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Southeastern Regional Biomass Energy Program

Feasibility Study of Wood-Fired Cogeneration At A Wood Products Industrial Park-Phase II

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FEASIBILITY STUDY OF WOOD-FIRED COGENERATION AT A WOOD PRODUCTS INDUSTRIAL PARK BELINGTON, WV

Phase II

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INTRODUCTION

Customarily, electricity is generated in a utility power plant while thermal energy is generated in a heating/cooling plant; the electricity produced at the power plant is transmitted to the heating/cooling plant to power equipment, as shown in Figures 1a and 1b (30). These two separate systems waste vast amounts of heat and result in individual efficiencies of about 35%.

Cogeneration is the sequential production of power (electrical or mechanical) and thermal energy (process steam, hot/chilled water) from a single power source; the reject heat of one process is used as input into the subsequent process (14,19). Cogeneration increases the efficiency of these stand-alone systems by producing these two products sequentially at one location using a small additional amount of fuel, rendering the system efficiency greater than 70% (2). Figure 2 illustrates a typical cogeneration system (30).

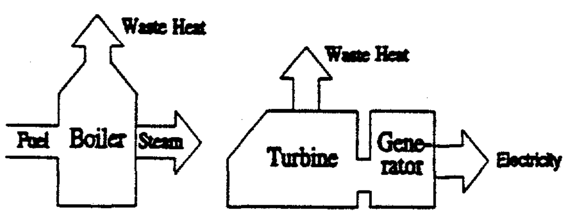

Figure 1a. Utility power plant without cogeneration.

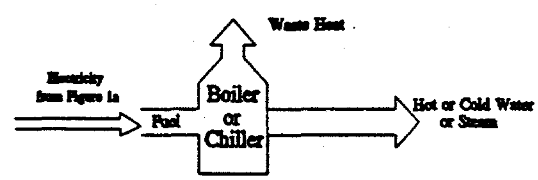

Figure 1b. Heating/cooling plant without cogeneration.

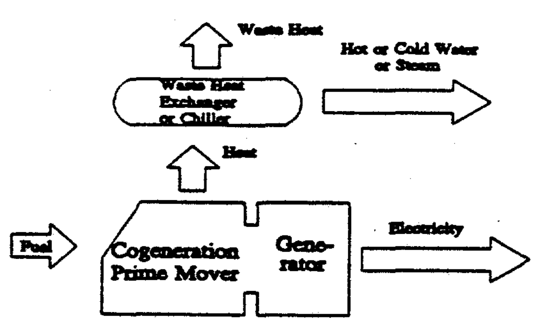

Figure 2. Cogeneration power plant.

A comparison between the energy requirements of two stand-alone plants versus one cogeneration plant can be made to illustrate the energy savings. A stand-alone electric utility uses the equivalent of 1 barrel of oil to produce 600 kWh of electricity, a stand alone steam-generating plant uses the equivalent of approximately 2.25 barrels to produce 8,500 pounds of process steam; total fuel consumed is 3.25 barrels. A cogeneration plant would use about 2.75 barrels to produce both 600 kWh and 8,500 pounds of steam resulting in a savings of 1/2 barrel of oil, or 15% (19).

Although a cogeneration system requires an initial outlay of capital, it can provide many long-term financial benefits. Cogeneration provides savings to the user in the form of energy that would otherwise need to be purchased from the utility. In addition, energy produced by cogeneration at the site where it will be used provides the user with a certainty that cost of energy produced will remain stable in the event of a utility rate increase. A cogeneration system also ensures that energy will be provided in case of a utility outage.

Aside from financial benefits to the user, environmental benefits can also be realized in the form of energy efficiency. In addition, if sources of energy such as geothermal, wind, solar, or biomass are used in place of fossil fuels, less SO_2, a contributor to global warming, is emitted (5).

Cogeneration Technologies as Applied to Wood-Fired Systems

Cogeneration plants have integrated equipment systems which convert energy in several different steps. Wood-fired systems include fuel systems, energy conversion systems, electrical generating systems, and environmental systems. A fuel system transports and processes the wood from its original form to the energy conversion system. The conversion system first converts the potential energy in the fuel to thermal energy then into steam to be used by a mechanical process, space heating, or a process, such as a dry kiln. This system also converts steam that is not used into mechanical energy. The electrical generating system then converts the mechanical energy into electrical energy. Figure 3 is a configuration of a typical cogeneration plant showing these systems (33).

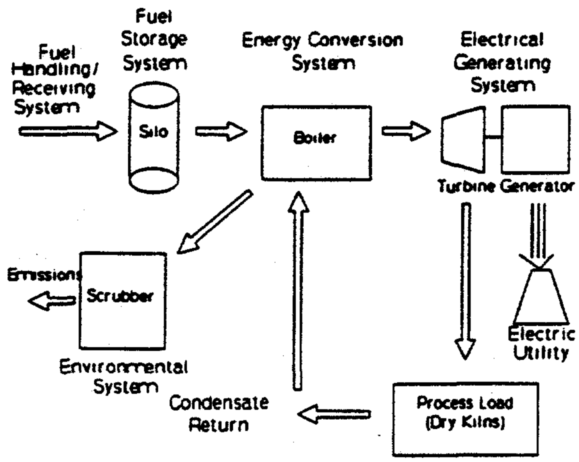

Figure 3. Configuration of systems in a wood-fired cogeneration plant.

Topping and Bottoming Cycles

Cogeneration facilities have two basic cycles: topping and bottoming. In a topping cycle, electricity is the primary product; the reject heat is used as process steam for kiln drying, water heating, or space heating/cooling. In a bottoming cycle, high temperature steam is produced first for such processes as steel furnaces, glass kilns or aluminum furnaces; electricity is produced from the heat remaining in the steam after the process heat requirements are met (19,7). Even though this distinction exists, the system is most often referred to by the type of turbine used. Topping-cycle systems, used more often than bottoming-cycles, employ steam turbines, open-cycle and closed-cycle gas turbines, combined gas turbines/steam turbines, and diesel engine systems. Bottoming-cycle cogeneration technologies include steam turbines, gas turbines, and Rankine-cycle turbines. Steam turbines are the primary systems for cogenerating electricity and process steam (19,24).

Of the cogeneration technologies, only the steam turbine, closed-cycle gas turbine, and Stirling engine can be fired directly with wood fuel. Closed-cycle gas turbines are not commercially available in the U.S. but are widely used in Europe (19).

Wood as a Fuel

Wood residue (one form of biomass) is gaining favor as an alternative renewable energy; however, in West Virginia, wood as an energy source is substantially underutilized (1). Currently, wood energy makes up almost half of all domestic renewable energy sources, contributing an estimated 7,500 MW of capacity (25).

Types of Facilities

Cogeneration is a term often used in reference to various types of facilities. A cogeneration facility is one type of system that can be included under the general category of non-utility generation (NUG). Figure 4 shows the categories of facilities included under non-utility generation.

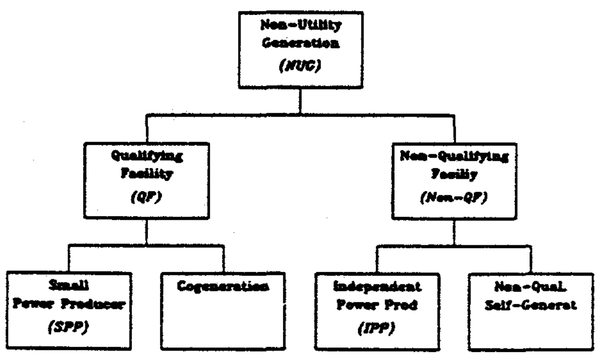

Figure 4. Types of non-utility generation.

Non-utility generation encompasses systems that generate electricity and are less than 50% utility owned. Included under NUGs are qualifying facilities (QFs) and non-qualifying facilities (Non-QFs) (18). Both cogeneration and small power production facilities are qualifying facilities; these will be discussed further in the next section.

Independent power production facilities (IPPs) and self-generation are included under non-qualifying facilities. Independent power producers are not restricted by the same criteria as QFs (size limitations, cogeneration requirements, and fuel constraints). However, an IPP is restricted under the regulatory limitations of the Public Utility Holding Company Act of 1935 (PUHCA), which limits the organizational structure and business practices of an IPP.[1] An IPP is also subject to state regulation and its transactions come under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The number of IPPs is increasing in areas where independent power production is welcome, especially where utilities are interested in obtaining over 50% ownership (prohibited under PURPA) (28).

Non-qualifying self-generation is on-site power production at a commercial or industrial facility with all the electric output being used internally; in this case, thermal energy may or may not be produced. There is a degree of overlap in Figure 4 in that self-generation may be not only a non-qualifying facility, but some cogeneration and SPP's may also be considered self-generation qualifying facilities (18).

Background

Federal Regulations

Decentralized energy systems have been employed by companies since the turn of the last century. In 1900, over 59% of total U.S. electrical generation capacity was located at industrial sites (22). However, beginning in the 1930's, improved economics of electric power generation, transmission and distribution, along with availability of inexpensive fuel, and regulatory barriers and constraints, contributed to the decline of onsite generation and cogeneration (7). By 1977, industrial self generation and cogeneration accounted for only 4% of total U.S. generation of electricity (27).

The 1973 Arab oil embargo prompted significant changes to the system of centralized generation of electricity. This led to the passage of the National Energy Act (NEA) of 1978, which attempted to resolve the economic and regulatory constraints to the use of cogeneration by industry. Specific to cogeneration in the NEA was the Public Utilities Regulatory Policies Act (PURPA). The intent of

[1] A controlling general partner of an IPP owning or controlling 10% or more of the voting securities of an electric utility would require that the IPP be classified as a holding company and therefore subject to PUHCA. Those companies registered under PUHCA experience restrictive financial and operational requirements.

PURPA was to encourage the development of cogeneration and small power production facilities without adversely affecting consumers of electricity who were not cogenerators (4).

Fundamental to PURPA are Sections 201 and 210. Section 201 distinguished between small power production (SPP) and cogeneration facilities as follows:

> A "'small power production facility' means a facility which (i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and (ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts."(35)
>
> A "'cogeneration facility' means a facility which produces electric energy, and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes."(36)

Either SPP's or cogeneration facilities can be qualifying facilities (QFs), as specified in Section 210. Application to become a QF is obtained through the FERC, which is also in charge of enforcing PURPA. Three criteria (an operating standard, an efficiency standard, and ownership criteria) must be met before a facility can become a QF and thereby receive the benefits as specified by PURPA.

The operating standard requires that a new topping cycle facility produce at least 5% of the total energy output as useful thermal energy. The efficiency standard (applicable only if oil or gas is used) requires that the annual power produced plus half the useful thermal energy must be at least 42.5% of the total energy input. The ownership criteria limits electric utility (or electric utility holding company) ownership to less than 50% (10).

State Regulations

Title 150, Legislative Rule, Public Service Commission § 150-3-12, "Cogeneration and small power production" contains State of West Virginia rules and regulations for these facilities; this section of the State of WV Agencies Rules and Regulations is attached as Appendix A.

The criteria of a public utility is found in WV Code § 24-2-1:

> "The test as to whether a person, firm or corporation is a public utility is the dedication or holding out, either express or implied that

such person firm or corporation is engaged in the business of supplying his or its product or services to the public as a class or any part of such public as distinguished from services to only particular individuals. ..."

Relationship of QF to Utility

As defined by PURPA, utilities pay the avoided cost rate for power sold to them by a QF. Avoided cost is what a utility would pay to produce that energy, and consists of a capacity credit and a fuel credit. Capacity credit is paid by utilities that need capacity while fuel credit is paid by all utilities, whether they need capacity or not. An IPP is an electric wholesale generator which is permitted under the Federal Power Act to charge market-based rates for the electricity generated (28).

Relationships between QF's and their local utilities differ throughout the country. Each utility calculates its own avoided cost rate. Some utilities that currently need, or anticipate a need for capacity have created subsidiaries to help finance cogeneration projects and actively seek new projects to help them meet capacity increases. Utilities that do not presently need or anticipate a need for additional capacity do not pay capacity credit.

Under PURPA, a utility must purchase excess power produced by a cogenerator within its area. However, if the utility does not require this power and the utility agrees, power may be wheeled to a neighboring utility; these types of agreements are common in the industry. No utility is forced to wheel. However, if a cogenerator is not a QF, then any agreement made between them and the utility is outside the scope of the FERC regulations (35).

Cogeneration as Applied to Industrial Parks

Although created primarily for individual users, cogeneration may also be applied to industrial parks (20). An advantage of this arrangement is that there is less impact on the power-generating system if one company changes its energy requirement or fuel supply. However, disadvantages include increased cost due to inclusion of different companies in the system and unresolved regulatory issues regarding cogeneration servicing a multi-company entity, such as an industrial park.

Belington Industrial Park

The Belington Industrial Park was selected for this study because it exhibits three key criteria which make cogeneration an attractive option: 1) some companies generate wood residue which may be used as fuel; 2) the dry kilns consume process steam on a 24-hour basis; and 3) the companies may be better able to combine equity to attract potential investors of a cogeneration system than a single company would.

The topographic map of Belington, along with its location in West Virginia is shown in Figure 5. The 74-acre Belington Industrial Park is located approximately 1.5 miles south of Belington in Barbour County, WV (Figure 6). All the companies in the park are either primary or secondary wood products firms. Three groups of companies were included in this study (*Phase II*) (Table 1): Group 1 comprised all companies presently located inside the park (# 1-7), Group 2 is made up of two companies presently constructing their plants in the park (#8,9), and Group 3 is an unoccupied building that presently houses two unused radiofrequency (RF) kilns (#10).

Water is available from the Tygart River approximately 2 miles from the plant. The City of Belington has a pumping capacity of 432,000 gallons/24 hours, with an excess capacity of 375,000 gallons/day. The sewage system in Belington has no excess capacity, but the town of Junior, located 2 miles south of Belington has excess capacity.

Phase I (Summary)[2]

The objective of *Phase I* was to utilize the wood residue produced in the industrial park. For *Phase I*, which was completed in February, 1991, data was collected from each company regarding the

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1 References to Phase I will be made throughout this report. The entire *Phase I* report is available from the Appalachian Hardwood Center upon request.

Figure 5. Location of Belington and Topographic Map.

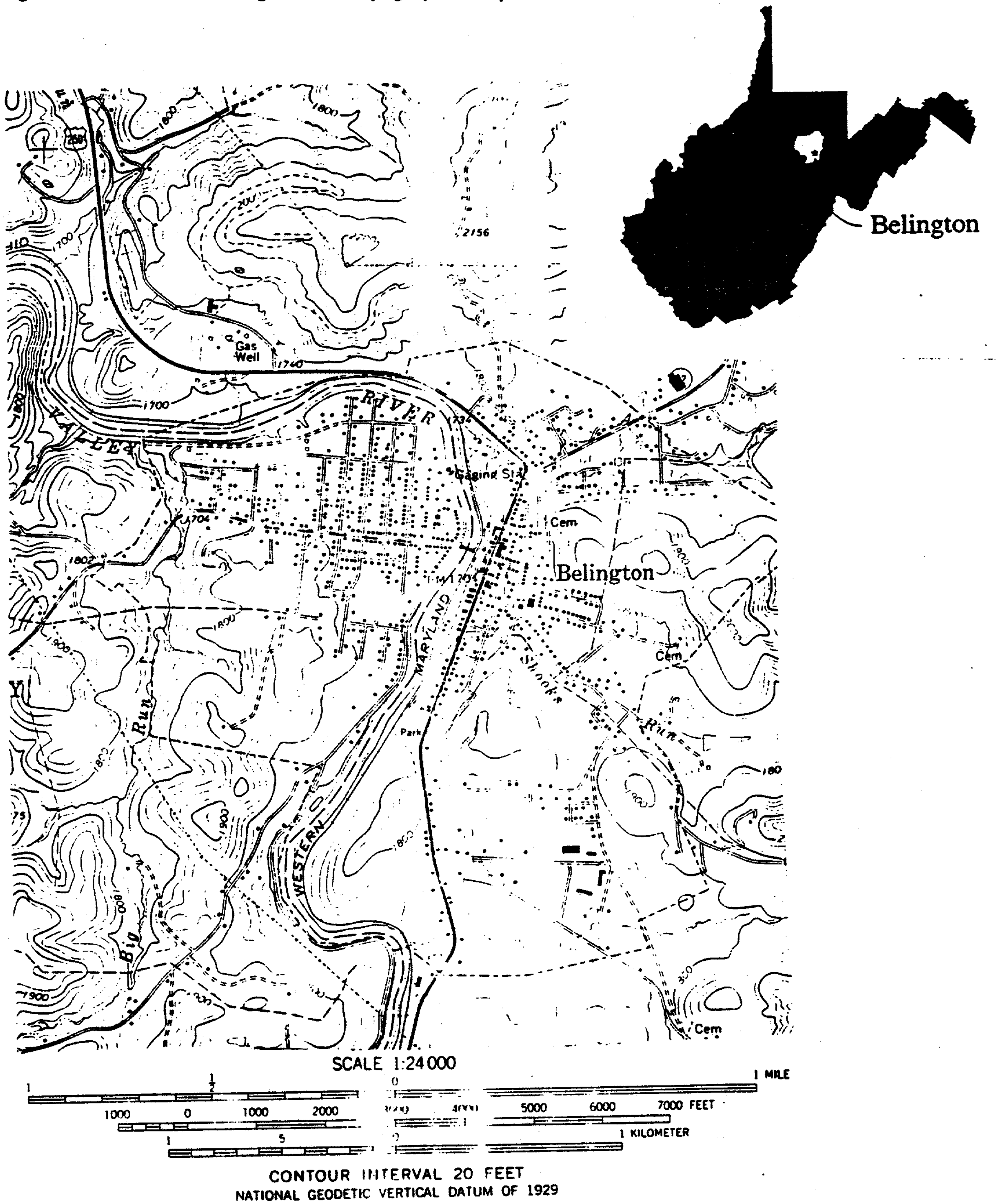


Figure 6. Belington Industrial Park.

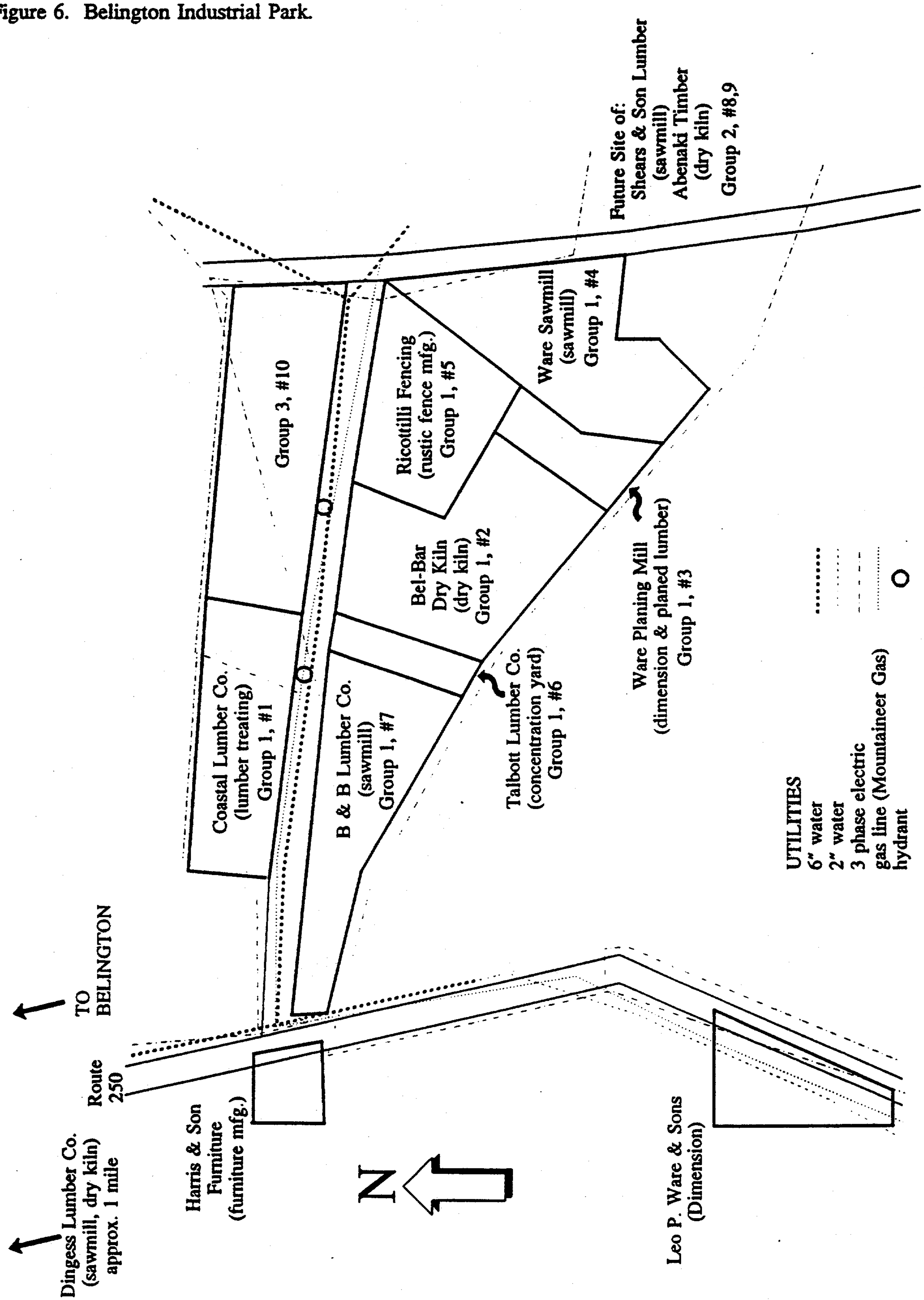


Table 1. Companies included in study.

COMPANY NAME	TYPE OF OPERATION
Group 1 Presently Inside Park	
1. Coastal Lumber Co.	Lumber Treating
2. Bel-Bar Dry Kiln	Steam Dry Kiln
3. Ware Planing Mill	Planing Mill
4. Ware Sawmill	Sawmill
5. Ricottilli Fencing of WV	Rustic Fence Mfg.
6. Talbott Lumber Co.	Concentration Yard
7. B & B Lumber Co.	Sawmill
Group 2 Future Inside Park	
8. Shears & Son Lumber	Sawmill
9. Abenaki Timber Corp.	Steam Dry Kiln
Group 3 Potential Companies	
10. 2 Radiofrequency Kilns	

amount and characteristic of residue generated, and quantity and cost of electricity and natural gas usage. Amount of residue generated by all companies included in the study (including residue which currently has a market value) was estimated at 161 tons/day, of which approximately 97% is above 40% moisture content (wet basis). Size of facility was based upon amount of residue generated and determined to be 2.5 MW. Developers of similar cogeneration projects and manufacturers of equipment were contacted to determine approximate costs associated with this project. Capital cost was estimated to be approximately $4.3 Million, and annual operation/maintenance cost was estimated to be $421,642 for the first 5 years, and $501,993 thereafter, taking into consideration availability of free fuel. Savings of electricity and natural gas was estimated at $179,513 and $381,163, respectively. Avoided cost rate and MARR were altered in a cash flow analysis. Feasibility at a 4-year discounted payback period with NPV of $5,439,203 based upon a 20-year investment period, was realized at 10% MARR and an avoided cost rate of $0.05023.

Phase I relied on revenue (in the form of avoided cost) from the electric utility to offset the relatively high capital cost of a new plant. The published avoided cost rate of Monongahela Power Co. is $0.015/kWh for off-peak and $0.01502/kWh for peak (16). Since this avoided cost rate is well below $0.05023, *Phase I* concluded that it was not feasible to construct a new cogeneration plant which would burn 161 tons of wood residue generated inside and nearby the park. In addition, the 2.5 MW cogeneration plant does not meet economies of scale as well as a plant in the 5-15 MW range.

Phase II

Phase II explored four alternatives to the one examined in *Phase I* with feasibility analyses performed for each one. These were developed based upon feedback received from engineers, manufacturers and developers with experience in cogeneration systems. For each alternative, only wood residue from industrial processes is considered as fuel. As it is not known at this time whether one cogeneration facility can service electricity to more than one company, alternative 1 was included. Used equipment refers to a turbine/generator only. Alternatives for *Phase II* were:

1. A plant sized to service all companies in the park;
    a. Excluding RF kilns, new equipment;
    b. Including RF kilns, new equipment;
    c. Excluding RF kilns, used equipment;
    d. Including RF kilns, used equipment.

2. A plant sized to take in additional residue produced within a 25- and 50-mile radius surrounding Belington (excluding RF kilns for all options);
    a. Servicing companies only within park: using new equipment, considering both savings and revenue:
        1) Within 25-mile radius;
        2) Within 50-mile radius;
    b. Servicing companies only within park: using used equipment, considering both savings and revenue:
        1) Within 25-mile radius;
        2) Within 50-mile radius;
    c. Selling power only to the utility: using new equipment, considering only revenue:
        1) Within 25-mile radius;
        2) Within 50-mile radius;
    d. Selling power only to the utility: using used equipment, considering only revenue:
        1) Within 25-mile radius;
        2) Within 50-mile radius.

3. Three possible examples of one system sized to meet the steam demands of the steam user(s) and supply electricity to only one company:
    a. Bel-Bar using steam and electricity;
    b. Abenaki using steam and electricity;
    c. Radiofrequency kilns using electricity and selling steam to Bel-Bar.

4. Request for proposals sent to 90 developers of biomass energy projects to determine what would be most suitable for the site.

Considerations for this Study and Assumptions Made

Data was collected on amount of residue produced and amount of energy consumed. Based upon this data, the feasibility was determined. Two components of feasibility are considered in this study: technical/economic and social/regulatory. Technical/economic feasibility takes into account the specialized needs of the site using the data collected. Considerations of this component of the analysis include data collected at the site, such as amount, type and cost of fuel available; energy usage pattern(s); energy requirements of the user; and type of system already in place. Based upon this data, equipment size and type, cost of equipment, cost of annual operation/maintenance, savings and/or revenue was determined. After the technical information was obtained, economic feasibility, specifically net present value of the investment, was calculated.

Social/regulatory feasibility takes into consideration the impact that the cogeneration plant will have on the users and the surrounding community, and whether it will be accepted by the community. Regulatory feasibility includes the incorporation and interpretation of PURPA regulations, and compliance with federal and state building and environmental regulations. All these considerations were examined as accurately as possible for both *Phase I* and *Phase II*.

With these aspects in mind, the following general and specific tasks were performed:

Data Collected:
1. Characteristic and amount of wood residue available for fuel from wood products companies were examined;
2. An energy profile for each company of maximum, average, and annual use based upon energy bills was defined (during *Phase I*).

Technical/Economic Feasibility:
1. Size of systems for each alternative were estimated;
2. Configurations of appropriate systems were determined;
3. Approximate capital and operating costs, along with savings and revenue were determined; and
4. Cash flow analyses based upon approximate costs and revenues (if applicable) were calculated.

Social/Regulatory Feasibility:
1. Sentiments of park tenants, community and surrounding wood products industry were examined;
2. Applicable Federal and State rules, regulations, and laws pertaining to cogeneration at this location were researched.

It was necessary to make assumptions regarding residue production, energy consumed, equipment selected, and pertaining to the cash flow analysis as follows:

Residue production:
1. All wood residue used is considered 50% moisture content (wet basis);
2. Approximately 2.5 lbs. of steam are produced per lb. of residue;
3. One van (trailer) holds 20 tons of wet residue.
4. Of all residue available from outside the park, only 80% of available sawdust is considered as fuel for this study;

Energy consumption:
(Assumptions are shown in Energy Usage section).

Equipment and operations:
1. The plant would operate 8,400 hrs./yr.;
2. Boiler is sized to operate at maximum continuous rating;
3. Used turbine/generator obtained for 10% cost of new (17);
4. Maintenance of new equipment is calculated at 5% for the first 5 years, and 7.5% thereafter (33);
5. Maintenance of used equipment is calculated at 7.5% (of the cost of new equipment) for the first 5 years and 10% thereafter (33);

Cash flow analysis:
1. The cogeneration plant would be funded entirely by state tax-free industrial revenue bonds (IRBs) and one annual payment of IRBs at an interest rate of 8%;
2. No inflation rate is considered because a) the rate will fluctuate over the 20-year period, making any rate chosen invalid, and b) an inflation rate tends to increase larger amounts by a greater percentage than smaller amounts;
3. Feasibility would be achieved with a discounted payback period of four years (the same criteria used by most companies to evaluate a cogeneration investment);
4. Plant life is 20 years;
5. State tax rate is 9.6%, Federal tax rate is 34%;
6. Minimum acceptable rate of return (MARR) is 8%, 10%, and 12%;
7. Project losses cannot be applied to another business component of the company owning the cogeneration plant.

DATA COLLECTED

Table 2 shows a list of conversion factors used in this report. For *Phase I*, data was collected on residue production and energy consumption of only the companies within the industrial park; this data was used for *Phase II*. For *Phase II*, additional data was collected on residue production from wood products companies within a 50-mile radius of Belington. First, residue production will be discussed, then energy consumption.

Table 2. Conversion factors used for report.

1 Thousand Cubic Feet (MCF)	= 1,040,000 Btu
1 therm	= 100,000 Btu
1 decatherm	= 10 therm
1 lb. of steam	= 970 Btu
1 Kilowatt hour (kWh)	= 3,413 Btu
1 megawatt (MW)	= 1,000 kilowatts
1 horsepower	= 0.7457 kW

Residue Production

Wood residue from sawmill operations is the only type of fuel considered for this study. Residue is generated as bark, sawdust, shavings, chips, and slabs. The amount of residue available was obtained from estimates provided by sawmills and secondary wood products manufacturers generating residue. Amounts were given in tons/day, or vans/day.

Belington Site

At the present time, all residue produced at Belington is either disposed of off-site or stored on-site, none is used to create energy. Sawdust is either hauled to a local charcoal manufacturer, or other small manufacturer, or burned in wood-fired boilers; sawdust has the lowest economic value of all wood residue. Bark is hauled to several mulch plants, and chips are hauled to several paper companies located outside of West Virginia. Slabs which are not hogged are often sold as firewood. The distance to haul residue is often quite far in this mostly-rural area, and little, if any money is made on the sale of residue.

Phase I determined that one hundred and sixty-one tons of residue per day is produced by all the companies in and surrounding the industrial park. For *Phase II*, however, it is assumed that 120 tons will be made available for the facility; this amount does not take into account chips and bark produced in the immediate vicinity of the industrial park because these have an acceptable value in other markets.

Within 50-Mile Radius of Belington

Data on wood residue production was collected from sawmills and secondary wood products companies within a 50-mile radius of Belington, as illustrated in Figure 7. Often, the distance is much greater than what is measured because the roads are quite twisting.

Although data was collected on exact moisture content of the residue within the industrial park for *Phase I*, it was not possible to collect this same data for all the additional companies included in *Phase II*. Table 3 is a summary of residue availability in this area excluding amounts used in wood-fired boilers. Individual amounts and company names are confidential. Only sawdust, bark and chips are considered in Table 3 because it was thought that shavings and slabs would be minimal.

Table 3 shows the amounts available from three different areas: the immediate Belington area, the area within a 25-mile radius (data collected from both sawmills and secondary companies), and the area between a 25-and 50-mile radius (data collected from sawmills only). Data from sawmills only was obtained from the 25-to 50-mile radius because it is likely that smaller secondary industries outside a 25-mile radius would not have enough residue to economically haul such an extended distance.

Residue availability was obtained by calling each company and asking the following questions: 1) How much (sawdust, bark, chips) are generated in tons/day?; and 2) What becomes of these residues?

Figure 7. Map of 25- and 50-mile radius surrounding Belington.

Table 3. Residue availability within 50-mile radius of Belington.

Type of Residue	Tons/Day Belington area	Within 25-miles	Between 25- and 50-miles	Total
Sawdust	80	190	287	527
Bark	40	183	288	511
Chips	30	193	497	720
Total	150	566	1,072	1,758

Energy Usage

Electric and natural gas bills were analyzed to determine approximate peak, average and annual energy usage for each company. Two years of bills were requested from companies in Group 1 that covered 1989-1990. Energy data for companies in Group 2 was estimated from conversations with owners regarding anticipated energy requirements. Group 3 data was obtained from the previous owner of the radiofrequency kilns and covers only 1989.

An approximation of energy usage for each company is shown in Table 4. This table was produced without consideration of seasonal changes in energy usage because energy usage is limited by the market for wood products, which is somewhat unpredictable.

Electricity Consumption at the Belington Site

Electricity consumption is shown in columns 2-5. Columns 2 and 3 show two different values for peak electrical demand. The peak demand in Column 2 represents the total of all equipment horsepower, while the peak demand in column 3 represents the highest demand shown on any electric bill; column 3 is considered a more accurate representation of demand.

Monthly bills (or estimations of monthly usage if bills were not available) were totalled to obtain a rough estimation of annual kWh used. This rough determination of annual consumption was used to obtain an accurate representation of average (col. 4) and annual (col. 5) kWh used.

Using the rough calculation for kWh/year, col. 4 was determined as follows:

$$\frac{kWh}{hour} = \frac{kWh}{year} x \frac{year}{month} x \frac{month}{hours}$$

Table 4. Energy profiles of all companies in study.

Hours/month depended upon the type of business and was calculated to be:

168 (plants/offices open 8 hours/day x 21 days/mo. = 168), or
128 (plants/offices during holiday weeks in July & Nov. when open 8 hrs./day x 16 days/mo.).

Based upon the number obtained in column 4, column 5 was calculated using two different methods based upon company usage of electricity:

1. Companies expected to use electricity 2000 hrs/yr (# 1,3,4,5,6,7,8):
   a. *Assume* that peak kW occurs for 2, 15-min. periods/day (1/16 of an 8-hour day or 125 hours/year);
   b. *Assume* that average kWh/h occurs 7.5 hours/day (15/16 of an 8-hour day or 1,875 hours/year);
   c. *Therefore* annual kWh = (peak kW x 125 hrs./yr)+(avg. kWh/h x 1,875 hrs./yr.);
2. Companies expected to use electricity 8400 hrs/yr (# 2,9,10):
   a. *Assume* that peak kW occurs for 1, 15-minute period/week (12.5 hrs./yr.);
   b. *Assume* that average kWh/h occurs 8,387.5 hrs./yr.;
   c. *Therefore* annual kWh = (peak kW x 12.5)+(avg.kWh/h x 8,387 hrs./yr.).

Thermal Consumption at the Belington Site

Although it could not be determined what portion of gas was used for heating/cooling just by examining gas bills, it is assumed that gas usage for dry kilns is used primarily as process steam.

It was more difficult to calculate thermal consumption than electricity consumption, as bills to be used as a basis were difficult to obtain. Thermal data is shown in columns 6-8. Peak mmBtu/hour (column 6) was obtained by determining the month which had the highest gas consumption, then dividing the total amount for that month by the number of days the company operated that month.

Average mmBtu/hour (col. 7) was calculated the same way as average kWh/hour by:

Hours/month was calculated to be:

$$\frac{MMBtu}{hour} = \frac{MMBtu}{year} x \frac{year}{month} x \frac{month}{hour}$$

732 (for the steam kilns operating 24 hours/day x 30.5 days/mo.),
168 (for offices open 8 hours/day x 21 days/mo.), or
128 (for offices during holiday weeks in July & Nov. when open 8 hours/day x 16 days/mo.).

Annual mmBtu (column 8) was obtained by totalling all Btu consumed during one year and multiplying by either 2,000 or 8,750 hours/year.

TECHNICAL/ECONOMIC FEASIBILITY

It is difficult to determine exact equipment and equipment sizes required at this point. Costs are also site-specific. The reader is reminded that use of general cost information is limited; the more costly equipment required is normally customized and the price for this equipment will be unique (33).

Capital cost estimates for equipment were provided by developers and by equipment manufacturers based upon preliminary descriptions of this project; no on-site visits were conducted. Percentages of capital cost to be allocated to insurance, operation/maintenance, and engineering were, in some cases provided by developers of similar projects and, in other cases are general industry rules-of-thumb. The four major alternatives will be discussed in the order listed in the introduction. First, technical feasibility will be discussed for the first case in each alternative, then economic feasibility.

Technical Feasibility

Alternative 1. Plant sized to service companies only inside park.

The alternatives are:

a. Excluding RF kilns, new equipment;
b. Include RF kilns, new equipment;
c. Exclude RF kilns, used equipment;
d. Include RF kilns, used equipment.

Alternative, 1A, which excludes the RF kilns and considers all new equipment is the one featured for discussion; changes made to consider alternatives B-D are discussed in the sections entitled "Alternative 1B", "Alternative 1C", and "Alternative 1D", which follow.

Sizing the System

From Table 4, column 2, maximum electric demand for Groups 1 and 2 is 806.5 kW. A condensing turbine was selected for this alternative to maximize production of electricity; a non-condensing turbine would produce electricity based upon steam usage, which is low. The amount of steam required by the kilns can be diverted to them. The single stage condensing turbine/generator that should effectively meet this demand is approximately 800 kW. The amount of steam needed to generate 1 kW from a pressure drop from 250 psi at the boiler to 15 psig at the dry kiln is 41 pounds/hour, at 50% efficiency. Therefore, the amount of steam necessary to meet this generator capacity is:

800 kW x 41 lbs. of steam per hour/kW = 32,800 lbs. of steam./hr.

The boiler capacity required is:

32,800 lbs. of steam x 970 Btu/lb. of steam = 31,816,000 Btu
31,816,000 Btu / 33,475 Btu/BHP = 950 BHP

Determining Amount of Waste to Meet Boiler Size

The amount of waste required per week to meet this boiler capacity can be divided between 1) peak periods of 40 hours/week when the demand for electricity and process steam are at maximum and 2) non-peak periods of 128 hours/week when the demand for electricity is low but process steam is still needed. The demand to meet steam process only can be determined from Table 4, col. 7 as 9.95 mmBtu/hour (10,257 lbs. of steam per hour):

1. Peak periods
   31,816,000 Btu/hr. / 0.662 combustion efficiency = 48,060,423 Btu/hr.
   48,060,423 Btu/hr. / 3,000 Btu/lb. = 16,020 lbs. of residue/hr.
   16,020 lbs. of residue x 40 hrs./week = 640,800 lbs. of residue/week
   640,800 lbs. of residue/week / 2,000 lbs./ton = 320 tons/week

2. Non-peak periods:
   10,257 lbs. of steam x 970 Btu/lb. of steam = 9,949,290 Btu/hr.
   9,949,290 Btu/hr. / 0.662 combustion efficiency = 15,029,139 Btu/hr.
   15,029,139 Btu/hr. / 3,000 Btu/lb. = 5,010 lbs. of residue/hr.
   5,010 lbs. of residue x 128 hrs./week = 641,280 lbs. of residue/week
   641,280 lbs. of residue/week / 2,000 lbs./ton = 321 tons/week

The total amount of residue required is then 641 tons/week (320 + 321). Since only 500 tons/week is generated within and nearby the park that would be made available at no charge, there would be 150 tons per week that would have to be purchased.

System Selection and Cost

A summary of equipment items, start-up and operating costs follow. Table 5 shows the list of all capital costs for Alternative 1a.

Project Cost (Equipment)

Fuel Storage and Handling - The density of green sawdust is approximately 20 lbs./ft^3 (32). Since the plant will use approximately 641 tons/week, it is estimated that a cement slab 5,000 ft^2 could store 600 tons of residue, which is more than 5 days of fuel, packed to an average height of 12 feet:

12' x 5,000 ft^2 x 20 lbs. of residue per ft^3 = 1,200,000 lbs. of residue
1,200,000 lbs. / 2,000 lbs./ton = 600 tons

This amount of residue is produced by the companies within and surrounding the park. Since all the companies that have residue also own their own vans, they can continue to blow the residue into their vans, then drive to the site where they will be unloaded. A truck dump (60' x 20') and scale will be needed to unload vans that are not self-unloading. About 5 vans/day will unload at the site. A hogger will be required to size the bark and slabs; these will need to be separated at the mills prior to arriving at the site.

Boiler - One 975 BHP spreader stoker, with combination watertube furnace and multi-pass firetube boiler, is able to handle wet fuel and can quickly change firing rates. The boiler system includes metering system and all controls.

Steam Turbine/Generator - An 800 kW single-stage condensing turbine/generator with inlet pressure of 250 psig and outlet pressure of 15 psig is considered for this system. This system includes turbine controls, synchronous generator, pressure lubrication system and water condenser.

Cooling Tower - A cooling tower is installed in all condensing systems to dissipate the heat produced by the condenser. This system will include cooling water pump, piping and valves.

Table 5. Capital cost estimates for alternative 1a.

Equipment	Item Cost	Total Cost
Site prep & concrete	60,000	
Belt conveyer	40,000	
Truck dumper, conveyers	135,000	
Hogger	50,000	
Installation	110,000	
Total Fuel Storage and Handling		395,000
Boiler	387,500	
Metering bin, controls, valves, pumps	25,000	
Installation	287,500	
Total Boiler System		700,000
Condensing Turbine/Generator	170,000	
Controls, relays, switchgear, piping, valves, pumps	60,000	
Installation	95,000	
Total Turbine/Generator		325,000
Cooling Tower	75,000	
Pumps, piping, valves	40,000	
Installation	65,000	
Total Cooling Tower		180,000
Piping	271,900	
Installation	200,900	
Total Piping to Steam Dry Kilns		472,800
Equipment	150,000	
Installation	75,000	
Total Cyclone Collector		225,000
Foundation	22,500	
Interior mechanics (plumbing,gas)	15,000	
Excavation and site prep.	22,500	
Fees	7,500	
Construction of Building	75,000	
Permits	7,500	
Total Plant		150,000
Engineering	137,868	
Project Management	68,934	
Contingency	229,780	
Construction Insurance	22,978	
Construction Financing	137,868	
Total Construction Cost		597,428
Legal Fees		75,000
Interconnection		60,000
Permits		50,000
TOTAL CAPITAL COST		3,230,228

Piping to Steam Dry Kilns - Steam lines will carry the extraction steam from the cogeneration plant to both dry kiln companies. This piping will be above ground and insulated. Throttle pressure is 250 psig (saturated) and exhaust pressure is 15 psig. It is anticipated that 6 in. Schedule 80 pipe will be required.

Bel-Bar Dry Kiln is approximately 0.5 miles and Abenaki Timber will be approximately 0.125 miles from a possible location of the cogeneration plant. Total length of piping required is 0.625 miles (0.500 + 0.125), or 3,300 feet. Cost is estimated at $143/ft. (23).

Pollution Control - Since the park is located in a rural county and not a PSD Class I area (see Figure 8 at the end of this report), it is anticipated that a mechanical collector, such as a multitube cyclone will be adequate to meet air quality requirements. Because this emissions control device has a relatively low efficiency, several cyclones might need to be operated in series to remove finer particles. This type of pollution control system will reduce particulates to levels of 0.1-0.5 lb./MMBtu, acceptable for most areas.

Project Costs (Plant)

Structure - It is estimated that a building approximately 75' x 40', with an eave of 30' will be adequate. From contact with construction companies, it is estimated that the cost will be approximately $150,000. This includes the possibility of excess excavation, since the potential site for the plant is on hilly terrain.

Project Costs (Start-Up)

Construction - Additional project costs that a developer would encounter need to be considered. These can be calculated as a percentage of total plant and equipment as shown in Table 6:

Land - It is estimated that approximately ten acres will be required. It is assumed that land will be made available for the project by the Barbour County Development Authority free-of-charge.

Legal Fees - Legal fees are difficult to anticipate, but an estimation is made based upon similar projects.

Table 6. Estimation of construction cost based upon percentages.

Engineering	$2,297,800	x 0.06 =	$137,868
Project Management		x 0.03 =	68,934
Contingency		x 0.10 =	229,780
Construction Insurance		x 0.01 =	22,978
Construction Financing		x 0.06 =	137,868
TOTAL			$597,428

Interconnection - The electric utility will need to be satisfied that the electricity generated by the facility will by in synchronization to their own, to prevent outages. This represents the cost of inspection by the utility to ensure compatibility.

Permits - Permits include site preparation, filing fees, and environmental compliance.

Savings

The two primary benefits from a cogeneration plant are savings of electricity and process steam that would otherwise need to be purchased from the utility, and revenue from the sale of excess electricity to the utility. Since revenue is not being considered in this alternative, only savings will be calculated.

Process Steam - Savings of thermal energy is based upon the assumption that all energy can be obtained from the cogeneration facility. The cost of natural gas for industrial use in West Virginia is approximately $2.00/MCF (9). Estimated annual Btu consumption for both dry kiln companies is 77,000 mmBtu (50,750 mmBtu Bel-Bar+26,250 mmBtu Abenaki). Annual savings in natural gas is $148,077 (77,000 mmBtu x (1,000,000 MCF/1,040,000 Btu) x $2.00/MCF).

Electricity - To determine savings, annual kWh was multiplied by $0.05/kWh. Therefore, savings for all companies excluding the RF kilns is calculated to be 2,045,834 kWh x $0.05/kWh = $102,292. Savings including the RF kilns is calculated to be $201,004 (4,020,088 kWh x $0.05/kWh). Total savings is then $148,077 + $102,292 = $250,369 ($349,081 for the R/F kilns).

Operating Costs (Fixed)

Labor - Wood fuel systems generally experience higher operating costs than non-biomass systems because of reduced levels of automation and increased personnel requirements (32). Since the cogeneration plant will operate 24-hours/day, one operator will need to be on-site during all three shifts. Two additional operators, possibly people already working nearby, will be needed to operate the plant during the weekends. The weekday operators might also work weekends, so that weekend operators would not have to work two shifts in a row. If no person is hired to specifically do maintenance (this study assumes no extra maintenance personnel), operators will need to be trained in maintenance. A plant manager will oversee the operators and wood handlers and a part-time secretary will handle the paperwork. Table 7 shows the breakdown of labor; only the values for *direct* and *indirect* cost are shown on the cash flow projections in the Economic Feasibility section.

Table 7. Breakdown of labor cost for 6 employees.

Labor	Hourly Wage	Hours/Yr.	Annual Wage
Operators (3)	$ 9.00	2,000	$54,000
Wood Handler (1)	7.50	2,000	15,000
Plant Manager (1)	11.50	2,080	23,920
Secretary (1)	5.00	1,000	5,000
TOTAL Annual Wages			$97,920
Fringe Benefits @ 10%			9,792
Direct TOTAL Wages + Benefits			$107,712
Worker's Compensation		$97,920 x 0.0333	3,260
Unemployment Insurance		$40,000 x 0.027	1,080
Liability Insurance		$25 x $98	2,450
Social Security Matching		$97,920 x 0.060	5,875
Indirect TOTAL Compensation, Insurance, Matching		$12,665	
TOTAL Wages, Compensation, Matching			$120,377

Operation and Maintenance - The plant will require regular maintenance on all items of equipment, in addition to building maintenance. It is reasonable to expect that maintenance will cost about 5% of original equipment (less installation) cost during the first three to five years, then increase to 7.5% thereafter (33). Cost of equipment less installation is $1,465,400. Therefore, during the first five years @ 5%, maintenance cost will be approximately $73,220 ($1,465,400 x 0.05) while after the fifth year, it will be $109,830 ($1,465,400 x 0.075).

Insurance (11) - Although insurance on building and equipment may vary, equipment insurance can be estimated to be approximately $1.50 per $100 of equipment cost. Since cost of equipment less installation is $1,465,400, annual insurance cost is estimated to be $21,966 annually. Insurance on buildings can range from $2.50 - $3.00 per $100 of building cost. The average of $2.75 will be used for this study; therefore, insurance for the $150,000 building is estimated to be $4,125 annually. Total insurance is $21,966 + $4,125 = $26,091.

Miscellaneous - In addition, money must be set aside for items that will be needed during the year, such as parts, computer equipment, contingency, office supplies, etc. This study assumes $10,000 for parts, $6,000 for supplies, and $15,000 for contingency.

Operating Costs (Variable)

Water - Water is used to cool the condenser; most of the water is recirculated and what is not is dissipated by the cooling tower. A water-cooled, direct combustion facility uses an average of 490 to 550 GPM (gallons/minute); however, most of it is recirculated (6). From conversations with developers of similar projects, it is estimated that a likely amount of consumption is approximately 164,000 gallons/month. Based upon water rates obtained for the city of Belington, it is anticipated that cost of water will be approximately $168.05/month, or $2,017 annually.

Electricity - A standby charge will need to be paid to the electric utility to remain connected with them; this charge is estimated to be $28,000 annually.

Chemicals - For wood combustion plants, chemicals are required to treat water that is used to transport boiler ash. Dry wood ash is not toxic, but the solution of ash when combined with water is corrosive (2). Although this wastewater may be discharged directly into the sewer system, the water is sometimes pretreated prior to discharge. The cost, which is estimated from a similar project, is approximately $14,600.

Ash disposal - Ash left over after combustion could be given away or hauled to a landfill (ash is considered valuable, especially by gardeners). It is estimated that for a plant this size, about 3 tons of ash will be produced/week. With a tipping fee of approximately $20/ton, about $3,120 will be spent on ash disposal annually (3 tons/week x $20/ton x 52 weeks/year).

Alternative 1B, including RF kilns, new equipment

Capital and operating cost differences between alternatives la-ld are shown in Table 8. To include the radiofrequency kilns, turbine size increased to 1,200 kW ($425,000) and boiler size increased to 1300 BHP ($910,000). The increase in equipment costs consequently increased construction cost to $678,028, as this cost is calculated as a percentage of equipment cost. Therefore, total capital cost increased to $3,620,828.

Annual operating costs that are tied in to capital costs, such as maintenance and insurance, increased. Maintenance for the first five years was $82,821 and $124,232 thereafter. Insurance increased to $28,971. Savings increased from $102,292 to $201,004 as the radiofrequency kilns consume a great deal of electricity (nearly double of the rest of the park). There was still ample fuel available from the companies within and surrounding the park for a plant of this size.

Alternative 1C, exclude RF kilns, used equipment

Alternative 1C takes into account a used turbine/generator. A used turbine is estimated to be 50% of original cost; other equipment is often custom-made and rarely purchased used. Cost of the turbine/generator was $162,500. This decrease in capital cost decreased construction cost to $521,378; a consequence of using percentages to calculate construction cost. Total capital cost was then $2,861,678. Annual maintenance cost for used equipment is difficult to predict (17), but was calculated to be 5% for the first five years (of the cost of new equipment) + 20% the cost of the used equipment; thereafter, it was 7.5% the cost of new equipment and 20% cost of used equipment. Insurance was $22,986.

Alternative 1D, include RF kilns, used equipment

Cost of used turbine/generator was estimated at $212,500. This subsequently decreased construction cost to $622,778 and total capital cost was estimated at $3,353,078. Maintenance for the first five years was $97,533, and $135,184 thereafter. Insurance was estimated to be $24,911.

Table 8. Comparison of key costs for alternatives 1A-1D.

	Capital Cost				*Operating Cost*				
						Maintenance			
	Boiler	*Turbine/ Generator*	*Construction*	*Total*	*Insurance*	*First 5 yrs*	*After 5 yrs*	*Total First 5 yrs*	*Total > 5 yrs*
1A	\$700,000	\$325,000	\$597,428	\$3,230,228	\$26,091	\$73,220	\$109,830	\$353,026	\$389,636
1B	910,000	425,000	678,028	3,620,828	28,971	82,821	124,232	365,507	406,918
1C	700,000	162,500	555,178	3,025,478	24,366	84,470	118,205	362,551	396,286
1D	910,000	212,500	622,718	3,353,078	26,716	97,533	135,184	377,963	415,614

Alternative 2. Plant Sized to Take Residue Within 25-and 50-Mile Radius.

The radiofrequency kilns are excluded for all options. The alternatives are:

a) Servicing companies within park, new equipment, savings and revenue;
b) Servicing companies within park, used equipment, savings and revenue;
c) Selling all power, new equipment;
d) Selling all power, used equipment.

For these four alternatives, analysis was performed for both 25-mile versus 50-mile radius. Alternative 2A(25-mi), which includes servicing companies within the park, selling excess to the utility, new equipment, and within a 25-mile radius is the alternative featured for discussion; changes made to alternatives B-D are discussed in the section Alternatives 2B-2D, which follows.

Sizing the System

While alternative 1 based system size upon energy demand, alternative 2 based system size on amount of waste wood available. Only sawdust was considered from companies outside Belington, as this waste has the least value and could be made available at a cost less than what might be paid for bark or chips. The amount of waste available for fuel was determined by adding the amount of waste that might be hauled to Belington (from within a 25- and 50-mile radius) to the 100 tons/day already produced there.

The amount of waste available was calculated from Table 3. Approximately 190 tons/day of sawdust is generated from within a 25-mile radius of Belington. An additional 287 tons/day is generated from between 25- and 50-miles. Assuming that only 80% of this sawdust could be made available to the plant, an additional 152 tons/day (190 x 0.80) and 230 tons/day (287 x 0.80) are considered. Therefore, adding in the 120 tons/day from the Belington area, 272 tons/day (120 + 152) is available from within 25-miles, and 502 tons (120 + 152 + 230) is available from within 50-miles.

Boiler size based upon 272 tons/day was determined to be:

272 tons/day x 5 days/week = 1,360 tons/week
1,360 tons/week / 7 days/week = 194.3 tons/day
194.3 tons/day x 2,000 lbs./ton = 388,600 lbs./day
388,600 lbs./day / 24 hrs./day = 16,192 lbs./hr.
16,192 lbs./hr. x 2.5 lbs. of steam/lb. of wood = 40,480 lbs. of steam
40,480 lbs. of steam / 34.5 = 1173 BHP

The single-stage non-condensing turbine/generator size can be calculated:

40,480 lbs. of steam/hr. / (41 kW/1,000 lbs. of steam) = 1 MW

System Selection and Cost

The plant for alternative 2 was configured identically to alternative 1. All costs were the same, except for the addition of fuel cost. Table 9 shows the estimated capital costs for 2A(25-mi).

Project Costs (Start-Up)

Land, legal fees, interconnection, and permits did not change in cost.

Construction - Increased, in equipment cost increased construction cost by the amounts shown in Table 10.

Project Cost (Equipment)

Fuel storage and handling, boiler, steam turbine/generator, cooling tower, and cyclone collector increased in size, therefore cost increased. Piping to both dry kilns remained the same distance.

Project Costs (Plant)

Structure - It is estimated that a larger building will be needed, including the possibility of excess excavation, since the potential site for the plant is on hilly terrain.

Interconnection Costs - Under PURPA requirements, it is the responsibility of the cogeneration plant to pay for any services the utility would have to provide in order for the plant to connect with it. Even though there is ample residue so that the users might possibly become self-sufficient from the electric utility, it is wise to remain connected to the utility, which would

Table 9. Capital cost estimates for alternative 2A(25-mi).

Equipment	Item Cost	Total Cost
Site prep & concrete	75,000	
Belt conveyer	50,000	
Truck dumper, conveyers	135,000	
Hogger	50,000	
Installation	150,000	
Total Fuel Storage and Handling		460,000
Boiler	420,000	
Metering bin, controls, valves, pumps	25,000	
Installation	390,000	
Total Boiler System		835,000
Condensing Turbine/Generator	500,000	
Controls, relays, switchgear, piping, valves, pumps	50,000	
Installation	200,000	
Total Turbine/Generator		600,000
Cooling Tower	400,000	
Pumps, piping, valves	50,000	
Installation	150,000	
Total Cooling Tower		210,000
Piping	271,900	
Installation	200,900	
Total Piping to Steam Dry Kilns		472,800
Equipment	170,000	
Installation	85,000	
Total Cyclone Collector		255,000
Foundation	27,500	
Interior mechanics (plumbing,gas)	25,000	
Excavation and site prep.	25,000	
Fees	10,000	
Construction of Building	90,000	
Permits	7,500	
Total Plant		185,000
Engineering	169,968	
Project Management	84,984	
Contingency	283,280	
Construction Insurance	28,328	
Construction Financing	169,968	
Total Project Cost		736,528
Legal Fees		75,000
Interconnection		150,000
Permits		50,000
TOTAL CAPITAL COST		4,029,328

Table 10. Estimation of construction cost based upon percentages.

Engineering	$2,832,800	x 0.06 =	$169,968
Project Management		x 0.03 =	84,984
Contingency		x 0.10 =	283,280
Construction Insurance		x 0.01 =	28,328
Construction Financing		x 0.06 =	169,968
TOTAL			$736,528

provide power during times of maintenance and outages at the cogeneration plant.

Interconnection costs include relays and circuit breakers for the connection, transformers to match incoming lines, and extension, if necessary, to connect the plant with the utility lines (6). To accurately determine the cost of connection, a site visit by the utility will be required, since the cost depends on the proximity of the plant to the kV line that would support the expected amount of power from the plant. From conversations with the electric utility, it was estimated that a system of this size would require either a 138 kV line, or possibly only a 23 kV line (if the 23 kV line has the ability to handle the excess power) (5,2).

Savings and Revenue

Savings - Process Steam - Same as alternative 1 ($148,077); would include both dry kilns.

Savings - Electricity - Again, calculated the same as for alternative 1, $102,292.

Revenue - Electricity - Revenue is calculated by determining annual production of electricity then subtracting from it the number of kWh used on-site. The total annual electric production of a 1.0 MW plant is 1,000 kW/h x 8,400 hrs./yr. = 8,400,000 kW/yr.

Operating Costs (Fixed)

Labor - Two laborers (one operator and one wood handler) were added for alternative 2, bringing the total to 8; these are shown in Table 11.

Operation and Maintenance - Cost of equipment less installation is $1,781,900. Therefore, during the first five years, maintenance cost will be approximately $89,095 and after the fifth year $133,642.

Insurance - Equipment and building insurance totalled to $31,816.

Table 11. Breakdown of labor cost for 8 employees.

Labor	Hourly Wage	Hours/Yr.	Annual Wage
Operators (4)	$ 9.00	2,000	$72,000
Wood Handlers (2)	7.50	2,000	30,000
Plant Manager (1)	11.50	2,080	23,920
Secretary (1)	5.00	1,000	5,000
TOTAL Annual Wages			$130,920
Fringe Benefits @ 10%			13,092
Direct TOTAL Wages + Benefits			$144,012
Worker's Compensation		$130,920 x 0.033	4,360
Unemployment Insurance		$40,000 x 0.027	1,080
Liability Insurance		$25 x $98	2,450
Social Security Matching		$130,920 x 0.060	7,855
Indirect TOTAL Compensation, Insurance, Matching		$15,745	
TOTAL Wages, Compensation, Matching			$159,757

Fuel - Cost of fuel that the plant will have to purchase within a 25-mile radius is designated as $7.00/ton. Therefore, annual cost of fuel is ($7.00 x 152 tons x 250 days) = $266,000.

Miscellaneous - The same amount for miscellaneous cost is assumed for this alternative.

Operating Costs (Variable)

The same amounts for water, standby charge, chemicals, and ash disposal are assumed.

Alternative 2A(50-mi)

Comparisons between alternative 2A(25-mi) and the rest of the alternatives associated with #2 are shown in Table 12. A larger plant (estimated 6 MW) could be constructed with the additional residue obtained from a radius of 50-miles, as nearing economies of scale. There were differences of capital and operating costs, and revenue between 2A(25-mi) and 2A(50-mi). The increase in plant size increased both capital and operating costs, but not proportionally. Increase in boiler and turbine/generator costs had the greatest effect on capital cost.

Table 12. Comparison of key costs for alternatives 2A-2D.

	Capital Cost				*Operating Cost*				
						Maintenance			
	Boiler	*T/G*	*Construction*	*Total*	*Insurance*	*First 5 yrs*	*After 5 yrs*	*Total First 5 yrs*	*Total > 5 yrs*
2A(25-mi) 2C(25-mi)	$ 835,000	$ 600,000	$ 736,528	$4,029,328	$31,816	$ 89,095	$133,643	$ 625,405	$ 677,452
2A(50-mi) 2C(50-mi)	1,500,000	1,700,000	1,088,828	5,757,128	51,785	153,595	230,393	1,112,374	1,141,434
2B(25-mi) 2D(25-mi)	835,000	300,000	658,528	3,651,328	28,366	117,595	156,393	650,455	689,252
2B(50-mi) 2D(50-mi)	1,500,000	850,000	1,008,228	5,368,528	42,035	241,095	301,643	1,190,124	1,250,671

Items affected by the increase in capital cost were operation & maintenance ($153,595, $230,393) and insurance ($51,785). Fuel increased to $668,500 ((152 tons + 230 tons) x $7/ton x 250 days/yr.).

Revenue increased to $725,312 from $259,112, as annual production of a 6 MW plant is 50,400,000 kWh/yr ((50,400,000 kWh - 2,045,834 kWh (RF kilns)) x $0.015). However, fuel requirements are not proportional to the size of the cogeneration plant and tend to decrease for larger-scale plants. A plant that uses 108,800 tons/yr. of wood residue can support a generator of 5 MW (2); at 125,500 tons/yr., this plant will be sized at approximately 6 MW.[3]

Alternatives 2B(25-mi and 50-mi), servicing companies inside park, used equipment

Used equipment again reduced the cost of a turbine/generator from $1,700,000 to $850,000. This decreased project cost to $658,528 (25-mi) and $1,008,228 (50-mi). Total capital cost decreased to $3,651,328 and $5,368,528 for 25-mile and 50-mile, respectively. Total operating cost was $650,455 (25-mi) and $1,190,124 (50-mi); the increase from the 50-mile radius was due to the increase in cost of fuel.

Alternatives 2C(25-mi and 50-mi), selling power to the utility, new equipment

Capital and operating costs for alternatives 2C correspond to 2A. Since there is no savings, all 50,400,000 kWh are sold to the utility, generating $756,000.

[3] Wood Power Inc., a 6 MW plant currently operating in Idaho uses 80,000 tons of fuel/yr. and operates 8,000 hrs.

Alternatives 2D(25-mi and 50-mi), selling power to the utility, used equipment

Alternative 2D corresponds to 2B except that all power is sold, generating $756,000.

Alternative 3. Plant Sized for One Company

An alternative to a large-scale system servicing the companies in the park is a small-sized system to service either one company for both steam and electricity, or one company for electricity and run steam lines to a dry kiln. A plant that is downsized to meet the energy requirements of one user would lower the capital and operating costs (i.e., using labor already available), and avoid the problem of selling electricity back to the utility.

Based upon electricity and steam usage of the companies within the park, three likely alternatives were developed. Two are designed solely for the two dry kiln companies. However, since the system for Bel-Bar dry kiln company will generate more electricity than they require, a third alternative was developed. The alternatives are:

a. Bel-Bar using steam and electricity;
b. Abenaki using steam and electricity;
c. RF kilns using electricity and selling steam to Bel-Bar;

Only alternative (a) will be discussed; the others will be discussed in terms of variations to alternative 3A.

Sizing the System

A backpressure turbine/generator was considered with a pressure drop of 125 psig to 15 psig, or 58 pounds of steam to generate 1 kW of electricity, at 50% efficiency. Therefore, size of the system would depend upon the amount of steam Bel-Bar uses. From Table 4, it was estimated from monthly gas bills that Bel-Bar uses 5.8 mmBtu/hr. on the average. Therefore, 9,131 tons/yr. is required to supply this amount of steam to Bel-Bar, and 103 kW could be generated from a system this size.

5.8 mmBtu/hour / 970 Btu/lb. of steam = 5,979 lbs. of steam/hr.
5,979 lbs. / 2.75 lbs. steam / lb. of waste = 2,174 lbs. of waste/hr.
2,174 lbs/hr. x 8,400 hrs/yr. = 9,131 tons of waste required/yr.
5.8 mmBtu/hour / 33,475 Btu/BHP = 173 BHP
5,979 lbs. of steam/hr. / 58 turbine steaming rate = 103 kW/hr.

System Selection and Cost

Project Cost (Equipment, Plant, Start-Up)

Capital costs for alternative 3a are shown in Table 13. Since Bel-Bar presently uses natural gas to heat their kilns and has no boiler on-site, a wood-fired boiler must be purchased ($170,000 includes installation). The cost of a fuel storage and handling system is estimated to be $40,000. The cost of a 105 kW turbine/generator is estimated to be about $145,000 (includes installation). However, since they need less electricity than they can produce, they will only require an 80 kW turbine/generator, which is estimated to cost about $120,000. Additional amounts for piping are estimated to be $10,000.

An additional building might be constructed to house the boiler and turbine/generator. This study will assume an extra building constructed at a cost of $23,750. It is estimated that permitting and paperwork will total to approximately $5,000.

Therefore, total capital cost is estimated at $393,750.

Savings

Process Steam - If Bel-Bar is able to save money on all their process steam, the savings will amount to $105,560 (52,780 MCF x $2.00/MCF).

Electricity - It is possible for Bel-Bar to save all of their electricity, as this system is able to produce 865,200 kW/yr (103 kW x 8,400 hrs/yr.). Since they only need 662,235 kWh/yr, they can save (662,235 kWh/yr.x $0.05/kW) $33,112 annually.

Operating Costs

Operating costs were estimated using the same percentages as were used for the previous alternatives.

Table 13. Capital cost estimates for alternative 3A.

Equipment	Item Cost	Total Cost
Site prep & concrete	7,500	
Belt conveyer	11,000	
Hogger	5,000	
Installation	16,500	
Total Fuel Storage and Handling		40,000
Boiler	85,000	
Metering bin, controls, valves, pumps	5,000	
Installation	80,000	
Total Boiler System		170,000
Turbine/Generator	60,000	
Controls, relays, switchgear, piping, valves, pumps	15,000	
Installation	45,000	
Total Turbine/Generator		120,000
Piping		10,000
Building		23,750
Permits		5,000
TOTAL CAPITAL COST		393,750

Operation and Maintenance - Cost is estimated at $17,000 for the first five years and $25,500 thereafter, at 5% and 7.5% respectively.

Insurance - Using the same percentages as before, insurance cost is calculated as $5,100.

Parts - Parts are calculated at 0.01 of equipment cost or $3,400.

Fuel and Labor - We are assuming that fuel is free (there is ample fuel from the industrial park area), and that no extra personnel for maintenance need to be hired.

Alternatives 3B and 3C

Alternative 3B is similar to 3A; data for Abenaki was substituted and the system was downsized, accordingly. Total equipment cost decreased to $165,000, while the cost of building and permits remained the same. Therefore, total capital cost became $193,750. Savings of process steam was $54,600 and electricity $19,707, based upon a 65 kW turbine. Operation/maintenance was $8,250 ($12,375), insurance $2,475, and parts $1,650.

Alternative 3C included a boiler and turbine/generator in an existing building, and running steam lines to Bel-Bar Dry Kiln. The cost of the boiler and turbine/generator would be the same as that of 3A, $330,000. The cost of piping, while only $10,000 for 3A, is increased to $144,400 for this option (800 ft. x $143/ft.). Total capital cost was $484,400. Operation/maintenance is $23,470, insurance is $7,041 and parts/contingency is $4,694.

Alternative 4. Send Request For Proposals to Potential Developers.

The request for proposals (RFP) is a summary of this project along with information on all the data collected. This RFP was reviewed by Bill Willis and John F. Herholdt of the West Virginia Fuel and Energy Office; David Warner, West Virginia Economic Development Authority; Lynette Woda, WV Governor's Office of Community and Industrial Development; Dave Stephenson, SERBEP; and the tenants of the Belington Industrial Park. All comments received were incorporated into the document and the RFP was sent to 90 developers and owners/operators of biomass energy projects on April 6, 1992. The list of recipients was obtained from an industry directory (15) and from a list provided by SERBEP.

All responses must be postmarked by June 30, 1992. At that time, a task force will have been formed consisting of representatives from the Fuel and Energy Office, Appalachian Hardwood Center, Barbour County Development Authority, and the Belington Industrial Park who will review any responses received to the RFP.

The RFP, along with the list of all the developers/owners and operators of biomass cogeneration projects is in Appendix B.

Economic Feasibility

Economic analysis incorporates the data collected on capital costs, operating costs, and savings and/or revenue, to produce a discounted cash flow for the 20-year estimated life of the project which is used to determine project feasibility.

Depreciation Methods

Biomass property which is also a qualifying small power production facility within the meaning of section 3(17)(c) of the Federal Power Act, is classified for depreciation purposes in Section 48(1)(15) of the Internal Revenue Code (12). Depreciation was taken on two classes of items: 1) equipment, and 2) business start-up costs. Depreciation was taken on the building as nonresidential real property.

Biomass equipment was depreciated using 5-year MACRS (modified accelerated cost recovery system) 200% declining balance with a half-year convention. The depreciation schedule is:

Year	Rate
1	20.00%
2	32.00%
3	19.20%
4	11.52%
5	11.52%
6	5.76%

The building is considered nonresidential real property and is depreciated over 31.5 years using a straight-line method.

Permitting and legal fees, along with project cost are considered business start-up expenses and can be amortized for not less than 60 months; an amortization period of 60 months was chosen for this project.

Method Used to Calculate Cash Flow

Cash flow was calculated by the following procedure:

1. Savings and/or Revenue - Operating Cost - Depreciation (Equipment + Building + Start-Up) - Loan Payment (Interest) = Earnings Before Income Taxes;
2. If there is a net operating loss (NOL), the loss may be carried back 3 years, or carried forward 15 years. NOL is subtracted from income before Federal taxes to determine taxable income for that year);

3. Earnings After NOL - State Income Tax = Earnings After State Tax;
4. Earnings After State Tax - Federal Income Tax = Earnings After Taxes;
5. Earnings After Taxes + Depreciation (Equipment + Building + Start-Up) + - Loan Payment (Principal) = Net Cash Flow;
6. Net Cash Flow x MARR = Present Value of Cash Flow;
7. Net present value calculated (next section).

Net Present Value Method

A discounted cash flow technique is used to account for the annual inflows and outflows and takes into consideration the time value of money. The technique used for this analysis is the net present value method (discounted payback period). The formula for calculating net present value (NPV) of cash flow is:

$$NPV=\sum_{t=1}^{N}\frac{Y_t}{(1+i)^t}-CI$$

where:
t = the year under consideration (1,2,...10);
Y_t = the net cash flow for year t (cash outflow - cash inflow);
i = the minimum acceptable rate of return (MARR);
N = the life of the project;
CI = total capital investment.

This method finds the present value of the expected net cash flows of an investment, discounted at the cost of capital, and subtracts from it the initial cost outlay of the project. If the net present value is positive, the project is acceptable, if negative, the project should be rejected (34). The cost of capital is the minimum acceptable rate of return (MARR) the investor will accept for a project.

Results

Tables 14-17 show the 20-year cash flow projections for all alternatives at MARR of 10%; these table also contain breakdowns of operating costs. The cash flow projection tables that correspond to each alternative discussed are: alternative 1 (Table 14), alternative 2 (Tables 15-16), and alternative 3 (Table 17). These projections were performed for each alternative using 8%, 10%, and 12% MARR; 10% MARR is included in this report.

ALTERNATIVE 1A:
Exide R/F Kilns; New Equipment
MARR = 10%
20-Year Loan Interest Rate = 8%

	Initial	1	2	3	4	5	6	7	8	9
Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	2,297,800									
TOTAL Plant	150,000									
TOTAL Start-up	782,428									
TOTAL Capital Cost	3,230,228									
Savings:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity		102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
TOTAL Savings		250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369
Operating Cost:										
Fixed Costs:										
Labor										
Direct		107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
Indirect		12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,656
Operation & Maintenance		73,220	73,220	73,220	73,220	73,220	109,830	109,830	109,830	109,830
Insurance		26,091	26,091	26,091	26,091	26,091	26,091	26,091	26,091	26,091
Fuel		54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		305,289	305,289	305,289	305,289	305,289	341,899	341,899	341,899	341,899
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		353,026	353,026	353,026	353,026	353,026	389,636	389,636	389,636	389,636
(Net Savings + Revenue)-Operating Cost		(102,657)	(102,657)	(102,657)	(102,657)	(102,657)	(139,267)	(139,267)	(139,267)	(139,267)
(Depreciation Equipment)		(459,560)	(735,296)	(441,178)	(264,707)	(264,707)	(132,353)			
(Depreciation Building)		(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
(Depreciation Start-up)		(156,486)	(156,486)	(156,486)	(156,486)	(156,486)				
(Loan Payment - Interest)		(257,876)	(252,772)	(246,673)	(240,086)	(232,973)	(225,290)	(216,992)	(208,031)	(198,353)
Earnings before Income Taxes		(981,341)	(1,251,973)	(951,756)	(768,697)	(761,584)	(501,672)	(361,022)	(352,060)	(342,383)
If (Net Operating Loss)										
Earnings after NOL		0	0	0	0	0	0	0	0	0
(Less State Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings before Federal Taxes		0	0	0	0	0	0	0	0	0
(Less Federal Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings after Taxes		(981,341)	(1,251,973)	(951,756)	(768,697)	(761,584)	(501,672)	(361,022)	(352,060)	(342,383)
(Depreciation Equipment)		459,560	735,296	441,178	264,707	264,707	132,353			
(Depreciation Building)		4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
(Depreciation Start-up)		156,486	156,486	156,486	156,486	156,486				
Loan Payment - Principal		(70,587)	(76,234)	(82,333)	(88,920)	(96,034)	(103,716)	(112,014)	(120,975)	(130,653)
Net Cash Flow		(431,121)	(431,663)	(431,664)	(431,663)	(431,664)	(468,273)	(468,273)	(468,273)	(468,273)
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		(391,928)	(356,746)	(324,316)	(294,832)	(268,030)	(264,328)	(240,298)	(218,453)	(198,594)
Net Present Value		(3,847,412)								

Table 14a. Cash flow projection for alternative 1a.

10	11	12	13	14	15	16	17	18	19	20
48,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
02,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
50,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369
07,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
09,830	109,830	109,830	109,830	109,830	109,830	109,830	109,830	109,830	109,830	109,830
26,091	26,091	26,091	26,091	26,091	26,091	26,091	26,091	26,091	26,091	26,091
54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
0	0	0	0	0	0	0	0	0	0	0
10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
41,899	341,899	341,899	341,899	341,899	341,899	341,899	341,899	341,899	341,899	341,899
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
9,636	389,636	389,636	389,636	389,636	389,636	389,636	389,636	389,636	389,636	389,636
9,267)	(139,267)	(139,267)	(139,267)	(139,267)	(139,267)	(139,267)	(139,267)	(139,267)	(139,267)	(139,267)
(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
7,901)	(176,613)	(164,421)	(151,255)	(137,067)	(121,676)	(105,090)	(87,177)	(67,831)	(46,936)	(24,371)
1,930)	(320,643)	(308,450)	(295,284)	(281,096)	(265,706)	(249,119)	(231,206)	(211,860)	(190,966)	(168,400)
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
1,930)	(320,643)	(308,450)	(295,284)	(281,096)	(265,706)	(249,119)	(231,206)	(211,860)	(190,966)	(168,400)
4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
1,106)	(152,394)	(164,585)	(177,752)	(191,973)	(207,330)	(223,917)	(241,829)	(261,176)	(282,070)	(304,636)
8,274)	(468,274)	(468,273)	(468,274)	(468,307)	(468,273)	(468,274)	(468,273)	(468,274)	(468,273)	(468,274)
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
0,540)	(164,127)	(149,206)	(135,642)	(123,320)	(112,101)	(101,910)	(92,645)	(84,223)	(76,566)	(69,606)

ALTERNATIVE 1B:
Include R/F/ Kilns; New Equipment
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Costs:										
TOTAL Equipment	2,607,800									
TOTAL Plant	150,000									
TOTAL Start-up	863,028									
TOTAL Capital Cost	3,620,828									
Savings:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity		201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004
TOTAL Savings		349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081
Operating Cost:										
Fixed Costs:										
Labor										
Direct		107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
Indirect		12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
Operation & Maintenance		82,821	82,821	82,821	82,821	82,821	124,232	124,232	124,232	124,232
Insurance		28,971	28,971	28,971	28,971	28,971	28,971	28,971	28,971	28,971
Fuel		54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		317,770	317,770	317,770	317,770	317,770	359,181	359,181	359,181	359,181
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		365,507	365,507	365,507	365,507	365,507	406,918	406,918	406,918	406,918
(Net Savings + Revenue)-Operating Cost		(16,426)	(16,426)	(16,426)	(16,426)	(16,426)	(57,836)	(57,836)	(57,836)	(57,836)
(Depreciation Equipment)		(521,560)	(834,496)	(500,698)	(300,419)	(300,419)	(150,209)			
(Depreciation Building)		(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
(Depreciation Start-up)		(172,606)	(172,606)	(172,606)	(172,606)	(172,606)				
(Loan Payment - Interest)		(289,059)	(283,337)	(276,501)	(269,117)	(261,144)	(252,532)	(243,231)	(233,186)	(222,33[illegible])
Earnings before Income Taxes		(1,004,412)	(1,311,626)	(970,992)	(763,329)	(755,356)	(465,339)	(305,829)	(295,785)	(284,937)
If (Net Operating Loss)										
Earnings after NOL		0	0	0	0	0	0	0	0	0
(Less State Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings before Federal Taxes		0	0	0	0	0	0	0	0	0
(Less Federal Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings after Taxes		(1,004,412)	(1,311,626)	(970,992)	(763,329)	(755,356)	(465,339)	(305,829)	(295,785)	(284,937)
(Depreciation Equipment)		521,560	834,496	500,698	300,419	300,419	150,209			
(Depreciation Building)		4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
(Depreciation Start-up)		172,606	172,606	172,606	172,606	172,606				
Loan Payment - Principal		(79,123)	(85,452)	(92,289)	(99,672)	(107,646)	(116,258)	(125,558)	(135,603)	(146,451)
Net Cash Flow		(384,607)	(385,215)	(385,216)	(385,215)	(385,216)	(426,626)	(426,626)	(426,626)	(426,626)
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		(349,643)	(318,360)	(289,419)	(263,107)	(239,189)	(240,819)	(218,926)	(199,024)	(180,931)
Net Present Value		(3,442,385)								

able 14b. Cash flow projection for alternative 1b.

0	11	12	13	14	15	16	17	18	19	20
8,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
1,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004
9,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081
7,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
2,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
4,232	124,232	124,232	124,232	124,232	124,232	124,232	124,232	124,232	124,232	124,232
8,971	28,971	28,971	28,971	28,971	28,971	28,971	28,971	28,971	28,971	28,971
4,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
0	0	0	0	0	0	0	0	0	0	0
0,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
5,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
9,181	359,181	359,181	359,181	359,181	359,181	359,181	359,181	359,181	359,181	359,181
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
8,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
4,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
6,918	406,918	406,918	406,918	406,918	406,918	406,918	406,918	405,918	406,918	406,918
7,836)	(57,836)	(57,836)	(57,836)	(57,836)	(57,836)	(57,836)	(57,836)	(57,836)	(57,836)	(57,836)
,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
,622)	(197,969)	(184,303)	(169,544)	(153,641)	(136,389)	(117,798)	(97,718)	(76,033)	(52,612)	(27,318)
,221)	(260,568)	(246,901)	(232,143)	(216,239)	(198,988)	(180,396)	(160,317)	(138,631)	(115,210)	(89,917)
									2,755	25,237
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
,221)	(260,568)	(246,901)	(232,143)	(216,239)	(198,988)	(180,396)	(160,317)	(138,631)	0	0
,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
,168)	(170,821)	(184,486)	(199,246)	(215,186)	(232,400)	(250,993)	(271,071)	(292,758)	(316,177)	(341,472)
,627)	(426,627)	(426,626)	(426,627)	(426,663)	(426,626)	(426,627)	(426,626)	(426,627)	(311,416)	(336,710)
.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
,483)	(149,530)	(135,936)	(123,579)	(112,354)	(102,131)	(92,846)	(84,406)	(76,733)	(50,919)	(50,050)

ALTERNATIVE 1C:
Exclude R/F/ Kilns; Used Equipment
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	2,135,300									
TOTAL Plant	150,000									
TOTAL Start-up	740,178									
TOTAL Capital Cost	3,025,478									
Savings:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity		102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
TOTAL Savings		250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369
Operating Cost:										
Fixed Costs:										
Labor										
Direct		107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
Indirect		12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
Operation & Maintenance		84,470	84,470	84,470	84,470	84,470	118,205	118,205	118,205	118,205
Insurance		24,366	24,366	24,366	24,366	24,366	24,366	24,366	24,366	24,366
Fuel		54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		314,814	314,814	314,814	314,814	314,814	348,549	348,549	348,549	348,549
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		362,551	362,551	362,551	362,551	362,551	396,286	396,286	396,286	396,286
(Net Savings + Revenue)-Operating Cost		(112,182)	(112,182)	(112,182)	(112,182)	(112,182)	(145,917)	(145,917)	(145,917)	(145,917)
(Depreciation Equipment)		(427,060)	(683,296)	(409,978)	(245,987)	(245,987)	(122,993)			
(Depreciation Building)		(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
(Depreciation Start-up)		(148,036)	(148,036)	(148,036)	(148,036)	(148,036)				
(Loan Payment - Interest)		(241,530)	(236,750)	(231,038)	(224,868)	(218,206)	(211,010)	(203,238)	(194,845)	(185,781)
Earnings before Income Taxes		(933,570)	(1,185,025)	(905,995)	(735,834)	(729,172)	(484,682)	(353,917)	(345,524)	(336,460)
If (Net Operating Loss)										
Earnings after NOL		0	0	0	0	0	0	0	0	0
(Less State Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings before Federal Taxes		0	0	0	0	0	0	0	0	0
(Less Federal Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings after Taxes		(933,570)	(1,185,025)	(905,995)	(735,834)	(729,172)	(484,682)	(353,917)	(345,524)	(336,460)
(Depreciation Equipment)		427,060	683,296	409,978	245,987	245,987	122,993			
(Depreciation Building)		4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
(Depreciation Start-up)		148,036	148,036	148,036	148,036	148,036				
Loan Payment - Principal		(66,113)	(71,402)	(77,115)	(83,284)	(89,947)	(97,142)	(104,914)	(113,307)	(122,371)
Net Cash Flow		(419,826)	(420,334)	(420,335)	(420,334)	(420,335)	(454,069)	(454,069)	(454,069)	(454,069)
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		(381,660)	(347,383)	(315,804)	(287,094)	(260,995)	(256,310)	(233,009)	(211,827)	(192,570)
Net Present Value		(3,737,412)								

Table 14 c. Cash flow projection for alternative 1c.

10	11	12	13	14	15	16	17	18	19	20
148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369	250,369
107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
118,205	118,205	118,205	118,205	118,205	118,205	118,205	118,205	118,205	118,205	118,205
24,366	24,366	24,366	24,366	24,366	24,366	24,366	24,366	24,366	24,366	24,366
54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
0	0	0	0	0	0	0	0	0	0	0
10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
48,549	348,549	348,549	348,549	348,549	348,549	348,549	348,549	348,549	348,549	348,549
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
96,286	396,286	396,286	396,286	396,286	396,286	396,286	396,286	396,286	396,286	396,286
45,917)	(145,917)	(145,917)	(145,917)	(145,917)	(145,917)	(145,917)	(145,917)	(145,917)	(145,917)	(145,917)
(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
75,991)	(165,419)	(153,999)	(141,667)	(128,379)	(113,964)	(98,429)	(81,651)	(63,531)	(43,961)	(22,826)
26,670)	(316,098)	(304,678)	(292,346)	(279,058)	(264,643)	(249,108)	(232,330)	(214,210)	(194,640)	(173,506)
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0
26,670)	(316,098)	(304,678)	(292,346)	(279,058)	(264,643)	(249,108)	(232,330)	(214,210)	(194,640)	(173,506)
4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
2,162)	(142,734)	(154,152)	(166,485)	(179,804)	(194,188)	(209,724)	(226,501)	(244,621)	(264,190)	(285,326)
4,070)	(454,070)	(454,069)	(454,070)	(454,100)	(454,069)	(454,070)	(454,069)	(454,070)	(454,069)	(454,070)
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
5,064)	(159,149)	(144,680)	(131,528)	(119,579)	(108,700)	(98,819)	(89,835)	(81,668)	(74,244)	(67,495)

ALTERNATIVE 1D:
Include R/F/ Kilns; Used Equipment
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	2,395,300									
TOTAL Plant	150,000									
TOTAL Start-up	807,778									
TOTAL Capital Cost	3,353,078									
Savings:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity		201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004
TOTAL Savings		349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081
Operating Cost:										
Fixed Costs:										
Labor										
Direct		107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
Indirect		12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
Operation & Maintenance		97,533	97,533	97,533	97,533	97,533	135,184	135,184	135,184	135,184
Insurance		26,716	26,716	26,716	26,716	26,716	26,716	26,716	26,716	26,716
Fuel		54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		330,226	330,226	330,226	330,226	330,226	367,877	367,877	367,877	367,877
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		377,963	377,963	377,963	377,963	377,963	415,614	415,614	415,614	415,614
(Net Savings + Revenue)-Operating Cost		(28,882)	(28,882)	(28,882)	(28,882)	(28,882)	(66,533)	(66,533)	(66,533)	(66,533)
(Depreciation Equipment)		(479,060)	(766,496)	(459,898)	(275,939)	(275,939)	(137,969)			
(Depreciation Building)		(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
(Depreciation Start-up)		(161,556)	(161,556)	(161,556)	(161,556)	(161,556)				
(Loan Payment - Interest)		(267,684)	(262,385)	(256,055)	(249,217)	(241,833)	(233,858)	(225,245)	(215,943)	(205,897)
Earnings before Income Taxes		(941,943)	(1,224,080)	(911,152)	(720,355)	(712,971)	(443,122)	(296,540)	(287,238)	(277,192)
If (Net Operating Loss)										
Earnings after NOL		0	0	0	0	0	0	0	0	0
(Less State Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings before Federal Taxes		0	0	0	0	0	0	0	0	0
(Less Federal Income Taxes)		0	0	0	0	0	0	0	0	0
Earnings after Taxes		(941,943)	(1,224,080)	(911,152)	(720,355)	(712,971)	(443,122)	(296,540)	(287,238)	(277,192)
(Depreciation Equipment)		479,060	766,496	459,898	275,939	275,939	137,969			
(Depreciation Building)		4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
(Depreciation Start-up)		161,556	161,556	161,556	161,556	161,556				
Loan Payment - Principal		(73,272)	(79,133)	(85,465)	(92,302)	(99,686)	(107,661)	(116,274)	(125,575)	(135,621)
Net Cash Flow		(369,837)	(370,400)	(370,401)	(370,400)	(370,401)	(408,051)	(408,051)	(408,051)	(408,051)
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		(336,216)	(306,116)	(278,288)	(252,988)	(229,990)	(230,334)	(209,395)	(190,359)	(173,054)
Net Present Value		(3,232,019)								

able 14 d. Cash flow projection for alternative 1d.

10	11	12	13	14	15	16	17	18	19	20
48,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
01,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004	201,004
49,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081	349,081
07,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712	107,712
12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666	12,666
35,184	135,184	135,184	135,184	135,184	135,184	135,184	135,184	135,184	135,184	135,184
26,716	26,716	26,716	26,716	26,716	26,716	26,716	26,716	26,716	26,716	26,716
54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
0	0	0	0	0	0	0	0	0	0	0
10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
57,877	367,877	367,877	367,877	367,877	367,877	367,877	367,877	367,877	367,877	367,877
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
5,614	415,614	415,614	415,614	415,614	415,614	415,614	415,614	415,614	415,614	415,614
66,533)	(66,533)	(66,533)	(66,533)	(66,533)	(66,533)	(66,533)	(66,533)	(66,533)	(66,533)	(66,533)
4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)	(4,762)
5,047)	(183,330)	(170,674)	(157,007)	(142,280)	(126,304)	(109,087)	(90,492)	(70,410)	(48,721)	(25,298)
6,342)	(254,625)	(241,969)	(228,302)	(213,574)	(197,598)	(180,382)	(161,787)	(141,705)	(120,016)	(96,593)
						7,370	23,319	40,544	59,148	79,239
0	0	0	0	0	0	(187,752)	(185,106)	(182,249)		(175,832)
0	0	0	0	0	0	0	0	0		0
0	0	0	0	0	0	(187,752)	(185,106)	(182,249)	0	(175,832)
0	0	0	0	0	0	0	0	0	0	0
6,342)	(254,625)	(241,969)	(228,302)	(213,574)	(197,598)	0	(161,787)	0	0	0
4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762	4,762
6,472)	(158,189)	(170,844)	(184,513)	(199,273)	(215,215)	(232,433)	(251,026)	(271,109)	(292,797)	(316,221)
3,052)	(408,052)	(408,051)	(408,052)	(408,086)	(408,051)	(227,671)	(408,051)	(266,347)	(288,035)	(311,460)
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
7,322)	(143,020)	(130,018)	(118,198)	(107,462)	(97,684)	(49,548)	(80,731)	(47,905)	(47,096)	(46,296)

ALTERNATIVE 2A(1):
25-Mile Radius; New Equipment - 1.0 MW
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	2,832,800									
TOTAL Plant	185,000									
TOTAL Start-up	1,011,528									
TOTAL Capital Cost	4,029,328									
Savings and Revenue:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (savings)		102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
Electricity (revenue)		2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291
TOTAL Savings and Revenue		2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660
Operating Cost:										
Fixed Costs:										
Labor										
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance		89,095	89,095	89,095	89,095	89,095	133,643	133,643	133,643	133,643
Insurance		31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816
Fuel		266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		577,668	577,668	577,668	577,668	577,668	622,215	622,215	622,215	622,215
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		625,405	625,405	625,405	625,405	625,405	669,952	669,952	669,952	669,952
(Net Savings + Revenue)-Operating Cost		2,052,255	2,052,255	2,052,255	2,052,255	2,052,255	2,007,708	2,007,708	2,007,708	2,007,708
(Depreciation Equipment)		(566,560)	(906,496)	(543,898)	(326,339)	(326,339)	(163,169)			
(Depreciation Building)		(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
(Depreciation Start-up)		(202,306)	(202,306)	(202,306)	(202,306)	(202,306)				
(Loan Payment - Interest)		(321,670)	(315,303)	(307,696)	(299,479)	(290,606)	(281,022)	(270,672)	(259,494)	(247,422)
Earnings before Income Taxes		955,847	622,278	992,483	1,218,259	1,227,132	1,557,643	1,731,162	1,742,340	1,754,412
If (Net Operating Loss)										
Earnings after NOL		955,847	622,278	992,483	1,218,259	1,227,132	1,557,643	1,731,162	1,742,340	1,754,412
(Less State Income Taxes)		86,026	56,005	89,323	109,643	110,442	140,188	155,805	156,811	157,897
Earnings before Federal Taxes		869,820	566,273	903,159	1,108,616	1,116,690	1,417,455	1,575,358	1,585,530	1,596,515
(Less Federal Income Taxes)		295,739	192,533	307,074	376,929	379,675	481,935	535,622	539,080	542,815
Earnings after Taxes		574,081	373,740	596,085	731,687	737,015	935,520	1,039,736	1,046,450	1,053,700
(Depreciation Equipment)		566,560	906,496	543,898	326,339	326,339	163,169			
(Depreciation Building)		5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
(Depreciation Start-up)		202,306	202,306	202,306	202,306	202,306				
Loan Payment - Principal		(88,050)	(95,093)	(102,701)	(110,917)	(119,791)	(129,374)	(139,724)	(150,902)	(162,974)
Net Cash Flow		1,260,770	1,393,321	1,245,460	1,155,286	1,151,741	975,189	905,885	901,421	896,599
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		1,146,155	1,151,505	935,733	789,076	715,141	550,469	464,862	420,520	380,246
Net Present Value		8,930,255								

able 15a. Cash flow projection for alternative 2a(25-mi).

10	11	12	13	14	15	16	17	18	19	20
48,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
02,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
27,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291	2,427,291
77,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660	2,677,660
44,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
33,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643
31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816
66,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
0	0	0	0	0	0	0	0	0	0	0
10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
22,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
17,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
59,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952
07,708	2,007,708	2,007,708	2,007,708	2,007,708	2,007,708	2,007,708	2,007,708	2,007,708	2,007,708	2,007,708
(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
4,385)	(220,304)	(205,096)	(188,672)	(170,975)	(151,777)	(131,088)	(108,743)	(84,611)	(58,548)	(30,400)
57,450	1,781,530	1,796,739	1,813,162	1,830,860	1,850,058	1,870,747	1,893,092	1,917,224	1,943,287	1,971,434
57,450	1,781,530	1,796,739	1,813,162	1,830,860	1,850,058	1,870,747	1,893,092	1,917,224	1,943,287	1,971,434
59,071	160,338	161,706	163,185	164,777	166,505	168,367	170,378	172,550	174,896	177,429
8,380	1,621,193	1,635,032	1,649,978	1,666,082	1,683,553	1,702,380	1,722,714	1,744,674	1,768,391	1,794,005
6,849	551,206	555,911	560,992	566,468	572,408	578,809	585,723	593,189	601,253	609,962
1,530	1,069,987	1,079,121	1,088,985	1,099,614	1,111,145	1,123,571	1,136,991	1,151,485	1,167,138	1,184,044
5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
6,013)	(190,093)	(205,300)	(221,725)	(239,463)	(258,619)	(279,310)	(301,653)	(325,786)	(351,848)	(379,997)
1,391	885,767	879,694	873,133	866,024	858,399	850,134	841,211	831,571	821,163	809,919
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
3,670	310,456	280,298	252,916	228,051	205,494	185,014	166,429	149,565	134,267	120,389

ALTERNATIVE 2B(1):
25-Mile Radius; Used Equipment - 2.3 MW
MARR = 10%
20-Year Loan Interest Rate = 8%

	Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:											
TOTAL Equipment		2,532,800									
TOTAL Plant		185,000									
TOTAL Start-up		933,528									
TOTAL Capital Cost		3,651,328									
Savings and Revenue:											
Natural Gas for Process Steam			148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (savings)			102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
Electricity (revenue)			2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791
TOTAL Savings and Revenue			2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160
Operating Cost:											
Fixed Costs:											
Labor											
Direct			144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect			15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance			117,595	117,595	117,595	117,595	117,595	156,393	156,393	156,393	156,393
Insurance			28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366
Property Tax			0	0	0	0	0	0	0	0	0
Fuel			266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
Parts			10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies			6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency			15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs			602,718	602,718	602,718	602,718	602,718	641,515	641,515	641,515	641,515
Variable Costs:											
Water			2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity			28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment			14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal			3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs			47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)			650,455	650,455	650,455	650,455	650,455	689,252	689,252	689,252	689,252
(Net Savings + Revenue)-Operating Cost			1,874,705	1,874,705	1,874,705	1,874,705	1,874,705	1,835,908	1,835,908	1,835,908	1,835,908
(Depreciation Equipment)			(506,560)	(810,496)	(486,298)	(291,779)	(291,779)	(145,889)			
(Depreciation Building)			(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
(Depreciation Start-up)			(186,706)	(186,706)	(186,706)	(186,706)	(186,706)				
(Loan Payment - Interest)			(291,493)	(285,724)	(278,830)	(271,384)	(263,344)	(254,659)	(245,280)	(235,151)	(224,211)
Earnings before Income Taxes			884,073	585,907	916,999	1,118,964	1,127,004	1,429,486	1,584,755	1,594,884	1,605,824
If (Net Operating Loss)											
Earnings after NOL			884,073	585,907	916,999	1,118,964	1,127,004	1,429,486	1,584,755	1,594,884	1,605,824
(Less State Income Taxes)			79,567	52,732	82,530	100,707	101,430	128,654	142,628	143,540	144,524
Earnings before Federal Taxes			804,507	533,175	834,469	1,018,257	1,025,574	1,300,833	1,442,127	1,451,344	1,461,299
(Less Federal Income Taxes)			273,532	181,280	283,719	346,207	348,695	442,283	490,323	493,457	496,842
Earnings after Taxes			530,974	351,896	550,749	672,050	676,879	858,550	951,804	957,887	964,458
(Depreciation Equipment)			506,560	810,496	486,298	291,779	291,779	145,889			
(Depreciation Building)			5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
(Depreciation Start-up)			186,706	186,706	186,706	186,706	186,706				
Loan Payment - Principal			(79,789)	(86,172)	(93,067)	(100,512)	(108,553)	(117,237)	(126,616)	(136,745)	(147,685)
Net Cash Flow			1,150,323	1,268,798	1,136,559	1,055,895	1,052,683	893,075	831,061	827,015	822,646
PVIF @ 10%			0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow			1,045,749	1,048,593	853,914	721,191	653,633	504,118	426,466	385,809	348,882
Net Present Value			8,169,935								

Table 15b. Cash flow projection for alternative 2b(25-mi).

10	11	12	13	14	15	16	17	18	19	20
48,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
02,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
74,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,274,791	2,276,791
25,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160	2,525,160
4,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
5,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
6,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393
8,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366
0	0	0	0	0	0	0	0	0	0	0
6,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
0,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
5,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
1,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
8,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
4,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
9,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252
5,908	1,835,908	1,835,908	1,835,908	1,835,908	1,835,908	1,835,908	1,835,908	1,835,908	1,835,908	1,835,908
5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
2,396)	(199,637)	(185,856)	(170,972)	(154,935)	(137,538)	(118,790)	(98,541)	(76,673)	(53,055)	(27,548)
7,638	1,630,398	1,644,179	1,659,062	1,675,099	1,692,496	1,711,245	1,731,493	1,753,361	1,776,980	1,802,486
7,638	1,630,398	1,644,179	1,659,062	1,675,099	1,692,496	1,711,245	1,731,493	1,753,361	1,776,980	1,802,486
5,587	146,736	147,976	149,316	150,759	152,325	154,012	155,834	157,803	159,928	162,224
2,051	1,483,662	1,496,203	1,509,747	1,524,340	1,540,172	1,557,233	1,575,659	1,595,559	1,617,051	1,640,263
0,497	504,445	508,709	513,314	518,276	523,658	529,459	535,724	542,490	549,797	557,689
1,553	979,217	987,494	996,433	1,006,065	1,016,513	1,027,774	1,039,935	1,053,069	1,067,254	1,082,573
5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
9,501)	(172,260)	(186,040)	(200,925)	(216,998)	(234,358)	(253,107)	(273,354)	(295,224)	(318,841)	(344,349)
7,926	812,830	807,327	801,381	794,939	788,029	780,540	772,453	763,718	754,286	744,098
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
5,346	284,892	257,239	232,132	209,332	188,648	169,868	152,826	137,361	123,332	110,605

ALTERNATIVE 2C(1):
25-Mile Radius; New Equipment - 2.3 MW
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9	
Project Cost:											
TOTAL Equipment	2,832,800										
TOTAL Plant	185,000										
TOTAL Start-up	1,011,528										
TOTAL Capital Cost	4,029,328										
Savings and Revenue:											
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	
Electricity (revenue)		2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2
TOTAL Savings and Revenue		2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2
Operating Cost:											
Fixed Costs:											
Labor											
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	
Operation & Maintenance		89,095	89,095	89,095	89,095	89,095	133,643	133,643	133,643	133,643	
Insurance		31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	
Property Tax		0	0	0	0	0	0	0	0	0	
Fuel		266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	
TOTAL Fixed Costs		577,668	577,668	577,668	577,668	577,668	622,215	622,215	622,215	622,215	
Variable Costs:											
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	
TOTAL Operating Costs (Fixed & Variable)		625,405	625,405	625,405	625,405	625,405	669,952	669,952	669,952	669,952	
(Net Savings + Revenue)-Operating Cost		2,244,272	2,244,272	2,244,272	2,244,272	2,244,272	2,199,725	2,199,725	2,199,725	2,199,725	2,
(Depreciation Equipment)		(566,560)	(906,496)	(543,898)	(326,339)	(326,339)	(163,169)				
(Depreciation Building)		(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	
(Depreciation Start-up)		(202,306)	(202,306)	(202,306)	(202,306)	(202,306)					
(Loan Payment - Interest)		(321,670)	(315,303)	(307,696)	(299,479)	(290,606)	(281,022)	(270,672)	(259,494)	(247,422)	(
Earnings before Income Taxes		1,147,863	814,295	1,184,500	1,410,276	1,419,149	1,749,660	1,923,179	1,934,357	1,946,429	1.
If (Net Operating Loss)											
Earnings after NOL		1,147,863	814,295	1,184,500	1,410,276	1,419,149	1,749,660	1,923,179	1,934,357	1,946,429	1.
(Less State Income Taxes)		103,308	73,287	106,605	126,925	127,723	157,469	173,086	174,092	175,179	
Earnings before Federal Taxes		1,044,556	741,008	1,077,895	1,283,351	1,291,425	1,592,191	1,750,093	1,760,265	1,771,251	1.
(Less Federal Income Taxes)		355,149	251,943	366,484	436,339	439,085	541,345	595,032	598,490	602,225	
Earnings after Taxes		689,407	489,065	711,411	847,012	852,341	1,050,846	1,155,061	1,161,775	1,169,025	1.
(Depreciation Equipment)		566,560	906,496	543,898	326,339	326,339	163,169				
(Depreciation Building)		5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	
(Depreciation Start-up)		202,306	202,306	202,306	202,306	202,306					
Loan Payment - Principal		(88,050)	(95,093)	(102,701)	(110,917)	(119,791)	(129,374)	(139,724)	(150,902)	(162,974)	(
Net Cash Flow		1,376,096	1,508,647	1,360,786	1,270,612	1,267,067	1,090,514	1,021,211	1,016,746	1,011,925	1.
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	
Present Value of Cash Flow		1,250,996	1,246,816	1,022,378	867,845	786,749	615,567	524,043	474,320	429,155	
Net Present Value		9,912,085									

'able 15c. Cash flow projection for alternative 2c(25-mi).

0	11	12	13	14	15	16	17	18	19	20
8,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
1,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600	2,721,600
9,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677	2,869,677
4,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
5,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
3,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643	133,643
1,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816	31,816
0	0	0	0	0	0	0	0	0	0	0
6,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
0,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
5,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
2,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215	622,215
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
8,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
4,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
9,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952	669,952
9,725	2,199,725	2,199,725	2,199,725	2,199,725	2,199,725	2,199,725	2,199,725	2,199,725	2,199,725	2,199,725
5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
,385)	(220,304)	(205,096)	(188,672)	(170,975)	(151,777)	(131,088)	(108,743)	(84,611)	(58,548)	(30,400)
9,467	1,973,547	1,988,756	2,005,179	2,022,877	2,042,075	2,062,764	2,085,109	2,109,241	2,135,304	2,163,451
9,467	1,973,547	1,988,756	2,005,179	2,022,877	2,042,075	2,062,764	2,085,109	2,109,241	2,135,304	2,163,451
6,352	177,619	178,988	180,466	182,059	183,787	185,649	187,660	189,832	192,177	194,711
8,115	1,795,928	1,809,768	1,824,713	1,840,818	1,858,288	1,877,115	1,897,449	1,919,409	1,943,127	1,968,741
6,259	610,616	615,321	620,402	625,878	631,818	638,219	645,133	652,599	660,663	669,372
6,856	1,185,313	1,194,447	1,204,311	1,214,940	1,226,470	1,238,896	1,252,316	1,266,810	1,282,464	1,299,369
5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
,013)	(190,093)	(205,300)	(221,725)	(239,463)	(258,619)	(279,310)	(301,653)	(325,786)	(351,848)	(379,997)
,716	1,001,092	995,020	988,459	981,350	973,724	965,459	956,536	946,897	936,488	925,245
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
,133	350,877	317,044	286,321	258,420	233,102	210,112	189,246	170,308	153,123	137,532

ALTERNATIVE 2D(1):
25-Mile Radius; Used Equipment - 2.3 MW
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	2,532,800									
TOTAL Plant	185,000									
TOTAL Start-up	933,528									
TOTAL Capital Cost	3,651,328									
Savings and Revenue:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (revenue)		2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000
TOTAL Savings and Revenue		2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077
Operating Cost:										
Fixed Costs:										
Labor										
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance		117,595	117,595	117,595	117,595	117,595	156,393	156,393	156,393	156,393
Insurance		28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366
Property Tax		0	0	0	0	0	0	0	0	0
Fuel		266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		602,718	602,718	602,718	602,718	602,718	641,515	641,515	641,515	641,515
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		650,455	650,455	650,455	650,455	650,455	689,252	689,252	689,252	689,252
(Net Savings + Revenue)-Operating Cost		1,849,622	1,849,622	1,849,622	1,849,622	1,849,622	1,810,825	1,810,825	1,810,825	1,810,825
(Depreciation Equipment)		(506,560)	(810,496)	(486,298)	(291,779)	(291,779)	(145,889)			
(Depreciation Building)		(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
(Depreciation Start-up)		(186,706)	(186,706)	(186,706)	(186,706)	(186,706)				
(Loan Payment - Interest)		(291,493)	(285,724)	(278,830)	(271,384)	(263,344)	(254,659)	(245,280)	(235,151)	(224,211)
Earnings before Income Taxes		858,990	560,824	891,915	1,093,881	1,101,921	1,404,403	1,559,672	1,569,801	1,580,740
If (Net Operating Loss)										
Earnings after NOL		858,990	560,824	891,915	1,093,881	1,101,921	1,404,403	1,559,672	1,569,801	1,580,740
(Less State Income Taxes)		77,309	50,474	80,272	98,449	99,173	126,396	140,370	141,282	142,267
Earnings before Federal Taxes		781,681	510,350	811,643	995,432	1,002,748	1,278,007	1,419,301	1,428,519	1,438,474
(Less Federal Income Taxes)		265,772	173,519	275,959	338,447	340,934	434,522	482,562	485,696	489,081
Earnings after Taxes		515,909	336,831	535,684	656,985	661,814	843,485	936,739	942,822	949,393
(Depreciation Equipment)		506,560	810,496	486,298	291,779	291,779	145,889			
(Depreciation Building)		5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
(Depreciation Start-up)		186,706	186,706	186,706	186,706	186,706				
Loan Payment - Principal		(79,789)	(86,172)	(93,067)	(100,512)	(108,553)	(117,237)	(126,616)	(136,745)	(147,685)
Net Cash Flow		1,135,259	1,253,733	1,121,494	1,040,830	1,037,618	878,010	815,996	811,950	807,581
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		1,032,053	1,036,143	842,595	710,901	644,279	495,614	418,735	378,781	342,493
Net Present Value		8,041,679								

Table 15d. Cash flow projection for alternative 2d(25-mi).

10	11	12	13	14	15	16	17	18	19	20
48,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
52,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000	2,352,000
00,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077	2,500,077
44,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
56,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393	156,393
28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366	28,366
0	0	0	0	0	0	0	0	0	0	0
66,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000
10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
41,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515	641,515
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
89,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252	689,252
10,825	1,810,825	1,810,825	1,810,825	1,810,825	1,810,825	1,810,825	1,810,825	1,810,825	1,810,825	1,810,825
(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)	(5,873)
2,396)	(199,637)	(185,856)	(170,972)	(154,935)	(137,538)	(118,790)	(98,541)	(76,673)	(53,055)	(27,548)
2,555	1,605,315	1,619,096	1,633,979	1,650,016	1,667,413	1,686,161	1,706,410	1,728,278	1,751,897	1,777,403
2,555	1,605,315	1,619,096	1,633,979	1,650,016	1,667,413	1,686,161	1,706,410	1,728,278	1,751,897	1,777,403
3,330	144,478	145,719	147,058	148,501	150,067	151,755	153,577	155,545	157,671	159,966
9,225	1,460,836	1,473,377	1,486,921	1,501,515	1,517,346	1,534,407	1,552,833	1,572,733	1,594,226	1,617,437
2,737	496,684	500,948	505,553	510,515	515,898	521,698	527,963	534,729	542,037	549,929
6,489	964,152	972,429	981,368	991,000	1,001,448	1,012,709	1,024,870	1,038,004	1,052,189	1,067,508
5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873	5,873
9,501)	(172,260)	(186,040)	(200,925)	(216,998)	(234,358)	(253,107)	(273,354)	(295,224)	(318,841)	(344,349)
2,861	797,765	792,262	786,316	779,874	772,964	765,475	757,389	748,653	739,221	729,033
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
9,538	279,612	252,439	227,768	205,365	185,041	166,590	149,845	134,652	120,869	108,366

ALTERNATIVE 2A(2):
50-Mile Radius; New Equipment - 6 MW
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	4,727,800									
TOTAL Plant	207,500									
TOTAL Start-up	1,504,228									
TOTAL Capital Cost	6,439,528									
Savings and Revenue:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (savings)		102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
Electricity (revenue)		4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952
TOTAL Savings and Revenue		4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321
Operating Cost:										
Fixed Costs:										
Labor										
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance		153,595	153,595	153,595	153,595	153,595	230,393	230,393	230,393	230,393
Insurance		51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785
Fuel		668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		1,064,637	1,064,637	1,064,637	1,064,637	1,064,637	1,141,434	1,141,434	1,141,434	1,141,434
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		1,112,374	1,112,374	1,112,374	1,112,374	1,112,374	1,189,171	1,189,171	1,189,171	1,189,171
(Net Savings + Revenue)-Operating Cost		3,281,947	3,281,947	3,281,947	3,281,947	3,281,947	3,205,150	3,205,150	3,205,150	3,205,150
(Depreciation Equipment)		(945,560)	(1,512,896)	(907,738)	(544,643)	(544,643)	(272,321)			
(Depreciation Building)		(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
(Depreciation Start-up)		(300,846)	(300,846)	(300,846)	(300,846)	(300,846)				
(Loan Payment - Interest)		(514,082)	(503,906)	(491,749)	(478,616)	(464,437)	(449,120)	(432,579)	(414,715)	(395,422)
Earnings before Income Taxes		1,514,873	957,712	1,575,028	1,951,255	1,965,435	2,477,121	2,765,984	2,783,848	2,803,141
If (Net Operating Loss)										
Earnings after NOL		1,514,873	957,712	1,575,028	1,951,255	1,965,435	2,477,121	2,765,984	2,783,848	2,803,141
(Less State Income Taxes)		136,339	86,194	141,753	175,613	176,889	222,941	248,939	250,546	252,283
Earnings before Federal Taxes		1,378,534	871,518	1,433,275	1,775,642	1,788,546	2,254,180	2,517,045	2,533,301	2,550,858
(Less Federal Income Taxes)		468,702	296,316	487,314	603,718	608,106	766,421	855,795	861,322	867,292
Earnings after Taxes		909,832	575,202	945,962	1,171,924	1,180,440	1,487,759	1,661,250	1,671,979	1,683,566
(Depreciation Equipment)		945,560	1,512,896	907,738	544,643	544,643	272,321			
(Depreciation Building)		6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
(Depreciation Start-up)		300,846	300,846	300,846	300,846	300,846				
Loan Payment - Principal		(140,718)	(151,974)	(164,134)	(177,264)	(191,446)	(206,760)	(223,301)	(241,166)	(260,459)
Net Cash Flow		2,022,108	2,243,557	1,996,999	1,846,735	1,841,070	1,559,907	1,444,536	1,437,401	1,429,695
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		1,838,280	1,854,179	1,500,375	1,261,345	1,143,160	880,527	741,275	670,558	606,330
Net Present Value		14,285,279								

able 16a. Cash flow projection for alternative 2a(50-mi).

10	11	12	13	14	15	16	17	18	19	20
148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
02,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
43,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952	4,143,952
94,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321	4,394,321
44,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
30,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393
51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785
68,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
0	0	0	0	0	0	0	0	0	0	0
10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
41,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
89,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171
05,150	3,205,150	3,205,150	3,205,150	3,205,150	3,205,150	3,205,150	3,205,150	3,205,150	3,205,150	3,205,150
(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
74,585)	(352,082)	(327,777)	(301,529)	(273,246)	(242,564)	(209,500)	(173,789)	(135,222)	(93,569)	(48,585)
23,977	2,846,480	2,870,785	2,897,033	2,925,316	2,955,998	2,989,063	3,024,774	3,063,340	3,104,994	3,149,978
23,977	2,846,480	2,870,785	2,897,033	2,925,316	2,955,998	2,989,063	3,024,774	3,063,340	3,104,994	3,149,978
54,158	256,183	258,371	260,733	263,278	266,040	269,016	272,230	275,701	279,449	283,498
59,819	2,590,297	2,612,414	2,636,300	2,662,038	2,689,958	2,720,047	2,752,544	2,787,640	2,825,544	2,866,480
73,739	880,701	888,221	896,342	905,093	914,586	924,816	935,865	947,797	960,685	974,603
96,081	1,709,596	1,724,194	1,739,958	1,756,945	1,775,372	1,795,231	1,816,679	1,839,842	1,864,859	1,891,877
6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
1,297)	(303,800)	(328,103)	(354,353)	(382,701)	(413,316)	(446,383)	(482,091)	(520,660)	(562,312)	(607,298)
1,371	1,412,383	1,402,678	1,392,192	1,380,831	1,368,644	1,355,436	1,341,175	1,325,769	1,309,135	1,291,166
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
8,000	495,032	446,936	403,269	363,616	327,642	294,982	265,344	238,451	214,054	191,924

ALTERNATIVE 2B(2):

25-Mile Radius; Used Equipment - 6 MW

MARR = 10%

20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	3,877,800									
TOTAL Plant	207,500									
TOTAL Start-up	1,283,228									
TOTAL Capital Cost	5,368,528									
Savings and Revenue:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (savings)		102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
Electricity (revenue)		3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200
TOTAL Savings and Revenue		3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569
Operating Cost:										
Fixed Costs:										
Labor										
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance		241,095	241,095	241,095	241,095	241,095	301,643	301,643	301,643	301,643
Insurance		42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035
Property Tax		0	0	0	0	0	0	0	0	0
Fuel		668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		1,142,387	1,142,387	1,142,387	1,142,387	1,142,387	1,202,934	1,202,934	1,202,934	1,202,934
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		1,190,124	1,190,124	1,190,124	1,190,124	1,190,124	1,250,671	1,250,671	1,250,671	1,250,671
(Net Savings + Revenue)-Operating Cost		2,739,445	2,739,445	2,739,445	2,739,445	2,739,445	2,678,898	2,678,898	2,678,898	2,678,898
(Depreciation Equipment)		(775,560)	(1,240,896)	(744,538)	(446,723)	(446,723)	(223,361)			
(Depreciation Building)		(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
(Depreciation Start-up)		(256,646)	(256,646)	(256,646)	(256,646)	(256,646)				
(Loan Payment - Interest)		(428,581)	(420,098)	(409,963)	(399,014)	(387,193)	(374,424)	(360,634)	(345,741)	(329,656)
Earnings before Income Taxes		1,272,071	815,218	1,321,712	1,630,475	1,642,296	2,074,525	2,311,676	2,326,569	2,342,654
If (Net Operating Loss)										
Earnings after NOL		1,272,071	815,218	1,321,712	1,630,475	1,642,296	2,074,525	2,311,676	2,326,569	2,342,654
(Less State Income Taxes)		114,486	73,370	118,954	146,743	147,807	186,707	208,051	209,391	210,839
Earnings before Federal Taxes		1,157,584	741,849	1,202,758	1,483,732	1,494,490	1,887,818	2,103,626	2,117,178	2,131,815
(Less Federal Income Taxes)		393,579	252,229	408,938	504,469	508,126	641,858	715,233	719,841	724,817
Earnings after Taxes		764,006	489,620	793,820	979,263	986,363	1,245,960	1,388,393	1,397,338	1,406,998
(Depreciation Equipment)		775,560	1,240,896	744,538	446,723	446,723	223,361			
(Depreciation Building)		6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
(Depreciation Start-up)		256,646	256,646	256,646	256,646	256,646				
Loan Payment - Principal		(117,314)	(126,699)	(136,835)	(147,782)	(159,605)	(172,373)	(186,163)	(201,056)	(217,140)
Net Cash Flow		1,685,485	1,867,050	1,664,755	1,541,437	1,536,714	1,303,536	1,208,818	1,202,869	1,196,445
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		1,532,259	1,543,017	1,250,755	1,052,822	954,178	735,812	620,315	561,147	507,410
Net Present Value		11,929,234								

Table 16b. Cash flow projection for alternative 2b(50-mi).

0	11	12	13	14	15	16	17	18	19	20
8,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
2,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292	102,292
9,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200	3,679,200
9,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569	3,929,569
4,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
5,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
1,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643
2,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035
0	0	0	0	0	0	0	0	0	0	0
8,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
0,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
5,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
2,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
8,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
4,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
0,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671
8,898	2,678,898	2,678,898	2,678,898	2,678,898	2,678,898	2,678,898	2,678,898	2,678,898	2,678,898	2,678,898
6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
2,285)	(293,525)	(273,262)	(251,380)	(227,801)	(202,222)	(174,656)	(144,885)	(112,732)	(78,007)	(40,504)
0,025	2,378,785	2,399,048	2,420,930	2,444,510	2,470,088	2,497,654	2,527,425	2,559,578	2,594,304	2,631,806
0,025	2,378,785	2,399,048	2,420,930	2,444,510	2,470,088	2,497,654	2,527,425	2,559,578	2,594,304	2,631,806
,402	214,091	215,914	217,884	220,006	222,308	224,789	227,468	230,362	233,487	236,863
,623	2,164,694	2,183,134	2,203,047	2,224,504	2,247,780	2,272,865	2,299,957	2,329,216	2,360,816	2,394,944
,192	735,996	742,265	749,036	756,331	764,245	772,774	781,985	791,933	802,678	814,281
,431	1,428,698	1,440,868	1,454,011	1,468,173	1,483,535	1,500,091	1,517,972	1,537,282	1,558,139	1,580,663
,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
,513)	(253,273)	(273,534)	(295,418)	(319,052)	(344,575)	(372,142)	(401,912)	(434,066)	(468,790)	(506,294)
,505	1,182,013	1,173,921	1,165,180	1,155,708	1,145,548	1,134,536	1,122,647	1,109,804	1,095,936	1,080,956
,386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
,606	414,288	374,048	337,511	304,334	274,235	246,908	222,110	199,608	179,194	160,677

ALTERNATIVE 2C(2):
50-Mile Radius; New Equipment - 6 MW
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	4,727,800									
TOTAL Plant	207,500									
TOTAL Start-up	1,504,228									
TOTAL Capital Cost	6,439,528									
Savings and Revenue:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (revenue)		4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720
TOTAL Savings and Revenue		4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797
Operating Cost:										
Fixed Costs:										
Labor										
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance		153,595	153,595	153,595	153,595	153,595	230,393	230,393	230,393	230,393
Insurance		51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785
Fuel		668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
Property Tax		0	0	0	0	0	0	0	0	0
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		1,064,637	1,064,637	1,064,637	1,064,637	1,064,637	1,141,434	1,141,434	1,141,434	1,141,434
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		1,112,374	1,112,374	1,112,374	1,112,374	1,112,374	1,189,171	1,189,171	1,189,171	1,189,171
(Net Savings + Revenue)-Operating Cost		3,284,423	3,284,423	3,284,423	3,284,423	3,284,423	3,207,626	3,207,626	3,207,626	3,207,626
(Depreciation Equipment)		(945,560)	(1,512,896)	(907,738)	(544,643)	(544,643)	(272,321)			
(Depreciation Building)		(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
(Depreciation Start-up)		(300,846)	(300,846)	(300,846)	(300,846)	(300,846)				
(Loan Payment - Interest)		(514,082)	(503,906)	(491,749)	(478,616)	(464,437)	(449,120)	(432,579)	(414,715)	(395,422)
Earnings before Income Taxes		1,517,349	960,189	1,577,504	1,953,732	1,967,911	2,479,598	2,768,460	2,786,324	2,805,617
If (Net Operating Loss)										
Earnings after NOL		1,517,349	960,189	1,577,504	1,953,732	1,967,911	2,479,598	2,768,460	2,786,324	2,805,617
(Less State Income Taxes)		136,561	86,417	141,975	175,836	177,112	223,164	249,161	250,769	252,506
Earnings before Federal Taxes		1,380,788	873,772	1,435,529	1,777,896	1,790,799	2,256,434	2,519,298	2,535,555	2,553,111
(Less Federal Income Taxes)		469,468	297,082	488,080	604,485	608,872	767,187	856,561	862,089	868,055
Earnings after Taxes		911,320	576,689	947,449	1,173,411	1,181,927	1,489,246	1,662,737	1,673,466	1,685,054
(Depreciation Equipment)		945,560	1,512,896	907,738	544,643	544,643	272,321			
(Depreciation Building)		6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
(Depreciation Start-up)		300,846	300,846	300,846	300,846	300,846				
Loan Payment - Principal		(140,718)	(151,974)	(164,134)	(177,264)	(191,446)	(206,760)	(223,301)	(241,166)	(260,459)
Net Cash Flow		2,023,595	2,245,044	1,998,486	1,848,223	1,842,557	1,561,394	1,446,023	1,438,888	1,431,182
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		1,839,632	1,855,408	1,501,492	1,262,361	1,144,083	881,366	742,038	671,252	606,961
Net Present Value		14,297,941								

able 16c. Cash flow projection for alternative 2c(50-mi).

0	11	12	13	14	15	16	17	18	19	20
8,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
8,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720	4,248,720
6,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797	4,396,797
4,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
5,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
0,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393	230,393
1,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785	51,785
8,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
0	0	0	0	0	0	0	0	0	0	0
0,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
5,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
1,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434	1,141,434
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
8,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
4,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
9,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171	1,189,171
7,626	3,207,626	3,207,626	3,207,626	3,207,626	3,207,626	3,207,626	3,207,626	3,207,626	3,207,626	3,207,626
6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
4,585)	(352,082)	(327,777)	(301,529)	(273,246)	(242,564)	(209,500)	(173,789)	(135,222)	(93,569)	(48,585)
6,453	2,848,956	2,873,261	2,899,509	2,927,793	2,958,474	2,991,539	3,027,250	3,065,817	3,107,470	3,152,454
6,453	2,848,956	2,873,261	2,899,509	2,927,793	2,958,474	2,991,539	3,027,250	3,065,817	3,107,470	3,152,454
4,381	256,406	258,594	260,956	263,501	266,263	269,238	272,452	275,923	279,672	283,721
2,073	2,592,550	2,614,668	2,638,553	2,664,291	2,692,212	2,722,300	2,754,797	2,789,893	2,827,798	2,868,733
4,505	881,467	888,987	897,108	905,859	915,352	925,582	936,631	948,564	961,451	975,369
7,568	1,711,083	1,725,681	1,741,445	1,758,432	1,776,860	1,796,718	1,818,166	1,841,329	1,866,346	1,893,364
6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
,297)	(303,800)	(328,103)	(354,353)	(382,701)	(413,316)	(446,383)	(482,091)	(520,660)	(562,312)	(607,298)
2,858	1,413,870	1,404,165	1,393,680	1,382,318	1,370,131	1,356,923	1,342,662	1,327,256	1,310,622	1,292,653
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
3,573	495,553	447,410	403,699	364,008	327,998	295,306	265,639	238,719	214,297	192,145

ALTERNATIVE 2D(2):

25-Mile Radius; Used Equipment - 6 MW

MARR = 10%

20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9
Project Cost:										
TOTAL Equipment	3,877,800									
TOTAL Plant	207,500									
TOTAL Start-up	1,283,228									
TOTAL Capital Cost	5,368,528									
Savings and Revenue:										
Natural Gas for Process Steam		148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
Electricity (revenue)		3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080
TOTAL Savings and Revenue		3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157
Operating Cost:										
Fixed Costs:										
Labor										
Direct		144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
Indirect		15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
Operation & Maintenance		241,095	241,095	241,095	241,095	241,095	301,643	301,643	301,643	301,643
Insurance		42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035
Property Tax		0	0	0	0	0	0	0	0	0
Fuel		668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
Parts		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Supplies		6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Contingency		15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
TOTAL Fixed Costs		1,142,387	1,142,387	1,142,387	1,142,387	1,142,387	1,202,934	1,202,934	1,202,934	1,202,934
Variable Costs:										
Water		2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
Electricity		28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
Chemicals for Water Treatment		14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
Ash Disposal		3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
TOTAL Variable Costs		47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
TOTAL Operating Costs (Fixed & Variable)		1,190,124	1,190,124	1,190,124	1,190,124	1,190,124	1,250,671	1,250,671	1,250,671	1,250,671
(Net Savings + Revenue)-Operating Cost		2,622,033	2,622,033	2,622,033	2,622,033	2,622,033	2,561,486	2,561,486	2,561,486	2,561,486
(Depreciation Equipment)		(775,560)	(1,240,896)	(744,538)	(446,723)	(446,723)	(223,361)			
(Depreciation Building)		(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
(Depreciation Start-up)		(256,646)	(256,646)	(256,646)	(256,646)	(256,646)				
(Loan Payment - Interest)		(428,581)	(420,098)	(409,963)	(399,014)	(387,193)	(374,424)	(360,634)	(345,741)	(329,656)
Earnings before Income Taxes		1,154,659	697,807	1,204,300	1,513,063	1,524,885	1,957,114	2,194,265	2,209,158	2,225,242
If (Net Operating Loss)										
Earnings after NOL		1,154,659	697,807	1,204,300	1,513,063	1,524,885	1,957,114	2,194,265	2,209,158	2,225,242
(Less State Income Taxes)		103,919	62,803	108,387	136,176	137,240	176,140	197,484	198,824	200,272
Earnings before Federal Taxes		1,050,740	635,004	1,095,913	1,376,888	1,387,645	1,780,973	1,996,781	2,010,334	2,024,970
(Less Federal Income Taxes)		357,252	215,901	372,610	468,142	471,799	605,531	678,906	683,513	688,490
Earnings after Taxes		693,488	419,103	723,303	908,746	915,846	1,175,442	1,317,875	1,326,820	1,336,480
(Depreciation Equipment)		775,560	1,240,896	744,538	446,723	446,723	223,361			
(Depreciation Building)		6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
(Depreciation Start-up)		256,646	256,646	256,646	256,646	256,646				
Loan Payment - Principal		(117,314)	(126,699)	(136,835)	(147,782)	(159,605)	(172,373)	(186,163)	(201,056)	(217,140)
Net Cash Flow		1,614,967	1,796,533	1,594,238	1,470,919	1,466,196	1,233,018	1,138,300	1,132,352	1,125,928
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424
Present Value of Cash Flow		1,468,152	1,484,738	1,197,774	1,004,658	910,392	696,007	584,128	528,250	477,503
Net Present Value		11,328,879								

Table 16d. Cash flow projection for alternative 2d(50-mi).

0	11	12	13	14	15	16	17	18	19	20
8,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077	148,077
4,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080	3,664,080
2,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157	3,812,157
4,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012	144,012
5,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745	15,745
1,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643	301,643
2,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035	42,035
0	0	0	0	0	0	0	0	0	0	0
8,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500	668,500
0,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
5,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
2,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934	1,202,934
2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017	2,017
8,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000
4,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600	14,600
3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
7,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737	47,737
0,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671	1,250,671
1,486	2,561,486	2,561,486	2,561,486	2,561,486	2,561,486	2,561,486	2,561,486	2,561,486	2,561,486	2,561,486
6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)	(6,587)
2,285)	(293,525)	(273,262)	(251,380)	(227,801)	(202,222)	(174,656)	(144,885)	(112,732)	(78,007)	(40,504)
2,613	2,261,373	2,281,636	2,303,519	2,327,098	2,352,677	2,380,242	2,410,014	2,442,166	2,476,892	2,514,394
2,613	2,261,373	2,281,636	2,303,519	2,327,098	2,352,677	2,380,242	2,410,014	2,442,166	2,476,892	2,514,394
1,835	203,524	205,347	207,317	209,439	211,741	214,222	216,901	219,795	222,920	226,295
0,778	2,057,850	2,076,289	2,096,202	2,117,659	2,140,936	2,166,020	2,193,113	2,222,371	2,253,972	2,288,099
3,864	699,669	705,938	712,709	720,004	727,918	736,447	745,658	755,606	766,350	777,954
6,913	1,358,181	1,370,351	1,383,493	1,397,655	1,413,018	1,429,573	1,447,454	1,466,765	1,487,621	1,510,145
6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587	6,587
4,513)	(253,273)	(273,534)	(295,418)	(319,052)	(344,575)	(372,142)	(401,912)	(434,066)	(468,790)	(506,294)
3,988	1,111,495	1,103,404	1,094,662	1,085,191	1,075,030	1,064,019	1,052,130	1,039,286	1,025,419	1,010,438
0.386	0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
1,418	389,572	351,578	317,085	285,765	257,354	231,562	208,158	186,925	167,664	150,195

ALTERNATIVE 3A

Small Backpressure System for Bel-Bar

Year:	Initial	1	2	3	4	5	6	7	8	9	10
Equipment	340,000										
Building	23,750										
Start-Up	5,000										
TOTAL Capital Cost	368,750										
Savings of Steam		105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,56
Savings of Electricity:		33,112	33,112	33,112	33,112	33,112	33,112	33,112	33,112	33,112	33,11
TOTAL Savings		138,672	138,672	138,672	138,672	138,672	138,672	138,672	138,672	138,672	138,67
Operation & Maintenance		(17,000)	(17,000)	(17,000)	(17,000)	(17,000)	(25,500)	(25,500)	(25,500)	(25,500)	(25,50
Insurance of Equipment		(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,10
Parts		(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,40
Earnings (Savings - Costs)		113,172	113,172	113,172	113,172	113,172	104,672	104,672	104,672	104,672	104,672
(Depreciation - Equipment)		(48,586)	(83,266)	(59,466)	(42,466)	(30,362)	(30,328)	(30,362)	(30,362)	(15,164)	
(Depreciation - Start-Up)		(1,000)	(1,000)	(1,000)	(1,000)	(1,000)					
(Amortization - Bldg.)		(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754
(Loan Payment - Interest)		(29,438)	(28,855)	(28,159)	(27,407)	(26,595)	(25,718)	(24,771)	(23,748)	(22,643)	(21,450
Earnings before Income Taxes		33,394	(703)	23,793	41,545	54,461	47,872	48,785	49,808	66,111	82,468
Net Operating Loss		(703)									
Earnings After NOL		32,691									
State Income Taxes @ 9.6%		(3,206)		(2,284)	(3,988)	(5,228)	(4,596)	(4,683)	(4,782)	(6,347)	(7,917
Earnings before Federal Taxes		29,485		21,509	37,556	49,233	43,276	44,102	45,026	59,764	74,551
(Less Federal Income Taxes)		(10,025)	0	(7,313)	(12,769)	(16,739)	(14,714)	(14,995)	(15,309)	(20,320)	(25,347)
Earnings after Taxes		19,460	(703)	14,196	24,787	32,493	28,562	29,107	29,717	39,444	49,204
Depreciation Equipment		48,586	83,266	59,466	42,466	30,362	30,328	30,362	30,362	15,164	
Depreciation - Start-Up		1,000	1,000	1,000	1,000	1,000					
Amortization - Bldg.		754	754	754	754	754	754	754	754	754	754
Loan Payment - Principal		(8,058)	(8,703)	(9,399)	(10,151)	(10,963)	(11,840)	(12,787)	(13,810)	(14,915)	(16,108
Net Cash Flow		61,742	75,614	66,017	58,856	53,647	47,804	47,436	47,023	40,448	33,850
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	0.386
Present Value of Cash Flow		56,129	62,491	49,599	40,200	33,310	26,984	24,342	21,937	17,154	13,050
Net Present Value		418,102									

Table 17a. Cash flow projection for alternative 3a

11	12	13	14	15	16	17	18	19	20
105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560
33,112	33,112	33,112	33,112	33,112	33,112	33,112	33,112	33,112	33,112
138,672	138,672	138,672	138,672	138,672	138,672	138,672	138,672	138,672	138,672
(25,500)	(25,500)	(25,500)	(25,500)	(25,500)	(25,500)	(25,500)	(25,500)	(25,500)	(25,500)
(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)	(5,100)
(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)	(3,400)
104,672	104,672	104,672	104,672	104,672	104,672	104,672	104,672	104,672	104,672
(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)
(20,161)	(18,770)	(17,267)	(15,647)	(13,890)	(11,997)	(9,952)	(7,743)	(5,358)	(2,782)
83,757	85,148	86,651	88,271	90,028	91,921	93,966	96,175	98,560	101,136
(8,041)	(8,174)	(8,319)	(8,474)	(8,643)	(8,824)	(9,021)	(9,233)	(9,462)	(9,709)
75,716	76,974	78,333	79,797	81,385	83,097	84,946	86,942	89,098	91,427
(25,743)	(26,171)	(26,633)	(27,131)	(27,671)	(28,253)	(28,881)	(29,560)	(30,293)	(31,085)
49,973	50,803	51,700	52,666	53,714	54,844	56,064	57,382	58,805	60,342
754	754	754	754	754	754	754	754	754	754
(17,397)	(18,788)	(20,292)	(21,915)	(23,668)	(25,561)	(27,606)	(29,815)	(32,200)	(34,776)
33,330	32,769	32,162	31,505	30,800	30,036	29,212	28,321	27,359	26,320
0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
11,682	10,441	9,316	8,296	7,373	6,537	5,779	5,094	4,473	3,912

ALTERNATIVE 3B:
System Providing Steam and Electricity for Abenaki
MARR = 10%
20-Year Loan Interest Rate = 8%

		C	A	S	H		F	L	O	W		P
	Year:	Initial	1	2	3	4	5	6	7	8	9	10
Equipment		165,000										
Building		23,750										
Start-Up		5,000										
TOTAL Capital Cost		193,750										
Savings of Steam			54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,60
Savings of Electricity:			19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,70
TOTAL Savings			74,307	74,307	74,307	74,307	74,307	74,307	74,307	74,307	74,307	74,30
Operation & Maintenance			(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(12,375)	(12,375)	(12,375)	(12,375)	(12,37
Insurance of Equipment			(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,47
Parts			(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,65
Earnings (Savings - Costs)			61,932	61,932	61,932	61,932	61,932	57,807	57,807	57,807	57,807	57,80
(Depreciation - Equipment)			(23,579)	(40,409)	(28,859)	(20,609)	(14,735)	(14,718)	(14,735)	(14,735)	(7,359)	
(Depreciation - Start-Up)			(1,000)	(1,000)	(1,000)	(1,000)	(1,000)					
(Amortization - Bldg.)			(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(75
(Loan Payment - Interest)			(15,467)	(15,161)	(14,796)	(14,400)	(13,974)	(13,513)	(13,015)	(12,478)	(11,897)	(11,27
Earnings before Income Taxes			21,132	4,609	16,524	25,170	31,470	28,823	29,304	29,841	37,797	45,78
State Income Taxes @ 9.6%			(2,029)	(442)	(1,586)	(2,416)	(3,021)	(2,767)	(2,813)	(2,865)	(3,629)	(4,39
Earnings before Federal Taxes			19,104	4,166	14,938	22,753	28,449	26,056	26,491	26,976	34,169	41,38
(Less Federal Income Taxes)			(6,495)	(1,417)	(5,079)	(7,736)	(9,673)	(8,859)	(9,007)	(9,172)	(11,617)	(14,072
Earnings after Taxes			12,608	2,750	9,859	15,017	18,776	17,197	17,484	17,804	22,551	27,316
Depreciation Equipment			23,579	40,409	28,859	20,609	14,735	14,718	14,735	14,735	7,359	
Depreciation - Start-Up			1,000	1,000	1,000	1,000	1,000					
Amortization - Bldg.			754	754	754	754	754	754	754	754	754	754
Loan Payment - Principal			(4,234)	(4,573)	(4,938)	(5,333)	(5,760)	(6,221)	(6,719)	(7,256)	(7,837)	(8,464
Net Cash Flow			33,707	40,340	35,533	32,046	29,505	26,448	26,254	26,037	22,828	19,606
PVIF @ 10%			0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	0.386
Present Value of Cash Flow			30,643	33,339	26,697	21,888	18,320	14,929	13,472	12,146	9,681	7,559
Net Present Value			231,294									

able 17b. Cash flow projection for alternative 3b

R	*O*	*J*	*E*	*C*	*T*	*I*	*O*	*N*	
11	12	13	14	15	16	17	18	19	20
54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600	54,600
19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,707	19,707
74,307	74,307	74,307	74,307	74,307	74,307	74,307	74,307	74,307	74,307
(12,375)	(12,375)	(12,375)	(12,375)	(12,375)	(12,375)	(12,375)	(12,375)	(12,375)	(12,375)
(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)	(2,475)
(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
57,807	57,807	57,807	57,807	57,807	57,807	57,807	57,807	57,807	57,807
(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)	(754)
(10,593)	(9,862)	(9,072)	(8,221)	(7,298)	(6,303)	(5,229)	(4,069)	(2,815)	(1,462)
46,460	47,191	47,981	48,832	49,755	50,750	51,825	52,985	54,238	55,592
(4,460)	(4,530)	(4,606)	(4,688)	(4,777)	(4,872)	(4,975)	(5,087)	(5,207)	(5,337)
42,000	42,661	43,375	44,144	44,979	45,878	46,849	47,898	49,031	50,255
(14,280)	(14,505)	(14,747)	(15,009)	(15,293)	(15,599)	(15,929)	(16,285)	(16,671)	(17,087)
27,720	28,156	28,627	29,135	29,686	30,280	30,921	31,613	32,361	33,168
754	754	754	754	754	754	754	754	754	754
(9.141)	(9,872)	(10,662)	(11,515)	(12,436)	(13,431)	(14,505)	(15,665)	(16,919)	(18,272)
19,333	19,038	18,720	18,375	18,004	17,603	17,170	16,702	16,196	15,650
0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
6,776	6,066	5,422	4,839	4,310	3,831	3,397	3,004	2,648	2,326

C A S H F L O W P

ALTERNATIVE 3C:
System Providing Electricity for RF Kilns and Steam for Bel-Bar
MARR = 10%
20-Year Loan Interest Rate = 8%

Year:	Initial	1	2	3	4	5	6	7	8	9	10
Equipment	469,400										
Start-Up	15,000										
TOTAL Capital Cost	484,400										
Savings of Steam		105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,5
Savings of Electricity:		45,780	45,780	45,780	45,780	45,780	45,780	45,780	45,780	45,780	45,7
TOTAL Savings		151,340	151,340	151,340	151,340	151,340	151,340	151,340	151,340	151,340	151,3
Operation & Maintenance		(23,470)	(23,470)	(23,470)	(23,470)	(23,470)	(35,205)	(35,205)	(35,205)	(35,205)	(35,2
Insurance of Equipment		(7,041)	(7,041)	(7,041)	(7,041)	(7,041)	(7,041)	(7,041)	(7,041)	(7,041)	(7,04
Parts		(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,694)	(4,69
Earnings (Savings - Costs)		116,135	116,135	116,135	116,135	116,135	104,400	104,400	104,400	104,400	104,40
(Depreciation - Equipment)		(67,077)	(114,956)	(82,098)	(58,628)	(41,917)	(41,870)	(41,917)	(41,917)	(20,935)	
(Depreciation - Start-Up)		(3,000)	(3,000)	(3,000)	(3,000)	(3,000)					
(Loan Payment - Interest)		(38,671)	(37,905)	(36,991)	(36,003)	(34,936)	(33,784)	(32,540)	(31,196)	(29,745)	(28,17
Earnings before Income Taxes		4,387	(42,726)	(8,954)	15,504	33,281	28,745	29,943	31,287	53,720	76,22
Net Operating Loss		(4,387)			(15,504)	(31,789)					
Earnings After NOL						1,492					
State Income Taxes @ 9.6%						(143)	(2,760)	(2,875)	(3,004)	(5,157)	(7,31
Earnings before Federal Taxes		0	0	0	0	1,349	25,986	27,068	28,283	48,563	68,90
(Less Federal Income Taxes)		0	0	0	0	(459)	(8,835)	(9,203)	(9,616)	(16,511)	(23,42
Earnings after Taxes		0	(42,726)	(8,954)	0	890	17,151	17,865	18,667	32,052	45,47
Depreciation Equipment		67,077	114,956	82,098	58,628	41,917	41,870	41,917	41,917	20,935	
Depreciation - Start-Up		3,000	3,000	3,000	3,000	3,000					
Loan Payment - Principal		(10,585)	(11,432)	(12,347)	(13,334)	(14,401)	(15,553)	(16,797)	(18,141)	(19,592)	(21,160
Net Cash Flow		62,492	66,798	66,798	51,294	34,407	43,468	42,985	42,443	33,394	24,317
PVIF @ 10%		0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	0.386
Present Value of Cash Flow		56,811	55,205	50,186	35,034	21,364	24,537	22,058	19,800	14,162	9,375
Net Present Value		356,571									

Table 17c. Cash flow projection for alternative 3c.

R	O	J	E	C	T	I	O	N	
11	12	13	14	15	16	17	18	19	20
105.560	105.560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560
45,780	45,780	45,780	45,780	45,780	45,780	45,780	45,780	45,780	45,780
151,340	151,340	151,340	151,340	151,340	151,340	151,340	151,340	151,340	151,340
(35,205)	(35,205)	(35,205)	(35,205)	(35,205	(35,205)	(35,205)	(35,205)	(35,205)	(35,205)
(7,041)	(7,041)	(7,041)	(7,041)	(7,041	(7,041)	(7,041)	(7.041)	(7,041)	(7,041)
(4.694)	(4,694)	(4.694)	(4.694)	(4.694	(4,694)	(4,694)	(4,694)	(4.694)	(4,694)
104,400	104,400	104,400	104,400	104,400	104,400	104,400	104,400	104,400	104,400
(26,485)	(24,656)	(22,682)	(20,554)	(18,246	(15,759)	(13,073)	(10,172)	(7,039)	(3,655)
77,915	79,744	81,718	83,846	86,154	88,641	91,327	94,228	97,361	100,745
(7,480)	(7,655)	(7,845)	(8,049)	(8,271	(8,510)	(8,767)	(9,046)	(9,347)	(9,672)
70,435	72,088	73,873	75,796	77,883	80,131	82,560	85,182	88,015	91,074
(23,948)	(24,510)	(25,117)	(25,771)	(26,480	(27,245)	(28,070)	(28,962)	(29,925)	(30,965)
46,487	47,578	48,756	50,026	51,403	52,887	54,489	56,220	58,090	60,109
(22.853)	(24,681)	(26.655)	(28,788)	(31,091	(33,578)	(36,264)	(39,166)	(42,299)	(45,683)
23,635	22,897	22,101	21,238	20,312	19,308	18,225	17,055	15,791	14,426
0.35	0.319	0.29	0.263	0.239	0.218	0.198	0.18	0.164	0.149
8.284	7,296	6.402	5,593	4,862	4,202	3,606	3,067	2.582	2,144

Cash flow was used as a basis to determine NPV. The NPV derived is used exclusively in this report as the basis for discussion and as an indicator of feasibility.

Alternative 1

Table 18 shows the NPV of alternatives 1A-1D; numbers in () indicate a negative NPV. From Table 18, it can be seen that all NPVs are negative, evidence that this alternative is not a viable one. Alternative 1D which incorporates savings of RF kilns and has an NPV of ($1,939,658) @ 12% MARR, is the best of the group.

Using this analysis as a starting point, an effort was made to achieve feasibility, using alternative 1D as a basis. Feasibility could be obtained by either increasing savings or decreasing cost. Since savings could not be increased, capital and maintenance costs were decreased. Capital costs and maintenance costs were decreased to $1.5 Million and $150,000, respectively. Even at these costs, feasibility using our criteria still could not be obtained as the NPV was ($37,790).

Table 18. NPV for variations of alternative 1 using MARR 8%, 10%, and 12%.

	MARR		
Alternative:	8%	10%	12%
1a: Excluding RF kilns, new equipment	($4,443,708)	($3,847,412)	($3,359,500)
1b: Including RF kilns, new equipment	($3,688,777)	($3,442,385)	($2,794,258)
1c: Excluding RF kilns, used equipment	($3,983,017)	($3,737,412)	($3,010,976)
1d: Including RF kilns, used equipment	($3,277,775)	($3,232,019)	($2,502,344)

The conclusion reached for this alternative is that, it is not only unlikely that a cogeneration system could service all the companies within this park, but, even if they could be serviced, it would not be feasible to do so; it is impossible to rely only on savings for such a large-scale project.

Alternative 2

Alternative 2 considered a larger-scale system. The same type of economic analysis that was performed for alternative 1 was also performed for this alternative, but in addition, avoided cost rate was increased to determine what rate would be needed to achieve feasibility. Costs were not decreased in this analysis. Tables 19-20 show the NPV at avoided cost rate of $0.015/kWh and the avoided cost rate required to achieve feasibility.

All initial NPV values are negative, again indicating an unfeasible alternative. From Table 19, it can be seen that the increase in avoided cost rates required for feasibility range from $0.28 to $0.397, clearly unobtainable. However, as can be seen from Table 20, avoided cost rates required for feasibility decreased, as economies of scale at this size (approximately 6 MW) are approached. Avoided cost rates range from $0.0714 to $0.0888 at this size, possibly obtained through wheeling power.

Table 19. Alternative 2 (25-mile radius):
NPV at avoided cost rate $0.015/kWh, avoided cost rate required for feasibility.

ALTERNATIVES	Minimum Acceptable Rate of Return 8%	10%	12%
2A: Companies in park, new equip., savings & revenue.	($7,037,635) $0.369	($6,085,166) $0.383	($5,327,689) $0.397
2B: Companies in park, used equip., savings & revenue.	($6,443,980) $0.344	($5,943,558) $0.358	($4,841,859) $0.372
2C: Sell all power to utility, new equipment.	($6,694,773) $0.313	($7,785,668) $0.324	($5,868,336) $0.336
2D: Sell all power to utility, used equipment.	($6,553,164) $0.273	($7,134,708) $0.28	($5,374,492) $0.29

Table 20. Alternative 2 (50-mile radius):
NPV at avoided cost rate $0.015/kWh, avoided cost rate required for feasibility.

ALTERNATIVES	Minimum Acceptable Rate of Return 8%	10%	12%
2A: Companies in park, new equip., savings & revenue.	($8,228,003) $0.0828	($7,109,356) $0.0857	($6,215,927) $0.0888
2B: Companies in park, used equip., savings & revenue.	($6,969,192) $0.0716	($6,766,009) $0.073	($5,267,529) $0.0744
2C: Sell all power to utility, new equipment.	($8,931,024) $0.0815	($7,718,963) $0.0843	($6,750,771) $0.0872
2D: Sell all power to utility, used equipment.	($7,664,990) $0.0714	($7,375,616) $0.0727	($5,795,408) $0.074

Economies of scale at wood-fired plants are best maximized at 15 MW, 150,000 lbs./hr. steaming capacity. A 10 MW plant would require 184,000 tons/yr. of fuel (33). A 15.5 MW plant in Bridgewater, NH consumes 258,420 tons of waste/yr.(21). For this alternative, it may be possible to utilize additional waste or decrease cost in order to better approach scale; it is predicted that scale might be achieved by taking in between 184,000 and 258,420 tons/yr. (this alternative considered 125,000 tons/yr.). The conclusion reached for alternative 2 is that a larger-scale system is certainly more viable than a small-scale system designed to meet the energy requirements of the park. However, while economies of scale are best met at larger systems, avoided cost is also a major consideration. The alternative that incorporates residue obtainable from a 50-mile radius and incorporates used equipment is, again, the best of the group. However, even for this case, the avoided cost rate required for feasibility is greater than $0.06/kWh, clearly unobtainable. Therefore, this alternative, although promising, is not sufficient to achieve feasibility.

Alternative 3

Alternative 3, a smaller-scale system servicing one or two companies, is the most viable option. Table 21 shows NPV's and discounted payback periods for all alternatives.

Although NPV for each alternative is positive (indicative of a good investment) none of the alternatives achieved payback in four years. The best scenario, alternative 3B, at 8% MARR, discounted payback period is estimated to be 8.88 years.

Table 21. Alternative 3: NPV and discounted payback periods (in years), MARR 8%, 10%, and 12%.

Alternatives	MARR 8%	10%	12%
1A: Bel-Bar Dry Kiln	$468,601 9.71	$418,102 12.15	$376,572 17.48
1B: Abenaki Dry Kiln	$259,927 8.88	$231,294 20.75	$207,820 14.08
1C: RF Kilns/Bel-Bar Dry Kiln	$336,554 >> 20	$304,819 >> 20	$279,242 >> 20

Although a positive NPV is important, it is also fundamental to have a reasonable payback period. Therefore this alternative could be considered most viable.

SOCIAL/REGULATORY FEASIBILITY

Social Feasibility

Social feasibility is becoming increasingly important in cogeneration projects. Social feasibility takes into consideration acceptance by various sectors of the community. A cogeneration plant burning wood waste would assuredly be welcome by the tenants of this park and the primary and secondary wood products companies in the surrounding area, because of the existing problems in disposing of wood residue and the possibility of savings of energy bills that the plant would provide.

However, the industrial park is located very close to a residential area and they are the ones who would have to live with emissions resulting from the plant. It is likely that a cogeneration plant that burns solely wood waste would be acceptable to not only the residents surrounding the park, but also those living in the nearby community. The additional truck traffic into the industrial park area might pose a problem, but it would not represent any new traffic patterns as many of the trucks that would dispose of their waste at the park already use Route 92 to the present disposal site in Parsons. However, one potential problem lies with the 6 MW plant; approximately 25 trucks/day are anticipated to enter the park. Some will go through Belington, others will come from the south. Some coordination must be involved that takes into account new patterns of truck traffic.

It is recommended to any developer of this project that the citizens of Belington and the surrounding area be kept informed of stages of the project through public meetings and in making available documents open and available to interested parties.

Regulatory Feasibility

Environmental Regulations

A new cogeneration plant at this location would be governed by several types of environmental regulations, including air quality, water discharge, and emergency planning and community right-to-know.

Some regulations are regulated at the federal level, while others are regulated at both the federal and state levels.

All proposed cogeneration or independent power projects require a "Permit to Construct a Stationary Combustion Source". Without this permit, construction cannot begin and financing cannot be obtained (13).

Air Quality

Regulations for air quality at the Federal level include a variety of rules and regulations. If a plant is large, a formal Prevention of Significant Deterioration review takes place and control measures for each pollutant whose emission rate exceeds regulatory defined emission rates must be addressed (13). PSD rules are designed to prevent areas where air quality is presently good from deteriorating (6). This process applies only if the region where the plant will be located has attained the National Ambient Air Quality Standard (NAAQS) for that pollutant; best available control technology (BACT) must be used for those pollutants for which the region is in attainment. If the region is nonattainment for that pollutant, a New Source Review (NSR) process applies and lowest achievable emission rate (LAER) technology is to be used instead of BACT (13). Figure 8 shows a map of West Virginia illustrating which counties meet primary and secondary standards of major air pollutants (6); Barbour county meets all standards.

Air quality permits are issued by a state to enforce limitations of both Federal and state air quality emissions. The West Virginia Air Pollution Control Commission (WVAPCC) handles permits and monitoring.

A wood-fueled cogeneration plant may or may not require an air quality permit, depending upon the exact type and amount of anticipated emissions and the location of the plant. A permit will likely be required, however, if the plant:

- emits a sufficient amount of any of the seven critical air pollutants (TSP, ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide, hydrocarbons, or lead);
- emits a sufficient amount of any of the pollutants for which National Emissions

Standards for Hazardous Air Pollutants (NESHAPS) have been established (asbestos, beryllium, mercury,
vinyl chloride and benzene);
- locates within a Non-Attainment area;
- significantly impacts either a Non-Attainment area or a Class I area.

Particulate emissions are the major concern for a plant burning solely wood residue due to high volatiles and carbon content in wood (33).

Water Quality

Various agencies regulate the withdraw, allocation, and use of water. The requirements are determined by whether the water will be pumped from groundwater, withdrawn from a natural body of water, or supplied by a municipal wastewater system (13).

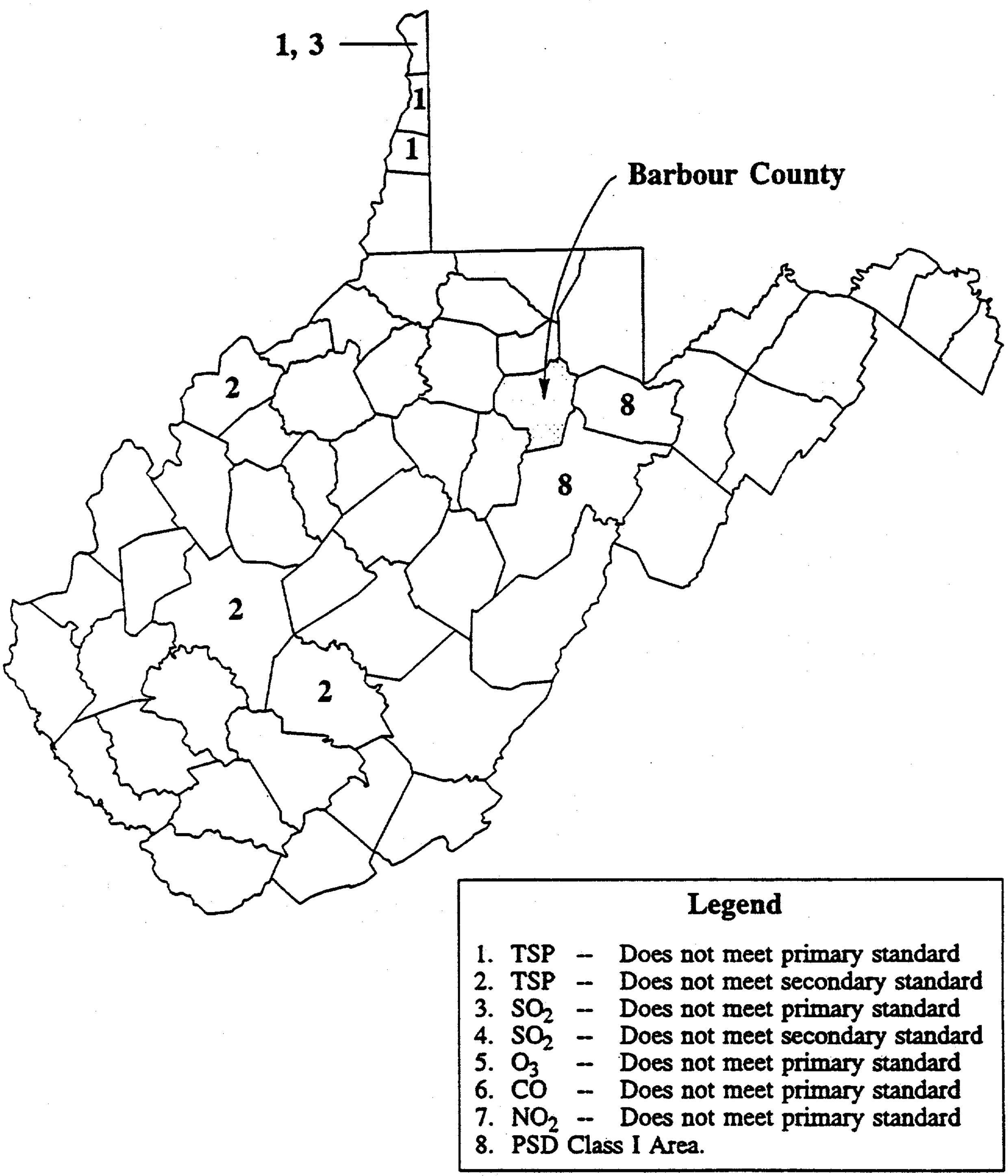
West Virginia requires a National Pollution Discharge Elimination System (NPDES) permit. This is handled by the Water Resources Section, Division of Natural Resources. A plant burning solely wood waste should have little problem obtaining an NPDES permit.

Emergency Planning and Community Right-to-Know

A cogeneration plant may require use hazardous materials such as ammonia for NO_x control and sulfuric acid and caustic soda for regenerating boiler feedwater demineralizers. These substances are regulated under Title III of the Emergency Planning and Community Right-to-Know Act. Facilities that use these substances must prepare comprehensive emergency plans (sections 302 and 303). Facilities that produce, use or store hazardous substances must report accidental releases to state and local officials (section 304). Section 313 requires annual reports to Local Emergency Planning Committees (LEPCs) (13).

For plants that incorporate a cooling tower, biocides are considered as pesticides and must be registered and approved by the EPA for the specific use that appears on the label. The Federal Insecticide, Fungicide and Rodenticide Act (FIFRA) dictates the conditions under which pesticides are sold and used (13).

Figure 8. Air quality criteria for West Virginia counties.



PURPA Regulations

From preliminary discussions with Monongahela Power Co., the local utility which is a subsidiary of Allegheny Power Systems (APS) of Greensburg, PA, it is expected that they are not interested in purchasing any power produced by a cogenerator. However, in preliminary talks with Virginia Electric Power Company (VEPCO) and Philippi Municipal Utility, located approximately 12 miles away from this location, they are both interested in purchasing power. Perhaps an agreement to wheel power can be worked out between the two and Monongahela Power can then transmit the energy along their lines. A list of utilities interconnected to Monongahela Power are listed below: (8).

Potomac Edison Co.
Downsville Pike
Hagerstown, MD 21740
(301) 790-3400

Virginia Elec. & Power.
One James River Plaza
P.O. Box 26666
Richmond, VA 23261
(804) 771-3000

Ohio Edison Co.
76 South Main St.
Akron, OH 44308-1890
(216) 384-1500

Appalachian Power Co.
40 Franklin Rd.
Box 2021
Roanoke, VA 24022
(703) 985-2300

Ohio Power Co.
301 Cleveland Ave., SW
Canton, OH 44702
(216) 456-8173

West Penn Power Co.
Cabin Hill
Greensburg, PA 15601
(412) 837-3000

Wheeling Power Co.
51 Sixteenth St.
Box 751
Wheeling, WV 26003
(304) 234-3000

Appendix 1. WV Code § 150-3-12, Cogeneration and Small Power Production.

Appendix 2. Request for proposals and companies receiving the RFP.

APPENDIX A

TITLE 150
LEGISLATIVE RULE
PUBLIC SERVICE COMMISSION

SERIES 3
RULES AND REGULATIONS
FOR THE
GOVERNMENT OF ELECTRIC UTILITIES

§150-3-1. General.

1.1. Scope. -- These rules govern the operation and service of electric utilities subject to the jurisdiction of the Public Service Commission pursuant to West Virginia Code §24-2-1.

1.2. Authority. -- W. Va. Code §§24-1-1, 24-1-7, 24-2-1, and 24-2-2

1.3. Filing Date. -- March 30, 1987

1.4. Effective Date. -- May 29, 1987

1.5. Amendment of Former Rule. -- This legislative rule amends West Virginia Legislative Rule "Public Service Commission, Chapter 24-1, Series III, Rules and Regulations for the Government of Electric Utilities", filed March 20, 1986. subsection heading of the standard format.

1.6. Authorization of rules.

(1) These rules are intended to insure adequate service to the public, to provide standards for uniform and fair charges and requirements by the utilities and their customers, and to establish the rights and responsibilities of both the utility and the customer.

(2) The adoption of these rules and regulations shall in no way preclude the Public Service Commission from altering or amending them in whole or in part, or from requiring any other or additional service, equipment, facility, or standard, either upon complaint or upon its own motion, or upon the application of the utility.

(3) These rules shall not relieve in any way a utility from any of the duties under the laws of this State.

1.7. Application of rules.

(1) These rules apply to public utilities as defined in regulation 1.3.

(2) If hardship results from the application of any rule herein prescribed, or if unusual difficulty is involved in immediately complying with any rule, application may be made to the Commission for the modification of the particular rule or for temporary or permanent exemption from its provisions; provided that no application for such modification or exemption shall be considered by the Commission unless there is submitted therewith a full and complete justification for such action.

1.8. Definitions.

(1) Commission - Whenever in these rules and regulations the words "Commission" or "Public Service Commission" occur, such word or words shall, unless a different intent clearly appears from the context, be taken to mean the Public Service Commission of West Virginia.

(2) Public Utility - Except where a different meaning clearly appears from the context, the word or words "utility" or "public utility" when used in these rules and regulations shall mean and include any person or persons, or association of persons, however associated, whether incorporated or not, including municipalities, distributing or selling electric energy for light, heat, power or other purpose, which are now or may hereafter be held to be a public service.

(3) Customer - The word "customer" as used in these rules shall be construed to mean any person, group of persons, firm, corporation, institution, municipality or other service body furnished electric

(a) be available to persons who have or represent an interest which would not otherwise be adequately represented, the representation of which interest is necessary for a fair determination in the proceedings;

(b) be available to persons who are, or represent an interest which is, unable to effectively participate in the proceeding because of an inability to pay for reasonable attorneys' fees, expert witness fees, and other reasonable participation costs; and

(c) satisfy the definition of alternative means of adequate representation set forth in the statement of policy section of this Rule.

(3) The determination as to which electric consumer intervenors are entitled to reimbursement shall be made by the Commission after considering the quality of the consumer intervention and the effect of that intervention upon the ultimate decision of the Commission in the proceeding. An award shall be made only if, in the Commission's judgment, the electric consumer intervenor's participation in the proceeding substantially contributed to the approval, in whole or in part, of a position advocated by the electric consumer intervenor. The amount of the award shall be commensurate with the contribution made. In determining this amount, the Commission may consider the actual costs of participation to the electric consumer intervenor and the prevailing market rates in West Virginia for the kind and quality of services rendered. Reasonable attorneys' fees, expert witness fees and other reasonable expenses of participation are compensable.

(4) In the event that more than one utility is affected, each utility's share of the assessment shall be determined by multiplying the total award by the ratio of that utility's total retail Kwh sales in West Virginia to the total retail Kwh sales in West Virginia of all the affected utility companies in the proceedings. The ratio is to be calculated using figures for the most recently completed calendar year.

(5) The electric consumer intervenor shall include a memorandum of costs with the initial brief to be filed after the close of the taking of evidence. The memorandum must set forth with detail the name(s) and address(es) of the electric consumer(s); the name(s) of the utility(ies) from which compensation is being requested; the case name and number of the proceeding in which the applicant has intervened, and the costs for which compensation is claimed.

(a) Any party may include an objection to the reasonableness of any fee or cost with the filing of reply briefs. The Commission may, in its final order and after consideration of the memorandum of costs and any objections thereto make an award and, if necessary, allocate the responsibility for payment of that award among the various affected utilities.

(b) Any electric consumer intervenor who has not been awarded costs in the Commission's final order may petition the Commission for reconsideration. The petition must include a memorandum of cost as set forth above. The Commission shall dispose of such petition within a reasonable time by entering an order either granting or denying the petition.

11.4. Payment and accounting treatment.

(1) Payment of costs under this Rule shall be made by the affected utility or utilities within thirty (30) days of the date on which a Commission order granting an award issues under Subsection 3(e). If costs are not paid within thirty (30) days of said final order, the electric consumer intervenor may initiate procedures to enforce the order pursuant to Sections 24-4-6 or 24-4-7 of the West Virginia Code.

(2) All monies paid to electric consumer intervenors by an affected utility under this Rule shall be treated as allowable operating expense in the rate case in which the electric consumers intervened, unless the Commission determines that another approach is more appropriate.

§150-3-12. Cogeneration and small power production.

12.1. Definitions.

(1) Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 2601, et seq., shall have the same meaning for purposes of this rule (Rule 12.00) as they have under PURPA, unless further defined in this rule.

(a) "Qualifying facility" means a cogeneration facility or a small power production facility which satisfies the criteria for qualifying facilities set forth in Subpart B of Part 292 of the rules of the Federal Energy Regulatory Commission. Qualifying Cogeneration and Small Power Production Facilities, 18 C.F.R. §292.201 through §292.207.

(b) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(c) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(d) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(e) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(f) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(g) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(h) "Supplementary power" means electric energy or capacity or both supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(i) "Back-up power" means electric energy or capacity or both supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(j) "Interruptible power" means electric energy or capacity or both supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(k) "Maintenance power" means electric energy or capacity or both supplied by an electric utility during scheduled outages by the qualifying facility.

(l) "Commission" means Public Service Commission of West Virginia.

12.2. Scope.

(1) Applicability - The provisions of Rule 12.00 et seq. apply to the regulation of sales and purchases between qualifying facilities with a design capacity in excess of 100 KW and electric utilities.

(2) Negotiated rates or terms - Nothing in Rule 12.00 et seq.:

(a) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this rule; or

(b) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

12.3. Cost data to be supplied by electric utilities.

(1) Each utility required to file data with the Federal Energy Regulatory Commission under 18 C.F.R. 292.302, Availability of electric utility system cost data, shall file the same data with the Commission in accordance with the time schedules and utility classifications set forth in that section.

(2) Any data submitted by an electric utility under Rule 12.3 shall be subject to Commission review. In any such review, the electric utility has the burden of coming forward with justification for its data.

12.4. Electric utility obligation under Section 12 et seq.

(1) Obligation to purchase from qualifying facilities - Each electric utility shall purchase, in accordance with Rule 12.6, any energy and capacity which is made available from a qualifying facility:

(a) Directly to the electric utility; or

(b) Indirectly to the electric utility in accordance with paragraph 12.4(4) of this rule.

(2) Obligation to sell to qualifying facilities Each electric utility shall sell to any qualifying facility, in accordance with Rule 12.7, any energy and capacity requested by the qualifying facility.

(3) Obligation to interconnect -

(a) Any electric utility shall make such interconnection with any qualifying facility as may be necessary to accomplish purchases or sales under these rules. (12.00 et seq.); provided, however, that if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act, then the electric utility will not be required to interconnect.

(b) The obligation to pay for any interconnection costs shall be determined in accordance with Rule 12.8.

(4) Transmission to other electric utilities - If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this paragraph as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses and shall not include any charges for transmission.

(5) Parallel operation - Each qualifying facility shall agree to operate in parallel with the electric utility; provided that the qualifying facility complies with the utility's reliability and safety standards on file with the Commission.

12.5. Procedure for establishing rates for purchases.

(1) Utilities and qualifying facilities shall negotiate a mutually acceptable rate for purchase of power taking into consideration all relevant factors, including the factors set forth in paragraph 12.6(4) of this rule. Prior to becoming effective, all negotiated contracts between utilities and qualifying facilities shall be filed with the Commission and approved by the Commission. Unless the Commission specifically modifies or disapproves a negotiated contract within thirty (30) days after filing, the contract shall be approved, as filed.

(2) If a utility and a qualifying facility cannot negotiate terms acceptable to both parties, either party, or both, may request an informal conference with the Commission Staff wherein the matters in controversy will be discussed. If after such conference a resolution acceptable to both parties has not been reached, either party, or both, may file a formal complaint with the Commission, pursuant to Rule 6 of the Commission's Rules of Practice and Procedure, setting forth in detail the matters in controversy; the basis for that party's position, including the necessary data in support thereof; and a history of the negotiations.

(a) Prefiled testimony shall be required unless waived by the Commission for good cause shown.

(b) The Commission shall make such order as necessary to reasonably resolve the controversy.

12.6. Rates for purchases.

(1) Rates for purchases - Rates for purchases shall:

(a) be just and reasonable to the electric consumer and in the public interest, and (b) not discriminate against qualifying cogeneration and small power production facilities; however, nothing in this rule shall require an electric utility to pay more than the avoided costs for purchases, as those costs are defined in Rule 12.1(1)(f).

(2) Relationship to avoided costs:

(a) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(b) Rates for purchases of new capacity shall equal the avoided costs determined after consideration of the factors set forth in paragraph 12.6(4) of this rule, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility. A rate so determined satisfies the requirements of paragraph 12.6(1) of this rule.

(c) A rate for purchases (other than from new capacity) may be less than the avoided cost if the Commission determined that a lower rate is consistent with paragraph 12.6(1) and is sufficient to encourage cogeneration and small power production.

(d) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this rule if the rates for such purchases differ from avoided costs at the time of delivery.

(3) Purchases "as available" or pursuant to a legally enforceable obligation - Each qualifying facility shall have the option either:

(a) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(b) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(4) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(a) The date provided pursuant to Rule 12.03, including Commission review of any such data

(b) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation.

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(c) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph 12.6(4)(b) of this rule, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(d) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(5) Periods during which purchases are not required.

(a) Any electric utility which gives reasonable notice pursuant to paragraph 12.6(5)(b), below, will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself. The costs referred to herein shall be calculated in the same or a similar manner that was used to calculate costs for the purpose of establishing the rate for purchases from the qualifying facility.

(b) For the purposes of paragraph 12.6(5)(a), reason able notice is that which provides each affected qualifying facility adequate time to cease delivery of energy or capacity to the electric utility.

(i) Any utility failing to provide reasonable notice will be required to pay the contract rate for such purchase of energy or capacity from the facility.

(c) A claim by an electric utility that such period as described in paragraph 12.6(5)(a) has occurred or will occur is subject to verification by the Commission.

12..7. Rates for sales.

(1) Rates for sales shall be just and reasonable and in the public interest and not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) When a qualifying facility's load or other cost-related characteristics are similar to those of other customers receiving service under a given rate schedule, the same rate schedule shall apply to the qualifying facility. If there is no existing rate schedule applicable to the qualifying facility, the utility shall file with the Commission a proposed tariff and supporting cost-of-service data.

(3) Upon request of a qualifying facility, each electric utility shall provide supplementary power, back-up power, maintenance power and interruptible power; provided, however, that if, after public notice and hearing, it is determined that compliance with any of these requirements will impair the electric utility's ability to render adequate service to its customers or will place an undue burden on the electric utility, then the Commission may waive such requirement(s).

(a) The rates for sales of back-up power or maintenance power shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both, and shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

12.8. Interconnection costs.

(1) Each qualifying facility shall be obligated to pay any interconnection costs as defined in Rule 12.1(1)(g). Such costs shall be assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics. Reasonable costs of interconnection shall be negotiated by the qualifying facility and the utility, and any disputes shall be resolved in accordance with the procedure established in Rule 12.5(2).

(2) The utility shall be reimbursed by the qualifying facility at the time interconnection costs are incurred. Upon petition by any party involved and for good cause shown, the Commission may allow for reimbursement of costs over a reasonable period of time and upon such conditions as the Commission may determine; provided, however, that no other customers of the utility shall bear any of the costs of interconnection.

12.9. System emergencies or maintenance period.

During a system emergency:

(1) A qualifying facility will be required to supply energy or capacity only to the extent: (a) provided by contract between the utility and qualifying facility; or (b) ordered under Section 202(c) of the Federal Power Act;

(2) An electric utility may discontinue: (a) purchases from a qualifying facility if such purchases would contribute to the emergency; and (b) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

During system maintenance periods:

An electric utility may discontinue purchases from a qualifying facility during periods of maintenance when safety conditions would require the deenergizing of facilities.

ED. NOTE: All forms are available from the P.S.C.

APPENDIX B

REQUEST FOR PROPOSALS

For

A Wood-Fired Cogeneration Facility at Belington Industrial Park Belington, WV

TABLE OF CONTENTS

I. Intent of this Request for Proposals

The purpose of this document is to determine both the degree of interest and the intent of potential developers of a cogeneration facility at a wood products industrial park located near the town of Belington, Barbour County, West Virginia. The primary purpose of this facility should be to fully utilize the wood residue generated at this location; only proposals that utilize wood residue will be considered.

II. Location and Climate

This park is located just to the south of Belington, WV, east of Route 250. Figure 1 shows the location of Belington and a topographic map of this location.

Water is available from the Tygart River, located on the west side of Route 250, approximately 2 miles from the park. The City of Belington has a pumping capacity of 432,000 gallons in 24 hours, with an excess capacity of 375,000 gallons/day. Although the sewage system for Belington has no excess capacity, there is excess capacity in the town of Junior, two miles south of Belington.

Climate data for Barbour County:*

- Average temperature: mean 52.0°F; high 74.5°F; low 29.6°F;
- Average precipitation: January 2.14 inches; July 4.86 inches;
- Elevation around park: 1,740 feet - 1,900 feet;

III. Site Description

All 10 companies inside this 74-acre industrial park are either primary or secondary wood products firms. The layout of the park including existing gas, sewer, water and electric lines is shown in Figure 3. Most of the company offices are housed in small trailers. The companies are divided into three groups:

Group 1 (#1-7) Companies Presently Located In the Park:

1. Coastal Lumber Co.
2. Bel-Bar Dry Kiln Co.**
3. Ware Planing Mill
4. Ware Sawmill
5. Ricottilli Fencing of West Virginia
6. Talbott Lumber Co.
7. B&B Lumber Co.

* Urban, C. ed., Brief Facts about Barbour County, West Virginia, 1990 edition, Philippi-Barbour County Chamber of Commerce, Inc.

** Bel-Bar Co. is recently under new ownership; operations should begin shortly. The new owner has expressed an interest in a wood-fired boiler system for the company.

Group 2 (#8,9) Companies Presently Constructing Plants in the Park:
8. Shears & Son Lumber Co.
9. Abenaki Timber Corp.

Group 3 (#10) Unoccupied Building Housing 2 Radiofrequency (RF) Kilns.

The capacity of the dry kilns operated by company #2 are 7 kilns @ 35,000 BF each, and of company #9, 3 kilns @ 50,000 BF each.

These company numbers correspond to the numbers shown on Figure 2. Although it is unknown at this time if the RF kilns will ever be used again, there is at least one company currently seeking to purchase and operate them.

IV. Residue Availability

Residue is generated as sawdust, bark, chips, shavings, and slabs. At the present time, all residue produced at Belington is disposed of off site; none is used for energy. Sawdust is sold to a local charcoal manufacturer, bark is sold to several mulch processing plants; chips are sold to several paper companies located outside of West Virginia; and slabs which are not hogged are sold to the mining industry or often given away to be used as firewood. The distance to haul residue is often quite far in this mostly-rural area and very little money is made on the residue.

To determine the potential amounts of wood residue available, three areas were designated:

1. Inside the Belington Corporation limit;
2. Within a 25-mile radius of the park;
3. Within a 50-mile radius of the park.

The amount of residue available was obtained from estimates taken during a phone survey of all sawmills and secondary wood products manufacturers generating residue. Information was obtained by calling each company and asking:

1. How much (sawdust, bark, chips, and/or slabs) are generated in tons/day?;
2. What becomes of these residues?

Answers regarding amounts were given in tons/day, or vans/day (assuming one van holds 20 tons of residue). Figure 3 shows these three designated areas and the amounts of residue available within each area. These amounts exclude waste used in wood-fired boilers and slabs.

Residue data for both sawmills and secondary companies was collected within a 25-mile radius, and sawmills only between a 25- and 50 mile radius. Data from only sawmills was collected from the 25-to 50-mile radius because it was thought that nearly all secondary industries in this area would not have much residue to be able to economically haul such an extended distance.

V. Energy Utilization at the Park

An approximation of average energy usage for each company is shown in Table 1. This table was produced without consideration of seasonal changes in energy usage because energy usage is controlled more by the market for wood products, which is somewhat unpredictable.

Electricity Usage

Electric bills for companies in Group 1 were analyzed to determine approximate peak, average and annual energy usage for each company. Two years of bills were requested from companies in Group 1 that covered 1989-1990. Energy data for companies in Group 2 was estimated from conversations with owners regarding anticipated energy requirements. Group 3 data was obtained from the previous owner of the RF kilns and covers only 1989.

Electricity consumption is shown in Table 1, cols. 2-5. Col. 2 was determined by totalling all equipment horsepower; peak demand in col. 3 was the highest demand shown on any electric bill.

Using electric bills as a basis, average and annual usage were calculated; these calculations depended upon annual operations of each company. This took two steps:

1. Hours/month for each company was assumed:
   - 732 (for the steam kilns operating 24 hours/day x 30.5 days/mo.)
   - 168 (for offices open 8 hours/day x 21 days/mo.) or
   - 128 (for offices during holiday weeks in July & Nov. when open 8 hours/day x 16 days/mo.)
2. Companies expected to use electricity 2,000 hrs/yr (#1,3,4,5,6,7, and 8):
   - *Assume* that peak kW occurs for 2, 15-minute periods/day (1/16 of an 8-hr day or 125 hrs/year);
   - *Assume* that average kWh/h occurs 7.5 hrs/day (15/16 of an 8-hr day or 1,875 hrs/year);
   - *Therefore* annual kWh = (peak kW x 125 hrs./yr.)+(avg. kWh/h x 1,875 hrs./yr.);

   Companies expected to use electricity 8,400 hrs/yr (#2,9,10):
   - *Assume* that peak kW occurs for 1, 15-minute period/week (12.5 hrs./yr.);
   - *Assume* that average kWh/h occurs 8,387.5 hrs./yr.
   - *Therefore* annual kWh = (peak kW x 12.5)+(avg.kWh/h x 8,387 hrs./yr.).

The cost of electricity for industrial users in West Virginia is approximately $0.05/kWh.

Thermal Usage

Companies in Group 1 were requested to provide two years worth of gas bills. Estimations were made for companies in Group 2, and one year of data was provided for the company in Group 3. Thermal data is shown in Table 1, cols. 6-8. Peak mmBtu/hour (col. 6) was obtained by determining what month had the highest gas consumption, then dividing the total amount for that month by the number of days the company operated that month.

Annual mmBtu (col. 8) was determined by totalling monthly bills. Average mmBtu/hour (col. 7) was calculated by dividing annual mmBtu/hr. by either 2,000 (companies #1,3,4,5,6,7,8, and 10) or 8,750 (companies 2 and 9).

The cost of natural gas for industrial users in this location is approximately $2.00/MCF.

VI. Social/Regulatory Concerns

It is expected that a cogeneration plant burning solely wood waste would be acceptable to residents of this area. The additional truck traffic into the industrial park area might pose a problem, although this would not represent any new traffic patterns, as many of the trucks that would dispose of their waste at the industrial park travel on Route 92 past the park on their route toward their present disposal site.

It is recommended to any developer of this facility to keep an open line of communication with citizens in Belington and surrounding areas through public meetings. It is also advised to make any documents readily available to interested parties.

<u>State Regulations</u>

Title 150, Series 3, § 150-3-12. Cogeneration and Small Power Production, contains regulations pertaining to cogeneration facilities; copies can be made available upon request.

Under WV Code § 24-2-1, "The test as to whether a person, firm or corporation is a public utility is the dedication or holding out, either express or implied that such person firm or corporation is engaged in the business of supplying his or its product or services to the public as a class or any part of such public as distinguished from services to only particular individuals. ..."

<u>Environmental Regulations</u>

The Air Pollution Control Commission (APCC) in West Virginia issues permits for combustion facilities. Presently, state air quality standards are the same as those at the federal level. WV H.B. 4643, passed in March, 1992, allows the APCC to formulate standards more strict that federal for certain areas of the state with scientific support.

The Water Resources Section of the Division of Natural Resources issues water quality permits; West Virginia requires a National Pollution Discharge Elimination System Permit (NPDES).

<u>PURPA Regulations</u>

Monongahela Power Co., a subsidiary of Allegheny Power System (APS) of Greenburg, PA, has stated that they do not presently need, or anticipate a need, for capacity until 1999. Avoided cost rate for Monongahela Power is $0.015/kWh for off-peak and $0.01502/kWh for peak and for installations without time-of-day metering. Producers are eligible for capacity payments if they sign contracts of at least two years. From contract service date through the 8th year, capacity payment is $0.005/kWh; for the ninth year to the end of the contract, the rate is the greater of $0.005/kWh or the monthly fixed charge per kW of the last fossil-fueled plant in operation during or prior to the 8th year of the contract, times a ratio of the contract term in years divided by 33.[***]

The West Virginia Public Service Commission stated that power from the site may be wheeled. According to WV Code § 150-3-12.4(4), transmission to other utilities occurs:

[***] Independent Power Report's Avoided-Cost Quarterly, McGraw Hill, New York., Third Quarter 1991, p. 99

If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this paragraph as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses and shall not include any charges for transmission.

Philippi Municipal Electric has expressed an interest in purchasing only peak power; presently they purchase all their power from Monongahela Power. Major interconnections with Monongahela Power are:****

Potomac Edison Co. Downsville Pike Hagerstown, MD 21740 (301) 790-3400	Ohio Edison Co. 76 South Main St. Akron, OH 44308-1890 (216) 384-1500	West Penn Power Co. Cabin Hill Greensburg, PA 15601 (412) 837-3000
Virginia Elec. & Power Co. One James River Plaza P.O. Box 26666 Richmond, VA 23261 (804) 771-3000	Appalachian Power Co. 40 Franklin Rd. Box 2021 Roanoke, VA 24022 (703) 985-2300	Wheeling Power Co. 51 Sixteenth St. Box 751 Wheeling, WV 26003 (304) 234-3000
	Ohio Power Co. 301 Cleveland Ave., SW Canton, OH 44702 (216) 456-8173	

VII. Possible Sources of Financial Support

Limited Partnership

There exists the possibility of the tenants forming a limited partnership which will allow them to pool their financial resources. This type of organization may provide a (small) amount of financial support for a project. At the present time, the tenants are very interested in the potential of a cogeneration facility at their industrial park. However, the potential of a limited partnership and, hence, financial support from the tenants will become more evident depending upon the degree of response from this request.

Land Available

The Barbour County Development Authority has stated that they will provide land owned by them (outside the limit of Belington Corporation) to the project free-of-charge

**** Electrical World Directory of Electric Utilities, 97th Edition, 1989, John E. Slater, Publisher, McGraw Hill, NY.

Industrial Revenue Bonds

Industrial Revenue Bonds (IRBs) are a potential means of financing this project. The State Development Authority is allocated $150 Million in funds annually to be used for the issuance of tax-exempt IRBs. Of this $150 Million, $100 Million is allocated to business projects. Of the $100 Million, half is allocated to counties and half is allocated to the state. Currently, the cap allocation for IRBs in West Virginia is $10 Million; there is no cap for cogeneration projects. This funding is on a first-come, first-serve basis. IRBs are issued around the first of January each year and it is recommended that the application process begin, including a prospectus, in October.

To apply for IRBs, an Inducement Resolution must be passed by the county where the project will take place. If the resolution passes, the resolution along with a cap allocation is forwarded to the State Development Authority. The Development Authority makes the decision regarding appropriation. It is then the responsibility of the individual or company awarded the IRBs to sell them; the bonds must be sold within a certain length of time.

Additional information about IRB availability and application procedures can be obtained from:

WV Economic Development Authority
Governor's Office of Community and Industrial Development
Charleston, WV 25305
(304) 348-3650 PHONE
(304) 348-0449 FAX

VIII. How to Reply

Companies interested in pursuing this proposal will need to include, at a minimum, the following information:

1. Company evidence of qualification;
2. General design of the project;
3. Description of proposed system, including:
   a. anticipated system size and amount of waste needed to meet this capacity;
   b. equipment;
   c. physical plant;
   d. special needs;
4. Estimate of project cost and projection of cash flow;
5. Timetable of completion.

Respondents should feel free to provide any additional information to support their proposal. Send to:

Dr. Curt Hassler, Leader
Appalachian Hardwood Center
P.O. Box 6125
West Virginia University
Morgantown, WV 26506-6125

Responses must be postmarked by June 30, 1992. A committee consisting of representatives from the AHC, WV Fuel & Energy Office, Barbour County Development Authority, and the industrial park will review all proposals. This committee will act as a resource and a liaison during all stages of project development. Companies submitting proposals may be requested to present their proposal before the committee.

Criteria to be used by the committee for judging proposals include:

1. Qualifications and previous experience of company;
2. Effective utilization of wood residue;
3. Economic considerations;

Those submitting documents will be notified of the outcome of their request no later August 15, 1992.

IX. Figures and Tables

Figure 1: General Location

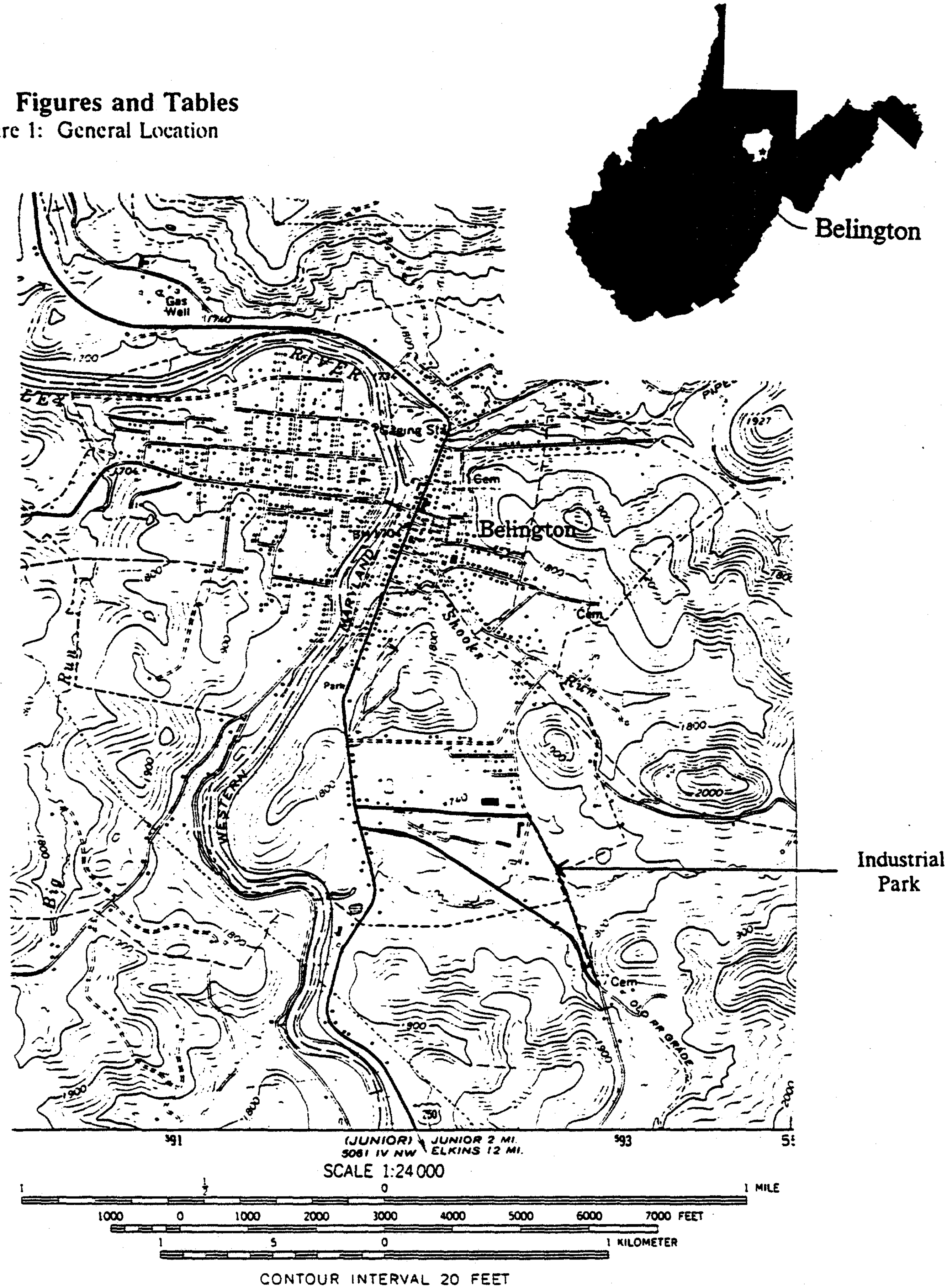


Figure 2. Layout of Belington Industrial Park.

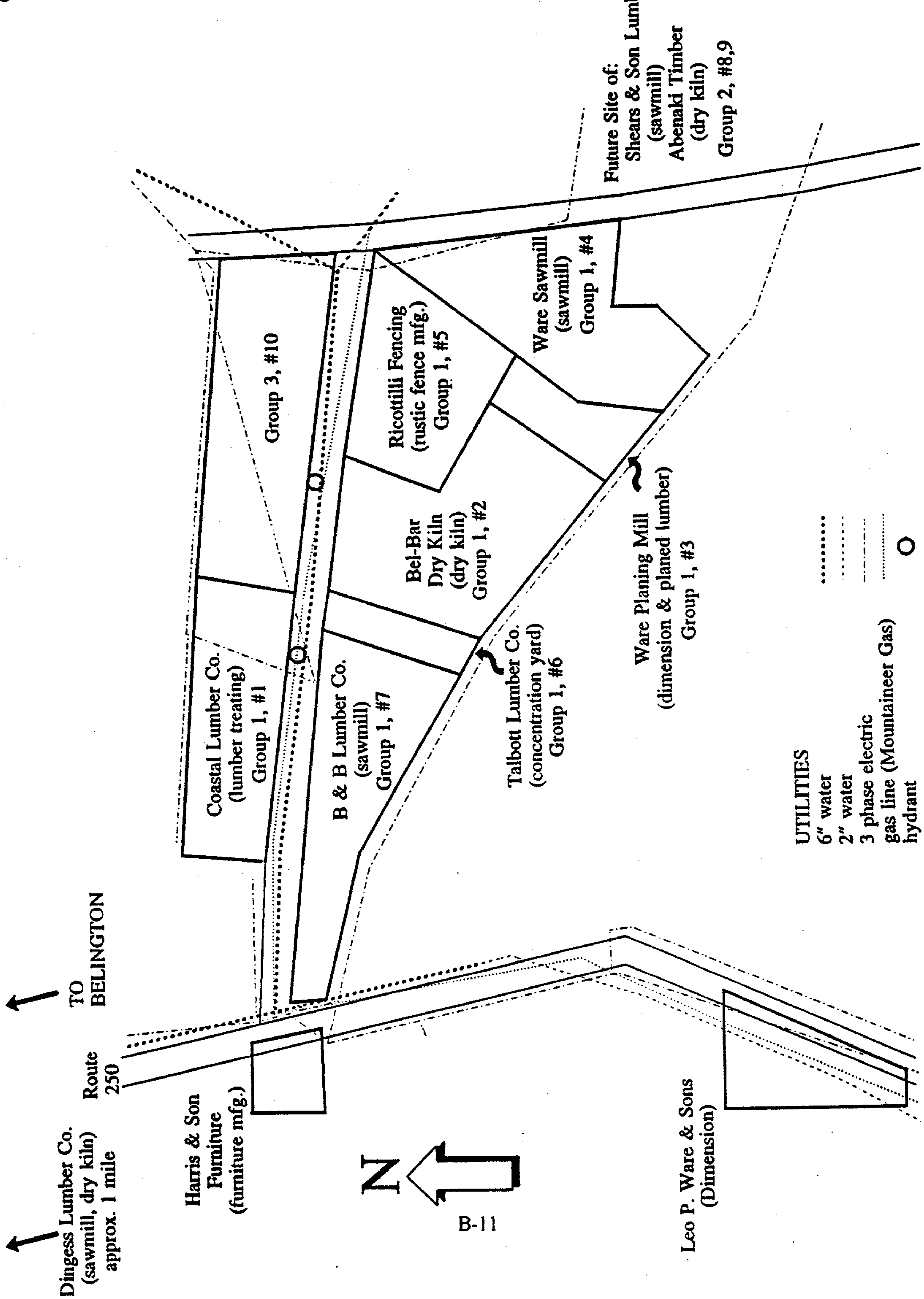
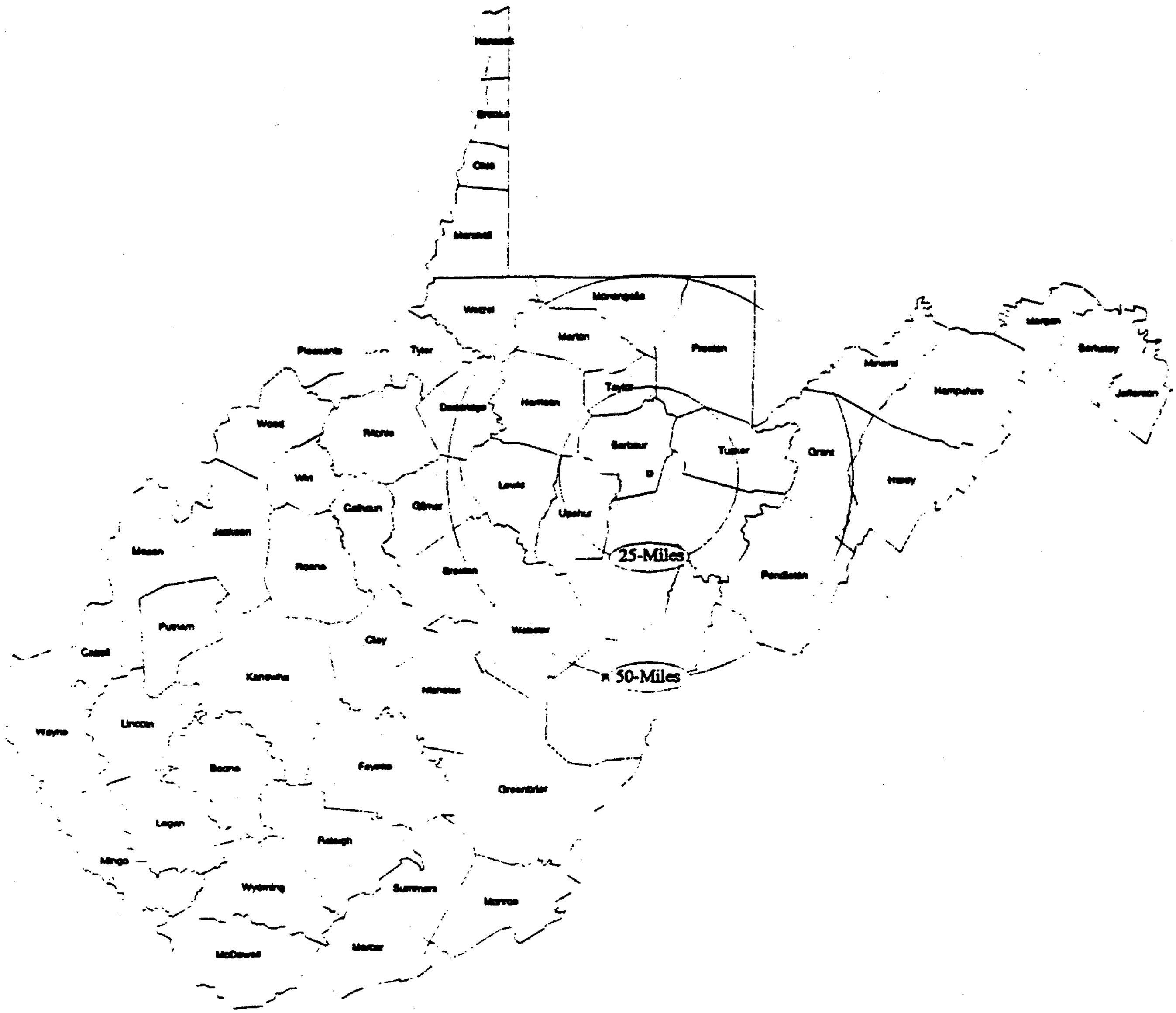


Figure 3. Amount of Residue Available Within 25- and 50-Mile Radius of Belington.



Type of Residue	Belington Area	Within 25-Miles	Bet. 25-50 Miles
Sawdust	50	190	287
Bark	40	183	288
Chips	30	193	497
TOTAL	120	566	1,072

Table 1. Energy profiles of all companies in study.

Company (1)	Electrical: peak kW[1] (2)	Electrical: peak kW[2] (3)	Electrical: avg kWh/h (4)	Electrical: annual kWh (5)	Thermal: peak mmBtu/h (6)	Thermal: avg mmBtu/h (7)	Thermal: annual mmBtu (8)
GROUP 1: Presently Inside Park:							
1. Coastal Lumber	69.3	44.7	34.5	70,275	1.0	0.2	400
2. Bel-Bar Dry Kiln	376.0	104.0	78.8	662,235	7.2	5.8	50,808
3. Ware Planing Mill	70.0	70.0	50.0	102,500	na	na	na
4. Ware Sawmill	214.0	122.0	72.2	150,625	0.7	0.2	400
5. Ricottilli Fencing of WV	516.5	197.8	166.2	336,350	na	na	na
6. Talbott Lumber	19.4	19.4	17.0	34,300	0.1	0.05	100
7. B & B Lumber Company	314.0	136.0	100.3	205,063	na	na	na
TOTAL GROUP 1:	1579.2	693.9	519.0	1,561,348	9.0	6.25	51,708
GROUP 2: Future Inside Park:							
8. Shears & Son Lumber	128.4	73.2	43.3	90,338	0.4	0.1	173
9. Abenaki Timber Corp.	236.9	39.4	46.9	394,149	4.0	3.0	26,280
TOTAL GROUP 2:	365.3	112.6	90.2	484,486	4.4	3.1	26,453
GROUP 3: Radiofrequency Kiln:	569.5	389.5	234.8	2,045,834	0.1	0.05	100
TOTAL GROUPS 1 + 2:	1944.5	806.5	609.2	1,974,254	13.4	9.35	78,188
TOTAL GROUPS 1 + 2 + 3:	2514.0	1218.6	844.0	4,020,088	13.5	9.4	78,261

[1] Determined by highest demand on bill;
[2] Determined by adding all equipment horsepower.

LIST OF 90 DEVELOPERS AND OWNER/OPERATORS TO WHOM RFP WAS SENT.

Bill Bousquet
Alternative Energy Inc.
Twenty South Street
P. O. Box 407
Bangor, ME 04402

Gaylen H. Oderkirk
Ark Energy Inc.
23293 S. Pointe Dr. Ste 100
Laguna Hills, CA 92653

Steven P. Levine
Besicorp Group Inc.
1151 Flatbush Rd.
Kingston, NY 12401

Guy Drouin
Biothermica International Inc.
3333 Boul Cavendish Rm 440
Montreal PQ H4B 3M5
Canada

Allen Jones
Boiler & Heat Exchange Systems, Inc.
P.O. Box 23566
Chattanooga, TN 37422

Bruce E. Lurie
Brown & Root Energy Dev. Inc.
P. O. Box 3
Houston, TX 77001

Karen Kagalis
Catalyst Energy Corp.
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New York, NY 10022

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Community Energy Alternatives, Inc.
1200 East Ridgewood Ave. 2 Fl.
Ridgewood, NJ 07450

Domenic J. Falcone
Creston Financial Group
180 Grand Ave. Tenth Fl.
Oakland, CA 94612

Craig P. Murphy
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219 N. Main Street
River Falls, WI 54022

Arnold Bendent
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313 High Street
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Biomass Energy & Recycling
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11401 Lamar
Overland Park, KS 66211

Robert L. Wood
Bonneville Pacific Corp.
257 E. 2nd South, Ste 800
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Robert McCambridge
Carbontec Energy Corp.
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