beverages, there may be some aspects where this expertise and focus on fermentation technology could translate into availability of personnel or suppliers relevant to a bioethanol facility at the AES Greenidge site.

- Transportation
    - Roads

The power plant staff does not believe transportation of biomass feedstock via trucks will be a significant local concern, either from the point of view of the capacity of the roads, or the concerns of residents – AES Greenidge has had coal delivered to their power plant via trucks in past years with no particular problems or complaints, and the local village of Dresden is well away from the main highway (Route 14) that would be used for truck transportation of biomass feedstock.

Assuming that large square bales are used, approximately 70 trucks per day would be needed to deliver 1000 short tons per day of stover when operating seven days per week [Hettenhaus & Wooley, 2000]. In order to avoid weekend and nighttime deliveries, a modified delivery schedule of five-days per week, 12-hours per day would require an average of 8.2 truck deliveries per hour. The local roads appear able to handle this amount of traffic – the main concern would be to have adequate unloading capabilities at the plant to prevent a backup of trucks waiting to be unloaded (this would probably require that two truck dumpers be available at the plant).

- Railroad

One alternative for reducing the frequency of truck deliveries to the Greenidge site would be to deliver a significant portion, or all of the stover via rail. The power plant's existing coal delivery infrastructure includes rail lines that go directly to the power plant and literally into the power plant building. The existing tracks on the AES Greenidge site can accommodate storage of 55 rail cars, plus 100 additional cars can be stored at the adjacent Dresden siding. In the AES Greenidge region, two transfer sites could be used where trucks or tractors could drop off stover bales for loading on rail cars could occur. One eastern site could be at Auburn, in Cayuga County; a second western site could be at Churchville, in western Monroe County. One option for transporting bales of stover from the field to the Auburn or Churchville rail loading sites could be to use "load-and-go" wagons and high-speed tractors.

A bioethanol facility that requires 1,000 dry tons per day of stover would require deliveries about 33 rail cars per day (assuming that "center beam" style railcars are used). This is a little less than half the number of trucks that would be required to deliver this amount of stover.

An approach that appears to offer promise would be to use a mix of tractors, trucks, and rail cars to deliver the corn stover. This would help avoid stress on any one mode of feedstock transportation. For example, corn acreage closest to the Greenidge site could be harvested in the early phase of the harvest season using a silage form of storage for the wet stover. Since it is expensive to transport wet stover long distances, the close-in areas are most suitable for this approach. Tractors could readily be used to transport the forage-type stover to silos for storage. Since this wetter stover would have a shorter storage life than dryer stover, it could be used first in an annual cycle of stover management/utilization. Corn acreage further from the AES Greenidge plant could be harvested later in the season as square bales, with truck and/or rail transport used to deliver the stover to the plant.

- Utilities

By co-locating at an existing electric power plant, the bioethanol facility will have a ready source of electricity and steam to meet all of its requirements without causing any strain on the existing utility infrastructure. A natural gas pipeline is also available at the site if this source of energy is needed (e.g., as a supplemental heat source for drying the lignin stream prior to combustion in a pulverized coal boiler).

It is anticipated that the bioethanol facility would have its own wastewater treatment system, where the goal would be to have essentially zero liquid effluent. Thus the bioethanol facility should not pose a wastewater treatment burden for the local community of Dresden.

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Task 7. Market Issues

7.0 Overview

At present, there is a great deal of change and uncertainty regarding ethanol market issues in New York State (NYS), as well as for the United States as a whole. Even with this uncertainty, it is still possible to make useful observations regarding ethanol market issues. The following chapter explores the status of ethanol market issues, with a primary focus on issues specific to NYS, including exploration of national issues where they pertain to ethanol markets in NYS.

7.1 New York State Market Issues

The State of New York has announced that it will no longer allow MTBE to be used as a fuel additive in gasoline after January 1, 2004. Approximately half of the gasoline sold in NYS is reformulated gasoline (RFG), which is required primarily in the urbanized regions where air quality is a problem. About 350 million gallons per year of MTBE is used to provide the 2 percent oxygen content required for the RFG [Post, 2001]. Ethanol fuel could play a significant role in replacing this MTBE (from an octane, oxygen, and fuel volume perspective), and could also reduce New York State's 100 percent dependence on external fuel supplies. If EPA continues to require 2 percent oxygen content in RFG (per the U.S. Clean Air Act Amendment), the amount of ethanol needed in NYS to replace oxygen content currently provided by MTBE will be about 175 million gallons per year (since ethanol has about twice as much oxygen per gallon as MTBE, half as many gallons of ethanol would be required as MTBE gallons).

The New York Corn Growers Association has estimated that eliminating MTBE sales in New York could create a demand for 300 million gallons of ethanol a year [Stashenko, 2001]. This is probably a reasonable estimate, assuming ethanol is blended at a 10 percent level instead of a 5.7 percent level, to make up for the oxygen, octane, and volumetric content of gasoline that would be lost with the phase out of MTBE.

7.2 Regional Perspectives of Northeastern States

Environmental regulators in NYS and other surrounding northeast states have expressed a variety of reservations regarding ethanol fuel use. Their views on ethanol fuel use in the northeast are discussed in detail in the report titled, "Health, Environmental, and Economic Impacts of Adding Ethanol to Gasoline in the Northeast States," by NESCAUM (Northeast States for Coordinated Air Use Management) and NEIWPCC (New England Interstate Water Pollution Control Commission) [see NESCAUM, 2001]. The report notes that more than one million gallons of MTBE is sold annually in the Northeast. Under current federal law regarding RFG, "eliminating MTBE represents a de facto mandate for ethanol in RFG. Because MTBE and ethanol are valuable high-octane components, the use of ethanol in gasoline is likely to increase dramatically as MTBE is phased-out in the Northeast, even without the oxygen requirement."

The NESCAUM report notes a variety of environmental concerns regarding the use of ethanol as a replacement for MTBE:

- One concern is that "backsliding" of air quality could occur. Since only 5.7 percent by volume of ethanol is needed, compared to 11 percent MTBE by volume to provide the same amount of oxygenate for gasoline, there is a concern that the 5 or 6% of gasoline components used to make up this difference in fuel supply volume (and octane value) could include toxic components such as benzene or toluene, which could result in increases in toxic air emissions.

- NESCAUM is also concerned about the potential for increased evaporative air emissions, which may lead to higher ozone levels, since ethanol in gasoline increases the fuel volatility. Based on this concern, the northeast air regulators generally do not like the fuel volatility waivers that EPA has provided for ethanol/gasoline blends. In non-RFG areas where conventional gasoline is sold, NESCAUM is concerned about increased evaporative emissions due do co-mingling of conventional gasoline with gasoline containing 10 percent ethanol blends.

- Another concern is the potential that tailpipe emissions of acetaldehyde will increase with ethanol blends. Although a study in California indicated that ambient acetaldehyde emissions did not increase due to ethanol blends, NESCAUM is concerned that California airsheds are different from those in the Northeast, particularly in "microenvironments where elevated exposures are more likely."

- The NESCAUM report also notes that "…environmental transport properties of ethanol are cause for some concern: 1) at high concentrations, ethanol can make other gasoline constituents more soluble in groundwater; 2) when present in a gasoline spill, ethanol can delay the degradation of other, more toxic components in gasoline; and 3) ethanol can cause greater lateral spread of the layer of gasoline on top of the water table."

In general, the environmental concerns NESCAUM raises tend to be presented as potential causes for concern, rather than absolutely unacceptable characteristics of ethanol blends. In addition to environmental issues, NESCAUM raised concerns regarding economic considerations of ethanol blends. One concern is that the cost of gasoline could increase in order to produce the low volatility gasoline blendstock needed to accommodate ethanol while meeting emission (volatility) performance standards for Phase II RFG, which took effect in January 2000. This, again, is a potential concern – it is possible that other alternatives for meeting octane requirements in lieu of MTBE could be more expensive than ethanol.

It is important to note that one of the primary recommendations made in the NESCAUM report on ethanol was the need to "further explore opportunities to develop an indigenous industry to produce fuel ethanol from cellulosic biomass in the Northeast." The conclusion to the overall report notes "the development of ethanol production capacity in the Northeast based on cellulosic biomass offers an economic opportunity that could reduce the long-term cost and increase the economic and environmental benefits of fuel ethanol use in our region."

In summary, it can be said that the environmental regulators in the northeast (i.e., via NESCAUM and NEIWPCC) have a number of concerns regarding ethanol; however, regardless of these concerns they believe that efforts to reduce the use of MTBE will result in a substantial increase in fuel ethanol use in the Northeast. They also strongly support the development of cellulosic-based ethanol production in the Northeast. Thus, from a market perspective, a basic interpretation can clearly be made that market factors look quite favorable for the AES Greenidge bioethanol facility, even though there are various concerns that regulators raise regarding ethanol fuel use in the Northeast.

7.3 National Issues Impacting NYS Ethanol Markets

National energy legislation currently being developed by the U.S. Congress is likely to have a significant impact on future ethanol markets. The U.S. Senate recently passed its version of an energy bill which contains a number of provisions that would directly impact ethanol, including cellulosic-based ethanol in particular The Senate's version of the energy bill includes the following elements:

- Establishes a renewable fuels standard (RFS)
  - Annual targets are set for the required renewable fuel content in gasoline;
  - The main renewable fuel component is anticipated to be ethanol
  - By the year 2012, there must be 5 billion gallons of renewable fuel sales;

- Eliminates the oxygen requirement in RFG;

- Bans the use of MTBE in four years (however, states are allowed to opt out of this requirement);

- Creates a renewable fuel credit trading program for refiners who exceed their RFS target levels
  - Each gallon of cellulosic ethanol counts as 1.5 gallons towards meeting the requirement;
  - Small refiners are exempt unless they opt in;

- Allows states or regions to apply for a waiver from the RFS if they can show severe economic harm would result to their state or region, or if supply is inadequate;

- Protects the environmental performance of RFG – toxic air emissions are not allowed to increase due to the RFS or MTBE ban;

- Allows states to rescind the Reid Vapor Pressure (RVP) waiver for ethanol blended with conventional gasoline (the Northeast states lobbied for this);

- Requires that differences between summer and winter use of renewable fuel must not be greater than a 35/65 percent split (i.e., there cannot be an excessive reliance on renewable fuel use in only one season of the year).

Once the U.S. House of Representatives passes its version of the energy bill, it will then go to a House/Senate conference committee to resolve/determine the specific provisions to be included in the final energy bill legislation. At present, there appears to be good prospects that the renewable fuels standard will be approved, however the specific targets or requirements in a final bill obviously may not be identical to those currently specified in the Senate version of the energy bill. Approval of the entire bill is expected to take a fair amount of time, since other provisions of the bill are more controversial – final approval of the legislation is currently anticipated in the fall of 2002.

One interesting question that can be posed is whether ethanol markets in NYS would be stronger with the provisions under the national energy bill, or with the market conditions as they currently exist. If the situation were to continue on its current path, with no national energy bill and MTBE scheduled to be phased out in NYS, and if the oxygenate requirement is retained for RFG, then there will be a very strong demand/outlook for ethanol to replace large volumes of MTBE in NYS. In comparison, the national energy bill does not appear to require all states and regions to uniformly meet the new higher required standards for renewable fuel consumption – that is, the renewable fuel targets are national requirements, they are not state or region-specific. Also, NYS would be likely to take advantage of the ability to opt out of vapor pressure waivers for ethanol, which might tend to weaken ethanol markets in NYS.

One *possible* scenario is that a significant amount of the renewable fuel use to meet the targets specified under the renewable fuel standard could occur in mid-western states, where corn-derived ethanol is the most readily available (i.e., transportation costs are lower). Alternatively, with the phase-out of MTBE, the high-octane value and low toxicity of ethanol may justify higher transportation costs to supply ethanol to the east coast and west coast markets. The final market impact of this situation will depend on a number of factors that are currently hard to predict (including specifics regarding the rules for implementing the RFS program, regional cost factors regarding octane replacement, RVP waivers, etc.).

Another important consideration with respect to the Energy Bill is that the AES Greenidge facility will be producing ethanol from cellulose (bioethanol). Given the provisions of the RFS credit-trading program under the energy bill, where bioethanol will receive 1.5 credits per gallon of ethanol compared to 1.0 credit per gallon of corn-derived ethanol, it could be anticipated that the energy bill will provide added value and market stimulus for bioethanol. In an effort to quantify the potential value of this 1.5 to 1 incentive, a consultant was asked to do a preliminary analysis for DOE [LeGassie, 2002]. The consultant estimated that the incentive would add 23 cents per gallon to the value of bioethanol, if the excise tax exemption were to be eliminated. If the current excise tax exemption were to be retained, the consultant argued that gasoline marketers would not be willing to pay a higher price for bioethanol than for starch-based ethanol, even with the 1.5 to 1 incentive weighting for bioethanol credits. However, this interpretation seems flawed, since it essentially implies that all ethanol credits would have zero value under this program (in other words, the credit trading system would fail to function), which seems highly unlikely.

Given uncertainties regarding whether the energy bill will actually be passed, unknowns regarding the specific implementation rules that will be established, complexities involved in implementing a renewable fuel credit trading program, plus the added complexity of anticipating how the 1.5 to 1 credit for bioethanol will be valued in the marketplace, it seems premature to predict the quantitative impact of the energy bill on ethanol markets and prices. However, as discussed above, it seems reasonable to assume that if a credit trading system is established, it will be done in a way that translates into real value for the credits. Thus, if petroleum refiners/distributors are able to receive 50 percent more credits for using bioethanol compared to conventional ethanol, it seems likely that the market value of bioethanol will be distinctly enhanced if the energy bill is passed with the 1.5:1 bioethanol provisions currently included in the Senate version of the bill. Even for a "worst case" scenario, say if markets for ethanol are concentrated in Midwestern states as a result of the energy bill, Ohio is likely to included in the Midwestern market, and it is only about 300 miles from the AES Greenidge site in Dresden, New York (central western NYS) to Cleveland, Ohio, or about 25 miles further than it is between Dresden and New York City. By comparison it is about 340 miles between Cleveland and Chicago. This helps illustrate that the Dresden site in Western NYS is generally well located to supply large urban markets in the Northeast and in the Midwest. It should be noted that AES Greenidge has a rail spur that goes directly to their existing power plant, thus ethanol produced at this site could be transported to market via rail or truck. Regional ethanol transportation costs are addressed further in the following section.

7.4 Regional Ethanol Transportation Cost Factors

Given the current situation where essentially all ethanol is produced in the Midwest, what potential price advantage would a NYS-based ethanol production facility have in selling ethanol to gasoline markets in NYS and the broad northeast region, due to transportation cost savings? A detailed study was recently completed for DOE that included an evaluation of the costs for transporting ethanol from Midwestern states to other regions of the U.S., including the Northeast region (Reynolds, 2002). The study estimated that the average cost to transport ethanol from the Midwest to the Northeast region would be approximately 9.8 cents per gallon of ethanol, assuming a mix of rail and ship/barge transport, under a scenario where 1.3 billion gallons of ethanol is shipped to Northeast market.

7.5 Corn-to-Ethanol Production and Pricing Factors With a Renewable Fuel Standard

If a renewable fuel standard is implemented with a requirement for 5 billion gallons of ethanol consumption in ten years, it is anticipated that corn supplies could potentially be adequate to satisfy the entire ethanol fuel requirement. The increased demand for corn represented by this level of ethanol production would likely increase the price of corn nationwide by an average of 11 percent during this time frame [Urbanchuk, 2001]. Assuming a conversion yield of 2.6 gallons of ethanol per bushel of corn, and a price of $2.35 per bushel, corn costs alone represent about $0.90 per gallon. If corn costs increase 11 percent, this would represent an increase in feedstock costs that would correspond to about a 10 cent per gallon increase in corn-to-ethanol costs.

Since it is anticipated that dry-milling technology would be used for most new corn-to-ethanol facilities, 5 billion gallons of ethanol production from corn would result in a very large supply of distillers dried grains and solubles (DDGS) as a by-product of the corn-to-ethanol process. This supply would compete with soybeans as an animal feed and probably would result in some reduction of DDGS prices/values, due to supply and demand factors. With the possibility that revenues from sales of DDGS could be reduced due to a significant increase in DDGS supplies, it is possible the price of ethanol from corn could increase even more than 10 cents per gallon noted above, if the entire 5 billion gallon supply of renewable fuel is provided from corn in response to a national renewable fuel standard.

7.6 Potential Corn-Based Ethanol Production in NYS

The New York Corn Growers Association (NYCGA) has been working with a group to foster the development of a 30-million gallon corn-to-ethanol facility in NYS as a way to help increase the demand for corn in NYS. The NYCGA is also interested in helping the dairy industry grow in NYS, and they see the DDGS co-product that would result from an ethanol dry-mill facility as an attractive source of feed for dairy cows [Stashenko, 2001]. Corn production and demand in NYS are generally close to being in balance, at present, thus a new corn-to-ethanol facility would require that additional vacant cropland in NYS be brought into corn production, or else the grain would have to be obtained from suppliers outside of NYS, probably from the Midwest corn belt.

There are other miscellaneous rumors regarding organizations that are exploring the option of building starch-to-ethanol facilities in NYS. For example, at a recent ethanol conference, it was announced that preliminary efforts were underway to develop a 250-million gallon per year corn-to-ethanol "Foxhall Energy Park" facility near Newark, New Jersey. This facility would purportedly use 10,000 tons per day of corn shipped from the Midwest [Wallace, 2002]. With the cost for transporting corn from the Midwest, and the need to find adequate markets for by-products, it seems unlikely that such a facility would be economically competitive with ethanol produced and shipped from the Midwest. In general for corn-to-ethanol production, it seems that it would be less expensive to process corn into ethanol in the Midwest, then ship the refined ethanol product to markets such as NYS (i.e., the transportation costs for corn are likely to be higher than for ethanol, due simply to volumetric/bulk considerations for the two commodities, unless there is a strong demand for by-products like DDGS in the NYS area).

7.7 Bioethanol By-Product Markets/Credits

- Lignin

  The AES Greenidge facility can utilize the entire quantity of lignin produced as the by-product of a 20-million gallon per year (or 1,000 dry ton per day) bioethanol facility co-located at their site. In assessing the energy value of the lignin, one approach would be to assume that its value is similar to the average price paid for coal at AES Greenidge, on a dollar per BTU basis. The price of coal varies somewhat, depending to some extent on the price of natural gas and oil. AES Greenidge recently paid $1.92 per million BTU of coal [Chambers, Oct. 2001]. However, in addition to its energy value, lignin offers a variety of additional benefits that could also be factored into its value, as discussed below.

  - The lignin will have lower sulfur content than coal, which will help reduce SO_2 emissions. The sulfur content of coal used at AES Greenidge is typically around 2.2 percent [Chambers, April 15, 2002]; whereas the sulfur content of lignin residues has been measured by NREL to be in the range of 0.07 to 0.10 percent [Elam, 200]. The cost for AES Greenidge to purchase SO_2 credits is currently around $172 per ton [Evolution Markets, 2002].

- It appears that lignin will have lower nitrogen content than coal, which could help reduce NO_x emissions. Bituminous coal typically has nitrogen content in the range of 0.8 to 1.8 percent [Milne, 1986], whereas tests by NREL found lignin samples to have a nitrogen content ranging from 0.16 to 1.04 percent [Elam, 2000]. The cost of NO_x emission credits was recently $850 per ton for 2002, and $5,100 per ton in 2003 and 2004 when federal and regional regulations require significant reductions in NO_x emissions [Evolution Express, 2002].

If for some reason AES Greenidge were to decide that it does not want to use all (or a portion) of the lignin produced from the bioethanol operation, it is possible that the lignin stream has value as a soil amendment, which could help reduce net feedstock costs. However, studies would need to be performed to determine the value and suitability of the lignin as a soil amendment.

- Methane

It is anticipated that a bioethanol facility at AES Greenidge will utilize a wastewater treatment system that will include an anaerobic digester to reduce/treat the organic waste stream. The methane produced from this system represents another by-product from the bioethanol production process. Methane can be used as a supplemental boiler fuel, however it has a higher value if used in the AES Greenidge "re-burn" system to help reduce NO_x emissions from the boiler(s) – note that the re-burn system also delivers heat in the boiler that contributes to steam production. In this case the methane would be replacing natural gas use. The price of natural gas has varied a moderate amount over the last year; a recent price for natural gas was $2.48 per million BTU [Chambers, 2001].

- Electricity

Another by-product of the bioethanol facility would be electricity produced from using lignin and methane as boiler fuel. For electric utilities in western NYS, the wholesale price of electricity sold to the grid is anticipated to be $0.03 per kWh in 2003, on an average round-the-clock basis, including peak and off-peak rates [Chambers, April 24, 2002].

- New incentives may be available fairly soon for electricity produced from biomass, including expanded tax credits and a national renewable portfolio standard. As noted earlier, Congress is currently working on finalizing a national energy bill; the version of this bill recently passed by the Senate would expand the Section 45 tax credit of 1.7 cent/kWh, currently available for electric power produced using "closed loop" biomass (i.e., energy crops) and poultry litter, to allow a wide variety of waste "open loop" biomass materials to be eligible for the tax credit. One proposed amendment would allow a tax credit of 0.5 cents/kWh for electric power produced from biomass co-fired in coal power plants. If AES Greenidge were to change one or two of the boilers on their Unit 3 to dedicated use of lignin fuel, then it may be eligible for the full 1.7-cent/kWh credit; or, if lignin is cofired with coal in one of the AES Greenidge boilers, then the 0.5 cent/kWh tax credit may be available. Again, as noted earlier, there are wide discrepancies between the Senate and House versions of the energy bill and it is anticipated to take a number of months before the Conference Committee approves a final bill.

- Carbon Dioxide Sales

Recovery and sale of CO_2 resulting from fermentation is another potential source of revenue from the bioethanol process. Ethanol producers typically contract with CO_2 marketers to build and operate CO_2 recovery plants at their facilities. In general, there are good markets for carbon dioxide sales in the Northeastern U.S. The market value of CO_2 in New York State has typically been in the range of $9.00 per ton of CO_2 [New York Corn Growers Association, 2000]. (Note: per this reference, CO_2 marketers have generally preferred to locate at ethanol facilities with production capacities greater than 29 million gallons per year, based on experiences with corn-to-ethanol facilities, however, there may be some flexibility regarding this criteria.)

- Gypsum

Many farmers in the vicinity of the AES Greenidge site currently use gypsum as a soil amendment to improve the quality of their soil (e.g., in situations where additional calcium is desired. The gypsum produced as a by-product of the acid neutralization stage of a bioethanol facility could potentially be marketed as a soil amendment product. Gypsum is currently sold to farmers in the AES Greenidge area for $16.50 per ton, delivered [Horst, 2002]. The local gypsum supplier has said he would be willing to pay $3 per ton (at the plant gate) for gypsum produced by a bioethanol facility at AES Greenidge, assuming that tests of gypsum verify that it is acceptable as a soil amendment. Unlike the situation with wallboard production, where there are fairly stringent specifications for gypsum purity, it is possible that the gypsum from a bioethanol process (which will contain various fractions of organic substances) could actually make for a more valuable soil amendment product, since the organics in the gypsum could potentially provide beneficial organic content to the soil. The moisture content of gypsum from the bioethanol facility may be another important factor – some problems have occurred when unloading wet gypsum from dump trucks [Horst, 2002]. However, equipment for handling and applying wet gypsum is available from companies such as AGCO [Perry, 2002].

- Greenhouse Gas Credits

Preliminary efforts have been pursued in the U.S. to establish tradable credits for reductions achieved in greenhouse gas (GHG) emissions. However this effort has been highly restrained to date, since the U.S. government has not taken steps to formally require reductions in GHG emissions. Eventually the position of the U.S. government may change with regard to GHG policies, however, internationally there are already significant initiatives and policies in place to begin fostering an international greenhouse gas trading market [Fraser, 2002]. Multinational companies are in a position to benefit from and participate in international GHG trading/markets; in particular, AES Corporate may be in a position to benefit from GHG reductions that could be quantified for biomass power and renewable transportation fuel produced at an AES Greenidge bioethanol facility, since AES is a multinational company.

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Appendix A

Enzymatic Hydrolysis:

Process and Economic Parameters Summary

Enzymatic Hydrolysis

ASPEN+ Model #	bw0206a.inp	bw0206a.inp
Excel File	bw0206b_colocation_JE_ enz.xls	206b_colocation_NREL_ enz.xls
Minimum Ethanol Selling Price (MESP)	**$1.30**	**$0.97**
YR $	2000	2000
Ethanol Production (MM Gal. / Year)	31.4	31.4
Ethanol Yield (Gal / Dry US Ton Feedstock)	89.7	89.7
Feedstock Cost $/Dry US Ton	$35.70	$35.70
CAPITAL COSTS		
Feed Handling	$4,600,000	$4,600,000
Pretreatment	$11,700,000	$11,700,000
Neutralization/Conditioning	$4,900,000	$4,900,000
Saccharification & Fermentation	$4,700,000	$4,700,000
Distillation and Solids Recovery	$12,700,000	$12,700,000
Wastewater Treatment	$2,100,000	$2,100,000
Storage	$1,000,000	$1,000,000
Boiler/Turbogenerator	$0	$0
Utilities	$2,900,000	$2,900,000
Total Equipment Cost	$44,600,000	$44,600,000
Added Costs	$20,400,000	$20,400,000
(% of TPI)	31%	31%
Total Project Investment	$65,000,000	$65,000,000
OPERATING COSTS: (cents/gal ethanol)		
Feedstock	39.8	39.8
Biomass to Boiler	0.0	0.0
CSL	2.8	2.8
Cellulase	10.1	10.1
Other Raw Materials	6.7	6.7
Electricity	8.1	8.1
Fixed Costs	10.2	10.2
Steam Costs	2.0	2.0
Lignin Sales	-12.6	-12.6
By-products and credits	-3.7	-3.7
Capital Depreciation	10.5	10.5
Average Income Tax	8.3	6.3
Average Return on Investment	47.8	16.7

OPERATING COSTS: ($/year)

Feedstock	$12,500,000	$12,500,000
Biomass to Boiler	$0	$0
CSL	$900,000	$900,000
Cellulase	$3,200,000	$3,200,000
Other Raw Matl. Costs	$2,100,000	$2,100,000
Electricity	$2,500,000	$2,500,000
Fixed Costs	$3,200,000	$3,200,000
Steam Costs	$600,000	$600,000
Lignin Sales	-$4,000,000	-$4,000,000
By-products and credits	-$1,100,000	-$1,100,000
Capital Depreciation	$3,300,000	$3,300,000
Average Income Tax	$2,600,000	$2,000,000
Average Return on Investment	$15,000,000	$5,200,000

Plant Electricity Use (KWH/gal)	2.01	2.01
Plant Steam Use (kg steam/gal)	16.6	16.6
Boiler Feed -- LHV (Btu/lb)	2,862	2,862
Boiler Feed -- Water Fraction	0.519	0.519
Equity	25%	100%
Loan Interest	8.0%	7.5%
Loan Term, years	15	10
Interest rate (IRR) % after tax	**38%**	**10.0**
Income Tax Rate %	39.0	39.0
Type of Depreciation	DDB	DDB

PROCESS AREA:

Feedstock:		
Solids Fraction	52.1%	52.1%
Cellulose Fraction	42.03%	42.03%
Xylan Fraction	22.60%	22.60%
Arabinan Fraction	2.87%	2.87%
Mannan Fraction	1.51%	1.51%
Galactan Fraction	1.82%	1.82%
Lignin Fraction	20.61%	20.61%
Acetate	2.68%	2.68%
Ash	5.88%	5.88%
Pretreatment:		
Type	Dilute acid	Dilute acid
Reactor Solids Concentration	52.10%	52.10%
Reactor Residence Time (min)	10	10
Acid Concentration (acid/liquor)	1.10%	1.10%
Temperature (C)	190	190
Oligomer Conversion	No	No
Xylan to Xylose Yield	90%	90%
Mannan to Mannose Yield	90%	90%

Galactan to Galactose Yield	90%	90%
Arabinan to Arabinose Yield	90%	90%
Xylan to Oligomer Yield	2.50%	2.50%
Xylan to Furfural Yield	5%	5%
Xylan to Tar Yield	0	0
Unconverted Xylan	2.50%	2.50%
Cellulose to Glucose Yield	70%	70%
Lignin to Soluble Lignin Yield	5%	5%
Metal	SS316	SS316
Corrosion Rate (mils per year)	5.0	5.0
Corrosion Rating	Good	Good
Conditioning:		
Type of Conditioning	OL only	OL only
S/L separation	Yes	Yes
Solids Washing	Yes	Yes
Wash Water Temperature (°C)	46.0	46.0
Water/Hydrolyzate Ratio (kg/kg)	0.580	0.580
Gypsum removed	Yes	Yes
Gypsum to process (kg/hr)		
Acetic Acid Removal	N/A	N/A
O-Lime Addition Factor	0.0033	0.0033
Enzyme Production:		
Produced In-house or Purchased	Purchased	Purchased
Purchase Price ($/gal ethanol from cellulose)		
Purchase Price ($/gal ethanol)	0.108	0.108
Enzyme loading (FPU/g Cellulose)	12	12
Saccharification:		
Hydrolysis Residence Time	1.5 Day	1.5 Day
Hydrolysis Temperature (°C)	65	65
Fermentation:		
Fermentation Residence Time	1.5 Day	1.5 Day
Fermentation Temperature (°C)	41	41
Effective Solids Concentration	20%	20%
Modeled Ethanol Conc. (g/L)		
Nutrient Requirement	0.25% CSL + DAP	0.25% CSL + DAP
Cellulose to Glucose Yield	90%	90%
Glucose to Ethanol Yield	95%	95%
Xylose to Ethanol Yield	85%	85%
Arabinose to Ethanol Yield	85%	85%
Galactose to Ethanol Yield	85%	85%
Mannose to Ethanol Yield	85%	85%
Other:		
Chilled Water Fraction	0	0
Contamination Loss	3%	3%

Utilities:		
Boiler/Turbogenerator	No	No
Extra Fuel Required	No	No
Extra Fuel Required (kg/hr)	N/A	N/A
On-Line Time (hr/yr)	8406	8406
Treatment of Evap. Syrup	Burn	Burn
WWT Capital Cost Factor	1	1

Steam Type (by stream no.):

Stream 215	Medium Pressure	Medium Pressure
Stream 216	High Pressure	High Pressure
Stream 237	Medium Pressure	Medium Pressure
Stream 265A	Medium Pressure	Medium Pressure
Stream 592	Medium Pressure	Medium Pressure
Stream 594	Medium Pressure	Medium Pressure
Stream 596	Medium Pressure	Medium Pressure

Appendix B

Two-Stage Dilute Acid Hydrolysis:

Process and Economic Parameters Summary

Two Stage Dilute Acid Hydrolysis

ASPEN+ Model #	bw0402e_da.inp	bw0402e_da.inp
Excel File	**bw0402a_JE_da.xls**	**bw0402a_NREL_da_.xls**
Minimum Ethanol Selling Price (MESP)	**$1.30**	**$1.24**
YR $	2000	2000
Feedstock cost ($/BDT)	**$35.70**	**$35.70**
(Denatured) Ethanol Production (MM Gal/Year)	23.6	23.6
Pure Ethanol Yield (Gal / Dry Ton Feedstock)	64.4	64.4

CAPITAL COSTS:

Feed Handling	$4,600,000	$4,600,000
Pretreatment	$19,000,000	$19,000,000
Saccharification & Fermentation	$2,200,000	$2,200,000
Distillation and Solids Recovery	$10,600,000	$10,600,000
Wastewater Treatment	$2,400,000	$2,400,000
Storage	$900,000	$900,000
Boiler/Turbogenerator	$0	$0
Utilities	$2,400,000	$2,400,000
Total Equipment Cost	$42,100,000	$42,100,000
Added Costs	$19,300,000	$19,300,000
(% of TPI)	31%	31%
Fixed Capital Investment	$61,400,000	$61,400,000

OPERATING COSTS: (cents/gal ethanol)

Feedstock	55.4	55.4
CSL	1.4	1.4
Denaturant	2.6	2.6
Other Raw Materials	8.3	9.7
Electricity	12.0	12.0
Fixed Costs	16.8	17.5
Steam Costs	3.9	3.9
Lignin Sales	-24.2	-24.9
By-products and credits	-3.9	-4.0
Capital Depreciation	13.1	13.1
Average Income Tax	4.8	8.0
Average Return on Investment	39.9	31.3
	$130	**123.8**

OPERATING COSTS: ($/year)

Feedstock	$12,500,000	$12,500,000
CSL	$300,000	$300,000
Denaturant	$600,000	$600,000
Other Raw Matl. Costs	$2,500,000	$2,500,000
Electricity	$2,700,000	$2,700,000
Fixed Costs	$4,000,000	$4,000,000
Steam Costs	$900,000	$900,000
Lignin Sales	-$5,500,000	-$5,600,000
By-products and credits	-$900,000	-$900,000
Capital Depreciation	$3,100,000	$3,100,000
Average Income Tax	$1,100,000	$1,800,000
Average Return on Investment	$9,000,000	$7,100,000
	$30,300,000	**$29,000,000**

Ethanol Revenue	$29,300,000	$29,300,000
Other Revenue	$8,700,000	$8,700,000
	$38,000,000	**$35,900,000**
Equity	25%	100%
Loan Interest	8.0%	7.5%
Loan Term, years	15	10
Interest rate (ROR) %	**23.3**	**10.0**
Income Tax Rate %	39.0	39.0
Type of Depreciation	DDB	DDB

PROCESS AREA:

Feedstock:		
Solids Fraction	52%	52%
Cellulose Fraction	37.40%	37.40%
Xylan Fraction	21.07%	21.07%
Arabinan Fraction	2.92%	2.92%
Mannan Fraction	1.56%	1.56%
Galactan Fraction	1.94%	1.94%
Lignin Fraction	17.99%	17.99%
Pretreatment:		
Type	2-Stage Dilute acid	2-Stage Dilute acid
Reactor Solids Concentration	30.00%	30.00%
Stage 1Reactor Residence Time (min)	10	10
Stage 1 Acid Concentration (acid/liquor)	0.76%	0.76%
Stage 1 Temperature (C)	190	190
Stage 1 Pressure (atm)	1	1
Stage 2 Reactor Residence Time (min)	10	10
Stage 2 Acid Concentration (acid/liquor)	1.8%	1.8%
Stage 2 Temperature (C)	210	210
Stage 2 Pressure (atm)	1	1
Oligomer Conversion	No	No
Xylan to Xylose Yield	100%	100%

Mannan to Mannose Yield	93%	93%
Galactan to Galactose Yield	88%	88%
Arabinan to Arabinose Yield	90%	90%
Xylan to Oligomer Yield	0.00%	0.00%
Xylan to Furfural Yield	0%	0%
Xylan to Tar Yield	0	0
Unconverted Xylan	0.00%	0.00%
Cellulose to Glucose Yield	52%	52%
Lignin to Soluble Lignin Yield	5%	5%
Metal	SS316	SS316
Corrosion Rate (mils per year)	5.0	5.0
Corrosion Rating	Good	Good
Conditioning:		
Type of Conditioning	OL only	OL only
S/L separation	Yes	Yes
Solids Washing	Yes (Hot)	Yes (Hot)
Wash Water Temperature (°C)	130.5	130.5
S/L Separation Temperature (°C)	135.0	135.0
S/L Separation Pressure (atm)	5.0	5.0
Water/Hydrolyzate Ratio (kg/kg)	0.580	0.580
Gypsum removed	Yes	Yes
Gypsum to process (kg/hr)		
Acetic Acid Removal	N/A	N/A
O-Lime Addition Factor	0.0033	0.0033
Enzyme Production:		
Produced In-house or Purchased	Purchased	Purchased
Enzyme Purchase Price ($/gal ethanol)	0.108	0.108
Enzyme loading (FPU/g Cellulose)	12	12
Saccharification:		
Hydrolysis Residence Time	1.5 Day	1.5 Day
Hydrolysis Temperature (°C)	65	65
Fermentation:		
Fermentation Residence Time	1.5 Day	1.5 Day
Fermentation Temperature (°C)	41	41
Effective Solids Concentration	20%	20%
Modeled Ethanol Conc. (g/L)		
Nutrient Requirement	0.25% CSL + DAP	0.25% CSL + DAP
Overall Cellulose to Ethanol Yield		
Cellulose to Glucose Yield	52%	52%
Glucose to Ethanol Yield	95%	95%
Xylose to Ethanol Yield	85%	85%
Arabinose to Ethanol Yield	85%	85%
Galactose to Ethanol Yield	85%	85%
Mannose to Ethanol Yield	85%	85%
Other:		
Chilled Water Fraction	0	0
Contamination Loss	3%	3%

Utilities:		
Electricity Credit ($/kW h)	0.04	0.04
Boiler/Turbogenerator	No	No
Extra Fuel Required	No	No
Extra Fuel Required (kg/hr)	N/A	N/A
On-Line Time (hr/yr)	8406	8406
Treatment of Evap. Syrup	Burn	Burn
WWT Capital Cost Factor	1	1
Steam Type (by stream no.):		
Stream 215	Medium Pressure	Medium Pressure
Stream 216	High Pressure	High Pressure
Stream 237	Medium Pressure	Medium Pressure
Stream 265A	Medium Pressure	Medium Pressure
Stream 592	Medium Pressure	Medium Pressure
Stream 594	Medium Pressure	Medium Pressure
Stream 596	Medium Pressure	Medium Pressure

Appendix C

Cash Cost of Production and Net Production Cost For the Two-Stage Dilute Acid System and Enzymatic System

Note: The cash cost of production is defined as the variable costs plus fixed costs minus production credits for co-products. The net production cost is defined as the cash cost plus capital depreciation and amortization plus net interest on debt financing.

AES Greenidge Co-Location Assessment -- Appendix C

Variable Operating Costs	2-Stage Dilute		Enzymatic	
	MM$/yr	Cents/Gal.	MM$/yr	Cents/Gal.
Raw Material	(yr 2000$)	(yr 2000$)	(yr 2000$)	(yr 2000$)
Feedstock	12.50	55.42	12.51	39.81
Cellulase Enzyme			3.17	10.08
Sulfuric Acid	0.27	1.18	0.34	1.09
Hydrated Lime	0.56	2.50	0.70	2.23
Ammonia	0.72	3.18		
Corn Steep Liquor	0.33	1.45	0.88	2.81
Makeup Water	0.23	1.01	0.18	0.57
Other Chemicals	0.08	0.37	0.88	2.79
Bulk Unleaded Gasoline	0.59	2.64	0.83	2.64
Subtotal	15.28	67.76	19.49	62.03
Steam Costs:				
HP Steam to Pretreatment	0.57	2.52	0.33	1.06
MP Steam to EtOH Plant	0.28	1.24	0.29	0.92
LP Steam to Evaporator	0.02	0.10	0.00	0.01
Subtotal	0.87	3.86	0.63	2.00
Plant Electricity Cost	2.70	11.96	2.53	8.06
Lignin sales to Plant	-5.31	-23.56	-3.96	-12.60
Methane sales to Plant	-0.15	-0.68	-0.19	-0.61
Subtotal	-5.46	-24.24	-4.15	-13.20
By-Products and Credits:				
NOx Credit from biogas	0.02	0.10	0.03	0.09
SOx Credit	0.41	1.80	0.28	0.88
Ash disposal	-0.51	-2.25	-0.34	-1.10
GHG Emission Credit	0.28	1.25	0.21	0.68
CO2 Sales	0.64	2.84	0.89	2.82
Gypum Sales	0.04	0.16	0.09	0.29
Subtotal	-0.88	-3.91	-1.15	-3.66
Total Variable Operating Costs	12.50	55.42	17.35	55.22
Fixed Operating Costs:				
Total Salaries	1.19	5.03	1.19	3.78
Overhead/Maint	0.74	3.15	0.42	1.32
Maintenance	1.37	5.80	0.91	2.89
Insurance & Taxes	0.65	2.77	0.69	2.20
Total Fixed Operating Costs	3.96	16.75	3.20	10.20
Total Cash Cost of Production	**16.46**	**72.17**	**20.56**	**65.42**
Ave. Annual Capital Depreciation	3.07	13.01	3.25	10.35
Net Average Annual Interest	1.73	7.33	1.83	5.83
Net Production Cost	**21.26**	**92.51**	**25.64**	**81.60**

Appendix D

Financial Analysis Summary
Two-Stage Dilute Acid System

AES Greenidge Co-Location Assessment -- Appendix D

Ethanol Production Process Engineering Analysis

Base Case Summary

Feedstock-1000 U.S. BDT/d Corn Stover

2-Stage Dilute Acid Hydrolysis

All values in 2000$

(Denatured) Ethanol Selling Price	**$1.30**	
Internal Rate of Return	**23.3%**	(After Tax)
(Denatured) Ethanol Production (MM Gal. / Year)	**23.6**	
Pure Ethanol Yield (Gal / Dry Ton Feedstock)	64.4	
Feedstock Cost ($/Dry Ton)	35.7	

Capital Costs	
Feed Handling	$4,600,000
Pretreatment	$19,000,000
Fermentation	$2,200,000
Distillation	$10,600,000
WWT	$2,400,000
Storage	$900,000
Boiler	$0
Utilities	$2,400,000
Total Equipment Cost	$42,100,000
Added Costs	$19,300,000
(% of TPI)	31%
Total Capital Investment	$61,400,000
State & Federal Funding	$0
Fixed Capital Investment	$61,400,000

Theoretical Yields	Ethanol MM Gal/year
Cellulose	22.3
Xylan	12.3
Arabinan	1.6
Mannan	0.8
Galactan	1.0
Total Maximum (MM Gal/yr)	37.9
Maximum Yield (Gal/ton)	108.3
Current Yield (Actual/Theor)	60%

Operating Costs (centrs/gal ethanol)	
Feedstock	55.4
CSL	1.4
Denaturant	2.6
Other Raw Materials	8.3
Electricity	12.0
Fixed Costs	16.8
Steam Costs	3.9
Lignin Sales	-24.2
By-products and credits	-3.9
Capital Depreciation	13.1
Average Income Tax	4.8
Average Return on Investment	39.9
	130.0

Operating Costs ($/year)	
Feedstock	$12,500,000
CSL	$300,000
Denaturant	$600,000
Other Raw Matl. Costs	$2,500,000
Electricity	$2,700,000
Fixed Costs	$4,000,000
Steam Costs	$900,000
Lignin Sales	-$5,600,000
By-products and credits	$900,000
Capital Depreciation	$3,100,000
Average Income Tax	$1,100,000
Average Return on Investment	$9,000,000
	$32,100,000

Revenue ($/yr)	
Ethanol	$29,300,000
Electricity	$4,600,000
	$33,900,000

Appendix E

Financial Analysis Summary
Enzymatic Hydrolysis System

AES Greenidge Co-Location Assessment -- Appendix E

Ethanol Production Process Engineering Analysis

Corn Stover Design Report Case: 2010 plant start-up

Dilute Acid Prehydrolysis with Enzymatic Hydrolysis

All Values in 2000$

(Denatured) Ethanol Selling Price	**$1.30**	
Ethanol Production (MM Gal. / Year)	**31.4**	Ethanol at 68°F
Ethanol Yield (Gal / Dry US Ton Feedstock)	89.7	
Feedstock Cost $/Dry US Ton	$35.70	
Internal Rate of Return (After-Tax)	**38%**	
Equity Percent of Total Investment	25%	

Capital Costs	
Feed Handling	$4,600,000
Pretreatment	$11,700,000
Neutralization/Conditioning	$4,900,000
Saccharification & Fermentation	$4,700,000
Distillation and Solids Recovery	$12,700,000
Wastewater Treatment	$2,100,000
Storage	$1,000,000
Boiler/Turbogenerator	$0
Utilities	$2,900,000
Total Equipment Cost	$44,600,000
Added Costs	$20,400,000
(% of TPI)	31%
Total Project Investment	$ 65,000,000
Loan Rate	8.0%
Term (years)	15
Capital Charge Factor	0.322
Denatured Fuel Prod. (MMgal / yr)	32.9
Denatured Fuel Min. Sales Price	$1.27
Denaturant Cost ($/gal denaturant)	$0.555
Theoretical Yields	Ethanol
	MM Gal/year
Total Maximum (MM Gal/yr)	39.5
Maximum Yield (Gal/ton)	112.7
Current Yield (Actual/Theor)	79.6%

Operating Costs (cents/gal ethanol)	
Feedstock	39.8
Biomass to Boiler	0.0
CSL	2.8
Cellulase	10.1
Other Raw Materials	6.7
Electricity	8.1
Fixed Costs	10.2
Steam Costs	2.0
Lignin Sales	-12.6
By-products and credits	-3.7
Capital Depreciation	10.5
Average Income Tax	8.3
Average Return on Investment	47.8

Operating Costs ($/yr)	
Feedstock	$12,500,000
Biomass to Boiler	$0
CSL	$900,000
Cellulase	$3,200,000
Other Raw Matl. Costs	$2,100,000
Electricity	$2,500,000
Fixed Costs	$3,200,000
Steam Costs	$600,000
Lignin Sales	-$4,000,000
By-products and credits	-$1,100,000
Capital Depreciation	$3,300,000
Average Income Tax	$2,600,000
Average Return on Investment	$15,000,000

Plant Electricity Use (KWH/gal)	2.01
Plant Steam Use (kg steam/gal)	16.6
Boiler Feed -- LHV (Btu/lb)	2,862
Boiler Feed -- Water Fraction	0.519

Appendix F

Inputs for Income and Jobs Analyses

- **Enzymatic**
- **Two-Stage Dilute Acid**

Enzymatic Hydrolysis – Input Data for Jobs & Income Analysis

STATE INPUT DATA		INPUT NOTES
	Enter year 2000 dollars	**Notes on Entries in Column B**
Ethanol Facility Name	AES Greenidge	Enter Facility name for reference purposes
Facility Type	Stover - Enzymatic Hyd.	Enter short descriptor of facility (eg. Corn Dry Mill , Wood or MSW for information purposes.
State in current run (Use two letter state code in caps)	NY	Enter the state code for any one of the five states ME, NH, NJ, NY, PA
Number of ethanol plants in this model	1	Number of plants for information purposes only.(Usually 1)
Nominal total ethanol production capacity (gal/yr)	31,400,000	Enter the production capacity gal/yr
Total ethanol production (gal/yr)	31,400,000	Enter the expected annual production used for the calculation in gal/yr
Total grain feedstock use (bushels/yr)	0	Enter the expected annual grain feedstock use in bushels/yr
Total cellulosic or other feedstock (ton/yr)	350,000	Enter the expected annual wood or other cellulosic feedstock use in dry tons/yr
Construction Phase		
Construction (including contract labor) costs	**$ Cost**	Total Construction Phase e
Engineering, design & permitting costs	$10,482,533	Enter total cost of labor and materials for engineering, design and permitting
Equipment and materials (purchased)	$44,381,974	Enter the total purchase price of equipment boilers, pipes, tanks, pumps etc.
Construction (on site work)	$9,869,730	Enter the total contact for on site construction work site preparation concrete etc .
Total construction cost	**$64,734,237**	No entry will sum automatically.
Operations Phase		
Plant Operation and Maintenance	**Annual$ cost**	**Annual costs**
		Notes on Entries in Column B
Harvested corn stover purchase	$12,500,000	Enter the total annual cost of harvested corn stover feedstock
Waste material feedstock		Enter the total annual cost of wood waste, other cellulose waste or MSW
Corn Steep Liquor purchase	$880,000	Enter the total annual cost of corn or other grain feedstock
Natural gas purchase		Enter annual cost of natural gas purchases
Fuel oil purchase		Enter annual cost of fuel oil purchases
Steam purchase	$630,000	Enter annual cost of steam purchases
Electric power purchase	$2,300,000	Enter annual cost of electric purchases
Repairs & maintenance	$1,849,758	Enter annual repair and maintenance contract costs and materials

Chemicals and supplies	$4,920,000	Enter annual cost of chemicals & enzymes used
Other operating costs (credits for lignin, CO2, etc)	($8,450,000)	Enter other annual operating costs, minor supplies not elsewhere listed
Interest payments on debt (not equity)	$11,390,000	Enter annual Interest (not principal) payments of debt to in-state banks. Not dividends on equity.
Property taxes & other local taxes or fees	$621,000	Enter annual taxes or other payments to municipalities. Not state or federal.
Insurance payments	$69,000	Enter all annual insurance payments on plant operations including vehicles owned.
Waste (ash) Disposal	$200,000	Enter annual total fees paid by plant for solid waste and/or sewage disposal.
Total operating costs (excluding direct labor)	**$26,909,758**	No entry will sum automatically.
Employment (direct hires)	**Direct Employees**	
Total direct employees	25	In C63 Enter number of direct hired plant employees & managers in state. Not contractors
Plant payroll	$1,190,000	Enter the total annual plant payroll and direct benefits for the employees entered in cell C61.
Proprietors income, dividend or profit	$16,200,000	Enter the annual owners income, dividends or profits paid to state residents only.
Total Operating Expenditure	**$44,299,783**	No entry will sum automatically.
Savings	**Annual $ Savings**	
Waste disposal cost savings		Enter the current annual cost of disposing of any waste material used as feedstock.
Displacement Effects	**Annual $ Cost**	
Displaced sales of gasoline		See Users Guide for full explanation. Probably zero for ME, NH, NJ, NY & PA.
Displaced sales of electricity		Enter current wholesale price paid for any electricity sales made by the plant.
Displaced waste disposal service fees		Enter current waste disposal costs displaced for material used as feedstock.
State tax revenue reduction		Enter annual reduction in state taxes from tax incentives or the amount of direct state payments

Two-Stage Dilute Acid Hydrolysis – Input Data for Jobs & Income Analysis

STATE INPUT DATA		**INPUT NOTES**
	Enter year 2000 dollars	**Notes on Entries in Column B**
Ethanol Facility Name	AES Greenidge	Enter Facility name for reference purposes
Facility Type	Stover - 2-Stage Dilute	Enter short descriptor of facility (eg. Corn Dry Mill , Wood or MSW for information purposes.
State in current run (Use two letter state code in caps)	NY	Enter the state code for any one of the five states ME, NH, NJ, NY, PA
Number of ethanol plants in this model	1	Number of plants for information purposes only.(Usually 1)
Nominal total ethanol production capacity (gal/yr)	23,600,000	Enter the production capacity gal/yr
Total ethanol production (gal/yr)	23,600,000	Enter the expected annual production used for the calculation in gal/yr
Total grain feedstock use (bushels/yr)	0	Enter the expected annual grain feedstock use in bushels/yr
Total cellulosic or other feedstock (ton/yr)	350,000	Enter the expected annual wood or other cellulosic feedstock use in dry tons/yr
Construction Phase		
Construction (including contract labor) costs	**$ Cost**	Total Construction Phase e
Engineering, design & permitting costs	$9,945,179	Enter total cost of labor and materials for engineering, design and permitting
Equipment and materials (purchased)	$42,531,180	Enter the total purchase price of equipment boilers, pipes, tanks, pumps etc.
Construction (on site work)	$8,939,483	Enter the total contact for on site construction work site preparation concrete etc .
Total construction cost	**$61,415,841**	No entry will sum automatically.
Operations Phase		
Plant Operation and Maintenance	**Annual$ cost**	**Annual costs**
		Notes on Entries in Column B
Harvested corn stover purchase	$12,500,000	Enter the total annual cost of harvested ~~wood~~ corn stover feedstock
Waste material feedstock		Enter the total annual cost of wood waste, other cellulose waste or MSW
Corn Steep Liquor purchase	$330,000	Enter the total annual cost of corn or other grain feedstock
Natural gas purchase		Enter annual cost of natural gas purchases
Fuel oil purchase	$910,000	Enter annual cost of fuel oil purchases
Steam purchase	$870,000	Enter annual cost of stem purchases
Electric power purchase	$2,700,000	Enter annual cost of electric purchases
Repairs & maintenance	$2,114,351	Enter annual repair and maintenance contract costs and materials

Chemicals and supplies	$1,138,717	Enter annual cost of chemicals & enzymes used
Other operating costs (credits for lignin, CO2, etc)	($8,340,000)	Enter other annual operating costs, minor supplies not elsewhere listed
Interest payments on debt (not equity)	$10,809,188	Enter annual Interest (not principal) payments of debt to in-state banks. Not dividends on equity.
Property taxes & other local taxes or fees	$581,597	Enter annual taxes or other payments to municipalities. Not state or federal.
Insurance payments	$72,691	Enter all annual insurance payments on plant operations including vehicles owned.
Waste (ash) Disposal	$380,000	Enter annual total fees paid by plant for solid waste and/or sewage disposal.
Total operating costs (excluding direct labor)	**$24,066,545**	No entry will sum automatically.
Employment (direct hires)	**Direct Employees**	
Total direct employees	25	In C63 Enter number of direct hired plant employees & managers in state. Not contractors
Plant payroll	$1,360,000	Enter the total annual plant payroll and direct benefits for the employees entered in cell C61.
Proprietors income, dividend or profit	$11,000,000	Enter the annual owners income, dividends or profits paid to state residents only.
Total Operating Expenditure	**$36,426,570**	No entry will sum automatically.
Savings	**Annual $ Savings**	
Waste disposal cost savings		Enter the current annual cost of disposing of any waste material used as feedstock.
Displacement Effects	**Annual $ Cost**	
Displaced sales of gasoline		See Users Guide for full explanation. Probably zero for ME, NH, NJ, NY & PA.
Displaced sales of electricity		Enter current wholesale price paid for any electricity sales made by the plant.
Displaced waste disposal service fees		Enter current waste disposal costs displaced for material used as feedstock.
State tax revenue reduction		Enter annual reduction in state taxes from tax incentives or the amount of direct state payments

Appendix G

Economic Impact Results* from the "ORNL Report"

"Corn Stover to Ethanol: Macroeconomic Impacts Resulting from Industrial establishment" (revised 2001), originally published in the proceedings of the Bioenergy 2000 Conference, Oct. 15-19, 2000, in Buffalo, NY; by M. Walsh, B. English, J. Menard, C. Brandt, R. Wooley, A. Turhollow, and D. de la Torre Ugarte

[*Unlike the results shown in Table 6.2, in the body of the Task 6 report, the following results have not been modified with a scaling factor; they are the results for facilities sized to process 2,000 metric tons per day of corn stover.]

Economic Impact Results* from the "ORNL Report"

	One-time only construction			Annual combined industrial, agricultural, and transportation		
	Total Industry Output (million $)	Employ-ment (jobs)	Total Value Added (million $)	Total Industry Output (million $)	Employ-ment (jobs)	Total Value Added (million $)
Illinois	349.6	3,066	180.2	173.7	1,289	81.1
Indiana	315.7	3,084	141.3	160.6	1,323	69.9
Iowa	304.4	3,128	141.6	144.2	1,165	56.2
Kansas	322	3,335	149.1	203.4	1,872	89.8
Minnesota	334.8	3,220	159.3	157.3	1,266	63.2
Missouri	344.3	3,489	160.5	211.3	2,107	103.6
Nebraska	313.4	3,333	140	150.7	1,261	59.4
Ohio	300.3	2,820	137.2	165.2	1,351	70.3
South Dakota	297.2	3,224	125.8	140.8	1,104	45.4
Wisconsin	329.8	3,357	125.8	164.2	1,508	66.5
TOTAL	3211.5	32,056	1491.5	1671.3	14,246	705.5

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