

FINANCIAL FEASIBILITY AND REGIONAL ECONOMIC IMPACTS: THREE CASE STUDIES IN U.S. BIOPOWER

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ABSTRACT

Four arguments are commonly provided by renewable energy advocates: environmental benefits, energy security, positive regional economic impacts, and, more recently, with the increase in costs of fossil fuels, cost savings. This article presents evidence on the cost savings, financial feasibility and regional economic impacts of three case studies in U.S. biopower: an anaerobic biodigester in Minnesota, a landfill gas power facility in Kentucky, and a proposed biomass direct fire plant in Missouri. These cases illustrate the potential for financial and economic benefits in a multi-technology and multi-state study while demonstrating the use of an optimization model which will benefit proposed biopower projects entering the commercialization stage.

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INTRODUCTION

There are various arguments supporting the benefits of renewable energy such as biopower from agricultural and landfill waste sources. These include the arguments that biopower can have local and global environmental benefits, that biopower production can contribute to energy security, that biopower production can have significant rural economic growth impacts, and, finally, that biopower saves money and is financially feasible.

This article examines the last two arguments, regional economic impacts and financial feasibility, in detail, with three case studies that are representative of different technologies and fuels that are currently under consideration in the expanding biopower industry. Financial feasibility and cost savings as well as regional economic impacts are identified for the three case studies: an anaerobic digester in Minnesota, a landfill gas power plant in Kentucky, and a biomass direct fire plant in Missouri. The first two cases represent recently built facilities while the Missouri plant is under consideration.

The main methodology in this analysis is a combined linear programming, input-output spreadsheet model called the University of Missouri Biopower Toolkit (Johnson, Badger, Orr, and Altman, 2006). The linear programming component uses the Microsoft Excel LP add-in to find a mix of biofuel types and sources that minimizes costs. The program allows for up to 200 different fuel-distance combinations (for example, 10 types of fuel at 20 different distances). The model includes default data on 19 different biofuels (crop and forest residues, waste streams, and dedicated biomass crops). Default data includes energy contents, ash content, and several other critical values. The user may override these default values or add new biofuels to the model.

The regional impact component includes state-level multipliers from the Bureau of Economic Analysis' RIMS II input-output systems. The impact component uses information on transportation costs, biofuel costs, operating costs, and electricity cost savings to calculate the local economic impacts of substituting biopower for power generated from coal or natural gas.

The calculator also estimates reductions in nitrous oxides, sulfur oxides, and carbon dioxide gas emissions. It allows for various revenue streams, including green tags, subsidies, sale of excess steam, tipping fees, and sale of organic ash. It calculates various financial indicators, such as repayment period and internal rate of return, and allows sensitivity analyses of key variables.

The Biopower Toolkit¹ was produced on behalf of the National Rural Electric Cooperative Association's Cooperative Research Network. It is designed to determine the cost-minimizing fuel sources (when applicable) and calculate financial variables such as the internal rate of return and investment payback period and regional impacts based on multipliers from the Bureau of Economic Analysis (BEA). The remainder of this article presents background, technology and results for the three case studies. Results are generally encouraging, showing a positive internal rate of return for the two case studies on the existing biopower facilities, and a range from positive to negative for the Missouri biopower plant depending on the specific assumptions made.

¹ The Biopower Toolkit and full description is available upon request. More information is available at <http://www.cpac.missouri.edu/>.

HAUBENSCHILD FARMS ANAEROBIC DIGESTER CASE

Background – Haubenschild Case

Haubenschild Farms Inc. is an 800-cow/1000-acre family owned and operated dairy farm. In September of 1999, the company installed a heated plug-flow anaerobic digester that produces biogas that is used to operate a 135-kW engine-generator. In 1999, the dairy operation was increased from 100 to 425 cows, and in 2001, it was further expanded to 800 cows. With the increase to 800 cows, the digester produces more biogas than is necessary to run the generator. The surplus gas is currently flared, although the expansion into another power generator was being considered (Lazarus and Rudstrom, 2003).

With the increase in the size of the dairy operation, odor control from manure handling might have been problematic for neighbors. The anaerobic digester was installed in order to address the need for odor control. Other benefits of the digester include water quality protection, greenhouse gas reduction and manure pathogen reduction, which, in turn, improves the quality of fertilizer produced (Nelson and Lamb, 2002).

Technology – Haubenschild Case

There are three standard designs of anaerobic digesters appropriate for on-farm use: lagoon covered digester, complete mix digester, and plug-flow digester. The plug-flow digester system was chosen for Haubenschild Farms. It is a relatively dry system with the best manure quality having 11% to 14% solid concentration. This compares to a covered lagoon digester with less than two percent solids and a complete mix digester with three to ten percent solids. The plug-flow system can then rely on a low water-use scraping technique for manure collection while the others require water-intensive flushing collection techniques (Nelson and Lamb, 2002).

Different stages of the plug-flow system include: manure collection, raw manure mixing, anaerobic digestion, electricity generation or gas utilization, and processed manure storage. After the collection stage, the mixing tank ensures a consistent manure quality. As new material is added to the digester tank, older material is pushed into the storage tank.

The digester is a 350,000-gallon concrete tank installed underground. In the digester, the bacteria break down the manure under anaerobic (oxygen-free) conditions. The gas produced is 55% to 70% methane, which is used as fuel by the engine-generator. The generator burns about 70,000 cubic feet of biogas per day. In the final stage, the digested manure slurry is stored in a lined storage pond before being used or sold as fertilizer for crop production (Nelson and Lamb, 2002).

Economic Analysis and Results – Haubenschild Case

Like any energy production system, costs include capital costs, operation and maintenance costs, fuel costs, and interest costs. Capital costs for installation of the digester and generator totaled \$355,000. Of this, \$150,000 was provided by the Minnesota Department of

Agriculture. The AgSTAR² program provided an additional \$40,000 worth of technical assistance. The Federal Departments of Energy and Agriculture and the Environmental Protection Agency jointly fund the AgSTAR program. The Minnesota Office of Environmental Assistance and the Minnesota Department of Commerce awarded grants of \$37,500 and \$50,000, respectively. Haubenschild Farms provided approximately 22% in equity for their bioenergy expansion. Together these grants significantly improve the financial feasibility of the project for Haubenschild Farms. Other farms may find it necessary to provide more equity if no-interest loans, government grants, and free technical assistance are not available to them.

Lazarus and Rudstrom (2003) calculate actual operation and maintenance costs to be \$0.0144 per kilowatt-hour (kWh). The current study uses a slightly more conservative estimate of \$0.015/kWh as reported by Ross and Walsh (1996) and used by Nelson and Lamb (2002). Lazarus and Rudstrom (2003) also project a reduction to \$0.0123/kWh once the technology is past the demonstration phase, since some labor costs are due to time devoted to tours of the facility for interested groups. They assumed that unforeseen maintenance is more likely as the equipment ages, which would offset any reduction in time spent giving demonstrations. Thus the \$0.015/kWh remains constant.

The final costs to consider are fuel costs. Fuel costs for Haubenschild Farms are assumed to be nil since transportation and outside fuel sources are not expected to be used. Smaller scale dairy operations may incur fuel costs if they require manure from outside sources to keep their generator running at optimum scale. On the other hand, it is possible that tipping fees could be earned for accepting certain other materials.

Revenues are from the sale of electricity and savings from heat generation. The captured heat is used in the digestion phase and as space heat for the barns. The electricity price of \$0.073/kWh was negotiated with East Central Electric as their avoided cost. This is a very favorable rate since other non-utility power producers tend to get a much smaller price, in the \$0.02-\$0.03/kWh range (Lazarus and Rudstrom, 2003). Total revenue from biopower generation would also include the \$4,000 annual benefit from heat generation. Assuming total electricity production of 1,071 megawatt-hours (MWh) per year, Table I summarizes the main costs and revenues.

Table I. Habenschild Farms Biopower Costs and Revenues

Description	Amount
Total Capital Costs	\$355,000
Operation and Maintenance Costs	\$16,066/year
Sales from Electricity	\$78,186/year
Heat Cost Avoided	\$4,000/year

The University of Missouri biopower calculator estimates five financial indicators relevant to this case. These indicators include: gross margin (total revenues less costs other than capital costs), net margin (total revenue less all costs, including an assumed 5% interest charge on the entire investment),³ internal rate of return on investments,⁴ discounted capital

² See www.epa.gov/agstar/.

³ This calculation is made despite the fact that little or no interest was paid on this investment. This calculation is made to provide a more generic conclusion about the feasibility of the project. This, in effect,

recovery period (in months),⁵ and cost of electricity production (cents/ kWh). All of these indicators demonstrate the financial success of the Haubenschild Farms biopower operation, the successful use of the biopower calculator and possibilities for future applications. Table II presents the financial indicators.

Table II. Haubenschild Farms Financial Indicators

Indicator	Amount
Gross Margin	\$66,120
Net Margin	\$48,370*
Internal Rate of Return	18.63%
Discounted Capital Recovery Period (months)	57
Cost of Electricity Production (cents/kWh)	3.157*

*Assuming 5% rate of interest

These financial indicators imply the financial success of the Haubenschild Farms biopower operations. Gross margin and net margin of \$66,120 and \$48,370 are fairly attractive and imply an internal rate of return of 18.63% and a capital pay back period of 57 months (four years and nine months). The cost of electricity, \$0.03157/kWh, is also fairly low for renewable energy.

However, there is one important caveat for the indicators supporting future anaerobic digester biopower projects. Haubenschild Farms negotiated a very favorable price for their electricity. The assumed price of \$0.073 used for this financial feasibility study is very generous, and may not be available to future facilities. In addition, the zero interest loans and grants available to this project were not assumed in the calculation of financial indicators. New anaerobic projects should plan on paying higher cost debt or on covering a higher proportion of capital costs with equity.

The financial indicators in this article are comparable with calculations by both Nelson and Lamb (2002) and Lazarus and Rudstrom (2003). Nelson and Lamb report a payback time of five years and Lazarus and Rudstrom report a payback time of four years and an internal rate of return of 20%. Slightly different assumptions may account for these differences.

The state level economic impacts are also calculated. Although the impacts are relatively small, it must be restated that these are the impacts from a single dairy farm's investment into one anaerobic digester. Table III summarizes the economic impact estimates.

charges the investment's opportunity cost to all participants in the project. If the interest rate is assumed to be zero instead, the net and gross returns are equal.

⁴ The internal rate of return (IRR) is the implicit interest earned on the entire investment. If the project had been charged this IRR, then the net margin would be zero. Since 36% of this investment consisted of grants and free technical assistance, the actual return on the invested capital was significantly higher than reported here. This higher IRR can be easily calculated by reducing the capital costs in the biopower calculator by the amount of grants and free technical assistance.

⁵ As in the case of other financial indicators, this calculation is made assuming that all capital costs are being repaid. The calculator can be used to determine the recovery period of the repayable investment only by reducing the capital costs by the amount of grants and free technical assistance.

Table III. Economic Impacts of Biopower Production

Impact	Amount
Increase in State Output	\$101,030
Increase in Personal Income	\$78,301
Increase in Jobs	1

The biopower calculator estimates statewide economic impacts of the biopower component of the farm to be \$101,000 in total output, including all economic sectors. The personal income increase is estimated to be \$78,301 and the employment impact is an increase of one job. In all cases here, the increase in jobs is related to the change in sectoral activity to produce the inputs, transportation and income. All of these changes are included in the increase in jobs. In the Haubenschild case, because of ownership and its linkages with the local economy, much of this positive economic impact will occur in the local economy.

EAST KENTUCKY POWER COOPERATIVE LANDFILL GAS CASE

Background – East Kentucky Power Cooperative Case

East Kentucky Power Cooperative (EKPC) is a generation and transmission (G&T) cooperative with 16 member distribution cooperatives in the Eastern two-thirds of Kentucky. In the fall of 2003, EKPC commenced production of electricity from landfill gas at three locations. These plants, operating on a reciprocating engine technology, are located at the Bavarian Landfill in Boone County, the Laurel Ridge Landfill in Laurel County, and the Green Valley Landfill in Greenup County. The facilities' current capacity is 8.8 MW with expected capacity to reach 10.4 MW. This is enough electricity to serve about 7,000 homes (East Kentucky Power Cooperative, 2003). The three EKPC plants required an investment of \$12 million or about \$1,200/kW of installed capacity.

Using the reciprocating engine technology, it takes 12 million BTUs to produce a megawatt-hour of electricity. The current estimated production capacity of these plants is between 2.4 MW and 3.2 MW. Future capacity is expected to increase to between 3.2 MW and 4 MW.

While a block of 100-kilowatt hours would normally cost \$6 at the retail level, people who voluntarily enroll in Envirowatts, EKPC's green energy program, pay \$8.75. The additional revenue helps defray the costs of educating the members and marketing the product.

Technology – East Kentucky Power Cooperative Case

EKPC uses a reciprocating engine generation technology provided by Caterpillar Model 3516 LE (low emission) engines. This technology is specified to operate from gas with low methane concentration that is normally received from landfill gas. There is a minimum amount of pretreatment necessary for the gas, which includes condensate removal with

knock-out tanks, compression of the gas and subsequent cooling, removing more moisture, and a filter on the gas compressor skid (Tyree, 2005).

The gas is purchased from the landfill owners by Gas Purchase Agreements and Site Leases. EKPC has exclusive rights to the gas but can refuse excess gas production, at which time the landfill owner may sell the excess gas to other buyers. The gas is captured by the landfill owners as mandated by Title V of the Clean Air Act and the gas purchased provides the landfill owners with revenue and an alternative to flaring the gas. This environmental obligation makes the gas collection system a sunk cost, which also helps with financial feasibility.

The three generating facilities will have a combined capacity of 10.4 MW. Current capacity is 3.2 MW for each plant at the Laurel Ridge and Bavarian land fills and 2.4 at the Green Valley Landfill for a total of 8.8 MW. It is expected that 0.8 MW will be added to Green Valley and Laurel Ridge to reach their installed capacity. In the scenario for this report we assume (based on estimates from EKPC) that the three plants will generate 73,233.6 MWh per year. This is about 95% of the capacity rating of 8.8 MW. The first year of operation showed that a 95% capacity is easily attainable since one plant operated at 98%. The two other plants operated around 80% capacity for some initial months because of gas flow problems (Tyree, 2005).

The Caterpillar Model 3516 LE reciprocating engine technology employed in these plants requires 12 million BTUs to produce a megawatt hour of electricity. Thus in order to produce 73,233.6 MWh per year, these plants will consume 878,803 million BTUs of methane per year.

Economic Analysis and Results – East Kentucky Power Cooperative Case

Capital costs for installation of the generators were \$4,000,000 each, or about \$1,200/kW installed, for a total of \$12,000,000. EKPC used general funds to finance the project while preparing a loan package for reimbursement from the United States Department of Agriculture's Rural Utilities Services. The loan financed 100% of the \$12,000,000 capital costs.

The second type of costs is operation and maintenance. Based on information provided from EKPC, total annual operating costs are assumed to be \$651,276. Interest expenses are \$619,575 and depreciation costs account for another \$638,000 per year.

The final category of costs is fuel costs. Fuel costs in this case are reported to be \$281,000 per year. This payment goes to the county to offset some of its costs of building the methane collection and delivery infrastructure or to add to their general revenues.

Total revenue is from the sale of electricity to member cooperatives. EKPC reports total revenues of \$2,190,000, which is a wholesale price of 2.99 cents per kWh (\$2.99 per 100 kWh). We will assume 3 cents per kWh in this scenario. Future wholesale price may be in the 3.5 cent per kWh range. There is also the possibility that EKPC will receive a portion of the green power incentive payments. The results reported here do not include revenue from green power premiums.

The electricity from the landfill plants is then distributed and sold by one of the 16 member distribution cooperatives involved in the project. The standard retail electric rate is about \$6 per 100 kilowatt hours, but EKPC has instituted a green energy program called EnviroWatts which encourages customers to voluntarily pay a premium of \$2.75 per 100

kilowatt hours. The average EnviroWatts customer buys two 100-kilowatt-hour blocks of green power, plus 800 kilowatts at the standard price. This revenue is divided between EKPC and their member distributing cooperatives that participate in the EnviroWatts program. Table IV presents the costs and revenues for the EKPC case.

Table IV. EKPC Biopower Costs and Revenues

Description	Amount
Total Capital Costs	\$12,000,000
Operation and Maintenance Costs	\$651,276/year
Depreciation	\$638,000/year
Fuel Costs	\$281,000/year
Interest Expenses	\$619,575/ year
Sales from Electricity	\$2,190,000/year

Again, the University of Missouri biopower calculator estimates gross margins (total revenues less costs other than capital costs); net margins (total revenue less all costs), internal rate of return on investments, discounted capital recovery period (in months), and cost of electricity production (cents/kWh). All these factors demonstrate the financial viability of the EKPC biopower operation, and possible continued expansion of landfill methane power generation. Table V presents the financial indicators.

Table V. EKPC Financial Indicators

Indicator	Amount
Gross Margin	\$1,264,515
Net Margin	\$664,515
Internal Rate of Return	10.54%
Discounted Capital Recovery Period (months)	93
Cost of Electricity Production (cents/kWh)	2.093

These financial indicators imply the financial success of the current East Kentucky Power Cooperative's biopower operations. Gross and net margins of \$1,265,000 and \$665,000 respectively are very attractive and imply a reasonable internal rate of return of 10.54% and a capital pay back period of 93 months, or just less than eight years. It is estimated that the landfills will produce methane in sufficient quantities for 20 years

The state level economic impacts were also calculated and are reported in Table VI. The projected impacts are significant and reflect the fact that the fuel is locally produced and the expenditures for the methane stay in the community. This result assumes that the fuel being displaced does not have an impact on the economy, which in this case may not be true. If the landfill gas replaces in-state purchases of coal or natural gas, then these impacts are over stated. On the other hand, if the ultimate effect is to reduce dependence on imported energy, then these impacts are accurate. Furthermore, utilization of what is otherwise an environmental hazard will have benefits and impacts beyond those measured in this analysis.

Table VI. Economic Impact of Biopower Production – EKPC Case

Impact	Amount
Increase in State Output	\$3,375,953
Increase in Personal Income	\$922,717
Increase in Jobs	37

The biopower calculator estimated statewide economic impacts of the biopower component of the project to be \$3,376,000 in total output, including all economic sectors of the state. The impact on personal income is estimated to be \$923,000 and the employment impact estimate is an increase of 37 jobs, including those directly employed at the power plant.

CENTRAL ELECTRIC POWER COOPERATIVE CASE

Background- Central Electric Power Cooperative Case

Central Electric Power Cooperative (CEPC) is one of six generation and transmission rural electric cooperatives in Missouri that have combined to form Associated Electric Cooperative, Inc. (AECI). CEPC serves eight distribution cooperatives from Saline County, Missouri in the west to St. Charles County, Missouri in the east. In addition to electricity purchased from AECI, CEPC owns and operates the Chamois power plant that has a total nameplate generating capacity of 60 megawatts (MW). This case study considers the potential to retrofit the smaller of the two boiler plants at the Chamois facility to burn biomass fuels.

The current boiler is a Riley pulverized coal boiler that has been in service for 50 years providing 900°F steam at 900 pounds per square inch (psig) of pressure to produce 15 to 18 gross MW of electric power. Average production available for sale is 15 MW. Several aspects of electric generation technology, regulation, and marketing have changed since this unit was put into service. In the interest of providing the best future service to its owner-members, CEPC is considering the use of biomass fuels in a new boiler to provide this 15 to 18 MW of electric power.

The boiler was manufactured and sized to use high-BTU Illinois coal that has relatively high sulfur content. Illinois coal prices are increasing and switching to a low-BTU western coal source is not feasible since the size of the present firebox physically limits the amount of coal that can be burned. Likewise, biofuel, with its inherently lower energy density, will require a new combustion system. As the generator system is still quite serviceable, this presents a unique opportunity to partially convert to renewable electricity while incurring only the costs of a new boiler and fuel handling system. Since the boiler is now 50 years old, a plan for replacing it is needed in any event.

A biomass-fueled boiler offers certain opportunities not available with a coal- or gas-fired unit. Sulfur oxide emissions should be noticeably reduced over a coal fuel unit. Premium pricing may be realized for this “green” energy. New local jobs can be created to harvest and transport fuel to the generation facility. And, should a renewable portfolio

standard be implemented at either the state or national level, CEPC would be positioned to meet those standards and perhaps provide a portion of their renewable generation as a premium product to another utility.

Technology – Central Electric Power Cooperative Case

In order to accommodate a variety of solid fuels, CEPC requested an investigation of fluidized bed combustion technology to replace the existing pulverized coal boiler. The project team investigated existing vendors of this technology and received a budget proposal from Energy Products of Idaho (EPI) that is being used as a basis for further analyses in this pre-feasibility study report.

EPI was formed in 1973 and initially concentrated on designing systems that could convert sawmill wastes into usable energy rather than simply incinerating or burying these wastes. Over the last 20 years EPI has continued to expand and improve the scope of their installations, including both combustion and gasification systems. Over 80 of their systems are in operation in North America, Europe, and Asia. They accommodate a wide variety of fuels including sewage sludge, wood waste, urban demolition waste, hay, and agricultural wastes, such as grain straw.

We also analyze an alternative scenario. A proposal received from McBurney Boiler Systems of Norcross, Georgia is used in this scenario, and the assumed fuel prices remain the same. The 160,000 lb/hr steam boiler, rated at 1,250 psig and 900°F using 55% moisture wood waste, is capable of generating an 18 MW gross electricity output with a net of 16.4 MW. The capital cost of \$14.7 million was calculated by adding the \$7.5 million boiler island budget to the \$2.0 million estimate for fuel handling and storage systems, plus \$1.7 million estimated by the vendor for additional on-site construction and materials, \$1.25 million for controls, \$1 million for a fly ash silo, and \$1.25 million for Unit 1 demolition and asbestos disposal.

Economic Analysis and Results – Central Electric Power Cooperative Case

This economic analysis compares the internal rate of return under two different scenarios. Table VII presents the assumptions for the scenarios. The fluidized bed technology from EPI is referred to as the base scenario while the scenario involving the McBurney technology is referred to as the alternative scenario.⁶

Given these assumptions, the five financial indicators were calculated using the University of Missouri biopower calculator. The base case revealed a negative internal rate of return of -13%, making it financially nonviable. The alternative case had an internal rate of return of 5.4%, implying that if lower capital and operating costs, revenue from a tipping fee for ash disposal, and green energy credits of \$0.025 can be achieved, then adopting this technology should be considered. Table VIII presents the financial indicators for the two scenarios.

⁶ With both technologies, financing costs are unknown, thus 5% financing costs are assumed.

Table VII. Central Electric Power Cooperative Case – Scenario Assumptions

	Alternative Scenario (18 MW Gross)	Base Scenario (18 MW Gross)
Capital Cost	\$14,700,000	\$19,700,000
Electricity Generated Annually (MWh)	128,893	128,893
Operation and Maintenance Cost Annually	\$1,530,000	\$1,650,000
Electric Price (Wholesale + Premium) (per kWh)	\$0.032	\$0.032
Hay Price (per ton)	\$30	\$30
Crop Residue Price (per ton)	\$30	\$30
Wood Residue Price (per ton)	\$10	\$10
Availability of Biofuels	25%	25%
Cost of Ash Disposal (per ton)	-\$1 (Now a <u>negative</u> cost)	\$5
Biomass Transportation Cost (per ton-mile)	\$0.10	\$0.10
Green Energy Credits (per kWh)	\$0.025	0

Table VIII. CEPC Financial Indicators

Indicator	Base Scenario	Alternative Scenario
Gross Margin	-\$2,576,673	\$804,167
Net Margin	-\$3,561,673	\$69,167
Internal Rate of Return	-13.08%	5.57%
Discounted Capital Recovery Period (months)	n/a	156
Cost of Electricity Production (cents/kWh)	5.9	5.6

State wide economic impacts were calculated for the alternative scenario and revealed that state output would be increased by almost \$15 million and personal income by \$3.6 million. The project would lead to an increase of 131 jobs to Missouri's economy. Table IX summarizes these impacts.

Table IX. Economic Impact of Biopower Production – CECP Case

Impact	Amount
Increase in State Output	\$14,997,056
Increase in Personal Income	\$3,600,637
Increase in Jobs	131

CONCLUSIONS

This article analyzes three cases of biopower production on three different technologies. The economic analysis focuses on two aspects: financial feasibility and regional economic impacts. Results are calculated using a linear programming input-output tool, the University of Missouri biopower toolkit. Results indicate a generally positive view of biopower production. Two cases were analyzed where actual production data are used to calculate

financial indicators. Results from these two cases were very positive, yielding significantly positive internal rates of return of 18% for the Haubenschild biodigester case and 10.5% for the East Kentucky landfill gas cooperative case. The third case study projected the potential feasibility and impact of partially converting a coal-fired generator to biofuel. Two scenarios were analyzed for this third case with mixed results. One scenario generated a projected -13% internal rate of return while another scenario yielded a 5.4% return.

The three cases demonstrate the flexibility of the biopower calculator tool. In the first two cases, there were single captive fuel sources, while in the third case, the tool determined the cost-minimizing sources of fuels of several types and from a number of locations.

The case studies also demonstrate the range of impacts that biopower may generate from different sizes and types of facilities. Table X compares the economic impacts projected in the three cases.

Table X. A Comparison of Three Case Studies

	Habenschild Farms	East Kentucky Power Cooperative	Central Electric Power Cooperative
MWh	1,071	73,233	129,000
Jobs/1,000 MWh	.93	.51	1.02
Output/MWh	\$94.33	\$46.10	\$116.26
Income/MWh	\$72.91	\$12.60	\$27.91

The Habenschild Farm case is much larger than the others and has a larger absolute impact, but the impacts per unit of MWh are more comparable. Habenschild Farms produces more income per MWh, but this is because their capital costs were low and they are getting a high price for the electricity they generate. These advantages go straight into income rather than through the output of other sectors. The Kentucky landfill gas case is unusual in that the jobs, output, and income produced per MWh are all lower than in the other scenarios. This is largely because they do not have to buy their fuel. The Central Electric Power Cooperative generates less income per MWh than the others, because they are less profitable.

Extensive sensitivity analyses were conducted in each of the three case studies. Not surprisingly, the wholesale price of electricity is the most critical factor in the feasibility of biopower. Green tags and other complements to the wholesale price are thus important considerations in biopower projects. But feasibility was sensitive to other variables as well. The availability of biomass was important when it was collected from several sources (as in the case of the co-fire case study). We found ample supplies of biomass to make the plant feasible, if sufficient portions of this were made available to the power generators. Thus the development of efficient markets for biomass is essential. The capital costs obviously influence the rate of return generated by a biopower project, but the feasibility was not particularly sensitive to these costs.

Green credits and related incentives are another area that may influence financial feasibility. In this paper, East Kentucky Power Cooperative did report revenue from such sources. The authors were unaware of additional potential green credit revenue for Habenschild Farms, although their operation received considerable support on the financing costs side. The most realistic assumptions were made for the Central Electric Power Cooperative. No generous green credits or financing support were assumed for that potential biopower case.

In general, we conclude the biopower has real potential both from the narrower financial feasibility perspective and from the broader economic development perspective. Feasibility depends largely on three factors. In order of importance, these factors are: the capital costs of biopower facilities, the transportation costs involved in procuring the biomass, and the price of electricity generated.

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