Coyote Springs Biomass Power Feasibility Study

Coyote Springs, Nevada

THE BECK GROUP

Project Report
June 2011

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CHAPTER 1 – INTRODUCTION

1.1 PROJECT BACKGROUND

The Lincoln County Regional Development Authority (LCRDA), a political subdivision of the State of Nevada, contracted with The Beck Group (BECK), a Portland, Oregon based forest products planning and consulting firm, to assess the feasibility of producing 5 MW of “off the grid” electrical power at Coyote Springs, Nevada. The proposed power plant would be located in a 64-acre industrial site being planned for development within the Lincoln County portion of the 43,000 acre Coyote Springs development along the east side of U.S. Highway 93 approximately 50 miles north of Las Vegas The objective of the study is to identify the technical and economic feasibility of producing 5 MW of “off the grid” electrical power using biomass fuel, using leased and portable equipment, and producing power for a period of up to 5 years.

The reasons for the short time frame and for not simply connecting to the existing electrical grid are: 1) a potential industrial customer is considering locating at Coyote Springs and would need an average of 3 MW of electricity and 5 MW at peak load, so adding that much new load to the existing 69 KV transmission line near Coyote Springs is not feasible without system upgrades; and 2) within 5 years, the existing transmission line will be upgraded to a 138 KV line, which would be capable of supplying an additional 3 to 5 MW of new load. Therefore, the concept being tested is how much it would cost to produce biomass electrical power to supply the potential industrial customer during the interim period until the transmission line is upgraded and sufficient grid power becomes available.

Biomass power refers to the production of electricity from the combustion or gasification of various forms of biomass. When waste heat from the power production process is captured for another use (e.g., heating a building or supplying heat to a manufacturing process), it is called combined heat and power (CHP). For this study it was assumed that the plant would only produce electrical power because there are no heat customers located at Coyote Springs at the current time or expected to be during the anticipated 5 year life of the project.

The budget for this study was limited. Therefore, the analysis was completed at a relatively high level and used several assumptions that will need to be verified in any subsequent work related to the development of a biomass power plant at Coyote Springs.

CHAPTER 2 – TESTING THE MOBILE POWER PRODUCTION CONCEPT

As described in the introduction, this study will test the technical and economic feasibility of producing 5 MW of biomass power with leased mobile equipment for a relatively short time period (5 years). Given those parameters, the individual pieces of equipment must be small enough to be mobile, but also must be large enough (in combination) to achieve a peak power output of 5 MW. Since 5 MW is a relatively large amount of power, the parameters are diametrically opposed. In other words, it is difficult to produce 5 MW of power with small, mobile equipment.

The good news is that for at least the last decade, substantial sums have been invested in research on modular, mobile biomass power systems that are designed to capture the fuel transportation cost savings of "bringing the processing unit to the fuel" rather than the traditional approach of "bringing the fuel to the processing unit". With the high moisture content and low heating value of biomass, substantial freight savings would be realized, which gives the concept merit. However, the problem that has limited wide-spread commercialization of the approach is that if the objective is to supply power to the grid, it is very impractical if not impossible to interconnect a mobile unit to the grid from remote and mobile points.

2.1 TECHNOLOGY REVIEW

Research efforts have resulted in technology being available that can be used to meet the parameters of this study. More specifically, since the desired product from the biomass fuel is electrical energy (as opposed to heat), there are two likely candidate approaches: 1) direct combustion – standard boiler/steam turbine/condenser technology; and 2) gasification – converting biomass to combustible producer gas, which is then converted to power in an internal combustion engine. The following sections describe each approach.

2.1.1 Direct Combustion

Direct combustion is burning biomass fuel to produce heat. Typically, combustion occurs in a chamber where volatile hydrocarbons are formed and burned. From that process, heat energy is released from the combustion chamber (in the form of hot gases) to a heat exchanger that converts the gases into another medium (e.g., steam, hot water, or hot air). For electrical energy production, the hot gases are converted to steam, which in turn is run through a turbine generator to produce electricity.

The energy efficiency of this process is determined by measuring the amount of heat captured in the medium (steam, hot water, or hot air) relative to the amount of heat stored in the fuel, which is known as the heating value. Efficiency ratings range from 65 percent on the low end (i.e., 65 percent of the energy stored in the fuel is captured as usable energy) to efficiencies well above 90 percent for well designed and maintained systems able to use hot air as the working medium. When direct combustion systems are used to convert heat energy into power, overall system efficiency is about 25 percent.

In direct combustion a key technological design feature is the manner in which wood is combusted. The two basic options are: 1) fixed bed; and 2) fluidized bed. The majority of biomass boilers use a fixed bed design in which material is burned on a grate containing holes. The holes allow for primary combustion air to be introduced below the grate. The fuel is can be placed on the grate and ash is removed via a travelling, vibrating, reciprocating, or rotating grate. Key advantages of a grate system are that they are proven, rugged, efficient, reliable, and have a relatively low capital cost and operating costs. In addition, they are available from a variety of vendors. A key disadvantage is that they typically operate at higher temperatures, leading to higher uncontrolled emissions of some pollutants (CO and NO_x)

In contrast, the fluidized bed design burns biomass in a hot bed of non-combustible material such as sand. The injection of high velocity air from underneath the bed distributes and suspends the fuel as it is combusted. Fluidized bed designs are distinguished as either bubbling or circulating, depending on whether or not the hot char (the charcoal-like material left after gasification occurs) exits the bed and is captured and returned to the bed. A key advantage of a fluidized design is that the operating temperatures are lower, which reduces NO_x emissions. The key disadvantages are a higher capital cost and higher auxiliary power use.

The heating medium (steam, hot water, or hot air) that results from direct combustion can be used for a variety of purposes, including power generation, space heating, and even cooling. This study focuses on the production of steam used to drive a turbine to generate electricity.

2.1.2 Biomass Gasification

Gasification is the process of breaking down solid biomass fuels by the use of heat in an oxygen starved environment in order to produce a combustible gas. A variety of biomass materials, including woody biomass and agricultural residues are suitable feedstocks for biomass gasification.

More specifically, the biomass feedstock is fed into a reactor (an enclosed pressurized container), which is simultaneously heated and the amount of oxygen present in the reactor is limited. As the biomass is heated in this oxygen starved container, volatile gases (CO, H_2, and O_2) are released from the wood. The exact composition of the gas varies among processes and feedstocks, but in general, between the temperatures of 395 and 535 degrees Fahrenheit (F), about 60 to 80 percent of the heat content inherent in the biomass is driven off in the form of combustible gases. The gases driven off are called “producer gas,” and it typically contains about 20 to 50 percent of the amount of energy as an equivalent amount of natural gas (i.e., about 200 to 500 Btu per cubic foot of producer gas).

The producer gas obtained through a gasification process can theoretically be used to more efficiently generate power than can steam. This means that a major potential advantage of gasification is greater efficiency in power production than power production using direct combustion. In addition, gasification technology allows for the utilization of feedstocks (especially certain agricultural residues) that can otherwise be problematic in direct combustion systems. In other words, fuels with a low ash melting point are problematic in direct combustion systems because the melted ash fouls boiler tube surfaces. The lower operating temperatures of gasification systems largely eliminate this problem.

When the producer gas is used to generate electrical power the systems are called *power gasifiers*, and when the producer gas is used to fuel a burner that produces heat, the systems are called *heat gasifiers*. The distinction is important because in a power gasifier application, the producer gas must first be filtered, cooled, and mixed in a gas conditioning system before being combusted in an internal combustion engine. A heat gasifier, on the other hand, combusts the producer gas in an external burner, which requires little or no cleaning or conditioning of the producer gas. As a result, the heat gasifier systems are simpler to design and operate and less costly than power gasifiers. The process of cooling, cleaning and filtering producer gas prior to combustion gives back much of the potential efficiency advantage over steam generation systems.

2.2 GASIFICATION ANALYSIS

Although both direct combustion (boiler) and gasification technologies have been successfully commercialized for power production, they are not equally developed. Gasification is still in its infancy and does not have the variety of vendors and level of guarantees that are available from boiler vendors. Wood is easy to gasify, but the gas is difficult to clean up for purposes of power generation. Often, the gas must be cooled prior to combustion in order to remove tars and other contaminants, thus losing the sensible heat, which is associated with the change in temperature and which is the key to efficient operation. Likewise, in some instances, the wood must be externally dried prior to gasification or the resulting gas will not sustain combustion. The drying step adds to the complexity and capital cost, particularly in a mobile application. Gasification/internal combustion engine technology offers the advantage of solving the water supply issue in remote locations, needing only enough water for engine cooling, with the discharge from that system being used for ash wetting. For a 5 MW gasification system, it is estimated that water usage would be less than 1 gallon per minute.

There are vendors that provide mobile biomass gasification power systems (i.e., Community Power Corporation). However, their largest mobile unit has a generating capacity of 75 kilowatts. Thus, it would take nearly 70 of their units to generate the 5 MW of power required by this project. It simply would make no sense to develop such a complicated system. **There are larger gasification systems, but as the systems**

become larger they are no longer designed to be mobile. Therefore, BECK was not able to identify anyone that had installed 5 MW of power generation capacity using biomass fuel who also leased the mobile gasification equipment. Thus, there is no "blueprint" for this concept. Nevertheless, it is at least theoretically possible.

BECK envisions a system described as follows: For a 5MW mobile application in Lincoln County, the mobile gasification unit would likely consist of 5 gasification modules with each producing 1 MW of power. Each module would contain a gasifier and 2 CAT internal combustion engines with each generating 0.5 MW for a total of 5 MW. Each unit would have a complete fuel handling system and a dryer that uses waste heat to insure the feedstock is at the optimal moisture content. BECK obtained a budgetary quote for such a gasification system from Phoenix Energy of San Francisco, California (see Appendix 1 for more information and a layout drawing). **Note that the system is not mobile but is modular.**

It is possible to create a rough estimation of power cost. For a system capable of producing 5 MW, the budgetary capital cost provided by Phoenix Energy was $26.5 million. That cost includes some minor site prep allowance, but does not include delivery, or installation. Phoenix Energy did not indicate a strong interest in leasing a system. However, anyone that would be willing to lease such a system would almost certainly try to recover the whole cost of producing such equipment during the 5 year lease, because it would be difficult to find another user of a portable 5 MW biomass gasification system. The annual lease expense is estimated to be $5.3 million. Note that this estimate is conservative since the equipment is likely to have very low residual value, and the calculation does not include any profit or any financing costs incurred on the part of the lessor.

Phoenix Energy also indicated in their budgetary quote package that maintenance costs average about $25 per hour. It should be noted that cost seems very low in BECK's judgment. However, there are few of these systems in operation so there are few points of comparison. BECK estimates that two laborers are needed per shift for a total of 10 (one to supply fuel and another to operate the system) for a 24/7 operation, with the total annual labor cost for the 10 staff being an estimated $875,000. Phoenix also indicated that a 5 MW system (5 – 1 MW modules) would have a $100,000 annual expense (accrued into a repair account) for a major equipment overhaul every 5 years. Other miscellaneous costs such as property tax, insurance, and supplies are estimated to be $400,000 annually. Phoenix Energy indicated that their systems typically operate about 7,500 hour per year. Assuming the annual fuel requirement is 45,000 bone dry tons and that the delivered fuel cost is $33.00 per bone dry ton, the annual fuel expense would be $1.485 million, or nearly another $40.00 per megawatt hour. **Thus, the total cost of producing 5 MW of power using a gasification system is estimated to be about $225 per megawatt hour, or $.225/kwh)**. The total of all of the preceding costs are shown in **Table 1**.

TABLE 1 – ESTIMATED COST TO PRODUCE 5 MW OF POWER USING A MODULAR BIOMASS GASIFICATION SYSTEM

Expense Item	Annual Expense (Dollars)	Power Produced (Megawatt Hours)	Cost ($ per MW Hour)
Fuel	1,485,000	37,500	40
Lease	5,300,000	37,500	141
Labor	875,000	37,500	23
Property tax, insurance, misc. supplies	400,000	37,500	11
Routine repair	187,500	37,500	5
Major repair	100,000	37,500	3
Total	**8,347,500**	**37,500**	**223**

2.3 DIRECT COMBUSTION ANALYSIS

With respect to a mobile, standard direct combustion system, BECK was again not able to identify an existing system anywhere that had 5 MW of power generating capacity. The main reason for this is the daunting logistics required for a direct combustion system producing steam and with that steam directed to a steam turbine-generator (STG). Such a unit, with no customer for process steam, will be required to discharge all of its output into an air cooled condenser due to water constraints associated with a mobile or modular design. This means that a large modular air cooled condenser, on several trailers, will be required.

The boiler, which would need to be able to produce 45,000 to 55,000 pounds of steam per hour (depending on steam conditions), will not be of standard integrated combustion and heat transfer construction due to the size of the required firebox. Instead, it will require that the combustion take place outside of the heat transfer unit, and the hot gases be directed to a unit housing the water walls, superheater and convection section, since these cannot logically be separated into distinct units. The additional equipment needed, including an economizer, air heater, multiclone and electrostatic precipitator/stack would have to be mounted on separate mobile units.

In order to allow mobility, the plant would likely resort to a much lower temperature/pressure cycle in order not to require x-rayed welds at all connection points between units. While this allows potential mobility, it also lowers efficiency, thus increasing the size of units that are required to produce a net output of 5 MW.

It is, with dry cooling, at least theoretically possible to have a mobile 5 MW gross axial exhaust STG that can operate successfully, although anchoring of the unit to prevent vibration would be an overwhelming concern. It is likely that a single trailer could house the skid mounted STG and supporting lube oil and generator cooling systems. Even with dry cooling, perhaps 5-10 gpm of makeup water would still be required for boiler blowdown, generator cooling, and steam soot blowing. The discharge water could be used for ash wetting and for dust control on the site.

It is possible to at least make a crude approximation of the power cost from a modular direct combustion unit. Like the gasification plant, an estimated total of 10 staff would be required at an annual cost of $875,000. The total operation & maintenance costs would be an estimated $1.435 million annually. The capital cost for a dry cooled, modular plant is estimated to be about 30 percent higher than a conventional system, or about $35 million. Thus, using the same simple method to estimate the lease cost as was used in the gasification scenario, the annual lease cost is estimated to be $7 million. Assuming the annual fuel requirement is 45,000 bone dry tons and that the delivered fuel cost is $33.00 per bone dry ton, the annual fuel expense would be $1.485 million, or nearly another $40.00 per megawatt hour. **Thus, the total cost of producing 5 MW of power using a direct combustion system is estimated to be about $290 per megawatt hour (or $0.29/kwh)**. The total of all of the preceding costs are shown in **Table 2.**

TABLE 2 – ESTIMATED COST TO PRODUCE 5 MW OF POWER USING A MOBILE, DIRECT COMBUSTION SYSTEM

Expense Item	Annual Expense (Dollars)	Power Produced (Megawatt Hours)	Cost ($ per MW Hour)
Lease	7,000,000	37,500	187
Fuel	1,485,000	37,500	40
Labor	875,000	37,500	23
Routine repair	1,425,000	37,500	38
Total	**10,785,000**	**37,500**	**288**

2.4 CONCLUSIONS

The preceding sections contain analyses of mobile or modular temporary (5 year) gasification and direct combustion power production systems. As was demonstrated, the technical aspects of producing 5 MW of power, which is a relatively large amount of power, using mobile or modular equipment are very challenging. In addition, the short time-span in which the full capital cost of the equipment must likely be recovered by the lessor causes the lease costs to be very high. The end result is that in either approach, the cost to produce power is high relative to power produced using another source. For example, a recent study estimated that a 5 MW natural gas fired system could produce power for about $100 per megawatt hour[1]. In addition to the lower cost, such a system would be much easier to operate from a technical standpoint.

[1] Natural Gas – Fueled Distributed Generation Solid Oxide Fuel Cell Systems: Projection of Performance and Cost of Electricity. 2009. U.S. Dept. of Energy National Energy Technology Laboratory Report Number: R102-42009/1 accessed at:

http://www.netl.doe.gov/technologies/coalpower/fuelcells/publications/Natural%20Gas%20DG%20FC%20paper%20update%20090330a.pdf

CHAPTER 2 – TESTING THE MOBILE POWER PRODUCTION CONCEPT

To enhance the feasibility of an interim biomass generating source of electricity to supply the industrial user until such time as grid-based energy is available, BECK suggests a different approach in which a permanent facility is considered at Coyote Springs. During the first 5 years of operation, the electrical power could be utilized by an industrial customer located adjacent to the plant. After the upgrade to the nearby transmission line, at which time the industrial customer would no longer need the power from the on site biomass generation unit, that power could be sold as renewable power and transmitted through the planned 138 KV transmission line to the Las Vegas or Southern California energy markets. This scenario is modeled in the following sections of this report. This approach allows both a more traditional design and a more traditional capital recovery period, both of which lower power cost.

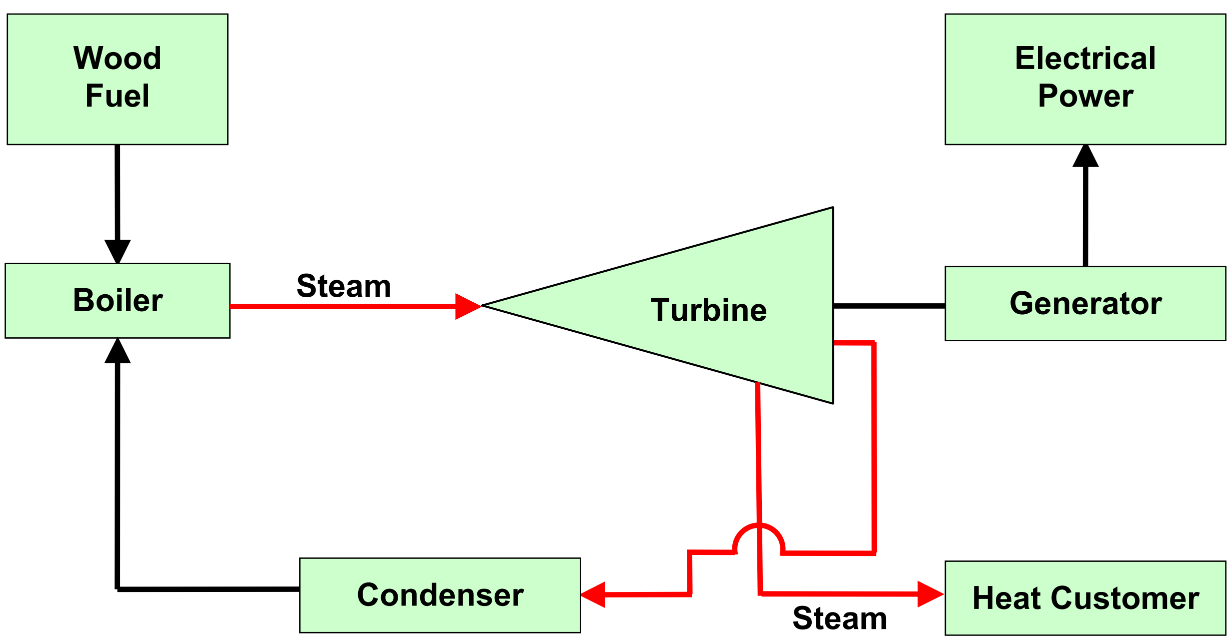
CHAPTER 3 – BIOMASS POWER TECHNOLOGY

3.1 TECHNOLOGY OVERVIEW

Figure 1 is a simplified diagram of a biomass fueled CHP system. The process begins when biomass fuel is combusted in a furnace whose walls are made up of water filled pipes. The water in the pipes turns into steam. Depending on the design of the boiler, the steam is heated to the desired temperature and pressure before it is passed through a turbine-generator (TG). The TG is a rotating, multi-stage unit that drops steam temperature and pressure at each stage as thermal energy is converted to mechanical energy.

As shown in **Figure 1**, there can be an extraction point in the turbine where a portion of the steam is extracted for use by a heat customer. Not shown in the diagram is a second extraction point in the turbine at which steam is extracted to supply the deaerator, a device that removes entrained oxygen (very small air bubbles trapped in water) from the feed water as it goes back to the boiler. The steam not needed for the heat customer or for the deaerator exits the back end of the turbine to the condenser to be turned back into water. The pressure level in the condenser is far below atmospheric pressure to ensure that steam is "pulled" through the turbine with maximum efficiency. The condenser is supplied with water from a wet mechanical draft cooling tower (not shown in the figure), which evaporates a portion of the water as it cools it for the return trip to the boiler.

FIGURE 1 – WOOD-FIRED COMBINED HEAT AND POWER SYSTEM



The primary choice to be made in plant design is the selection of the boiler technology. The large majority of biomass boilers burn the wood on a grate containing holes so that primary combustion air can be introduced below the grate. A metered amount of fuel is spread across the grate by an air swept stoker. The grate itself can be fixed, vibrating, traveling, reciprocating or rotating. The purpose of a moving grate is to automatically remove ash and to provide a space for fresh fuel. Another boiler design is a fluidized bed, which comes in either a bubbling bed or circulating bed version. In both designs, a large bed of sand and fuel is kept "fluidized" by large volumes of air introduced below the bed. There is no grate in this design. A third option is to gasify the fuel in a separate vessel. This occurs through heating the biomass fuel in an oxygen starved condition. As the biomass is heated, combustible gases are produced and collected. Those gases are then introduced to the boiler proper where combustion is completed.

The pros and cons of various designs are debated endlessly, but some of the advantages and disadvantages of each are as follows. The grate designs are proven, efficient, rugged and reliable. The fluidized beds are newer in design; they operate at a lower temperature, which means that some pollutants (e.g., NO_x and CO) are minimized. However, they require additional auxiliary power for the fluidizing process. Gasification offers advantages when fuels with very low ash melting points are used because burning the gases rather than the fuel itself can prevent boiler conditions that might otherwise foul boiler tube surfaces. For example, combustion of agricultural residues sometimes relies on gasification to prevent the build-up of silica deposits on boiler surfaces. The downside of gasification is that the systems are more complex, not proven at larger scale, and offer no thermal efficiency advantage so long as the resulting gas is simply burned in a standard boiler.

In this study, the fuel quality is known – chipped or ground urban wood waste, including industrial wastes, yard debris, and construction and demolition waste (see discussion in Chapter 4, Fuel Supply). The only variables of consequence in the fuel mix will be particle size and moisture content. There will be no combustion of high moisture sludges such as might be encountered in a pulp and paper industry application and which could require fluidized bed combustion. The proposed project at Coyote Springs does not anticipate combusting agricultural residues that might point to a gasification process. For these reasons, the choice for costing and efficiency calculations in this study is a moving grate system fed by an air swept stoker.

The moving grate/air swept stoker system gives the widest choice of vendors and has a relatively low capital cost and auxiliary power use. BECK has not investigated air quality in the region, but based on past experience a stoker grate design is likely to comply with a Nevada BACT determination when equipped with an electrostatic precipitator for particulate control and multiple levels of heated overfire air for CO, NOx and volatile organic compound (VOC) control. These pollution control technologies are proven in performance in dozens of biomass fueled applications, and commercial performance guarantees are available. This design system forms the basis of the financial model used in Chapter 6, the Financial Analysis section of this report.

CHAPTER 4 – FUEL SUPPLY

The sizing of a biomass power plant is dictated by several factors, including water supply, ability to interconnect and transmit power to the grid, and the available fuel supply. While all of these factors are important, perhaps the most fundamental factor to consider in sizing a plant is the volume of fuel available at a given location and the delivered cost of fuel from the given location. For this study, plant size was based on the volume of fuel estimated to be available from urban wood waste in the Las Vegas area.

Table 3 shows the volume of biomass fuel estimated to be available in the vicinity of Coyote Springs. The estimate is based on the application of urban wood waste production factors (bone dry tons per year per capita) to the 2010 population of Clark County, Nevada. The factors used in the analysis are from a comprehensive study of urban wood waste production in the United States.[2] The result is an estimated "total urban wood waste volume" in the Las Vegas region of about 650,000 bone dry tons per year.

TABLE 3 - ESTIMATED SUPPLY AND DELIVERED COST OF BIOMASS DELIVERED TO COYOTE SPRINGS

Fuel Source	Volume (Bone Dry Tons)	Value ($/Bone Dry Ton)
Urban Wood		
Urban Wood – Low Recovery	65,000	33.00
Urban Wood – High Recovery	325,000	unknown

Note that the volumes shown in **Table 3** are lower than the total amount of fuel estimated to be available. The reason for this is that not all urban wood waste is recoverable. Therefore, additional factors were applied to estimate the amount actually available. In the "Low Recovery" Scenario, it was assumed that 10 percent of the total was recoverable and in the "High Recovery" Scenario it was assumed that 50 percent was recoverable. Both recovery factors are from the Wiltsee study (see footnote) in which it was determined that among 30 metropolitan areas in the United States the recovery of urban wood waste ranged between 10 and 50 percent of the total amount produced.

The low recovery volume in **Table 3** was used for the purpose of sizing the plant. The primary reason for this is that the Moapa Indian Tribe, located in Moapa, Nevada, has been collecting urban wood waste from the Las Vegas area and knows that local market. In 2010, they reported to BECK that they had collected an estimated 12,500

[2] G. Wiltsee. 1998. Urban Wood Waste Resource Assessment. Appel Consultants, Inc., Valencia, CA.

bone dry tons. They also estimate that they could recover 4 to 5 times more urban wood waste if there was a strong local market and if the collection system were more effective at sorting urban wood waste from landfill waste.

Regarding the delivered cost of the urban wood waste shown in **Table 3**, the values are based on what the Moapa Indian Tribe is currently receiving for urban wood waste that it collects, processes, and sells to markets in California. In other words, the delivered cost shown in **Table 3** is based on the Moapa Tribe's current f.o.b. value in Moapa plus the cost of transporting the fuel from Moapa to Coyote Springs. As shown, the estimated delivered cost to Coyote Springs is $33 per bone dry ton.

Additional sources of biomass fuel arising from forest management treatments of Pinyon-Juniper forests lying roughly 75 to 100 (or more) miles north and northeast of Coyote Springs were also considered. According to information posted on the Coordinated Resource Offering Protocol (CROP) website, an estimated 5,000 bone dry tons of biomass fuel would be available annually from forest management treatments in Southwestern Utah, primarily in the area around St. George, Utah. An additional amount of 2,500 to 5,000 bone dry tons of forest derived fuel is likely to be available annually from forest management treatments in Lincoln County, Nevada. However, the cost of fuel from such treatments is far higher than the cost of biomass fuel derived from urban wood waste. Forest derived biomass delivered to Coyote Springs would have an all-in cost of $100 per bone dry ton and higher, depending on the haul distance. Therefore, the volume available from restoration treatments was not considered in selecting the appropriate power plant size.

The feasibility of delivering forest derived fuel by rail to Coyote Springs was also briefly investigated. However, it was judged to not be cost effective because of the extra handling required to: haul the material from the forest to a rail siding, unload the material from trucks, reload it into rail cars, deliver it to a siding near Las Vegas, unload it from the rail cars, reload it into trucks, transport it to Coyote Springs, and unload it at the power plant. The reloading cost is estimated to be about $6 to $7 per bone dry ton at each siding for a total of $12 to $14 per bone dry ton for reloading. In addition, there is the hauling cost from a siding near Las Vegas to the prospective power plant at Coyote Springs. That estimated haul cost is $14 per bone dry ton. Thus, the "extra" cost of shipping material by rail is estimated to be roughly $25 to $30 per bone dry ton.

CHAPTER 5 – PLANT SIZE AND CAPITAL COST

The amount of urban wood waste fuel estimated to be available in the “Low Recovery Scenario” was judged to be adequate for supplying a boiler capable of producing 60,000 pounds of steam per hour. A boiler of that size is capable of supplying a steam turbine generator that can produce just over 6 MW of power (assuming there is no customer for the excess heat). Note that this is a slightly larger plant than the 5 MW size considered in the modular, mobile concept scenario. The heat balance for such a plant is shown in Appendix 2. Note that the 6 MW is the gross amount of power produced. Some of the power produced is used to service the operation of the power plant. Thus, the net amount of power available for sale was projected to be 5.7 MW.

The budgetary capital cost for such a facility was estimated as shown in Table 4.

TABLE 4 – BUDGETARY CAPITAL COST 6MW PLANT

Cost Item	Cost ($ in 000s)
Construction Costs	27,500
Project Management/Permitting/Engineering	500
Site Preparation/Roads/Fencing	200
Working Capital	500
Utility Interconnection	800
Fuel Receiving and Processing	1,500
5% Contingency	1,550
Interest During Construction	2,058
Interest Earnings	0
Issuance Costs	485
Total Capital Costs:	35,093
Less: discounts	0
Net Capital Costs	**35,093**
Note: Cost per MW	5,774

The important things to note from **Table 4** are:

- The construction costs and fuel receiving and processing line items include all equipment and construction required for a complete and functioning power production system. All of the equipment would be new.
- The capital costs shown are not specific to this project, but were adapted from competitive quotes for a recent project in the Western U.S. of the same size. While BECK believes the costs shown are representative of actual costs for a

plant of this size, BECK recommends further research into the capital cost if a project at Coyote Springs is pursued.

- The federal Investment Tax Credit (ITC) which has normally been taken in the form of a grant equal to 30 percent of the eligible capital costs was not applied. Thus, the discount line item in **Table 4** is zero. The ITC grant expires at the end of 2011, and it is unclear whether the program will be renewed. Given this uncertainty, the ITC grant was not applied. As described in the financial analysis section, instead of taking the ITC in the form of a grant, the project was modeled as utilizing the federal Production Tax Credit (PTC), a renewable power incentive that has been in place since 1992 and previously extended by Congress several times.

CHAPTER 6 – FINANCIAL ANALYSIS

6.1 PRO FORMA INCOME STATEMENT

The project team completed a financial analysis with the goal of identifying the power sales price that would provide the Coyote Springs biomass power project with a 15 percent return on equity. **The results of that analysis indicate that the project would need to secure a power purchase agreement in which the power would be worth $125.50 per megawatt hour (or $0.125/kwh) initially and escalate at 2 percent annually**. The year one pro forma income statement for such a scenario is shown in **Table 5**.

TABLE 5 – YEAR 1 PRO FORMA

Revenue/Expense Line Item	($ 000s)	$/MWh
Electric Sales	6,255	125.50
Steam Sales	0	
TOTAL REVENUES:	**6,255**	**125.50**
O&M	2,133	42.80
Fuel	1,498	30.05
Ash Disposal	33	0.07
EXPENSES:	**3,663**	**73.51**
OPERATING INCOME:	**2,591**	**51.99**
– Interest	1,474	29.57
– Depreciation	2,749	55.16
PRETAX INCOME:	**(1,631)**	**32.73**
+ Depreciation	2,749	55.16
– loan principal	(668)	13.40
PRETAX CASH FLOW	**450**	**9.02**
+/- Taxes/Credits/Grants	**(1,773)**	**35.57**
NET CASH FLOW	**2,223**	**44.60**

The important things to note from the preceding analysis are:

- As shown in the pro forma income statement, the prototypical plant generates a year one revenue stream of over $6.255 million. From that revenue stream, $1.498 million is used to procure fuel and $2.133 million is used to pay operation and maintenance expenses. This leaves a net operating income of $2.591 million prior to application of depreciation, interest payments on long term debt, and taxes.

- Since the Production Tax Credit was applied (rather than the ITC taken as a grant), the project would receive tax credits equal to $1.773 million. The tax credit was calculated at a rate of 1.2 cents per kilowatt hour in year one and escalated at 3 percent per year for 10 years. This results in a net positive cash flow of $2.223 million per year.

- Please note that like the ITC grant, the Production Tax Credit is set to expire if a project is not placed in service by the end of 2013. However, unlike the ITC grant, which has only been in existence for 2 years, the production tax credit has been in existence for nearly 20 years, and it has been renewed by the federal government every time it was about to expire. Thus, *BECK has assumed that the PTC will be renewed again at the end of this year. This assumption needs to be verified in any further analysis of this project*.

- A tax equity partner would most likely need to be brought into the project to monetize the production tax credits arising from the project.

- The average delivered fuel cost was assumed to be $33.00 per bone dry ton escalating at 3 percent annually.

- It was assumed that the project owner would have 30 percent equity in the project ($10.528 million), and 70 percent ($24.565 million) would be financed at 6 percent interest on a 20 year note.

- The plant would require a staff of 10. The total labor cost (including benefits) would be $875,000 per year.

- The plant would operate 8,200 hours per year and generate 49,840 MWh of power (6.078 MW gross output, 5.7 MW net output).

- A 20 year pro-forma income statement has been included as Appendix 4.

- The operating costs expressed on a dollars per MWh basis total about $73.50/MWh. Note that the operating costs per MWh could be lower if the plant size was larger and the unit fuel price did not change and the staffing stayed the same. Staffing does not change significantly as plant size increases. However, the average fuel cost is likely to increase as plant size increases. A larger plant means reaching farther distances for fuel, which in turn means a higher delivered cost because of increasing transportation costs.

6.2 DISCUSSION

Based on a review of the renewable power market in the Southwestern U.S., it is estimated that a biomass power project would have to sell power at the closest regional trading hub at $95 per megawatt hour to be competitive with other renewable power projects. It is important to note that the $95 per MWH for biomass is equivalent to $130 to $135 per MWH that NVEnergy and other California utilities have paid for other renewables (e.g., solar). The reason these two prices are equivalent is due to the difference in the Renewable Energy Credit (REC) value between types of renewable power. For example, solar power receives 2.4 renewable energy certificates per megawatt hour, whereas biomass power only receives 1.0 renewable energy certificate per megawatt hour. This difference in REC value explains why the current market value of biomass power is $95/MWH while other renewables are significantly higher. **Thus, under the current conditions, the project does not appear to be feasible since the power price required to provide an investor with a satisfactory return is about $30 per MWh higher than the current market price.**

The following sections provide an analysis of key factors that, if changed, would affect the economic feasibility of the project.

6.2.1 Steam Customer

The ability to sell the “waste” heat associated with the production of power often improves the economics of a biomass power project. Therefore, a financial analysis was completed for a second scenario in which it was assumed that a hypothetical heat customer was located at or near the power plant in Coyote Springs. A heat balance for this scenario is shown in Appendix 3. The major assumptions in the second analysis were:

- The plant output would drop to 5.5 MW (gross) and 5.1 MW (net) because some of the steam that was used for power generation would now be used by the heat customer.
- The heat customer would use an average of 15,000 pounds of steam per hour.
- The heat customer would pay the power plant $8.00 per thousand pounds of steam used.
- All other assumptions related to capital cost, operating hours, fuel cost, etc. were unchanged.

Given the preceding assumptions, the financial model was solved for the price that would provide an investor with a 15 percent return on equity. **The result was a price of $116.50 per megawatt hour, or nearly $10 per megawatt hour lower than the “base case” scenario in which there was no steam customer.** Note however, that the price of $116.50 per megawatt hour is still higher than the current market value of $95 per megawatt hour. **Thus, while the presence of a heat customer improves the economics of a project, it still would not be feasible.**

6.2.2 Fuel Cost

Another way in which the project could become feasible, given the current market value of renewable power, is if the delivered cost of fuel was lower. The $33.00 per bone dry ton used in the "base case" analysis is based on current market values observed by the Moapa Tribe plus freight. To identify the fuel price at which the project becomes feasible given the current market values for renewable power ($95 per MWh), BECK solved the financial model for fuel price, rather than power price. In the no steam customer scenario, dropping the fuel price all the way to zero still only provides the investor with a 13.1 percent return on equity, when the power is valued at $95 per MWh. In the hypothetical steam customer scenario, dropping the delivered fuel price to $12.75 per bone dry ton would provide the investor with a 15 percent return on equity when the power is valued at $95 per MWh. **Since neither the $0/BDT or $12.75/BDT fuel prices are realistic, the project would still not be feasible if the plant size was unchanged and fuel prices dropped.**

6.2.3 Plant Size

A more likely condition in which the project would be feasible is to increase the plant size to 10 MW (or more) so that more power is produced while still having the same non-fuel operating costs (more or less). The key, however, to such a scenario being feasible is that the average delivered fuel price would have to not increase substantially as the plant size increases.

As described in the fuel supply section, The Moapa Tribe is currently processing about 12,500 bone dry tons of Las Vegas urban wood waste annually. They believe they could collect and process 4 to 5 times that much each year if better and more diligent collection methods were in place. Their assumption is supported by a separate analysis where per capita urban wood waste production factors are applied to the population of Clark County and which revealed that as much as 650,000 bone dry tons of urban wood waste might be produced in Las Vegas each year.

A deeper investigation into urban wood waste from the Las Vegas region is beyond the scope of this study. However, if there is continued interest in this project, BECK recommends a detailed study of urban wood waste volumes and costs (collection, processing, and transportation) be performed. The results of such a study could be used to determine if a larger biomass fueled power plant could be supported at Coyote Springs (or elsewhere in the region).

CHAPTER 7 – OTHER CONSIDERATIONS

7.1 SITE

Neither BECK nor CSPC staff visited the Coyote Springs site to determine if a suitable location is available. Thus, the analysis in this report is based on the assumption that a site is available. No costs for land acquisition were included in the analysis. A 6 MW biomass plant would require between 5 and 10 acres of land.

7.2 WATER

The 6 MW power plants modeled in this study (steam and no steam customer) would consume between 90 and 120 gallons of water per minute, or about 150 to 200 acre feet per year. It was assumed that water in those quantities would be available at the site since the long-term plans for development of the Coyote Springs area call for water usage at levels significantly higher than the usage of the biomass power plant.

7.3 INTERCONNECTION/TRANSMISSION

Since there was no site visit, no assessment was made of the ability to interconnect a project at Coyote Springs to the power grid. However, from a prior study completed by BECK and CSPC in Lincoln County, Nevada, it was assumed that interconnection could be made on the 69 KV radial line operated by the Lincoln County Power District that runs from the Reid Gardner power plant near Las Vegas to the north past Coyote Springs and on to the Caliente and Pioche area. The cost for interconnecting was assumed to be $800,000.

7.4 INCENTIVES

As described earlier in the report, the Investment Tax Credit taken in the form of a grant equal to 30 percent of the a project's eligible capital costs has been a key incentive for renewable power projects. However, that program expires at the end of 2011 and in BECK's judgment is not likely to be renewed. Therefore, the major incentive applied in this analysis was the Production Tax Credit, which was valued at 1.2 cents per kilowatt hour in 2014 and escalated at 3 percent annually.

CHAPTER 8 – CONCLUSIONS

Given the current assessment of fuel supply and cost and renewable power market value, the 6 MW permanent plant considered in this analysis is not feasible. The key reason for this finding is that the capital cost on a dollars per megawatt of power production capacity basis are too high.

There is a good possibility that a larger plant could be feasible if a more detailed study of urban wood waste in the Las Vegas area revealed that more economically priced fuel is available than the current estimate. Such a finding is suggested by the large population of Clark County, but a detailed analysis of the urban wood waste supply in Las Vegas was beyond the scope of this study. The main reason a larger plant might be feasible (if enough fuel was available in the low-to-mid $30 per bone dry ton delivered range) is that the fixed operating costs at a larger plant do not increase significantly relative to a smaller plant. Therefore, on a per unit of power basis, the operating costs are lower and the larger plant might be feasible. In addition, the capital cost of the facility increases more slowly than the increase in size. This situation leads to lower depreciation costs on a per unit basis.

APPENDIX

APPENDIX 1 – GASIFICATION EQUIPMENT VENDOR LITERATURE

Basic Process Description

The Phoenix Biomass Energy system converts wood and agricultural waste biomass into a natural gas substitute (“syngas”) through the process of thermo-chemical conversion (“gasification”). This syngas is then used to fuel a specially modified natural gas genset that produces renewable electricity and heat. A byproduct of the gasification process, called “biochar”, is a wood char that has sequestered carbon in solid form (~74% fixed carbon) and is used as a beneficial soil amendment.

The biomass conversion process is a thermo-chemical one that ‘cooks’ biomass in an oxygen starved environment. By depriving the fuel of sufficient oxygen, the wood biomass does not burn, but rather gives off a hydrogen rich syngas. As the biomass gives off the syngas, it is transformed into bio-char and ash of approximately 1-5% of the volume of biomass fuel. The syngas is then captured, cleaned and cooled before being sent as fuel to the genset. The gensets we utilize come from variety of nationally known vendors such as Cummins, Caterpillar, and GE. This ensures that there are readily available spare parts and maintenance technicians available locally. Further, we have incorporated an on-site water treatment as part of our core model, re-using much of the water for cooling and filtration process, to maintain a small footprint. Finally, our largest by-product, the biohcar, is sold to a variety of potential users.

One unique aspect of our system is that the footprint is very small – less than half an acre to generate 1 megawatt; versus wind systems that need 1-2 acres per MW, or solar which needs 8-10 acres per MW. Along with our module design, this small footprint allows our solution to be deployed close to the biomass feedstock.

Fuel Preparation

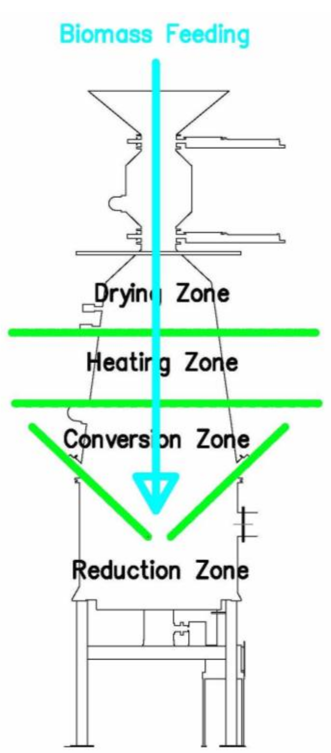


Figure 1

Fuel storage and handling is finalized with your company or host’s personnel prior to site work being carried out. There are several design options to choose from, which complement a site’s material flow. Currently, we believe a walking floor trailer and/or a combination conveyor fed hopper provide the most flexible solutions. Biomass fuel from your facility will be delivered via conveyer (or front-end loader,) to the fuel hopper. Once in the Phoenix Energy hopper, our automated system uses a robust transloading platform and fuel metering sensors to continuously feed the conversion unit in small batches as needed.

Biomass Conversion

The biomass conversion chamber (figure 1) is essentially a chamber where various complex thermo-chemical processes take place. As the material flows downward through the reactor, the biomass gets dried, heated, converted into gas and reduced into bio-char and ash.

Although there is a considerable overlap, each process can be considered to occupy a separate zone, where fundamentally different chemical and thermal reactions take place. The fuel must pass through all of these zones to be completely converted.

The downdraft conversion unit, employed by Phoenix Energy, is under negative air drawn by a high-pressure blower. The essential characteristic of the downdraft design is that the tars given off in the heating zone are drawn through the conversion zone, where they will be broken down or oxidized. When this happens, the energy they contain is usefully recovered with the mixture of gases in the exit stream being relatively clean, and ready for further processing. Expected total gas contaminant concentration prior to filtration is up to 100 times lower than what is often seen in updraft and fluid-bed systems.

Gas Cleansing

After the syngas has been extracted from the conversion chamber it is cooled and cleaned by a series of scrubbers and filters. First, the gas passes through a venturi scrubber, which is known to remove particulate in the sub-micrometer range. The gas is then passed through a series of four filters. The first is a coarse filter to coalesce residual liquids. The second is a rejuvenating active sawdust filter, the third is a similar passive filter, and the fourth is a fabric bag filter. The filter media are sawdust and biomass chips so instead of using expensive synthetic filters that need to be thrown away, the used filter media can be simply placed back into the fuel hopper and consumed.

Figure 2 – The P250 biomass conversion chamber (red) and filtering system (blue)

Power Generation

Phoenix Energy units are based on a spark-ignited engine genset. Depending on the size chosen, the engines are capable of providing 500 or 1,000KW operating on syngas. Phoenix Energy will customize the selected genset to allow syngas carburetion for this engine and provide standard paralleling switchgear for electrical output.

At present we believe the CAT 3516 or the Cummins 1710 offer the most attractive engine options for your firm, however we can work with *any* natural gas genset. First and foremost there is a large secondary market for CAT and Cummins engines and the service coverage in the US is very good. These engines also have unique features enabling good fuel economy, better emissions, high durability, and extended oil / filter change periods. They run on variety of gaseous fuels like natural gas, bio-gas, sewage gas, LPG etc. Engines are available in both types of aspirations, naturally aspirated and turbocharged, after-cooled

Figure 3 – A P500 installation in California

versions. Both CAT and Cummins engines have been designed to combine compact size, low emission levels and excellent performance characteristics of high-speed technology with the medium speed benefits of water-cooled exhaust valve seats, steel-crown pistons & combustion control.

Bio-char & ash handling, and Low Water usage

Bio-char & ash are removed from the conversion chamber using a dry extraction process designed around a water cooled auger at the base of the gasifier. Scrubbed particulate in the form of ash is extracted at the base of the cyclone. A closed water loop is used for both cooling and process water. On-site water treatment, utilizing biochar and sand filters allows for recirculation of both water loops reducing water usage to a minimum. In fact, at certain times of the year the system is actually water accretive as moisture is removed from the biomass and captured in the process water loop. Water levels are maintained in separate storage tanks for each loop and pumped through both the cooling and filtration process. The automated filter is typical for river sludge treatment and separates the solids from the re-circulated water. The biochar , is a "capture & store" byproduct that is separated out, using a special mechanical separator, for resale as a soil amendment or ADC, sequestering carbon in solid form while in the ground for up to 1,000 years! While we don't include these biochar sales in our conservative base financial forecast, we do believe that carbon credits related to biochar may become a valuable revenue source in the near future. Water leaving the filter is passed through a final stationary filter prior to heat exchange. The scrubbing water is absorbing heat from the syngas and must be cooled in a cooling tower prior to returning to the closed-loop scrubber.

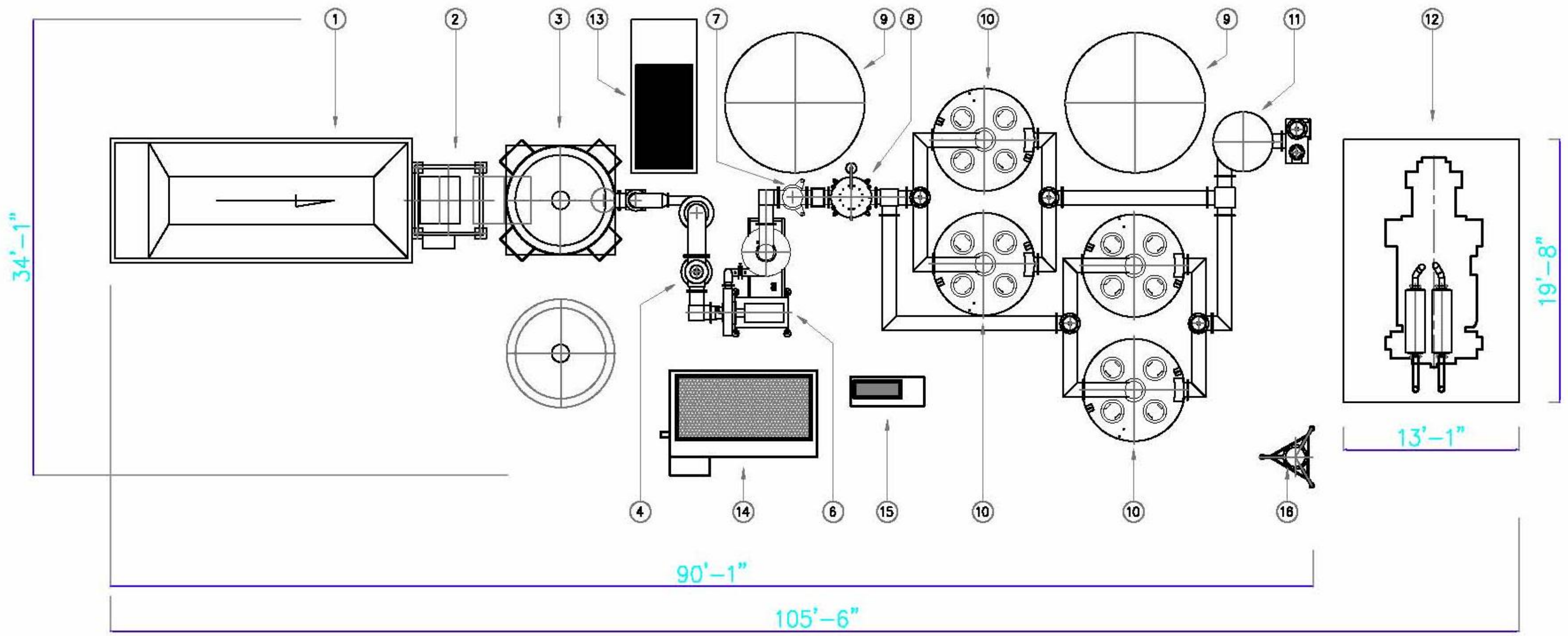
P1000 LAYOUT

Vertical Projection

10'

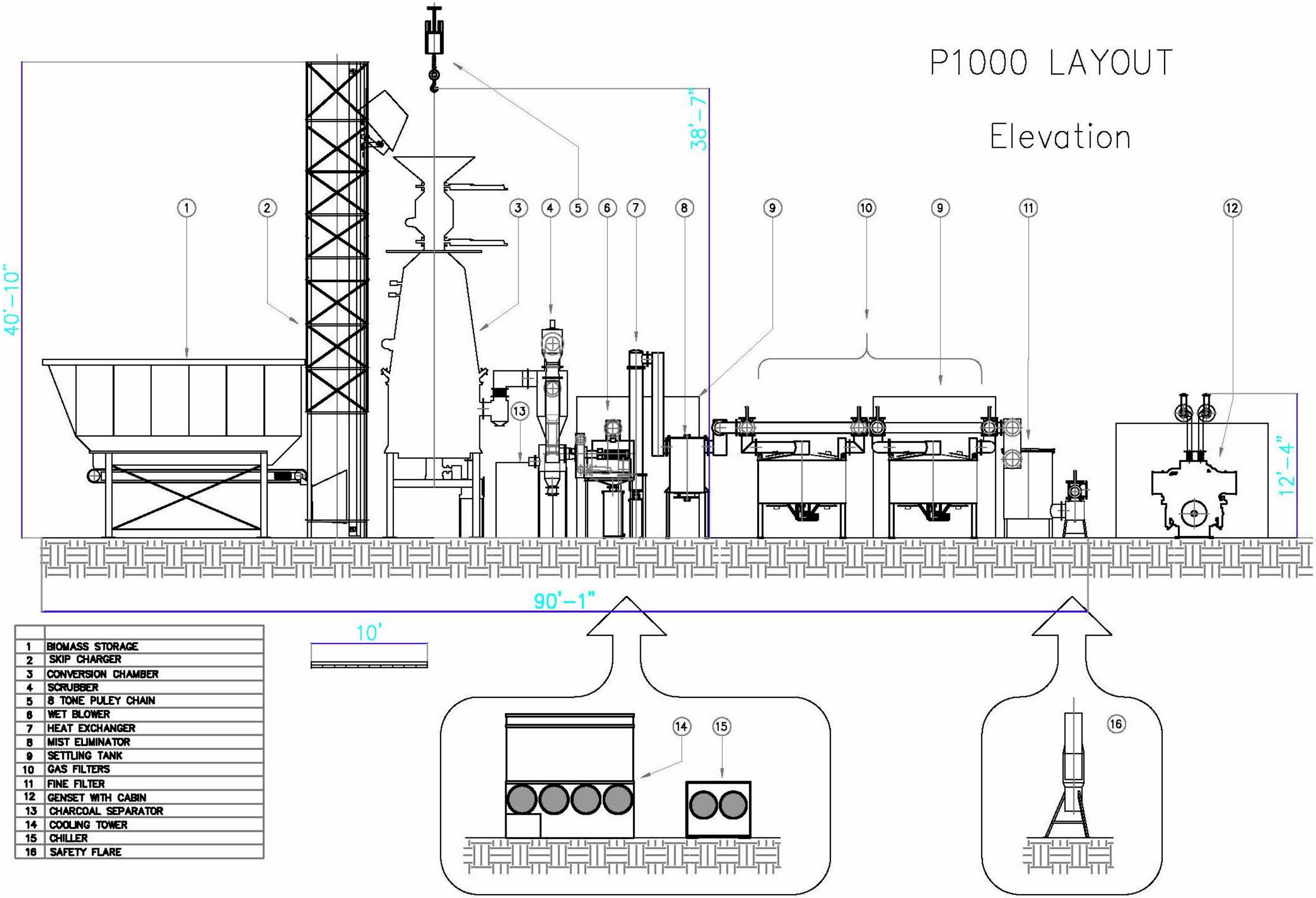
1	BIOMASS STORAGE
2	SKIP CHARGER
3	CONVERSION CHAMBER
4	SCRUBBER
5	8 TONE PULEY CHAIN
6	WET BLOWER
7	HEAT EXCHANGER
8	MIST ELIMINATOR

9	SETTLING TANK
10	GAS FILTERS
11	FINE FILTER
12	GENSET WITH CABIN
13	CHARCOAL SEPARATOR
14	COOLING TOWER
15	CHILLER
16	FLARE



P1000 LAYOUT

Elevation



1	BIOMASS STORAGE
2	SKIP CHARGER
3	CONVERSION CHAMBER
4	SCRUBBER
5	8 TONE PULEY CHAIN
6	WET BLOWER
7	HEAT EXCHANGER
8	MIST ELIMINATOR
9	SETTLING TANK
10	GAS FILTERS
11	FINE FILTER
12	GENSET WITH CABIN
13	CHARCOAL SEPARATOR
14	COOLING TOWER
15	CHILLER
16	SAFETY FLARE

Turning Waste Biomass into Profitable Energy

Appendix 1B

Phoenix Solution: High ROI, Clean Biomass-to-Energy

- **Proprietary Wood-Based Gasifier solution Addresses local needs**
  - Phoenix is **first (and only)** solution to receive CA air and site commercial permit
  - Reduces large landfill and transportation costs, plus PPA can reduces host rates by 20%.
  - Adds 5-10 jobs per site – appeal to local politicians /economy

- **Very scalable model from small footprint and <u>sustainable</u> local feedstock**
  - Town of 45-50K people generates enough clean wood waste for 1MW, NOT including Ag
  - Potentially 600-700 sites in CA, thousands across the US.
  - Disaster debris another viable, ancillary market – pine beetle, ash bore, weather damage.

- **Phoenix's gasifiers have Negative Carbon Footprint (validated by NREL)**
  - "Biochar" byproduct captures carbon used as soil amendment/activated carbon
  - High synergy with Landfill needs (heat, methane burn in engines, biofuel)

- **Small "footprint" of plant enables local deployment.**
  - 50'x 130' pad for a 1 MW gasifer ~0.5 acres (wind: 1-2 acres / MW; solar: 8-10 acres/MW)
  - Unique On-site water treatment limits concerns

- **Recurring operating cash flow + tax incentives + leverage = investor IRR target 40+%**
  - Unlevered, unsubsidized IRR ~13%; 7 yr MACRS tax benefit and 30% ITC/grant available
  - Treasury Grant (available for project start by 12/31/11) drives equity payback < 12 months

Phoenix Energy: Strong Pipeline in 2011, and Building

- **Phoenix Biomass Energy LLC started in 2006.**

- **Phoenix Energy has already built 3 facilities**
  - First two in Poland – to flush out design before migrating to tighter U.S. markets

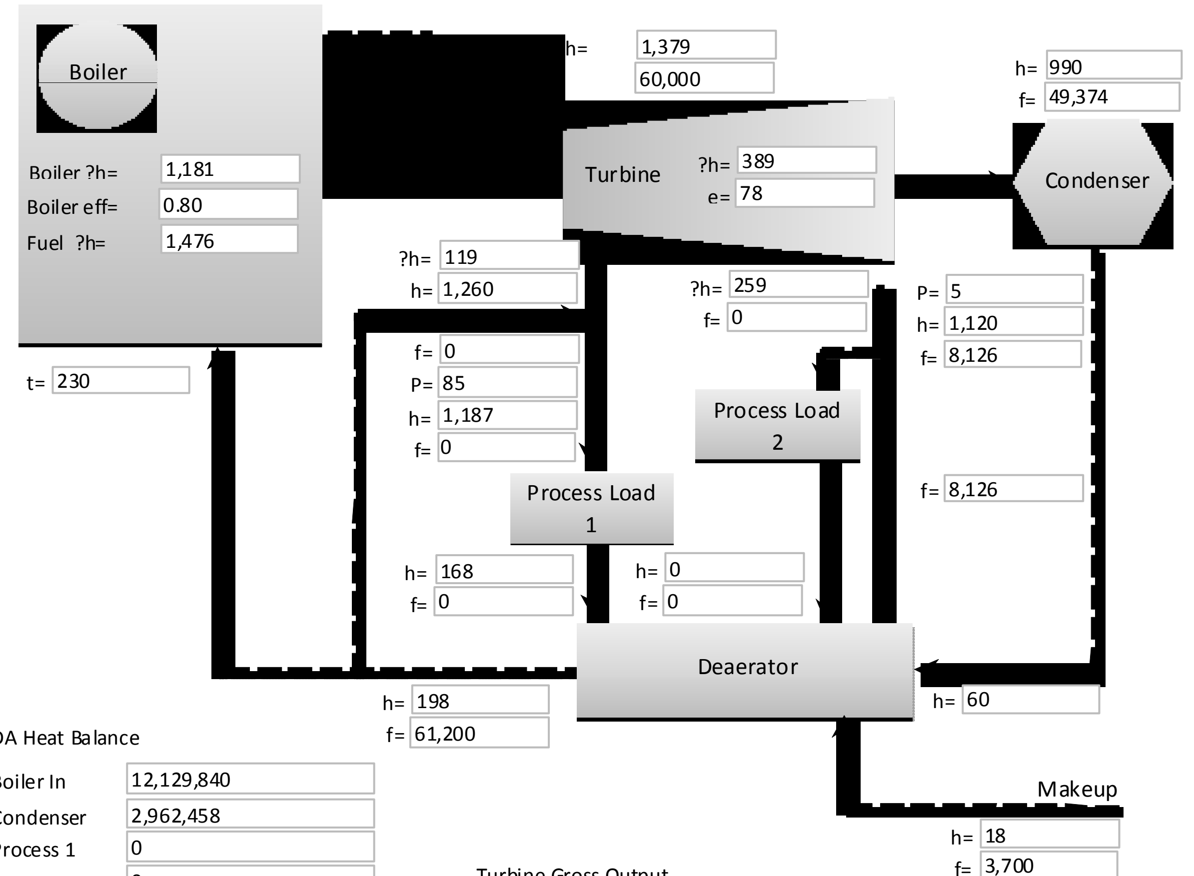
- **0.5MW Merced, CA plant - 100% owned by Phoenix Energy**
  - Interconnection by PG&E due on Feb 7

- **<u>Pipeline:</u>**
  - **1MW Oakdale, CA site next in pipeline**
    - Phoenix 33% owner with CVAG (Central Valley Ag Group)
    - Received 7-0 vote of support from County site us and permitting agencies.
  - **1MW Sonoma Compost, signed for 2011 (Phoenix 33% owner)**
  - **"Large Winery" – consulted on AD project, plus target pumice gasifier**
  - **Monroe County (NY) landfill -2011**

- **Plus: > 5 projects brought to Phoenix for proposals (CA, CO)**
  - UC Davis writing case study on Phoenix to advocate more gasifiers
  - Working with North Carolina Biz Dev, DOE, and USDA

APPENDIX 2 – COYOTE SPRINGS HEAT BALANCE, NO STEAM CUSTOMER

Client:	Coyote Springs Project
Project:	5MW Project, No Steam customer
Boiler Pressure / Temperature:	



DA Heat Balance

Boiler In	12,129,840
Condenser	2,962,458
Process 1	0
Process 2	0
Makeup	66,600
Net	9,100,782
DA Steam	8,126

Turbine Gross Output

Extraction 1	84
Extraction 2	592
Condensing	5,403
Total	6,078

Fuel Required

Fuel Heating Value	16,000,000
Hours of Operation	8,200
Annual Fuel Required	45,387

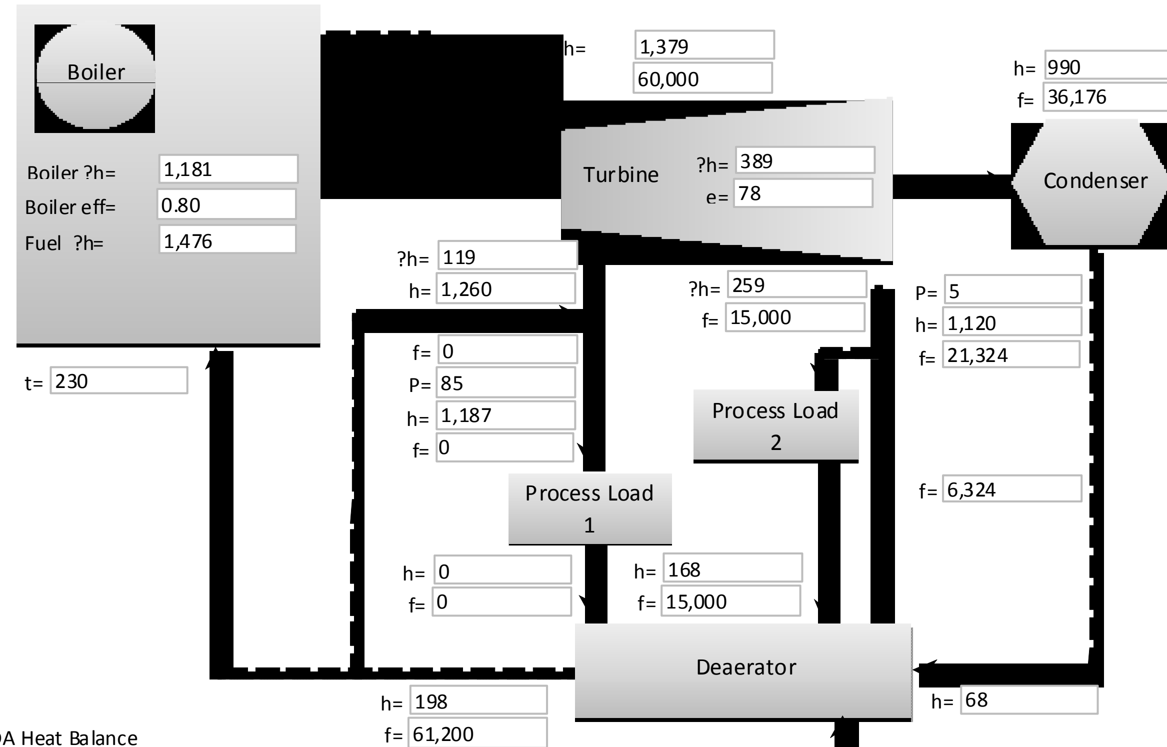
Makeup Water	100
Wastewater	20

Symbol Legend

H enthalpy in Btu/lb of steam or water
f flow in lbs per hour of steam or water
P pressure in pounds per square inch gage
T temperature in degrees F
e efficiency of conversion of steam Btu's to electrical Btu's in the turbine-generator
delta h change in enthalpy through the device in Btu/lb steam or water
turbine gross output - each box is KW generated by steam exiting at that point in the process

APPENDIX 3 – COYOTE SPRINGS HEAT BALANCE, STEAM CUSTOMER

Client:	Coyote Springs Project
Project:	5MW Project, Steam customer
Boiler Pressure / Temperature:	



DA Heat Balance

Boiler In	12,129,840
Condenser	2,459,943
Process 1	0
Process 2	2,520,000
Makeup	66,600
Net	7,083,297
DA Steam	6,324

Turbine Gross Output

Extraction 1	84
Extraction 2	1,554
Condensing	3,958
Total	5,596

Fuel Required

Fuel Heating Value	16,000,000
Hours of Operation	8,200
Annual Fuel Required	45,387

Makeup Water	74
Wastewater	15

Symbol Legend

H	enthalpy in Btu/lb of steam or water
f	flow in lbs per hour of steam or water
P	pressure in pounds per square inch gage
T	temperature in degrees F
e	efficiency of conversion of steam Btu's to electrical Btu's in the turbine-generator
delta h	change in enthalpy through the device in Btu/lb steam or water

turbine gross output - each box is KW generated by steam exiting at that point in the process

APPENDIX 4 – 6 MW POWER PLANT - PRO FORMA INCOME STATEMENT (20 YEARS; $ EXPRESSED IN THOUSANDS)

Years 2014 -- 2023	Year 0	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUE											
Electric Sales		6,255	6,380	6,508	6,638	6,770	6,906	7,044	7,185	7,329	7,475
Steam Sales		0	0	0	0	0	0	0	0	0	0
Total Revenue		**6,255**	**6,380**	**6,508**	**6,638**	**6,770**	**6,906**	**7,044**	**7,185**	**7,329**	**7,475**
EXPENSES											
Operating & Maintenance		2,133	2,159	2,166	2,192	2,232	2,274	2,326	2,388	2,453	2,520
Purchased Steam		0	0	0	0	0	0	0	0	0	0
Fuel		1,498	1,543	1,589	1,637	1,686	1,736	1,788	1,842	1,897	1,954
Ash Disposal		33	34	35	36	37	38	39	40	41	43
Total Operating Expenses		**3,663**	**3,735**	**3,789**	**3,865**	**3,954**	**4,048**	**4,153**	**4,271**	**4,392**	**4,517**
OPERATING INCOME		**2,591**	**2,645**	**2,718**	**2,773**	**2,816**	**2,858**	**2,891**	**2,914**	**2,937**	**2,958**
INTEREST		1,474	1,434	1,391	1,346	1,299	1,248	1,194	1,138	1,077	1,013
DEPRECIATION		2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749
PRETAX INCOME		**(1,631)**	**(1,538)**	**(1,422)**	**(1,322)**	**(1,232)**	**(1,139)**	**(1,053)**	**(972)**	**(890)**	**(804)**
TAXES		(1,175)	(2,151)	(1,213)	(630)	(570)	(124)	317	363	395	425
NET INCOME - BOOK		**(457)**	**613**	**(209)**	**(693)**	**(661)**	**(1,016)**	**(1,370)**	**(1,336)**	**(1,285)**	**(1,230)**
TAX INCOME STATEMENT											
PRETAX INCOME		(1,631)	(1,538)	(1,422)	(1,322)	(1,232)	(1,139)	(1,053)	(972)	(890)	(804)
PLUS: Book Depreciation		2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749	2,749
LESS: Loan Principal		(668)	(708)	(750)	(795)	(843)	(894)	(947)	(1,004)	(1,064)	(1,128)
PRETAX CASH FLOW		**450**	**503**	**577**	**631**	**674**	**716**	**749**	**772**	**795**	**816**
State Taxes		0	0	0	0	0	0	0	0	0	0
less: State credits		0	0	0	0	0	0	0	0	0	0
Federal Taxes		(1,175)	(2,151)	(1,213)	(630)	(570)	(124)	317	363	395	425
less: Federal credits		(598)	(616)	(634)	(654)	(673)	(693)	(714)	(736)	(758)	(780)
NET TAXES		(1,773)	(2,767)	(1,848)	(1,283)	(1,243)	(817)	(397)	(372)	(362)	(355)
NET CASH FLOW											
CAPITAL INVESTMENT	(35,093)										
AMOUNT TO FINANCE	24,565										
OPERATING PRETAX CASH FLOWS		450	503	577	631	674	716	749	772	795	816
STATE CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0
FEDERAL CREDITS / TAXES	0	1,773	2,767	1,848	1,283	1,243	817	397	372	362	355
TOTAL CASH FLOW BENEFITS	**(10,528)**	**2,223**	**3,270**	**2,424**	**1,915**	**1,918**	**1,533**	**1,146**	**1,145**	**1,157**	**1,171**
Cumulative Pretax Cash Flow		450	953	1,530	2,161	2,835	3,552	4,300	5,073	5,868	6,684
Cumulative After Tax Cash Flow		2,223	5,493	7,917	9,832	11,750	13,283	14,428	15,573	16,730	17,902

APPENDIX 4 – 6 MW POWER PLANT - PRO FORMA INCOME STATEMENT (CONTINUED)

Years 2024 -- 2033	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
REVENUE											
Electric Sales	7,625	7,777	7,933	8,091	8,253	8,418	8,587	8,758	8,933	9,112	151,977
Steam Sales	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	**7,625**	**7,777**	**7,933**	**8,091**	**8,253**	**8,418**	**8,587**	**8,758**	**8,933**	**9,112**	**151,977**
EXPENSES											
Operating & Maintenance	2,589	2,661	2,735	2,811	2,889	2,970	3,054	3,141	3,231	3,324	52,250
Purchased Steam	0	0	0	0	0	0	0	0	0	0	0
Fuel	2,013	2,073	2,135	2,200	2,266	2,333	2,403	2,476	2,550	2,626	40,246
Ash Disposal	44	45	47	48	49	51	52	54	56	57	878
Total Operating Expenses	**4,646**	**4,779**	**4,917**	**5,058**	**5,204**	**5,355**	**5,510**	**5,671**	**5,837**	**6,008**	**93,373**
OPERATING INCOME	**2,978**	**2,998**	**3,016**	**3,033**	**3,049**	**3,064**	**3,076**	**3,087**	**3,097**	**3,104**	**58,603**
INTEREST	946	874	798	717	632	541	445	343	236	121	18,269
DEPRECIATION	819	819	819	819	819	702	702	702	702	702	35,093
PRETAX INCOME	**1,214**	**1,305**	**1,399**	**1,497**	**1,598**	**1,820**	**1,929**	**2,042**	**2,159**	**2,281**	**5,242**
TAXES	456	488	521	555	590	645	702	741	782	825	1,944
NET INCOME - BOOK	**758**	**817**	**878**	**942**	**1,008**	**1,175**	**1,228**	**1,301**	**1,377**	**1,456**	**3,298**
TAX INCOME STATEMENT											
PRETAX INCOME	1,214	1,305	1,399	1,497	1,598	1,820	1,929	2,042	2,159	2,281	5,242
PLUS: Book Depreciation	819	819	819	819	819	702	702	702	702	702	35,093
LESS: Loan Principal	(1,196)	(1,268)	(1,344)	(1,424)	(1,510)	(1,600)	(1,696)	(1,798)	(1,906)	(2,020)	(24,565)
PRETAX CASH FLOW	**837**	**856**	**874**	**891**	**907**	**922**	**935**	**946**	**955**	**963**	**15,770**
State Taxes	0	0	0	0	0	0	0	0	0	0	0
less: State credits	0	0	0	0	0	0	0	0	0	0	0
Federal Taxes	456	488	521	555	590	645	702	741	782	825	1,944
less: Federal credits	0	0	0	0	0	0	0	0	0	0	(6,856)
NET TAXES	456	488	521	555	590	645	702	741	782	825	(4,912)
NET CASH FLOW											
CAPITAL INVESTMENT											(47,547)
AMOUNT TO FINANCE											33,283
OPERATING PRETAX CASH FLOWS	837	856	874	891	907	922	935	946	955	963	15,770
STATE CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0
FEDERAL CREDITS / TAXES	(456)	(488)	(521)	(555)	(590)	(645)	(702)	(741)	(782)	(825)	4,912
TOTAL CASH FLOW BENEFITS	**381**	**368**	**354**	**336**	**317**	**276**	**233**	**204**	**173**	**138**	**10,154**
Cumulative Pretax Cash Flow	7,521	8,377	9,251	10,143	11,050	11,972	12,906	13,852	14,807	15,770	
Cumulative After Tax Cash Flow	18,282	18,651	19,004	19,341	19,657	19,934	20,167	20,371	20,544	20,682	