state "bundled", though in certain limited circumstances the bundling can be a REC bundled with fossil power. For the 5 years prior to the current recession, California had been unable to increase the percentage of renewable power in the state, with the proportion stuck at 12 – 13 percent, despite Herculean efforts and hundreds of signed contracts. Load drops associated with the current recession has made compliance easier, however, and so the major utilities expect to deliver perhaps 15 – 18 percent renewable power by the end of 2010, falling just short of their 2010 goal of 20%.

9.3 POWER PRICE FOR A LINCOLN COUNTY PROJECT

Arriving, in advance, at a power/REC sales combination that will support a project financial model is absolutely critical to preparing a viable financial model and to subsequently moving forward with any biomass power or CHP development in Lincoln County. Based on the interconnection/transmission discussion in Section 9.2.2 , plus this section's discussion of markets, it is possible to reasonably project the value of power to a Lincoln County project at the point it enters the larger western grid. The two most viable opportunities are to sell to NV Energy as part of its next renewable RFP. Based on the most recent published prices for non-solar renewable power, a reasonable price for power would be $92 – 97/MWh at project startup for power delivered to Reid Gardner, plus a 1 percent annual escalator.

Since California utilities, both public and investor owned, have transmission assets in the Las Vegas area and are constantly issuing their own RFPs, it is instructive to look at the prices these entities are paying for power currently. Though most contract prices are not released publicly in California, it is possible to make projections based on the relationship of the contract price to the Market Price Referent (MPR), California's version of the avoided cost calculation. All contracts signed with California investor owned utilities must indicate whether the contract is at, below or above the MPR. Also, many publicly owned utilities choose to release power price information publicly.

In general, prices delivered to California utilities tend to be between $105 – 110/MWh at startup for non-solar projects, but with no or minimal escalation over the contract life. If the contract price is to escalate on some fixed basis, the starting price will be slightly lower, say $100 – 105/MWh. A recent example is an RFP released by the Southern California Public Power Authority (SCPPA) for renewable resources delivered to their members, which lists a maximum price for biomass power of $100/MWh at startup, escalating at 1.5 percent annually. One of the delivery points under this RFP is listed as Marketplace, NV, a substation in the Las Vegas area. Thus, after paying NV Energy the roughly $6/MWh charge to move the power from Reid Gardner to Marketplace, the net sales price for a Lincoln County project delivered to Reid Gardner is again likely in the range of $92 – 97/MWh at startup, with a low escalator of 1 – 1.5 percent annually.

For purposes of the financial model of the project in Lincoln County, a busbar[12] power price of $95/MWh at project startup is chosen, escalating at 1.5 percent annually. The wheeling charges from LCPD will be charged separately (assumed to be $50,000 per year) within the project Operation and Maintenance costs and no energy losses to Reid Gardner are assumed as the project is actually lowering flows north on the 69 KV system and thus saving losses.

[12] A busbar is an electrical conductor that connects two or more circuits. It is commonly used to define the point at which power is transferred from a generator to the utility.

CHAPTER 10 – FACILITY SCALE ASSESSMENT

Biomass power is distinct among baseload power technologies in that fuel becomes more expensive as transportation distances increase. This means that the "economy of scale" only works up to a certain plant size, which is distinct for each application depending primarily on delivered fuel costs. In contrast, at a gas-fired or coal plant, the cost of power keeps getting cheaper as plant size increases (within the normal size range of gas and coal fired plants; 500 to 1,000 MW). In other words, fuel cost is constant, or may even decrease slightly, with larger plant size.

Biomass power cost components react differently to size changes. Like gas and coal, as plant size goes up, both capital and non-fuel operating cost go down quickly. But unlike gas or coal, every size increase brings an increase in fuel price as the average haul distance increases. At the margin, in a biomass plant, you have an ever increasing fuel price.

In a Lincoln County context, this fuel situation is present because as size increases the plant must dig deeper into the fuel supply from the next fuel radius out from the chosen plant site. At some point, there are no longer enough acres of P-J to restore to support a larger plant over the time period of the debt, an absolute requirement to obtaining financing.

In addition, the LCPD 69 KV grid will only support a certain size plant without very expensive upgrading. It is uncertain at what size this will occur. However, preliminary studies indicate that at least 10MW can be supported. Thus, that size serves as the base case model used in the financial analysis section of this report.

Despite the limitations of the existing 69 KV grid, it is instructive to analyze how project economics shift with changing plant size. In the following analysis, financial models for three different size plants in Lincoln County were developed. The plants considered were:

1. A 60,000 pound per hour boiler and 7MW T-G
2. A 90,000 pound per hour boiler and 10MW T-G (the base case scenario)
3. A 150,000 pound per hour boiler and a 17MW T-G

Table 18 shows the plant size and associated capital, operating and fuel costs. With respect to fuel costs, the total maximum allowable fuel cost column is the fuel cost that will provide a minimum target return for each plant size. The fuel chipping and delivery costs are subtracted from that amount to identify the amount (if any) a prospective power plant can contribute to management treatment costs (i.e., tree felling, skidding, and chipping).

TABLE 18: PLANT SIZE IMPACT ON A PROJECT'S CONTRIBUTION TOWARD MANAGEMENT TREATMENT COSTS

Plant Size	Capital Cost ($1000s/Gross MW)	Non-Fuel O&M Cost ($/MWh)	Total Maximum "allowable" Fuel Cost ($/BDT)	Fuel Chipping & Delivery Cost ($/BDT)	Contribution to Management Treatment Cost ($/BDT	Contribution to Management Treatment Cost ($/acre)
60K/7MW	5,630	41.30	5.50	21.20	-15.70	-108.00
90K/10MW	4,755	34.38	27.00	23.00	4.00	28.00
150K/17MW	3,475	26.77	47.85	26.20	21.65	149.00

It is important to note that in some cases (depending on the restoration objectives) the BLM would require that the treated P-J be chipped (or masticated) regardless of whether or not a biomass power plant were operating. In such cases it is not appropriate to include the chipping costs in calculation of the biomass power plant's contribution toward management treatment costs. Thus, Table 19 displays the same information shown in Table 18 with the exception of the chipping costs being excluded.

TABLE 19: PLANT SIZE IMPACT ON A PROJECT'S CONTRIBUTION TOWARD MANAGEMENT TREATMENT COSTS (CHIPPING COSTS EXCLUDED)

Plant Size	Capital Cost ($1000s/Gross MW)	Non-Fuel O&M Cost ($/MWh)	Total Maximum "allowable" Fuel Cost ($/BDT)	Fuel & Delivery Cost ($/BDT)	Contribution to Management Treatment Cost ($/BDT	Contribution to Management Treatment Cost ($/acre)
60K/7MW	5,630	41.30	5.50	7.79	-2.29	-16.00
90K/10MW	4,755	34.38	27.00	9.59	17.41	120.00
150K/17MW	3,475	26.77	47.85	12.79	35.06	242.00

The same information shown in Table 18 and Table 19 is presented graphically in Figure 5 and Figure 6. As can be seen, when chipping costs are included, the smallest plant requires further subsidy, while larger plants begin to return an ever increasing amount to the restoration effort. The same is true when chipping costs are excluded, but the size of the subsidy is smaller at the smallest plant size and the contribution to management costs is greater at the larger plant sizes.

FIGURE 5: PLANT SIZE IMPACT ON CONTRIBUTION TOWARD MANAGEMENT TREATMENT COSTS (CHIPPING COSTS INCLUDED)

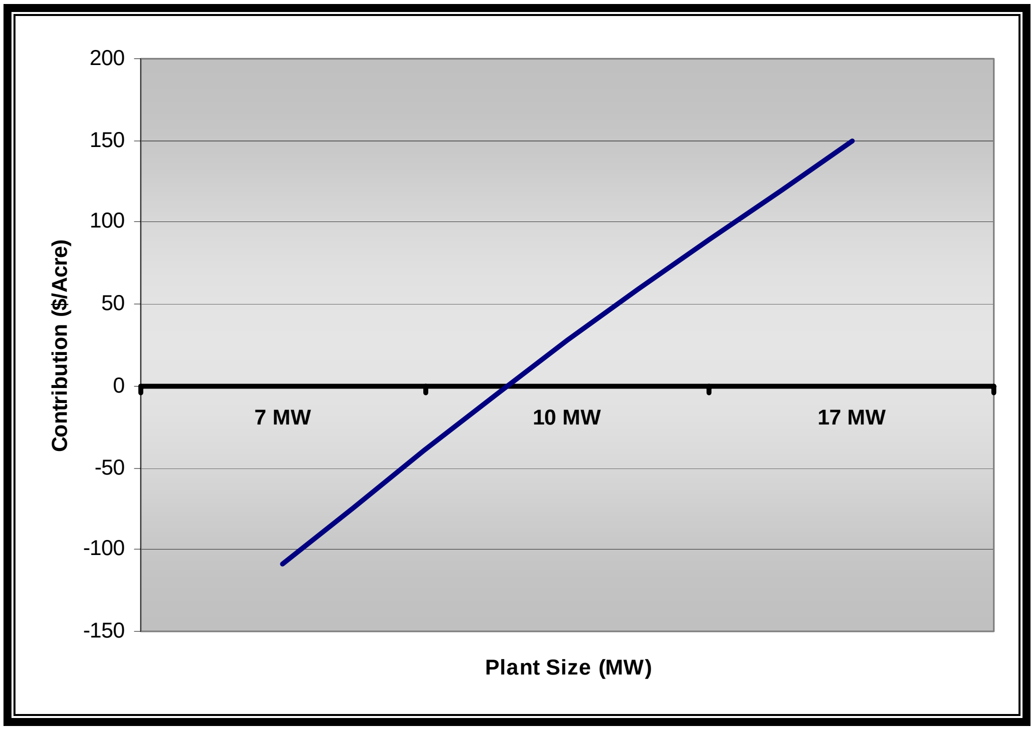
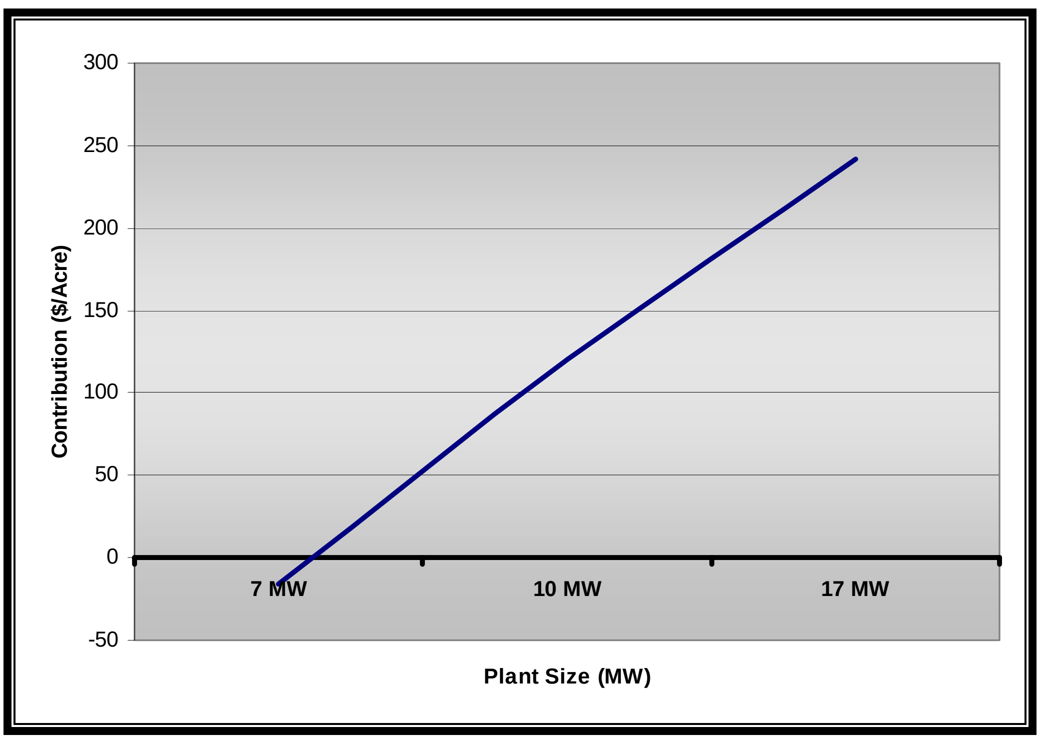


FIGURE 6: PLANT SIZE IMPACT ON CONTRIBUTION TOWARD MANAGEMENT TREATMENT COSTS (CHIPPING COSTS EXCLUDED)



CHAPTER 11 – ENVIRONMENTAL PERMITTING & REGULATORY REQUIREMENTS

11.1 PERMITTING AND REGULATORY BACKGROUND

Except for Clark and Washoe Counties, all environmental permitting in Nevada, with the exception of federal and local land use issues, is handled by the Nevada Division of Environmental Protection (NDEP), which is headquartered in Carson City. In the case of Renewable Energy Resources, the NDEP has also developed a streamlined permitting process for such resources, applicable to permitting for air emissions, wastewater discharge and solid waste management. The specific permitting that must be done for a biomass power project in Nevada is as follows:

11.1.1 Land Use Permit

Lincoln County will be the lead agency in permitting a project for local land use issues. The permit process, which takes the form of a Special Use Permit, will involve, among other issues, zoning, building/stack heights, access, traffic, fire safety, noise, aesthetics, fugitive emissions, utilities, hours of operation, etc. This process will require a minimum of two months, and is greatly simplified if the land on which the power facility is located is already zoned for the proposed purpose. The county permit process is the primary vehicle under which local residents have an opportunity to shape the outcome of the land use permit process.

11.1.2 Air Emissions Permit

The air emissions permit for a biomass power facility is typically the most complex and time consuming permit process. In Nevada, the NDEP Bureau of Air Pollution Control (BAPC) manages the air emissions permitting process.

Nevada has a tiered permitting system that begins at Class III for the smallest emission sources of less than 5 tons per year (TPY) of any regulated pollutant, through Class II for sources of 5 – 100 TPY of any pollutant, to Class I, which are major sources of greater than 100 TPY of any pollutant or more than 25 TPY of total hazardous air pollutants (HAPs) or more than 10 TPY of any one HAP.

A 10MW biomass power project in Lincoln County combusting P-J would likely consist of a 90,000 lb. steam/hour boiler equipped with a multiclone collector for coarse particulate control, an electrostatic precipitator for fine particulate control and heated combustion air and multiple levels of overfire air for control of both carbon monoxide (CO) and nitrogen oxides (NO_x). With that configuration, the likely guaranteed emissions from the facility are shown in Table 20.

TABLE 20: LIKELY GUARANTEED AIR EMISSIONS

Pollutant	Emission Rate (Lb./Million BTU)	Annual Emission (Tons/Year)
Particulate (PM-10)	0.025	15
Nitrogen Oxides	0.20	118
Carbon Monoxide	0.22	129
Volatile Organic Compounds	0.005	3

The basis for the figures in Table 20 is a heat input of 144 million BTU/hour and 8,200 hours of operation per year, both as shown on the project heat balance.

As can be seen in Table 20, two of the pollutants, CO and NO_x, are in excess of the 100 TPY cutoff for a Class II Permit. This means that the project will likely require a Class I Permit. It is possible that further refinement of emissions based on fuel tests and vendor discussions could result in vendor guarantees below 100 TPY for each of CO and NO_x. If such guarantees could be obtained, it would likely result in the ability to obtain a Class II Permit. However, for this analysis, a Class I Permit requirement is assumed. This distinction is important because the streamlined permitting process for renewable energy sources assumed biomass facilities would require only a Class II or III Permit. Consequently, the compressed timelines for a streamlined permit will not be used in this discussion.

The major source (Class I) designation also means that the project will be analyzed by BAPC against Prevention of Significant Deterioration (PSD) guidelines from the Federal Environmental Protection Agency (EPA). Neither evaluation requires an Environmental Impact Statement (EIS), so none is assumed here.

The Class I Permit process is triggered by the submission of a permit application and a proposed protocol for air quality modeling. BAPC has 30 days to respond to the modeling protocol and 60 days to declare the air permit application complete. Once complete, the BAPC has one year to either issue or deny a permit for the project. Factoring in time for permit application and modeling to occur, the total timeline to a Class I Permit is approximately 18 months, provided credible meteorological data is available that is representative of the proposed site. This timeline is contrasted with the streamlined process for a Class II Permit, which is estimated by BAPC to be 75 days.

The existing ambient air quality in Eastern Nevada is excellent, which greatly simplifies permitting. There are simply no areas in Eastern Nevada that are out of compliance with ambient air quality standards for any criteria pollutant. In establishing these standards, Nevada follows the federal standards, except in the Tahoe Basin, where more stringent standards are in place.

Nevada BAPC also publishes a map of PSD trigger areas in the state, meaning areas of special concern regarding potential air quality deterioration. In the case of Lincoln County, the only PSD trigger areas are in the Lower Meadow Wash and Virgin River

Valley areas in the far Southern end of the county. No such areas are close to the proposed project location in the Pioche/Panaca/Caliente area. In addition, national parks such as Zion, Great Basin, and the Grand Canyon are all too far away to be impacted by a small biomass plant in Lincoln County. Very little ambient air quality monitoring is done by BAPC in Eastern Nevada (outside Clark County). Particulate only monitoring is done just at McGill and Baker, both in White Pine County. Both sites show very low ambient particulate concentrations.

The air quality modeling that is part of a Class I application must rely on meteorological data that is gathered over a long period of time and is representative of the site. The locations in Eastern Nevada that gather such data (temperature profiles, wind direction, wind speed, air mixing, etc.) are in Ely, Las Vegas and at Desert Rock on the Nevada test site. The Desert Rock site is the only one monitoring upper air data as well as surface data and so would likely be the source of the 5 years of data preferred by the BAPC. BAPC has stated that, due to the lack of substantial meteorological data in rural Nevada, they will look at each application separately rather than make a blanket requirement. It is likely that the small size of the project and low existing ambient concentration will allow use of the Desert Rock data unless the site chosen is in a canyon, for instance, where the data might not be representative. If no representative data is found, the application will require one full year of onsite meteorological data, further delaying the permit process. Note that at this early stage in the development of the potential Lincoln County biomass project, it is not possible to determine whether or not the Desert Rock data is applicable. That determination would have to come at a later date when the project was more fully developed.

As can be seen from the previous discussion, the air quality permit will consume the bulk of the permitting effort. However, the location and size of the facility will likely produce a positive outcome without exceptional air emission reduction requirements.

11.1.3 Water Use Permit

Because of the arid conditions in Lincoln County, this project is being analyzed, for the base case, with an air cooled condenser as opposed to a more standard and cheaper wet mechanical draft cooling tower. This change will drop total water consumptive use by over 90 percent to approximately 9 gallons/minute (13.6 acre-ft./yr.). There may be locations in Lincoln County that could support wet cooling (approx. 180 acre-ft./yr.), and this situation would improve project economics provided the water cost was reasonable.

With this low base case usage, it is expected that the water will be purchased from the local water agency in the vicinity of the project or from a party holding existing water rights, and thus no state permitting process will be required. If the water is from a private party, an application to change the manner and place of use for the groundwater will need to be filed with and approved by the Nevada State Engineer. More information about water available is provided in section 12.1.2.

11.1.4 Wastewater Disposal Permit

Of the 9 gallons/minute makeup water mentioned in the previous section, only about 3 gallons/minute will require disposal. That amount is the blowdown from the boiler required to maintain mineral concentrations and is actually fairly high quality water by Eastern Nevada surface water standards. Choices for the disposal of that water include disposal to a public sewer system, if available, or reuse in the plant for wetting of ash prior to disposal and for humidification of air prior to the air cooled condenser to increase heat transfer efficiency.

The NDEP Bureau of Water Quality Planning (BWQP) governs such wastewater disposal. As in air quality permitting, the BWQP has a streamlined process for renewable energy resources. Because of the small quantity, high quality and reuse options available to the project, the wastewater permit issue is considered a minor permit issue.

11.1.5 Solid Waste Permit

In addition to a small amount of typical commercial/industrial trash which will be disposed of through normal channels, the project produces ash from the combustion of wood, which is estimated to total about 2,400 tons annually. This ash consists of bottom ash from under the boiler grates and fly ash collected downstream of the combustion process in pollution control equipment. A typical split is 50 percent each of bottom and fly ash.

The bottom ash consists of sand and gravel that was embedded in the wood as it was handled in the field. This clean material, almost indistinguishable from a sand and gravel operation, can typically be disposed of with a local aggregate supplier who will incorporate it into his normal products. The material will then become such things as road base, pipeline bedding or part of the recipe for asphalt or concrete.

The fly ash portion is much finer and contains a certain percentage of unburned carbon. It is typically high in pH. This material is often utilized in agricultural operations as a soil amendment. The material has excellent moisture retention capabilities, is often used as a "liming" agent on low pH soils, and possesses certain beneficial trace minerals. With the high pH typical of soils in eastern NV, agricultural spreading opportunities may be few, though application on the alfalfa and potato fields in the Pioche, Panaca, Caliente areas should be investigated. The material can also be used as a cover material at landfills, incorporated into commercial soil amendments or simply be returned to the land from which the fuel originated. In many regions, the ash has no market value, but can be disposed of for the cost of transporting it to its intended use (e.g., aggregate and low-grade fertilizer).

In areas with high concentrations of biomass projects, such as California, Best Management Practices have been developed for these various uses. It is expected that uses will be found for all of the ash components. This activity is regulated by the NDEP Bureau of Waste Management (BWM), which, again, has a streamlined process for permitting for renewable energy resources. Because of reuse options available locally and in Las Vegas, it is expected that solid waste permitting will be a minor permit activity.

11.1.6 Summary

The permitting process for a biomass power facility in Lincoln County will likely revolve around local land use and state air quality permit issues. All other permits are considered minor in comparison. The state air quality permit process will likely establish the project timeline critical path. If project sizing, pollution control equipment or vendor guarantees allow the project to obtain a Class II air quality permit, the timeline can be shortened by over one year. The permitting required for a Lincoln County project is expected to be straightforward and without any special circumstances.

CHAPTER 12 – TECHNOLOGY ASSESSMENT

This section describes the biomass power technology considered in this assessment and how technology choices affect the design of a power plant.

The findings from this analysis are that a boiler with a moving-grate, air-swept stoker system is appropriate for combusting woody P-J biomass of varying moisture contents and particle sizes. In addition, a standard direct connected steam turbine-generator is the proper prime mover for converting the steam energy into electrical energy. The turbine portion will feature a steam extraction port at an appropriate point to support a process steam use if a viable steam customer can be found. To be conservative, it is assumed that the project will have little water available to it and thus an air cooled condenser will be the exhaust steam cooling technology of choice.

The conclusions that can be drawn from these findings are that:

- The technology of combusting biomass to fire a boiler is mature. The reliability of the technology considered for the biomass fueled power plant modeled in this study has been proven many times over.
- The design of the boiler and balance of plant equipment would allow a power plant to comply with a Nevada BACT determination and produce emissions at levels that comply with NDEP standards.
- The lack of water in Lincoln County may force the choice of an air cooled condenser, which will raise capital cost and lower plant efficiency, but is available and proven technology. This more severe option is the base case modeled in the financial analysis section.

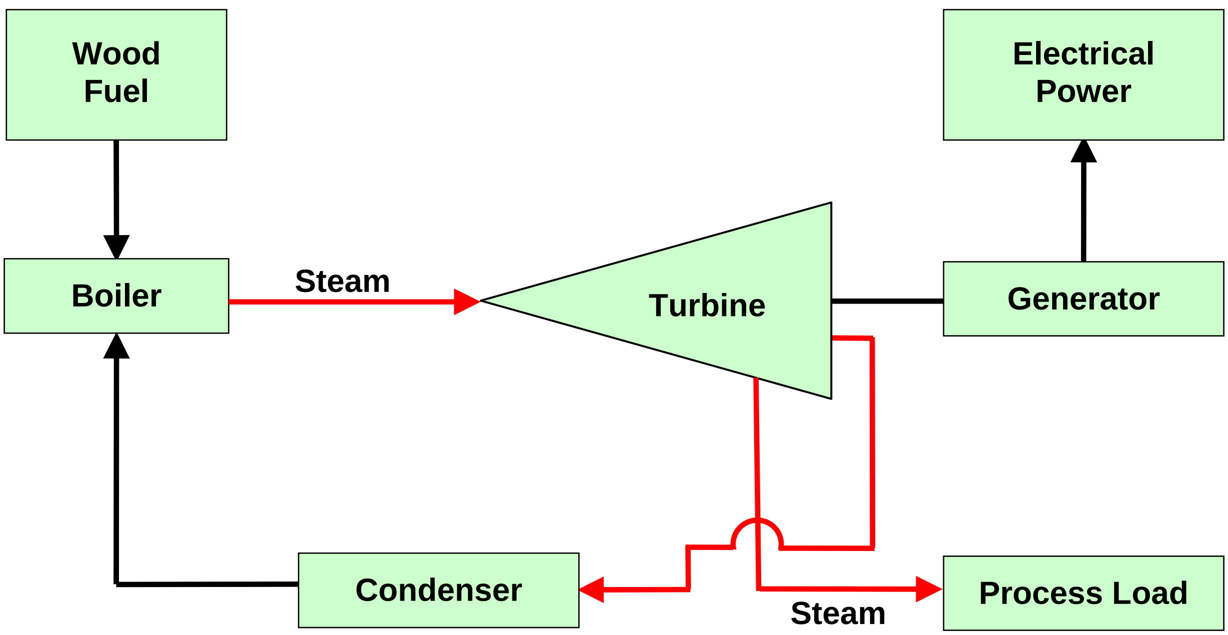
12.1 PROJECT DESIGN AND TECHNOLOGY

The technology underlying the power plant being considered as part of this study is mature. For example, biomass fuel, which varies little by species, has been successfully combusted in industrial and power generation applications for many decades. Juniper has been successfully combusted in other regions. The following section describes the design and technology of the power facilities considered in this study.

As shown in Figure 7, a simplified diagram of a wood-fired power system, the process begins when wood fuel is combusted in a furnace whose walls consist of water filled pipe. The high pressure water in the pipe boils to steam; the steam is then heated to a higher temperature before exiting to the turbine generator (T-G). The T-G is a multistage bladed rotor that turns within a series of bladed fixed diaphragms. The passage of steam through the unit drops steam temperature and pressure at each stage as thermal energy is converted into mechanical energy. The mechanical energy of the rotating turbine is converted into electrical energy in a direct or gearbox connected generator which uses a magnetic spinning rotor to induce electrical current in the windings of the fixed stator that surrounds it.

Part way down the T-G, a portion of the steam may be extracted for use by a process steam customer, should one be found for the particular application. The extracted amount is automatically controlled by the demand of the process load. Further down the T-G (but not shown in the diagram), a second lower pressure extraction supplies the deaerator, a device that removes entrained oxygen from the feedwater as it goes back to the boiler. The steam not needed for kilns or deaerator exits the back end of the turbine to the condenser to be turned back into water at a pressure far below atmospheric pressure in order to maximize T-G efficiency. The condenser is supplied either with water from a wet mechanical draft cooling tower, which evaporates a portion of the water as it cools it for the return trip to the condenser, or with large volumes of air if sufficient water is not available.

FIGURE 7: SIMPLIFIED DIAGRAM OF WOOD-FIRED COMBINED HEAT AND POWER SYSTEM



12.1.1 Boiler Technology

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, though much less common in boilers of this size range, is to gasify the fuel in a separate vessel. This occurs through heating the fuel in an oxygen starved condition. The combustible gases produced as part of this process are 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 gasification can prevent boiler conditions that might otherwise foul boiler tube surfaces. For example, combustion of agricultural residues sometimes relies on gasification. 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 P-J woodland residue including wood fiber, needles, and bark) and varies only by 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. These projects do 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. Since the location chosen is in an air quality attainment area, the stoker grate will be able 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 14, the Financial Analysis section of this report.

12.1.2 Balance of Plant Equipment

There are several vendors of T-Gs in this size range that should ensure competitive bids for the project. One unique feature of this project, necessitated by the uncertainty of obtaining a large volume water supply for the project, is an air cooled condenser. Since the potential project is at a very preliminary state, it cannot be assumed that the final site chosen will have the requisite water supply needed for a standard wet cooling tower due to the arid conditions in eastern Nevada.

An air cooled condenser is basically a very large radiator, mounted horizontally, into which the turbine exhaust steam enters to be condensed back into water. That condensing is done by passing large volumes of air over the outside of the tubes containing the steam. The air is forced through the condenser by large fans mounted on either the top or bottom of the air cooled condenser. While this technology is proven in hundreds of applications around the world, it is typically only chosen for applications such as this as it both raises the capital cost of the project and lowers the efficiency of the electrical generation process. Even though there may be locations in Lincoln County that have the available water to support the project with a standard wet cooling tower, the conservative choice is to include in the design an air cooled condenser to eliminate over 95 percent of traditional water use.

It would indeed be fortuitous for the project to obtain water rights to allow use of a standard two cell wet cooling tower in this application. This substitution would lower capital cost by roughly 10 percent, and allow 5.7 percent more power to be obtained from the same fuel supply quantity. This benefit would, of course, have to be balanced against the cost to obtain the nearly 180 acre-feet per year of water required for this method of cooling.

CHAPTER 13 – INCENTIVE PROGRAMS

The following sections describe various incentive programs and financing structures, both of which very often determine the success or failure of a proposed biomass development. With biomass power, particularly when the primary fuel source is a relatively high cost material from thinning operations, these programs are crucial to lowering the cost of power to an acceptable level for a utility purchaser.

13.1 STATE INCENTIVES

Nevada has a solid package of incentives for renewable energy producers, with clearly the most important being the Energy Portfolio Standard (EPS) discussed in Chapter 9, Markets for Renewable Power section. In addition to the EPS, Nevada offers other incentives, which are discussed below.

13.1.1 Renewable Energy Sales and Use Tax Abatement

Renewable energy systems of 10MW and larger are entitled to sales and use tax abatement such that the total sales and use tax paid is just 2.25 percent (after 6/30/11). In order to qualify for the abatement, the project must also:

- Employ a certain number of full-time employees during construction, a percentage of whom must be Nevada residents.
- Ensure that the hourly wage paid to the facility's employees and construction workers is a certain percentage higher than the average statewide hourly wage.
- Make a capital investment of a specified amount in the state of Nevada.
- Provide the construction workers with health insurance, which includes coverage for each worker's dependents.
- This incentive was applied in the financial model.

13.1.2 Renewable Energy Property Tax Abatement

Renewable energy systems of 10MW and larger can receive a property tax abatement of up to 55 percent of taxes otherwise due on both real and personal property for up to 20 years. In order to qualify for this abatement, the project must also:

- Employ a certain number of full-time employees during construction, a percentage of whom must be Nevada residents.

- Ensure that the hourly wage paid to the facility's employees and construction workers is a certain percentage higher than the average statewide hourly wage.
- Make a capital investment of a specified amount in the state of Nevada.
- Provide the construction workers with health insurance, which includes coverage for each worker's dependents.
- This incentive was applied in the financial model.

13.1.3 Portfolio Energy Credits

A somewhat more complicated incentive, the Portfolio Energy Credit (PEC) law, allows those generating their own electricity to earn PECs (1 PEC/KWh) that can then be sold to NV Energy to assist them in meeting their Energy Portfolio Standard requirements. In the case of a Lincoln County project, it was assumed that the PECs were sold along with the electricity in a "bundled" transaction.

Interestingly, the law also allows, at least for solar thermal applications, the generation of PECs for the thermal use of renewable energy (1 PEC for 3,412 BTU of thermal energy). Though not currently applicable to biomass thermal applications, the inclusion alongside solar thermal systems would dramatically boost the prospects for biomass combined heat and power systems, including a potential Lincoln County project.

13.2 FEDERAL INCENTIVES

Over the last six years, a substantial package of federal incentives has been assembled for biomass. This accelerated with the passage of the American Recovery and Reinvestment Act of 2009 (Stimulus Bill).

13.2.1 Investment Tax Credit/Production Tax Credit Election

Since 2005, biomass projects have been able to claim an IRS Section 45 Production Tax Credit (PTC) of 1.1 cents/KWh against federal income tax liability for the first 10 years of a project's life, with the 1.1 cent amount escalating with general inflation. That credit could be used in a consolidated return and carried forward for up to 20 years. The Stimulus Bill added an election in Section 48 to take instead a 30 percent of qualifying total capital cost Investment Tax Credit (ITC) in the first year of operation against federal income tax liability. In other words, a developer could choose either the PTC or the ITC.

The ITC can be further traded for a grant of an equivalent amount (30 percent of eligible project costs) from the U.S. Treasury at startup. In order to qualify for the ITC election, a project must have been under construction by the end of 2011 and be completed by the end of 2013. Grants cannot be applied for after October 1, 2011. Grants lower the depreciable asset base of the project by one half of the grant amount, but are not taxable for federal income tax purposes.

The grant feature was added in response to the loss of many "tax equity partners" as a result of the current financial crisis. Previously, many projects would bring in a partner with a high tax liability (financial institution) who would invest substantial equity in the project in order to collect nearly all the early year tax advantages. That partner would exit the project when its target return was reached. This was a way for the original developer to receive the value of the tax credits that the project would not otherwise have the tax liability to monetize. This new ITC/PTC election/grant is a powerful incentive for projects that can be placed under construction quickly, but will not be used because the maturity of the project development cannot meet the required timetable and the grant feature has a very uncertain future.

13.2.2 Combined Heat & Power Tax Credit (CHP)

Also in Section 48 of the United States Tax Code is a CHP ITC of up to 10 percent of project cost for projects that use steam sequentially for both power production and process heat. In order to qualify, at least 20 percent of the net heat must be used for each of power generation and process heat.

The CHP credit also has an efficiency and a size test. The full 10 percent ITC can only be claimed if the project has an overall thermal efficiency of 60 percent (power plus steam), a difficult standard for a biomass project. A prorated amount is awarded for lower efficiencies. Also, the full credit is also available only up to 15 MW of capacity, with reductions for larger projects and a full phase out at 50MW. Any project must be in service by 2016 to qualify.

With the passage of the previous PTC/ITC election described above, also in Section 48, changes were made to the program so that a project cannot collect both the PTC/grant and the CHP ITC. Because an industrial user of steam in Lincoln County has not been identified this credit is not included in the base case financial analysis of this project.

13.2.3 Accelerated Depreciation

The Lincoln County project would qualify for the Modified Accelerated Cost Recovery System (MACRS) depreciation tax treatment. For the boiler and fuel handling portion of the project, which typically represents 55 percent or more of total project cost, the depreciation time period is over just 5 years. The MACRS depreciation schedules are used in the following analyses of financial feasibility.

Also, the Stimulus Bill and subsequent action by Congress extended "bonus depreciation" for projects such as this through 2012. The bonus depreciation allows 50 percent of the total project cost to be depreciated in the first year of service in addition to the typical first year depreciation on the remainder. Since current bonus depreciation features require completion by the end of 2012 for full value, this feature will not be incorporated in the financial analysis.

13.2.4 USDA Grants

The U.S. Dept. of Agriculture has numerous small grant and loan guarantee programs for rural biomass projects such as this. A typical grant for such a project is $250,000 to $500,000. Federal loan guarantees can also be obtained for up to $10 million, with new program changes pushing that amount to $25 million in certain circumstances. The use of the federal loan guarantee will typically reduce market interest rates by up to 2 percent.

These aforementioned programs have been supplemented by the Stimulus Bill, as billions of additional dollars have been appropriated by this bill towards expanding these programs. No grant funds from this source have been assumed in the financial analyses..

13.3 PROJECT FINANCING

In the world of renewable power – post financial crisis – obtaining project financing, particularly construction financing, has become extremely difficult, frustrating, and time consuming. Lenders require extreme quality in terms of fuel supply, technology choice, power purchase agreements and steam host credit (if applicable) in order to move forward with a project. Governments, both state and federal, have responded by putting in place, or reviving, loan and loan guarantee programs that transfer some of the risk to the government entity.

For the last 15 years or so, the business development model for renewable projects was to find a tax equity partner who would fund the equity portion of the project development costs in exchange for the early tax benefits that the project would produce. The partner might receive 99 percent of the benefits in the early years and then "flip" to a 1 percent ownership position when his equity interest was repaid, with the original developer becoming the 99 percent owner. Since the onset of the financial crisis, these types of arrangements are almost nonexistent.

Today, projects seeking financing often need the federal grant, described in section 13.2.1, that replaced temporarily the tax credit driven project development scenario described above. That grant is typically pledged as equity towards a long term financing package that may include loan guarantees from a relevant federal agency. Most lenders will require additional equity beyond the federal grant to assure that the developer has "skin in the game" throughout. If the grant is indeed not extended again, the tax equity partnership must be revived.

Were it not for the ongoing financial crisis, the switch to a federal grant system versus a federal income tax credit would be seen as a simplification of the whole process. You simply get a check for nearly 30 percent of the total cost of the project, walk down the street to the bank and plunk it down for the equity that you need, get the loan, and go build the project. The big problem with the above scenario is a dual timing problem.

The first is that you cannot file to get preapproval of the federal grant until you are "under construction". To get to the point of being under construction you need to complete interconnection/transmission studies, permitting for long lead time permits, securing of property, term sheet for sale of power, financial modeling, preliminary engineering, equipment contracting, etc. The developer may have well over $1 – 2 million invested before he can even apply for qualification for the federal grant. Secondly, even if you are prequalified, you still need to complete construction and startup before you can certify expenditures and apply for the check. In other words, a developer has to spend a substantial amount of money before getting an indication that the project qualifies for the grant, and all of the money before he is reimbursed the 30 percent that becomes the equity for long term financing.

The topic of project finance is highly complex and transitional at this point in time. Things have definitely improved from the depths of the financial crisis, but are a long way from normal. Various programs are being put in place to help, but these are highly project and site specific, with applicability being determined by such things as the poverty level of the community or who the power purchaser is. Examples of current financing vehicles or assistance are discussed in the following sections.

13.3.1 New Market Tax Credits

This is a federal program whereby the project debt lender can claim a federal tax credit of up to 38 percent of the value of the loan to the project over 7 years. This program is only applicable in communities with a high poverty level or low income relative to state averages, and requires a third party who has an existing allocation of credits to apply. At the project level, the net effect is both a reduction in long term debt interest rates of 1 - 2 percent plus a cash infusion with no payback requirement from the lender. Unfortunately, the Lincoln County area does not qualify for this program, as both its poverty rate and income level do not meet program requirements.

13.3.2 Rural Utilities Service (RUS) Loan Program

This is a new federal loan program available to generators who sell their project output to a rural electric cooperative, cooperative buying group or a utility serving primarily a rural population. In that case, the borrower can obtain up to 75 percent of the project cost as debt financing for up to 20 years at an interest rate of 3.5 – 4 percent. The debt is not available for construction and can only be put in place at startup. Lincoln County Power District clearly serves a rural population, so this program may well be available for a P-J project in Lincoln County.

13.3.3 Local Revenue Bonds

In Nevada, cities and counties are able to issue tax exempt bonds to support development of private renewable energy facilities. The bonds are repaid by the project, with no recourse to the public entity. There is a limit on the amount of bonds that can be outstanding at any point in time within the state. Since bonds are continually being issued and repaid it is not possible to determine at this point in time, what bond authority will be available at the time of start of construction. The value of these bonds, beyond the low interest rate, is that they can be issued at project initiation and thus provide construction financing, as well as long term debt.

13.3.4 U.S. Department of Agriculture Loan Guarantee

The USDA has a longstanding loan guarantee program that can provide a federal guarantee of loans for up to 75 percent of the project cost on a long term basis. This is a competitive process, and Congress provides the USDA with the ceilings on the amount of loans that can be guaranteed. The USDA can guarantee up to $25 million in loans to an individual project, and the net effect of the guarantee is to lower interest rates in the market by 1 – 2 percent and certainly make credit more available to a project. It is not possible to predict at this time how competitive a P-J biomass project would be in securing a USDA loan guarantee.

13.3.5 U.S. Department of Energy Loan Guarantee

This is a new loan guarantee program put in place by the ARRA. It is designed to guarantee loans for innovative technology and biomass projects qualify under the program. Again, Congress provides the total loan ceiling, and the process is competitive. The program does not appear to have the same individual project ceilings as the USDA program, and the net effect on interest rates is the same.

13.3.6 Partnership with Purchasing Utility

Many renewable Requests for Proposals (RFPs) that have gone out recently in the West have included options of a partnership with the purchasing utility or sale of the project to the utility in the future. This potentially brings the utility's capital raising strength and a lower interest rate into a project. A guaranteed sale, for example, after development and 5 years of operation, would give lenders the comfort they would need to fund the construction. The 5 year hold period prior to sale is the amount of time required to extinguish any repayment obligation under the federal Section 1603 ITC grant program described in Section 13.2.2 should that remain applicable. If the partner is a federal tax paying entity, the 5 year hold period would not be necessary.

13.3.7 Prepayment for Power

When the power purchaser is a public entity, such as a city or a public utility district, it may be allowed by law to issue low interest bonds for the pre-purchase of power from the proposed project. This mechanism allows the developer to tap lower interest financing not otherwise available to them and to do so earlier in the project so that the funds can be used for construction. Deals such as this are often talked about, are very complex, and are not often completed.

Typically, only a portion of the above list of financing options will be able in a given location. The project owner must decide the ownership structure and level of risk that is acceptable. The first point of contact should likely be with the bank with which the developer has an established banking arrangement. The bank, if it participates at all in the financing, will do so as part of a syndicate of banks in order to lower the risk to any one bank. Equity requirements will be high during both construction and operation, often 30 percent or more of total project cost, and the equity portion will be expensive if acquired from independent investors or investment groups. Fortunately, the 30 percent federal grant can be used as equity substitution at startup, so outside equity investors may only be in place for a limited period of time. Again, because of timing concerns, the use of the 30% federal grant as part of the equity package is not incorporated in this analysis.

In today's risk averse world of finance, the developer will not be able to employ unproven new technology, despite its promise, and manufacturer guarantees must be ironclad and backed with a strong balance sheet. The developer will likely have to accept all future environmental costs, with no pass through to the utility, in order to obtain an acceptable power contract. Likewise, fuel risk will be on the developer, though this risk can be mitigated by the contract structure. The availability of fuel over the life of the power contract and financing must be almost absolute.

Though the above list is daunting, there are quality biomass projects that are finding their way through this maze and entering construction today. A quality project by a quality company can be successfully financed and developed.

CHAPTER 14 – FINANCIAL ANALYSIS

In this section of the report, BECK provides a financial analysis of the prospective biomass fueled power plant located in Lincoln County. As described in the Chapter 5, the Biomass Fuel Supply Assessment section, there is little difference between Pony Springs and Prince in terms of fuel supply. However, from a transmission, interconnection, water supply and cost, and land availability and cost perspective, the Prince location is preferable. Therefore, the financial analysis has been conducted using Prince as the site and using the fuel and capital investment costs associated with the Prince location.

Note that the financial analysis is structured in such a way that the financial model returns the fuel cost at which the plant will provide the project's investors a 15 percent net present value after tax return on their equity.

The key assumptions associated with the financial analysis are described as follows:

14.1 ESTIMATED BIOMASS FUEL REQUIREMENT AND COST

As described previously, BECK has estimated that approximately 5.43 million bone dry tons of fuel is available within a 50 mile radius of the Prince Substation. The power plant modeled here will consume 67,300 bone dry tons of fuel annually. Thus, BECK has concluded there is ample fuel available to supply a power plant.

As shown in the fuel supply analysis, BECK has estimated that fuel could be supplied to the facility for an all cost inclusive delivered price of $97.56 per bone dry ton (includes costs for felling, skidding, chipping, and transport, site rehabilitation, and administrative costs incurred by the BLM).

14.2 PLANT SIZE

Based on the fuel volumes and costs listed above and based on the capacity of the existing LCPD transmission lines, the project team identified an appropriately sized power plant with the following specifications:

- A 90,000 pound per hour steam 900 psig/900 degree Fahrenheit wood-fired stoker rotating grate boiler and a 10 MW nameplate extraction/condensing turbine-generator with an output voltage of 13.8 KV.

- The turbine will have only an uncontrolled extraction point for steam to the deaerator, with steam for soot-blowing and steam jet air ejection being supplied from the 900 psig system through a pressure reducing station. Exhaust steam from the turbine will be condensed in an air cooled condenser (ACC) to minimize water usage, with the ACC producing an annual average condensing pressure of 4 in. Hg absolute.

- The power plant will operate 8,200 hours per year. On this operating schedule, and at this size, the plant will consume 67,346 BDT per year, assuming the fuel has an aggregate annual moisture content of 40 percent.

14.3 TECHNOLOGY AND PROJECT EXECUTION

Standard stoker grate technology was chosen for the boiler and a standard multistage steam T-G for the turbine. The required cooling was provided by an air cooled condenser as water was assumed not to be available to utilize standard wet cooling technology. As described in the Technology Assessment in Chapter 12, all of these technologies are proven many times over.

Budgetary quotations were obtained from Wellons, Inc. for the supply of the required equipment. The quotations from Wellons were for delivering the project on a turnkey basis. The turnkey approach to developing a power plant minimizes the owner's risk of the plant not operating as designed since the vendor provides performance, completion, and environmental guarantees. Wellons is a leading supplier of such equipment to the forest products industry in this size range on such a contractual basis, and so the cost estimates supplied are considered to have a high level of credibility.

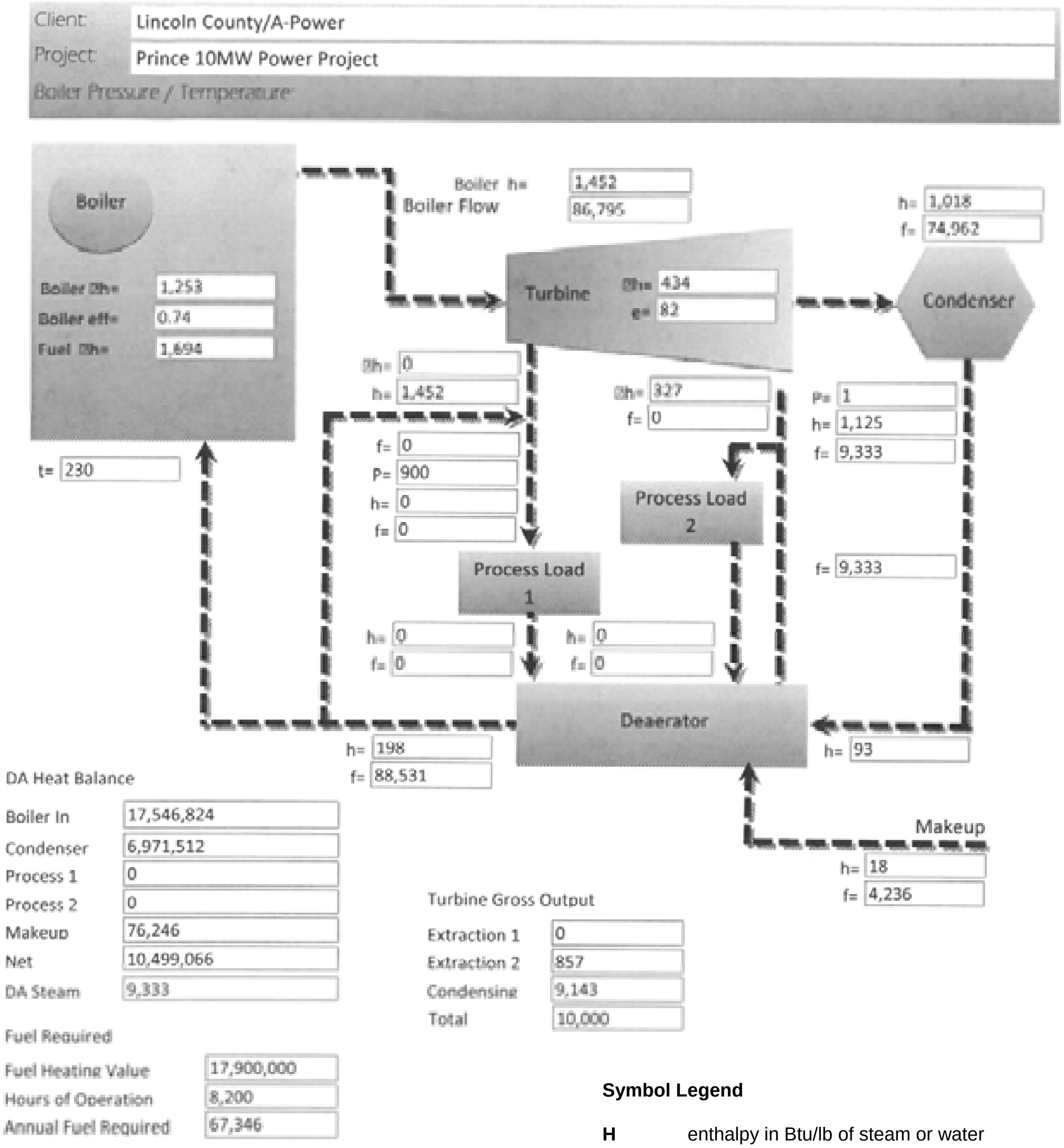
The design and method of delivery is such that the project can be completed in a timely manner; is designed to combust the available fuels successfully; can interconnect with the utility; will be financeable within the current financial environment; and can meet the requirements of NDEP.

For the purposes of the study, the power plant boiler was assumed to be equipped with the following air pollution control equipment:

- A three field electrostatic precipitator and a multi-clone mechanical collector for particulate control.
- Multiple levels of controlled, heated over-fire air for control of CO and VOCs.
- A complete set of continuous emission monitoring devices for NOx, CO, CO_2, O_2 and opacity, with an automatic data acquisition system.

A complete heat balance for the power plant is included as shown in Figure 8.

FIGURE 8: COMPLETE POWER PLANT HEAT BALANCE



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

Note the following key inputs from Figure 8.

- Boiler Efficiency – 74 percent (based on 40 percent average moisture content)
- Turbine Efficiency – 82 percent
- Annual Hours of Operation – 8,200
- Fuel Heating Value – 17,900,000 BTU/BDT (8,950 BTU/pound dry)[13]
- Annual Fuel Usage – 67,346 BDT
- Average Boiler Output – 86,795 pounds per hour
- Steam Conditions – 900 psig/900°F
- Generator Output – 10,000 KW

The two ash streams: bottom ash from beneath the grates and fly ash from the pollution control devices, will be collected separately because of their different characteristics. The bottom ash will be shipped to a sand and gravel operation as aggregate material, while the fly ash will be shipped to a mulch preparation yard for incorporation into landscaping products, used on fields or pastures as a soil conditioner, or land filled. The cost of hauling and disposal is included in the financial model (assumed to be $10 per ton and 2,400 tons per year).

14.4 BUDGETARY CAPITAL COST

As previously described, a budgetary estimate was obtained from Wellons, Inc. of Vancouver, WA for the turnkey engineering, procurement and construction (EPC) vendor for the project. Wellons is a leading supplier of biomass power projects in this size range to the forest products industry. Wellons provides in house engineering of their entire scope, plus manufacturing of boilers, ductwork, pollution control equipment, water treatment equipment and plant control systems. Major purchased equipment includes turbine-generator, air cooled condenser and main power transformer.

Wellons scope extends, on the boiler path, from the fuel storage silos through the boiler stack. On the turbine-generator path, the scope extends from the steam outlet of the boiler through the interconnection substation with the utility, including a 12.5 MVA 13.8 KV/69 KV main transformer. The fuel receiving, processing and storage facilities are handled outside of the Wellons scope. Likewise, the costs of interconnecting to the utility beyond the onsite substation are beyond the scope of Wellons, but are included separately in the financial model. Working capital consists of the cost of spare parts, initial chemical purchases, an initial 3 months of fuel supply and the cost of the first month Operating and Maintenance expense. The price for the Wellons scope, including startup and training is $37,750,000 (See Table 21). Note that within the scope provided by Wellons, engineering is typically 12 to 18 percent and construction is approximately 25 percent of the turnkey cost. Note also that a more detailed breakout of Wellons scope is provided in Appendix 3.

[13] Personal Communication: Dave Allen, Fuel Manager, HL Power Company. Wendel, California.

In addition, the project will require nearly $10 million in capital for project management, permitting, site preparation, working capital, interconnection costs, fuel system, sales tax and interest during construction, all as shown on the financial model, making the total installed capital cost $47,547,000. These additional expenditures were estimated based on a combination of the project team's experience and actual costs for similar items in recently completed or currently under construction projects. This amount is for a project that will be completed in 2013; using proven technology; with guarantees of completion, plant performance and environmental performance; and with an initial 3 month fuel inventory on site.

TABLE 21: BUDGETARY CAPITAL COST ESTIMATE ($ 000s)

Capital Cost Item	Cost
Equipment, Engineering, and Construction Costs	37,750
Project Management/Permitting/Engineering	400
Site Prep/Roads/Fencing	400
Working Capital	850
Utility Interconnection	800
Fuel Receiving/Processing	3,000
Interest During Construction	2,394
Issuance Costs	978
Total Capital Cost	**47,547**
Capital Cost per net MW	**4,755**

14.5 ADDITIONAL ASSUMPTIONS

- The power would be sold for $95 per megawatt hour at startup and will escalate at 1.5 percent per year.
- Power wheeling costs were assumed to be a flat $50,000 per year.
- Corporate ownership overheads were assumed to be $80,000 per year.
- The plant would operate 8,200 hours per year. After accounting for scheduled downtime and station service (power generated and consumed by the turbine portion of the plant), the plant would generate 82,000 MWh of power annually.
- Auxiliary Power – 1000 KW of plant power purchased from LCPD at their current industrial retail rate of $0.04 per KWh.
- All power and RECs generated at the plant would be sold to the power grid.
- The plant would require 12 full time employees. Wage rates and fringe benefits typical of other Nevada manufacturing businesses were used for the hourly labor as shown in Table 22. Note that the wages shown are base salaries; fringe

benefits were also included at a rate equal to about 38 percent of the base salary.

TABLE 22: WAGE RATES ASSUMED AT THE BIOMASS PLANT

Position	Number of Staff	Base Annual Salary ($)
Plant Manager	1	100,000
Fuel Manager	1	75,000
Admin Assistant	1	35,000
Maintenance Tech	1	60,000
Steam Plant Operator	4	55,000
Fuel Operator	4	35,000
Total	**12**	

- The routine and major maintenance costs are based on costs experienced at similar operations. The major maintenance costs are based on an annual accrual payment into an account for a major turbine overhaul every seven years and for periodic replacement of the boiler refractory and superheater.
- Construction financing assumes 100 percent would be borrowed at 6 percent interest.
- Project financing assumes 30 percent equity and 70 percent long-term debt.
- The interest rate on the long term debt was assumed to be 4.0 percent, typical of one of the federal loan or loan guarantee programs.
- The MACRS depreciation schedule was used for calculating depreciation costs, but without including bonus depreciation.
- Federal taxes are included as 35 percent of income.
- Sales Tax Reduction to 2.25 percent and Property Tax Abatement of 55 percent for 20 years were assumed.
- Water was assumed to be purchased from the local municipality, and wastewater was assumed to be consumed on site. The usage volumes were based on a dry cooled plant. The estimated usage rate was 3 gallons per minute and the cost was assumed to be $3.00 per thousand gallons.
- The federal production tax credit is applied at a rate of $0.012 cents per KWh beginning in 2013 for the first 10 years of the project. The tax credit escalates at 3 percent annually.

- The Corporate Owner/Tax Equity Partner was assumed to fully utilize tax credits depreciation, and tax losses.
- All expenses are assumed to rise by 3 percent annually due to inflation, with power revenue rising only 1.5 percent annually.
- The owner was assumed to require a 15 percent net present value rate of return on equity supplied to the project.
- The ash disposal and handling costs were assumed to be $10 per ton ($24,245/year).

14.6 PRO FORMA INCOME STATEMENT

As shown in the following Year One pro forma income statement (Table 23), the power plant generates the following revenues and expenses. Note that the fuel cost associated with this pro forma income statement is the $27.00 per bone dry ton required for the owner to obtain the target 15 percent rate of return. If the all inclusive estimated delivered fuel costs were input into the financial model, the total cash flow benefit would change from the $3.17 million shown in Table 23 to $155,000 in Year One and would drop into negative total cash flows during later years – ranging between negative $0.6 and $5.6 million.

TABLE 23: POWER PLANT YEAR ONE PRO FORMA INCOME STATEMENT ($000)

REVENUE/EXPENSE LINE ITEM	$27/BDT	$97.56/BDT
Electric Sales	7,790	7,790
Steam Sales	0	0
Total Revenues:	**7,790**	**7,790**
O&M	2,768	2,768
Fuel	1,845	6,485
Ash Disposal	24	24
Total Expenses:	**4,638**	**9,278**
OPERATING INCOME:	**3,152**	**(1,488)**
– Interest	1,331	1,331
– Depreciation	2,377	2,377
PRETAX INCOME:	**(557)**	**(5,197)**
– Taxes	**(1,485)**	**(3,109)**
NET INCOME (book)	**928**	**(2,088)**
PROJECT CASH FLOWS & BENEFITS		
PRETAX INCOME:	(557)	(5,197)
+ Book Depreciation	2,377	2,377
– Loan Principal	(1,118)	(1,118)
PRETAX CASH FLOW	703	(3,937)
TAXES/CREDITS		
State Taxes/Credits	0	0
Federal Taxes	(1,485)	(3,109)
Federal (Production Tax Credit)	(984)	(984)
NET TAXES	**(2,469)**	**(4,093)**
NET CASH FLOWS		
Operating Pretax Cash Flow	703	(3,937)
State Credits/Grants	0	0
Federal Credits/Taxes	2,469	4,093
Total Cash Flow Benefit	**3,172**	**155**

As shown in the preceding pro forma income statement, the project generates a Year One revenue stream of nearly $7.79 million, of which $1.85 million is used to procure fuel and $2.77 million is used to pay operation and maintenance expenses. This leaves a net operating income of $3.15 million prior to application of depreciation, payment of long-term debt, and taxes. The total after tax cash flow benefit is $3.17 million in Year One. A 20 year pro forma of the "Base Case" scenario (the $27 per bone dry ton starting fuel cost) is included in Appendix 4.

Given the preceding assumptions and analysis, the project requires a delivered fuel price of about $27.00 per bone dry ton, escalating at 3 percent annually, in order to provide the project owner with a 15 percent net present value after tax rate of return on their equity.

The $27.00 per bone dry ton fuel price required to meet the minimum return is a little more than $70.00 per bone dry ton lower than the all inclusive $97.56 per bone dry ton cost estimated by BECK. **This means that in order to provide the investor with the desired return, the plant's fuel cost would have to be less by approximately $4.71 million annually ($70.00 per bone dry ton x 67,300 bone dry tons) that the full cost incurred producing the fuel from P-J restoration efforts.**

14.7 DISCUSSION

The $27.00 per BDT fuel price returned by the financial model is substantially less than the cost to cut excess P-J, skid that material to roadside, chip it, and deliver it to the plant. The $27/BDT amount is greater, however, than the cost of chipping and transporting the material from the landing area to the plant. For the first year, the chipping and transport costs have been projected to be about $23.00/BDT. Thus the existence of a power plant leaves the BLM lands needing P-J vegetative treatment in a slightly better financial position. This is because; the plant owner can contribute about $4.00 per BDT ($27 minus $23) towards the total (inclusive) cost of P-J thinning projects in the Ely BLM District.

As modeled in this study, a 10 MW facility would require the treatment of about 9,800 acres per year and would have an average removal of 6.9 bone dry tons per acre (based on treating 10 percent Phase I, 40 percent Phase II, and 50 percent Phase III). **This means that the biomass plant could contribute on average about $28 per acre toward the cost of felling and skidding biomass ($4/BDT x 6.9 BDT/Acre).**

Please note that in some cases in the preceding analysis the chipping cost may not need to be included in calculating the value returned to the land. This is because on some projects the BLM may require chipping of biomass regardless of whether or not a biomass plant is developed. Thus, in those cases, the cost of chipping would not be included in the calculation on the value returned to the land. BLM staff indicated that the decision of whether or not to require chipping is handled on a case by case basis. If the cost of chipping is not included in calculating the amount the plant owner can contribute to the treatment cost is increased by about $92 per acre.

14.8 SENSITIVITY

As stated previously, the base case modeling effort attempted to be realistic, but slightly conservative in terms of capital, operation and maintenance costs. This included assumed qualification for most existing state and federal programs, but excluding those that required completion and startup by December 31, 2013. Perhaps the most problematic assumption in terms of limiting project feasibility is that of long term financing for 20 years at 4 percent and a 30 percent equity requirement.

Therefore, the project team also modeled a "best case" scenario in which assumptions about the following key factors were changed:

- Wet cooling was assumed instead of dry cooling. This reduced the capital cost by 10 percent and increased the T-G efficiency by 5.7 percent, allowing additional production for the same fuel input.
- Interest on construction financing was assumed to be 2 percent instead of the 6 percent assumed in the base case scenario.
- Interest on long-term debt was assumed to be 2 percent instead of the 4 percent assumed in the base case scenario.
- The owner's equity in the project was assumed to be 20 percent instead of the 30 percent assumed in the base case scenario.
- The project developer would require an 8 percent return on equity instead of the 15 percent assumed in the base case scenario.

Given the preceding list of changes in key assumptions, the "best case" scenario changes the "allowable" fuel cost to $52.00 per bone dry ton as opposed to the $27.00 per bone dry ton finding in the base case scenario. Thus, the changes allow for a higher allowable fuel cost, but the "allowable" cost in the best case scenario still falls about $45.00 per bone dry ton short of the estimated all-inclusive delivered fuel cost of $97.56 per bone dry ton. A pro forma income statement (year 1) for the "best case" scenario is shown in Table 24. In addition, a 20 year pro forma of the "Best Case" scenario is included in Appendix 5.

TABLE 24: POWER PLANT YEAR ONE PRO FORMA INCOME STATEMENT "BEST CASE SCENARIO" ($000)

REVENUE/EXPENSE LINE ITEM	$52/BDT
Electric Sales	8,232
Steam Sales	0
Total Revenues:	**8,232**
O&M	2,885
Fuel	3,502
Ash Disposal	24
Total Expenses:	**6,412**
OPERATING INCOME:	**1,820**
– Interest	664
– Depreciation	2,076
PRETAX INCOME:	**(920)**
– Taxes	**(1,448)**
NET INCOME (book)	**528**
PROJECT CASH FLOWS & BENEFITS	
PRETAX INCOME:	(920)
+ Book Depreciation	2,076
– Loan Principal	(1,367)
PRETAX CASH FLOW	(211)
TAXES/CREDITS	
State Taxes/Credits	0
Federal Taxes	(1,448)
Federal (Production Tax Credit)	(1,040)
NET TAXES	**(2,488)**
NET CASH FLOWS	
Operating Pretax Cash Flow	(211)
State Credits/Grants	0
Federal Credits/Taxes	2,488
Total Cash Flow Benefit	**2,277**

In the "best case" scenario, the contribution of the power plant to treatment costs (planning, administration, monitoring, cutting, skidding, chipping and rehabilitation) after accounting for transport is about $31 per bone dry ton ($52/BDT – $21/BDT). This means that the power plant project could contribute about $214 per acre to treatment costs ($31/ton x 6.9 tons per acre) in the best case scenario. There were other scenarios investigated, such as a slightly larger plant, continuation of federal grant program, etc. that yielded results between the base and best case results. Thus, the base case and the best case "bracket" the range of results that can be expected.

The differences between the "Base Case" and "Best Case" scenarios were due to simultaneous changes in several factors. Thus, from the information presented so far, it is impossible to isolate the impact of changes in financing or cooling design on allowable fuel price. Therefore, Table 25 was developed to "break apart" the impact of individual changes in key project factors in improving project feasibility.

As shown, changing the cooling design from dry to wet increases the allowable fuel cost in both cases by $8 to $10 per bone dry ton. On the other hand, changing the financing conditions raises the allowable fuel cost by $15 to $17 per bone dry ton. Note that in the "Financing Conditions" column the first set of numbers refers to the debt/equity ratio, (i.e., 70 percent debt to 30 percent equity). The second set of numbers is the interest rate (percent) for construction/long term. And the third number is the rate of return (percent) required by the investor.

TABLE 25: IMPACT OF FEASIBILITY FACTORS ON ALLOWABLE FUEL COST

Feasibility Condition	Financing Conditions	Cooling Design	Allowable Fuel Price ($/BDT)
Base Case	70/30; 6/4; 15	Dry	27.40
Cooling Improvement	70/30; 6/4; 15	Wet	37.80
Improved Financing	80/20; 2/2; 8	Dry	44.50
Improved Financing & Cooling	80/20; 2/2; 8	Wet	52.00

It should be mentioned in conclusion that the feasibility of both the base case and the best case scenarios would likely also depend upon the availability of a long term (15 – 20 year) stewardship contract being in place that would ensure the treatment of a sufficient number of acres annually to yield the necessary biomass to fuel the facility. Financing of the power plant project would depend heavily upon a reasonable assurance of biomass availability and cost structure over the operating life of the project.

CHAPTER 15 – REFERENCES

The following is a list of references cited or otherwise used in the development of this feasibility study report:

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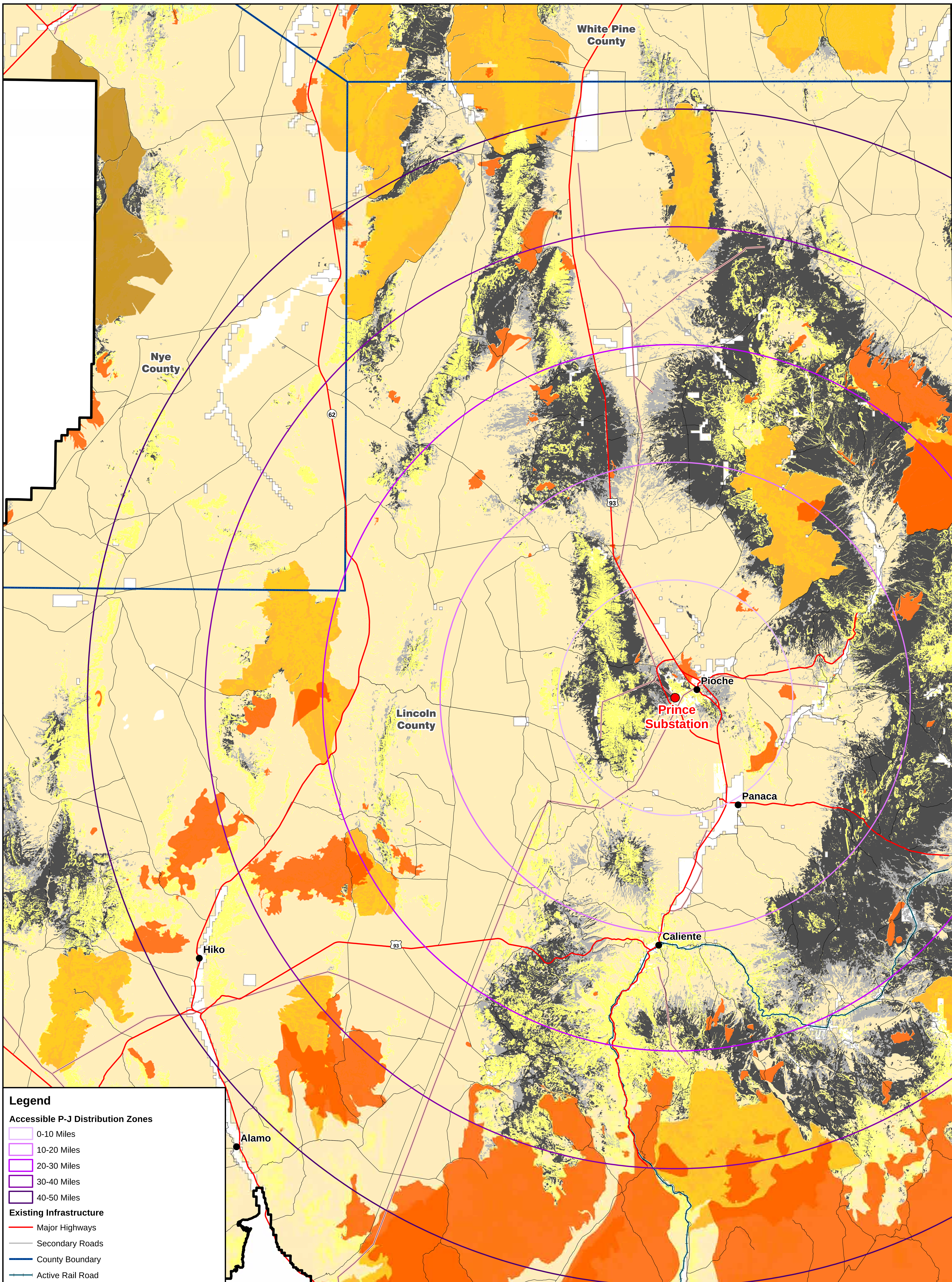
APPENDICES



**Accessible Pinyon-Juniper Near Prince Substation, Lincoln County, Nevada

Zone (Miles from Prince SS)	0-30% Canopy Cover (Zone Acreage)	30-60% Canopy Cover (Zone Acreage)	0-30% Canopy Cover (Cumulative Acreage)	30-60% Canopy Cover (Cumulative Acreage)	Combined Canopy (Cumulative Acreage)
0-10	8,900	25,200	8,900	25,200	34,000
10-20	26,300	96,400	35,200	121,600	156,800
20-30	68,600	260,000	103,800	381,600	485,400
30-40	46,900	151,600	150,700	533,200	683,900
40-50	12,100	25,800	162,800	559,000	721,800

Appendix 1

**Accessible Pinyon-Juniper within 50 Miles of Prince Substation

Data Source:
* BLM Ely District Office
**Based on P-J Distribution, less wilderness area, less fire area, less slopes>30%

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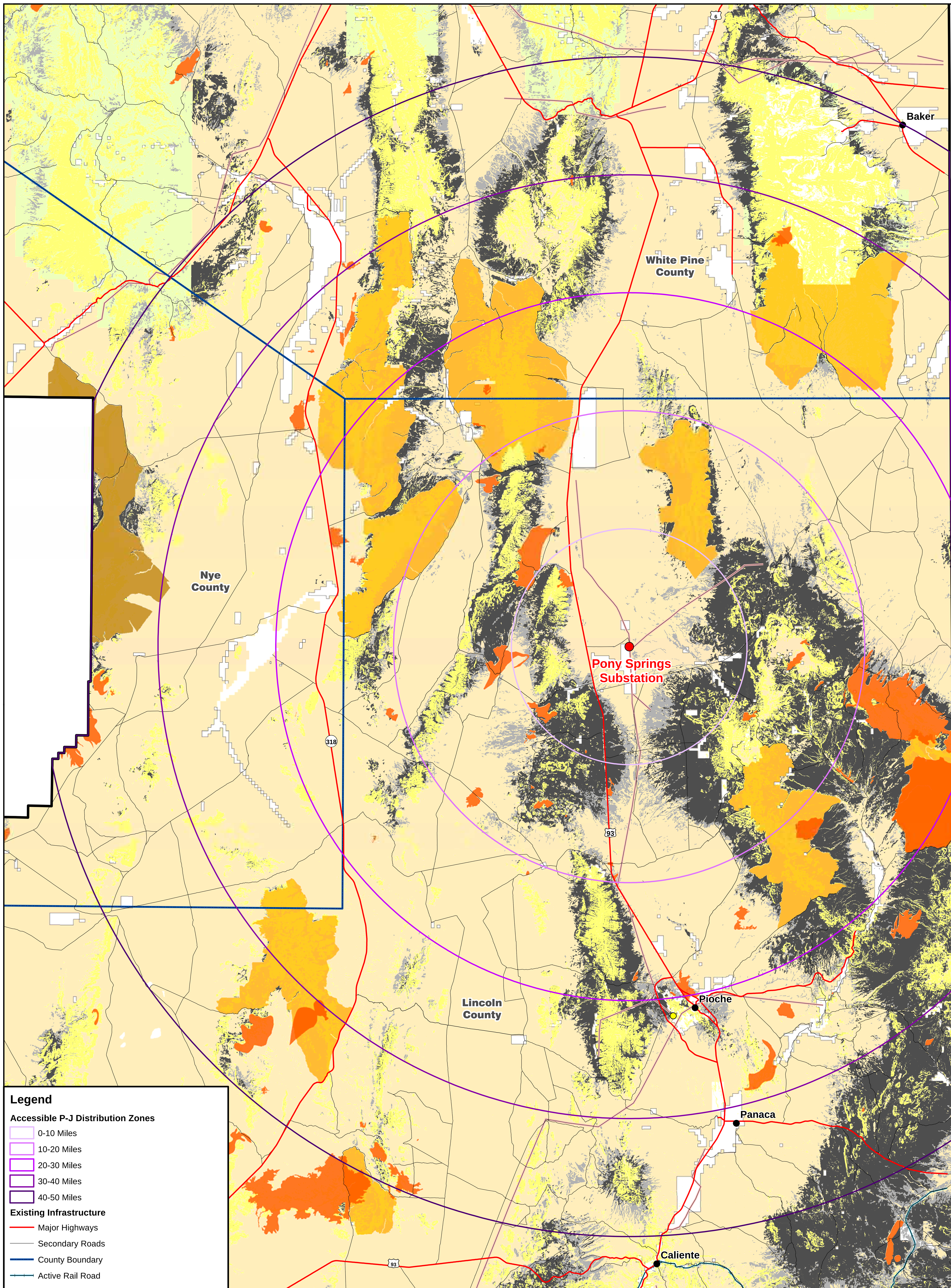

Data Source:
* BLM Ely District Office
**Based on P-J Distribution, less wilderness area, less fire area, less slopes>30%

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****Accessible Pinyon-Juniper Near Pony Springs Substation, Lincoln County, Nevada**

Zone (Miles from Pony Springs SS)	0-30% Canopy Cover (Zone Acreage)	30-60% Canopy Cover (Zone Acreage)	0-30% Canopy Cover (Cumulative Acreage)	30-60% Canopy Cover (Cumulative Acreage)	Combined Canopy (Cumulative Acreage)
0-10	19,200	54,600	19,200	54,600	73,800
10-20	33,800	135,600	53,000	190,100	243,000
20-30	26,700	95,300	79,700	285,500	365,100
30-40	18,200	96,600	97,900	382,000	479,900
40-50	40,500	119,000	138,400	501,000	639,400

Appendix 2

**Accessible Pinyon-Juniper within 50 Miles of Pony Springs Substation

N

0 2.5 5 10 Miles

WELLONS

2525 WEST FIRESTONE LANE
VANCOUVER, WASHINGTON 98660

(360) 750-3500
FAX (360) 750-3400

www.Wellons.com
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Appendix 3

BUDGETARY ESTIMATE SCOPE DESCRIPTION

PREPARED FOR

CARLSON SMALL POWER CONSULTANTS

LINCOLN COUNTY BIOMASS PROJECT

FOR

100,000 PPH BOILER

WITH A

NOMINALLY RATED 10,000 KW

TURBINE-GENERATOR SYSTEM

Budgetary Scope Description #KTK012811

January 28, 2011

Headquarters:
Vancouver, WA

Offices:
Boston, MA Columbia, SC Pittsburgh, PA

I. GENERAL DESCRIPTION

The following work description and budgetary estimate has been prepared to assist Carlson Small Power Consultants in the evaluation and review of a nominally rated 10,000 KW wood waste-fired electrical generation power plant prior to a definitive proposal being prepared.

The system is based on a Wellons wood-fired steam boiler and fuel storage components, a new turbine-generator, the balance of plant components, all systems and design engineering, and construction activities required to provide an operable plant.

All of the boiler and turbine-generator system components will be located in a building of Wellons' design and manufacture. Fuel storage will be adjacent to the boiler building. The cooling tower will be located in a down-wind location from the power plant, but within 50 feet of the condenser. Equipment layout within the turbine-generator and boiler building will be such to facilitate proper operation and maintenance.

II. FUEL STORAGE AND HANDLING

Two (2) Wellons Model A-30-40 severe duty fuel storage bins, each with 152 units of capacity, complete with roof, cone bottom section, level switches and controls, and a conveyor to the boiler system are included.

Item	Wellons	Purchaser	Optional
Fuel Storage and Handling System			
Two (2) A-30-40 Fuel Storage Silos	X		
Primary Fuel Conveyor	X		
Mixing Conveyor	X		

III. STEAM GENERATING SYSTEM

The steam generating system consists of a Wellons 100,000 PPH steam boiler, operating at 900 psig, 900 ºFTT with a watertube boiler, four (4) furnace cells with water-cooled grates and mulite based shotcrete refractory cell lining. A metal building will enclose the boiler and be complete with lighting, stairways, catwalks, doors, windows, vents, and an isolation wall between the turbine room and boiler room.

The combustion air is provided by forced draft and induced draft fans through an air preheater, with all electrical and pneumatic controls, dampers, and breeching included, and exhausts through an electrostatic precipitator (ESP) into an uptake stack.

Ash handling is automated and consists of a multiple cone collector and ESP, with an ash conveying system to convey ash from the boiler ash hopper, air heater hopper, economizer, multiple cone collector hopper and ESP hoppers, removing ash from the drop-outs to purchaser's tote bins. Cell cleanout is automatic.

The feedwater system consists of two (2) multi-staged centrifugal pumps (one [1] for emergency standby), two (2) gratewater pumps, water level controls and a deaerator. The feedwater treatment system provides for necessary chemical treatment utilizing a reverse osmosis demineralizing system.

The following equipment is included:

Item	Wellons	Purchaser	Optional
Watertube Boiler System			
Boiler Pressure Vessel	X		
Boiler Casing and Insulation	X		
Boiler Accessories	X		
Sootblowers	X		
Feedwater Control System	X		
Supporting Structure	X		
Furnace System			
Four (4) Cell Furnace System	X		
Metering Surge Bins	X		
Furnace Fuel Feed Screws	X		
Self-Cleaning Rotary Grates	X		
Combustion Air Handling System			
Forced Draft Fan	X		
Ducting and Insulation	X		
Exhaust Gas Handling System			
Combustion Air Preheater	X		
Economizer	X		
Multiple Cone Collector	X		
Ducting and Insulation	X		

Induced Draft Fan	X		
Computerized Control System			
Computer Equipment and Peripherals	X		
Proprietary Software	X		
Supplemental Equipment			
Electric Motors	X		
Motor Control Centers	X		
Boiler System Piping	X		
Blowdown Heat Exchanger	X		
Water Treatment Equipment	X		
Feedwater and Deaeration System	X		
Boiler Feedwater Pumps	X		
Boiler Gratewater Pumps	X		
Ash Handling	X		
Ash Receivers		X	
Opacity monitor	X		
Continuous Emissions Monitoring		X	
Boiler Walkways, Stairs, and Decks	X		
Air Compressor		X	
Boiler and Turbine-Generator Building	X		
Electrostatic Precipitator			
General Structure	X		
Precipitator Internal Components	X		
Electrical Equipment and Control	X		
Safety Key Interlock System	X		
Ash Handling System	X		

IV. ELECTRICAL GENERATING SYSTEM

The electrical generating system consists of a, new steam turbine-generator and condenser, and selected plant mechanical and electrical equipment, operating at

900 psig, 900ºFTT with a nominal rating of 10,000 KW at 0.80 power factor. The unit is a condensing type turbine, exhausting at approximately 2 in HgA.

The turbine-generator and auxiliary machinery are installed on a concrete pedestal foundation in a metal building complete with concrete and steel grating operating floor, stairways, catwalks, doors, etc., adjoining the boiler building. The building has a mechanical bridge crane of sufficient capacity to handle on-going maintenance.

The major piping systems (steam lube oil, service water, etc.) complete with hangers and valves are provided, along with PRV stations, drain tanks, etc. Motor starters, wire, conduit and miscellaneous electrical fittings are also provided, together with generator protective relaying and metering, one (1) generator circuit breaker, DC power supply, neutral grounding, main power transformer, and the turbine-generator control panel.

A multi-cell, air cooled condenser, and two (2) centrifugal condensate return pumps, each rated at half flow, are provided. The interconnection piping between the condenser and the power plant is also provided.

Equipment includes:

Item	Wellons	Purchaser	Optional
Electrical Generation System			
Steam Turbine	X		
Exhaust ducting to air cooled condenser	X		
Air Ejector	X		
Lube Oil System	X		
Condensate Pumps	X		
Air cooled condenser	X		
Circulating Pumps	X		
Generator and excitor	X		
Piping assemblies and valves	X		
Switchgear	X		
DC Power System	X		
Electric Motors	X		
Motor Control Center	X		
Control Panels	X		

Switchyard equipment	X		
Generator Breaker and Relays	X		
Electrical Wiring and Conduit	X		
Turbine Building	X		
Turbine Room Bridge Crane	X		
Main Power Transformer	X		
Auxiliary Power Transformer	X		
Protective Relaying and Metering	X		
Grounding Grid	X		
Utility Interface	X		

V. PROJECT SERVICES

Wellons will completely engineer, design, construct and erect all of the equipment and material as defined in this work description and equipment list. This includes all engineering and design for the plant components.

Installation, including foundations, will be complete with all labor, tools, equipment, technical direction and supervision being provided. Equipment orientation and system operational training with operation and maintenance manuals are included.

Item	Wellons	Purchaser	Optional
Project Services			
System Design and Engineering	X		
Foundation Design (No Pilings)	X		
Foundation Construction (No Pilings)	X		
Grounding Grid Design	X		
Installation Drawings	X		
Mechanical Installation	X		
Electrical Installation	X		
Start-up and Training	X		
Operation and Maintenance Manuals	X		
Recommended Spare Parts List	X		

Freight to Site	X		
Construction Utilities		X	
Touch-up Painting	X		

VI. PURCHASER TO PROVIDE

The Purchaser is responsible for providing certain items, such as:

Item	**Wellons**	**Purchaser**	**Optional**
Site preparation (3,000-psf soil bearing capacity).		X	
All permits and regulatory filings		X	
Building furnishings / outside lighting and site finishing.		X	
Electrical connection to the local utility		X	
Construction utilities and services		X	
Secondary pollution control equipment		X	
Clean water supply		X	
Electrical power to connections at MCC		X	
Wood fuel to Fuel Storage Bins		X	
Emergency Power Supply		X	

APPPENDIX 4

10 MW Base Case Power Plant - Pro Forma Income Statement (20 years; $ expressed in thousands)

	Year 0	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
REVENUE																						
Electric Sales		7,790	7,907	8,025	8,146	8,268	8,392	8,518	8,646	8,775	8,907	9,041	9,176	9,314	9,454	9,595	9,739	9,885	10,034	10,184	10,337	180,133
Steam Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue		**7,790**	**7,907**	**8,025**	**8,146**	**8,268**	**8,392**	**8,518**	**8,646**	**8,775**	**8,907**	**9,041**	**9,176**	**9,314**	**9,454**	**9,595**	**9,739**	**9,885**	**10,034**	**10,184**	**10,337**	**180,133**
EXPENSES																						
Operating & Maintenance		2,768	2,799	2,805	2,837	2,887	2,939	3,006	3,086	3,169	3,255	3,344	3,435	3,530	3,628	3,729	3,833	3,941	4,052	4,168	4,287	67,497
Purchased Steam		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel		1,845	1,901	1,958	2,016	2,077	2,139	2,203	2,269	2,338	2,408	2,480	2,554	2,631	2,710	2,791	2,875	2,961	3,050	3,141	3,236	49,583
Ash Disposal		24	25	26	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	43	651
Total Operating Expenses		**4,638**	**4,725**	**4,788**	**4,880**	**4,991**	**5,107**	**5,238**	**5,385**	**5,537**	**5,694**	**5,856**	**6,023**	**6,195**	**6,373**	**6,556**	**6,745**	**6,941**	**7,142**	**7,351**	**7,565**	**117,732**
OPERATING INCOME		**3,152**	**3,182**	**3,237**	**3,266**	**3,277**	**3,285**	**3,280**	**3,261**	**3,238**	**3,213**	**3,184**	**3,153**	**3,118**	**3,080**	**3,039**	**2,994**	**2,945**	**2,891**	**2,834**	**2,772**	**62,402**
INTEREST		1,331	1,287	1,240	1,192	1,141	1,089	1,035	978	919	858	795	728	660	588	514	436	356	272	185	94	15,697
																						0
DEPRECIATION		2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	47,547
																						0
PRETAX INCOME		**(557)**	**(482)**	**(380)**	**(303)**	**(242)**	**(181)**	**(132)**	**(95)**	**(59)**	**(23)**	**13**	**47**	**81**	**115**	**148**	**181**	**212**	**242**	**271**	**300**	**(843)**
TAXES		(1,485)	(2,825)	(1,574)	(804)	(745)	(162)	411	449	465	478	490	503	514	526	538	574	609	620	630	640	(147)
NET INCOME - BOOK		**928**	**2,343**	**1,194**	**500**	**503**	**(19)**	**(544)**	**(544)**	**(524)**	**(501)**	**(478)**	**(455)**	**(433)**	**(411)**	**(390)**	**(393)**	**(397)**	**(378)**	**(359)**	**(340)**	**(697)**
TAX INCOME STATEMENT																						
PRETAX INCOME		(557)	(482)	(380)	(303)	(242)	(181)	(132)	(95)	(59)	(23)	13	47	81	115	148	181	212	242	271	300	(843)
PLUS: Book Depreciation		2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	47,547
LESS: Loan Principal		(1,118)	(1,162)	(1,209)	(1,257)	(1,308)	(1,360)	(1,414)	(1,471)	(1,530)	(1,591)	(1,654)	(1,721)	(1,789)	(1,861)	(1,936)	(2,013)	(2,093)	(2,177)	(2,264)	(2,355)	(33,283)
PRETAX CASH FLOW		**703**	**733**	**788**	**817**	**828**	**836**	**831**	**812**	**789**	**764**	**735**	**704**	**669**	**631**	**590**	**545**	**496**	**442**	**385**	**323**	**13,421**
State Taxes		0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0
Federal Taxes		(1,485)	(2,825)	(1,574)	(804)	(745)	(162)	411	449	465	478	490	503	514	526	538	574	609	620	630	640	(147)
less: Federal credits		(984)	(1,014)	(1,044)	(1,075)	(1,108)	(1,141)	(1,175)	(1,210)	(1,247)	(1,284)	0	0	0	0	0	0	0	0	0	0	(11,280)
NET TAXES		(2,469)	(3,839)	(2,618)	(1,879)	(1,852)	(1,303)	(764)	(761)	(781)	(806)	490	503	514	526	538	574	609	620	630	640	(11,427)
NET CASH FLOW																						
CAPITAL INVESTMENT	(47,547)																					(47,547)
AMOUNT TO FINANCE	33,283																					33,283
OPERATING PRETAX CASH FLOWS		703	733	788	817	828	836	831	812	789	764	735	704	669	631	590	545	496	442	385	323	13,421
STATE CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEDERAL CREDITS / TAXES	0	2,469	3,839	2,618	1,879	1,852	1,303	764	761	781	806	(490)	(503)	(514)	(526)	(538)	(574)	(609)	(620)	(630)	(640)	11,427
TOTAL CASH FLOW BENEFITS	**(14,264)**	**3,172**	**4,572**	**3,406**	**2,696**	**2,680**	**2,139**	**1,594**	**1,573**	**1,570**	**1,570**	**245**	**201**	**155**	**105**	**52**	**(29)**	**(113)**	**(178)**	**(245)**	**(317)**	**10,584**
Cumulative Pretax Cash Flow		703	1,436	2,224	3,041	3,869	4,705	5,536	6,348	7,137	7,901	8,636	9,340	10,009	10,641	11,231	11,776	12,272	12,714	13,098	13,421	
Cumulative After Tax Cash Flow		3,172	7,743	11,149	13,845	16,525	18,665	20,259	21,832	23,402	24,972	25,217	25,419	25,573	25,679	25,731	25,702	25,589	25,411	25,166	24,848	

APPPENDIX 5

10 MW Best Case Power Plant - Pro Forma Income Statement (20 years; $ expressed in thousdands)

	Year 0	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
REVENUE																						
Electric Sales		8,232	8,355	8,480	8,608	8,737	8,868	9,001	9,136	9,273	9,412	9,553	9,697	9,842	9,990	10,139	10,292	10,446	10,603	10,762	10,923	190,347
Steam Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue		**8,232**	**8,355**	**8,480**	**8,608**	**8,737**	**8,868**	**9,001**	**9,136**	**9,273**	**9,412**	**9,553**	**9,697**	**9,842**	**9,990**	**10,139**	**10,292**	**10,446**	**10,603**	**10,762**	**10,923**	**190,347**
EXPENSES																						
Operating & Maintenance		2,885	2,926	2,946	2,989	3,048	3,109	3,184	3,270	3,360	3,453	3,549	3,648	3,750	3,856	3,964	4,077	4,193	4,313	4,437	4,565	71,524
Purchased Steam		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel		3,502	3,607	3,715	3,827	3,942	4,060	4,182	4,307	4,436	4,569	4,706	4,848	4,993	5,143	5,297	5,456	5,620	5,788	5,962	6,141	94,100
Ash Disposal		24	25	26	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	43	651
Total Operating Expenses		**6,412**	**6,558**	**6,687**	**6,842**	**7,016**	**7,197**	**7,394**	**7,607**	**7,827**	**8,054**	**8,288**	**8,529**	**8,778**	**9,034**	**9,298**	**9,570**	**9,851**	**10,141**	**10,440**	**10,749**	**166,275**
OPERATING INCOME		**1,820**	**1,797**	**1,794**	**1,766**	**1,720**	**1,671**	**1,607**	**1,529**	**1,446**	**1,358**	**1,265**	**1,167**	**1,064**	**956**	**841**	**721**	**594**	**461**	**321**	**175**	**24,072**
INTEREST		664	637	609	581	552	522	492	461	430	398	365	332	298	263	228	191	155	117	79	40	7,411
DEPRECIATION		2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	41,518
																						0
PRETAX INCOME		**(920)**	**(916)**	**(891)**	**(891)**	**(907)**	**(927)**	**(961)**	**(1,008)**	**(1,060)**	**(1,116)**	**(1,176)**	**(1,240)**	**(1,309)**	**(1,383)**	**(1,462)**	**(1,546)**	**(1,636)**	**(1,732)**	**(1,834)**	**(1,941)**	**(24,857)**
TAXES		(1,448)	(2,640)	(1,570)	(921)	(894)	(411)	63	68	53	34	13	(10)	(34)	(60)	(87)	(95)	(105)	(139)	(175)	(212)	(8,570)
NET INCOME - BOOK		**528**	**1,724**	**679**	**30**	**(13)**	**(516)**	**(1,024)**	**(1,076)**	**(1,113)**	**(1,150)**	**(1,188)**	**(1,231)**	**(1,275)**	**(1,324)**	**(1,375)**	**(1,451)**	**(1,531)**	**(1,593)**	**(1,659)**	**(1,729)**	**(16,287)**
TAX INCOME STATEMENT																						
PRETAX INCOME		(920)	(916)	(891)	(891)	(907)	(927)	(961)	(1,008)	(1,060)	(1,116)	(1,176)	(1,240)	(1,309)	(1,383)	(1,462)	(1,546)	(1,636)	(1,732)	(1,834)	(1,941)	(24,857)
PLUS: Book Depreciation		2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	2,076	41,518
LESS: Loan Principal		(1,367)	(1,394)	(1,422)	(1,451)	(1,480)	(1,509)	(1,539)	(1,570)	(1,602)	(1,634)	(1,666)	(1,700)	(1,734)	(1,768)	(1,804)	(1,840)	(1,877)	(1,914)	(1,952)	(1,991)	(33,214)
PRETAX CASH FLOW		**(211)**	**(234)**	**(238)**	**(266)**	**(311)**	**(361)**	**(425)**	**(503)**	**(586)**	**(673)**	**(766)**	**(864)**	**(967)**	**(1,076)**	**(1,190)**	**(1,310)**	**(1,437)**	**(1,570)**	**(1,710)**	**(1,857)**	**(16,554)**
State Taxes		0	0	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0	0	0
Federal Taxes		(1,448)	(2,640)	(1,570)	(921)	(894)	(411)	63	68	53	34	13	(10)	(34)	(60)	(87)	(95)	(105)	(139)	(175)	(212)	(8,570)
less: Federal credits		(1,040)	(1,071)	(1,103)	(1,136)	(1,170)	(1,205)	(1,242)	(1,279)	(1,317)	(1,357)	0	0	0	0	0	0	0	0	0	0	(11,920)
NET TAXES		(2,488)	(3,711)	(2,673)	(2,057)	(2,064)	(1,616)	(1,178)	(1,211)	(1,264)	(1,323)	13	(10)	(34)	(60)	(87)	(95)	(105)	(139)	(175)	(212)	(20,490)
NET CASH FLOW																						
CAPITAL INVESTMENT	(41,518)																					(41,518)
AMOUNT TO FINANCE	33,214																					33,214
OPERATING PRETAX CASH FLOWS		(211)	(234)	(238)	(266)	(311)	(361)	(425)	(503)	(586)	(673)	(766)	(864)	(967)	(1,076)	(1,190)	(1,310)	(1,437)	(1,570)	(1,710)	(1,857)	(16,554)
STATE CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEDERAL CREDITS / TAXES	0	2,488	3,711	2,673	2,057	2,064	1,616	1,178	1,211	1,264	1,323	(13)	10	34	60	87	95	105	139	175	212	20,490
TOTAL CASH FLOW BENEFITS	**(8,304)**	**2,277**	**3,477**	**2,436**	**1,791**	**1,753**	**1,256**	**754**	**708**	**678**	**649**	**(779)**	**(854)**	**(933)**	**(1,016)**	**(1,103)**	**(1,215)**	**(1,331)**	**(1,431)**	**(1,536)**	**(1,645)**	**(4,367)**
Cumulative Pretax Cash Flow		(211)	(446)	(683)	(949)	(1,260)	(1,621)	(2,045)	(2,548)	(3,133)	(3,807)	(4,573)	(5,437)	(6,404)	(7,480)	(8,670)	(9,980)	(11,417)	(12,987)	(14,697)	(16,554)	
Cumulative After Tax Cash Flow		2,277	5,753	8,189	9,980	11,734	12,990	13,743	14,452	15,130	15,779	15,000	14,146	13,213	12,197	11,094	9,879	8,548	7,117	5,581	3,937	

ADDENDUM

MATERIAL & LABOR COSTS AND VISA ANALYSIS
FOR FOREIGN WORKER ELIGIBILITY

CHAPTER 1 – INTRODUCTION

Lincoln County (LC) and A-Power Energy Generation Systems, Ltd. (A-Power) co-sponsored a feasibility study for Lincoln County, Nevada. The business concept tested in the study was the feasibility of using Pinyon-Juniper trees growing on public lands in Lincoln County as a fuel source for a biomass heat and power plant. The Beck Group (BECK), a forest products planning and consulting firm in Portland, Oregon, was selected to complete the study. BECK was assisted in its efforts by Bill Carlson of Carlson Small Power Consultants. The findings of that study were detailed in a written report.

Near the conclusion of the study, A-Power requested additional information about: 1) the cost of various construction materials; 2) labor rates; and 3) the ability to use Chinese workers to complete biomass projects in the United States. Since all of those items were beyond the scope of the original project, Lincoln County and A-Power amended the scope of work and contract in the original feasibility study to include the three items listed above. The findings from these additional scope of work items are included in the following sections.

CHAPTER 2 – MATERIALS COSTS

A-Power requested cost estimates (specific to the region around Lincoln County, Nevada) for the items shown in Table 1.

TABLE 1 – LIST OF BUILDING MATERIALS

Sand	Steel plate (various sizes)
Gravel	Spiral re-bar (various sizes)
Brick	Channel steel (various sizes)
Cement	Angle steel (various sizes)
Oxygen	Round steel (various sizes)
Acetylene	Aluminum sheet (various sizes)
Argon Gas	Pre-stressed concrete pipe
Fuel Oil	Fireproof coating
Gasoline	Non-alkali fiberglass cloth
Diesel	Lumber (for form work) and Plywood
Propane	

BECK obtained pricing for the preceding list of items from BMI Contractors, Inc. BMI is a mechanical installation contractor based in Salem, Oregon. The company was established in 1983, and they have completed numerous projects for a wide range of industries. Mr. Dave Talbot, estimator at BMI, obtained the pricing for the materials shown in Table 2.

With respect to the information in the table, it should be noted that:

*** One full truck load of steel delivered at current time is $469.00.

** Still working on pricing for delivery.

* These items are available for free shipping, but it depends on the order size.

All items subject are to state tax.

All items fluctuate in market pricing.

TABLE 2 – BUILDING MATERIAL UNIT COSTS; DELIVERED TO LINCOLN COUNTY

No.	Description	Unit	QTY	Practical price ($)	Material source	Transport fashion	Transport distance	Transport price	Remark
1	Spiral rebar #3	**KG**	1	1.40	PDM Steel	Delivered	175 miles ea. way	***	
2	Spiral rebar #4	**KG**	1	1.40	PDM Steel	Delivered	175 miles ea. way	***	
3	Spiral rebar #5	**KG**	1	1.40	PDM Steel	Delivered	176 miles ea. way	***	
4	Spiral rebar #6	**KG**	1	1.40	PDM Steel	Delivered	177 miles ea. way	***	
5	Spiral rebar #7	**KG**	1	1.40	PDM Steel	Delivered	178 miles ea. way	***	
6	Spiral rebar #8	**KG**	1	1.40	PDM Steel	Delivered	179 miles ea. way	***	
7	Spiral rebar #9	**KG**	1	1.40	PDM Steel	Delivered	179 miles ea. way	***	
8	Steel Plate 1/4 x 4	**20'**	1	38.32	PDM Steel	Delivered	179 miles ea. way	***	
9	Steel Plate 1/4 x 6	**20'**	1	57.48	PDM Steel	Delivered	179 miles ea. way	***	
10	Steel Plate 1/4 x 8	**20'**	1	87.90	PDM Steel	Delivered	180 miles ea. way	***	
11	Steel Plate 1/4 x 10	**20'**	1	120.75	PDM Steel	Delivered	181 miles ea. way	***	
12	Steel Plate 3/8 x 4	**20'**	1	57.60	PDM Steel	Delivered	179 miles ea. way	***	
13	Steel Plate 3/8 x 6	**20'**	1	98.18	PDM Steel	Delivered	179 miles ea. way	***	
14	Steel Plate 3/8 x 8	**20'**	1	137.96	PDM Steel	Delivered	179 miles ea. way	***	
15	Steel plate 3/8 x 10	**20'**	1	199.33	PDM Steel	Delivered	179 miles ea. way	***	
16	Steel plate 1/2 x 4	**20'**	1	86.80	PDM Steel	Delivered	179 miles ea. way	***	
17	Steel plate 1/2 x 6	**20'**	1	130.91	PDM Steel	Delivered	179 miles ea. way	***	
18	Steel plate 1/2 x 8	**20'**	1	183.95	PDM Steel	Delivered	179 miles ea. way	***	
19	Steel plate 1/2 x 10	**20'**	1	265.99	PDM Steel	Delivered	179 miles ea. way	***	
20	Steel plate 5/8 x 4	**20'**	1	110.26	PDM Steel	Delivered	179 miles ea. way	***	
21	Steel plate 5/8 x 6	**20'**	1	164.52	PDM Steel	Delivered	179 miles ea. way	***	
22	Steel plate 5/8 x 8	**20'**	1	229.93	PDM Steel	Delivered	179 miles ea. way	***	
23	Steel plate 5/8 x 10	**20'**	1	332.42	PDM Steel	Delivered	179 miles ea. way	***	
24	Steel plate 3/4 x 4	**20'**	1	125.51	PDM Steel	Delivered	179 miles ea. way	***	
25	Steel plate 3/4 x 6	**20'**	1	189.32	PDM Steel	Delivered	179 miles ea. way	***	
26	Steel plate 3/4 x 8	**20'**	1	271.22	PDM Steel	Delivered	179 miles ea. way	***	
27	Steel plate 3/4 x 10	**20'**	1	392.97	PDM Steel	Delivered	179 miles ea. way	***	
28	Channel steel 4 x 5.4	**20'**	1	73.02	PDM Steel	Delivered	179 miles ea. way	***	
29	Channel steel 6 x 8.2	**20'**	1	109.01	PDM Steel	Delivered	179 miles ea. way	***	
30	MC Channel 6 x 12	**20'**	1	237.08	PDM Steel	Delivered	179 miles ea. way	***	
31	MC Channel 6 x 15.1	**20'**	1	294.68	PDM Steel	Delivered	179 miles ea. way	***	
32	Angle steel 2 x 2 x 3/16	**20'**	1	32.04	PDM Steel	Delivered	179 miles ea. way	***	
33	Angle steel 2 x 2 x 1/4	**20'**	1	41.27	PDM Steel	Delivered	179 miles ea. way	***	

TABLE 2 – BUILDING MATERIAL UNIT COSTS; DELIVERED TO LINCOLN COUNTY

No.	Description	Unit	QTY	Practical price ($)	Material source	Transport fashion	Transport distance	Transport price	Remark
34	Angle steel 2 x 2 x 3/8	**20'**	1	63.29	PDM Steel	Delivered	179 miles ea. way	***	
35	Angle steel 3 x 3 x 3/16	**20'**	1	49.20	PDM Steel	Delivered	179 miles ea. way	***	
36	Angle steel 3 x 3 x 1/4	**20'**	1	64.02	PDM Steel	Delivered	179 miles ea. way	***	
37	Angle steel 3 x 3 x 3/8	**20'**	1	93.16	PDM Steel	Delivered	179 miles ea. way	***	
38	Angle steel 4 x 4 x 1/4	**20'**	1	87.82	PDM Steel	Delivered	179 miles ea. way	***	
39	Angle steel 4 x 4 x 3/8	**20'**	1	129.50	PDM Steel	Delivered	179 miles ea. way	***	
40	Angle steel 4 x 4 x 1/2	**20'**	1	172.98	PDM Steel	Delivered	179 miles ea. way	***	
41	Round steel	**20'**	1	7.69	PDM Steel	Delivered	179 miles ea. way	***	
42	.032 Alum. Sh. 48"x144"	**pc.**	1	59.29	PDM Steel	Delivered	179 miles ea. way	***	
43	.040 Alum. Sh. 48"x144"	**pc.**	1	73.97	PDM Steel	Delivered	179 miles ea. way	***	
44	.063 Alum. Sh. 48"x144"	**pc.**	1	114.15	PDM Steel	Delivered	179 miles ea. way	***	
45	.080 Alum. Sh. 48"x144"	**pc.**	1	146.60	PDM Steel	Delivered	179 miles ea. way	***	
46	.090 Alum. Sh. 48"x144"	**pc.**	1	163.07	PDM Steel	Delivered	179 miles ea. way	***	
47	Wood 2"x4"x16'	**unit**	1	1,990	Lowes	Pick up	85 miles ea. way	$360 projected	Unit Of Lumber
48	Plywood 23/32x4'x8'	**per.**	1	40.21	Lowes	Pick up	85 miles ea. way	$360 projected	Per sheet price
49	Steel Nail	**KG**	1	2.01	Lowes	Pick up	85 miles ea. way	$360 projected	16D Duplex
50	Fire proof paint	**gal.**	1	51.75	Torchout fire net	Delivered	N/A	*	
51	Fireproof coating	**gal.**	1	49.45	Univ. Fire Shield Prod.	Delivered	N/A	*	
52	Non-alkali fiberglass cloth	**M2**	1	4.14	Fibergalssite.com	Delivered	N/A	*	
53	#425 Cement	**yd.**	1	178.25	Sunroc	Delivered	97 miles ea. way	In the price	4000 psi.
54	Medium Sand	**ton**	1	12.19	Sunroc	Delivered	97 miles ea. way	Depends on amount ordered	
55	Detritus 1"or 1"-2 1/2"	**ton**	1	13.25	Sunroc	Delivered	97 miles ea. way	Depends on amount ordered	
56	Oxygen Bottle	**per.**	1	27.20	Airgas	Delivered	84 miles ea. way	**	Rental cost not included
57	Acetylene Bottle	**per.**	1	66.70	Airgas	Delivered	84 miles ea. way	**	Rental cost not included
58	Argon Bottle	**per.**	1	110.00	Airgas	Delivered	84 miles ea. way	**	Rental cost not included
59	Propane	**gal.**	1	$4.31	local	pick up	N/A	N/A	
60	Gasoline	**L**	1	$1.18	local	Pick up	N/A	N/A	
61	Diesel Oil	**L**	1	$1.28	local	Pick up	N/A	N/A	

CHAPTER 3 – WORKING IN THE UNITED STATES

Disclaimer: The findings and recommendations made in this section of the report are based on a review of immigration rules and regulations available on the U.S. Citizenship and Immigration Services website (www.uscis.gov) and from the U.S. Department of State website (www.state.gov). Note that much of the following information is taken directly from these websites. In addition, BECK contacted customer service agents at U.S. Citizenship and Immigration Services. Since The Beck Group is not a law firm, nor did any legal professionals review these findings and recommendations, the information presented here should not be construed as legal advice. BECK recommends that A-Power seek legal counsel regarding immigration issues.

3.1 INCORPORATING A BUSINESS IN THE UNITED STATES

The first step in bringing Chinese workers to the United States is that a U.S. company must exist at which the workers could be employed. Therefore, the first step in the process would be for A-Power to become incorporated as a business in the State of Nevada. A first step in getting assistance with the incorporation process, would be for A-Power to contact the Commercial Section of the U.S. Embassy or Consulate in China.

Once the business is incorporated, it must file a petition to hire a foreign worker with the Department of Homeland Security (DHS) and the United States Citizenship and Immigration Services (USCIS). The petition must be approved by USCIS. Finally, the visa is actually issued by the U.S. Department of State.

3.2 HIRING EMPLOYEES FOR THE CORPORATION

The U.S. allows many foreign workers to legally enter the country under a variety of worker categories. The following sections describe each of the categories and the implications for A-Power in the context of a biomass power plant (or other manufacturing facility) in Lincoln County.

3.3 TYPES OF FOREIGN WORKERS

The two broadest classifications for foreign works are temporary and permanent. A temporary worker is an individual seeking to enter the United States temporarily for a specific purpose. A permanent worker is an individual who is authorized to live and work permanently in the United States.

3.3.1 Temporary Workers

Temporary workers can enter the United States lawfully as non-immigrants to work temporarily in the United States. The following section describes the types of temporary workers that might be allowed into the United States as part of a biomass power project. Note that BECK has identified two types of temporary workers likely to be eligible to enter the country to work in the United States: E-2 and H-1B types.

3.3.1.1 E-2 Treaty Investors

This classification allows a national of a country with which the United States maintains a treaty of commerce and navigation (China is such a country) to be admitted to the United States when investing a substantial amount of capital in a U.S. business. Certain employees of such a person or of a qualifying organization may also be eligible for this classification. In BECK's judgment, one (or more) managers of an A-Power facility in Lincoln County Nevada would qualify for an E-2 classification under the third bullet point in section 3.3.1.1.2 below. The following sections describe the details of the E-2 classification.

3.3.1.1.1 How to Obtain the E-2 Classification

If a worker wishing to obtain E-2 classification status is already in the United States under some other classification, he/she must file For I-129 to request a change of statues to E-2. On the other hand, if the worker wishing to obtain E-2 classification is outside the United States, he or she must apply for an E-2 non-immigrant visa abroad. Once that visa is issued, the person may then apply to a Department of Human Services immigration officer at a United States port of entry for admission as an E-2 non-immigrant.

3.3.1.1.2 General Qualifications of a Treaty Investor (E-2)

To qualify as an E-2 non-immigrant, the treaty investor must:

- Be a national of a country with which the United States maintains a treaty of commerce and navigation.
- Have invested, or be actively in the process of investing, a substantial amount of capital in a bona fide enterprise in the United States.
- Be seeking to enter the United States solely to develop and direct the investment enterprise. This is established by showing at least 50% ownership of the enterprise or possession of operational control through a managerial position or other corporate device.

Note that an investment is defined as the treaty investor's placing of capital, including funds and/or other assets, at risk in the commercial sense with the objective of generating a profit. The capital must be subject to partial or total loss if the investment fails. The treaty investor must show that the funds have not been obtained, directly or indirectly, from criminal activity.

Note also, that a substantial amount of capital is defined as substantial in relationship to the total cost of either purchasing an established enterprise or establishing a new one; sufficient to ensure that the treaty investor's financial commitment to the successful operation of the enterprise; of a magnitude to support the likelihood that the treaty investor will successfully develop and direct the enterprise. The lower the cost of the enterprise, the higher, proportionately, the investment must be to be considered substantial.

Finally, a bona fide enterprise is defined as a real, active, and operating commercial or entrepreneurial undertaking which produces services or goods for profit. It must meet applicable legal requirements for doing business within its jurisdiction.

In BECK's judgment, A-Power through its investment in a biomass power plant in Lincoln County would qualify as a Treaty Investor.

3.3.1.1.3 General Qualifications of the Employee of a Treaty Investor (E-2)

For an employee to qualify for E-2 classification, under treaty investor status, the employee must:

- Be the same nationality of the principal alien employer (who must have the nationality of the treaty country).
- Meet the definition of "employee" under relevant law.
- Either be engaging in duties of an executive or supervisory character, or if employed in a lesser capacity, have special qualifications.

Importantly, if the principal alien employer is not an individual, it must be an enterprise or organization at least 50% owned by persons in the United States who have the nationality of the treaty country. These owners must be maintaining nonimmigrant treaty investor status. If the owners are not in the United States, they must be, if they were to seek admission to this country, classifiable as nonimmigrant treaty investors.

Duties which are of an executive or supervisory character are those which primarily provide the employee ultimate control and responsibility for the organization's overall operation, or a major component of it.

Special qualifications are skills which make the employee's services essential to the efficient operation of the business. There are several qualities or circumstances which could, depending on the facts, meet this requirement. These include, but are not limited to:

- The degree of proven expertise in the employee's area of operations.
- Whether others possess the employee's specific skills.
- The salary that the special qualifications can command.
- Whether the skills and qualifications are readily available in the United States.

Knowledge of a foreign language and culture does not, by itself, meet this requirement. Note that in some cases a skill that is essential at one point in time may become commonplace, and therefore no longer qualifying, at a later date. See 8 CFR 214.2(e)(18) for a more complete definition.

3.3.1.1.4 Period of Stay

Qualified treaty investors and employees will be allowed a maximum initial stay of two years. Requests for extension of stay may be granted in increments of up to two years each. There is no maximum limit to the number of extensions an E-2 nonimmigrant may be granted. All E-2 non-immigrants, however, must maintain an intention to depart the United States when their status expires or is terminated.

An E-2 non-immigrant who travels abroad may generally be granted an automatic two-year period of readmission when returning to the United States. It is generally not necessary to file a new Form I-129 with USCIS in this situation.

3.3.1.1.5 Terms and Conditions of E-2 Status

A treaty investor or employee may only work in the activity for which he or she was approved at the time the classification was granted. An E-2 employee, however, may also work for the treaty organization’s parent company or one of its subsidiaries as long as the:

- Relationship between the organizations is established.
- Subsidiary employment requires executive, supervisory, or essential skills.
- Terms and conditions of employment have not otherwise changed.

USCIS must approve any substantive change in the terms or conditions of E-2 status. A “substantive change” is defined as a fundamental change in the employer’s basic characteristics, such as, but not limited to, a merger, acquisition, or major event which affects the treaty investor or employee’s previously approved relationship with the organization. The treaty investor or enterprise must notify USCIS by filing a new Form I-129 with fee, and may simultaneously request an extension of stay for the treaty investor or affected employee. The Form I-129 must include evidence to show that the treaty investor or affected employee continues to qualify for E-2 classification.

It is not required to file a new Form I-129 to notify USCIS about non-substantive changes. A treaty investor or organization may seek advice from USCIS, however, to determine whether a change is considered substantive. To request advice, the treaty investor or organization must file Form I-129 with fee and a complete description of the change.

3.3.1.1.6 Family of E-2 Treaty Investors and Employees

Treaty investors and employees may be accompanied or followed by spouses and unmarried children who are under 21 years of age. Their nationalities need not be the same as the treaty investor or employee. These family members may seek E-2 nonimmigrant classification as dependents and, if approved, generally will be granted the same period of stay as the employee. If the family members are already in the United States and are seeking change of status to or extension of stay in an

E-2 dependent classification, they may apply by filing a single Form I-539 with fee. Spouses of E-2 workers may apply for work authorization by filing Form I-765 with fee. If approved, there is no specific restriction as to where the E-2 spouse may work.

As discussed above, the E-2 treaty investor or employee may travel abroad and will generally be granted an automatic two-year period of readmission when returning to the United States. Unless the family members are accompanying the E-2 treaty investor or employee at the time the latter seeks readmission to the United States, the new readmission period will not apply to the family members. To remain lawfully in the United States, family members must carefully note the period of stay they have been granted in E-2 status, and apply for an extension of stay before their own validity expires.

3.3.1.2 H-1B Specialty Occupations

Another possibility for A-Power to bring Chinese workers into the United States is through an H-1B visa. This category applies, among other areas, to people who wish to perform services in a specialty occupation. The general requirements for obtaining an H-1B visa are that the job must meet one of the following criteria to qualify as a special occupation:

- Bachelor's or higher degree or its equivalent is normally the minimum entry requirement for the position.
- The degree requirement for the job is common to the industry or the job is so complex or unique that it can be performed only by an individual with a degree.
- The employer normally requires a degree or its equivalent for the position.
- The nature of the specific duties is so specialized and complex that the knowledge required to perform the duties is usually associated with the attainment of a bachelor's or higher degree.

For a person to qualify to accept a job offer in a specialty occupation he or she must meet one of the following criteria:

- Have completed a U.S. bachelor's or higher degree required by the specific specialty occupation from an accredited college or university.
- Hold a foreign degree that is the equivalent to a U.S. bachelor's or higher degree in the specialty occupation.
- Hold an unrestricted state license, registration, or certification which authorizes the person to fully practice the specialty occupation and be engaged in that specialty in the state of intended employment.

- Have education, training, or progressively responsible experience in the specialty that is equivalent to the completion of such a degree, and have recognition of expertise in the specialty through progressively responsible positions directly related to the specialty.

Finally, in addition to meeting the above criteria, the prospective employer must file a labor certification application, which includes an approved form ETA-9035, labor condition application (LCA), with the form I-129, and petition for a non-immigrant worker. Labor certification is approval from the U.S. Department of Labor that there are: insufficient available, qualified, and willing U.S. workers to fill the position being offered at the prevailing wage; and hiring a foreign worker will not adversely affect the wages and working conditions of similarly employed U.S. workers.

In BECK's judgment, it is unlikely that A-Power will be able to obtain a labor certification, which demonstrates that there are insufficient available, qualified, and willing U.S. workers and/or that hiring a foreign worker will not adversely affect the wages and working conditions of similarly employed U.S. workers.

3.3.2 Permanent Workers

If a non-U.S. citizen has the right combination of job skills, education, and/or work experience and is otherwise eligible, he or she may be able to live permanently in the United States. Such workers are classified into one of five categories. Each year, approximately 140,000 such workers (and their spouses and dependant children) are granted permanent worker status.

Note that in some cases, labor certification is required before permanent worker status is granted. Labor certification is approval from the U.S. Department of Labor that there are: insufficient available, qualified, and willing U.S. workers to fill the position being offered at the prevailing wage; and hiring a foreign worker will not adversely affect the wages and working conditions of similarly employed U.S. workers. Importantly, the Permanent Worker Classification (EB-5) that BECK believes would apply to A-Power does not require labor certification.

3.3.2.1 EB-5 Immigrant Investor Classification

In the Immigration Act of 1990, an EB-5 immigrant investor visa category was created. It allows immigrants to enter the United States in order to invest in a new commercial enterprise that will benefit the U.S. economy and create at least 10 full-time jobs.

Investors seeking to obtain the visa must invest in either: 1) a new commercial enterprise; or 2) a troubled business. With respect to a new business enterprise, the investor must qualify for each of the following:

- Invest or be in the process of investing at least $1 million. If the investment is in a designated targeted employment area, then the minimum investment required is $500,000.

- Benefit the U.S. economy by providing goods or services to U.S. markets.
- The business must create full-time employment for at least 10 U.S. workers. Those workers can be U.S. citizens, green card holders, and other individuals lawfully authorized to work in the U.S.. It does not include the investor's spouse or children.
- The investor must be involved in the day-to-day management of the new business or directly manage it through formulating business policy.

Regarding a troubled business, the investor must meet the following to qualify:

- Invest in a business that has existed for at least two years.
- Invest in a business that has incurred a net loss, based on generally accepted accounting principles, for the 12 to 24 month period before the investor filed the Form I-526 Immigrant Petition by an Alien Entrepreneur.
- The loss for the 12 to 24 month period must be at least equal to 20 percent of the business's net worth before the loss.
- Maintain the number of jobs at no less than the pre-investment level for a period of at least two years.
- Be involved in the day-to-day management of the troubled business or directly manage it through formulating business policy (e.g., as a corporate officer or board member).
- The same investment requirements of the new commercial enterprise investment apply to a troubled business investment ($1,000,000 or $500,000 in a targeted employment area).

3.3.2.2 Application Process for EB-5 Status

Acquiring lawful permanent residence ("Green Card") through the EB-5 category is a three step self-petitioning process. First, the successful applicant must obtain approval of his or her Form I-526 Petition for an Alien Entrepreneur. Second, he or she must either file an I-485 application to adjust status to lawful permanent resident, or apply for an immigrant visa at a U.S. consulate or embassy outside of the United States. The EB-5 applicant (and he or her derivative family members) are granted conditional permanent residence for a two year period upon the approval of the I-485 application or upon entry into the United States with an EB-5 immigrant visa. Third, Form I-829 Petition by an Entrepreneur to Remove Conditions must be filed 90 days prior to the two year anniversary of the granting of the EB-5 applicant's conditional Green Card. If this petition is approved by CIS then the EB-5 applicant will be issued a new Green Card without any further conditions attached to it, and will be allowed to permanently live and work in the United States. A total of 10,000 immigrant visas per year are available to qualified individuals under the EB-5 program.

3.3.2.3 Dependents of Immigrant Workers with EB-5 Status

The spouse and unmarried children under the age of 21 of an immigrant worker with EB-5 status may be admitted to the U.S. on a two-year conditional period. If the worker's I-829 petition to remove conditions is approved, then the conditions will be removed from the worker's spouse and children's Green Card status. As a lawful permanent resident (Green Card holder) the worker's spouse and children will be authorized to work or attend school in the U.S.

3.3.2.4 EB-5 Implications for A-Power

In BECK's judgment, the EB-5 program seems to be the most likely method of allowing Chinese workers to permanently enter the United States.

BECK's understanding of the process is that for every 10 full-time jobs created, one EB-5 investor visa is allowed. Thus, the question is how many jobs would be created by a biomass power plant and what jobs can be counted? BECK estimates that 12 full-time jobs would be directly created by the development of a biomass power plant. In addition, approximately 18 indirect, full-time jobs would be created to supply the plant with fuel. Induced jobs created as a result of the biomass plant may also be counted toward allowing EB-5 visas. BECK, however, has no estimate of the amount of induced jobs that might be created as a result of the biomass plant.

Finally, there is some evidence of the temporary construction jobs being counted in the calculation of the number of investor visas allowed. However, it appears that in order for those jobs to be counted, the construction/development of the business must last longer than two years. BECK strongly recommends that A-Power consult a U.S. immigration attorney for clarification on the number of EB-5 visas likely to be available from A-Power's investment in a biomass power plant.

CHAPTER 4 – LABOR COSTS

BECK also was asked to investigate labor costs for a variety of professional and labor positions. The list of positions is shown in Table 3.

TABLE 3 – LIST OF POSITIONS

Engineer	High Pressure Welder	Tailer Operator
Worker Header	Structure Welder	Scaffolding Worker
Steel Bar Worker	Pipe Erection Worker	Helper
Concrete Worker	Machinery Erector	Secretary
Lift Worker	Painter	Safeguard
Electrician	Crane Operator	Driver

BECK obtained labor rates for each of the preceding positions from BMI Contractors, Inc. (the same firm that provided information about materials costs in Chapter 2), and a company that has completed numerous projects for a wide range of industries. Mr. Dave Brown, President of BMI, obtained the information. The results of his research are shown in Table 4.

TABLE 4 – HOURLY PAY RATE BY POSITION

Position	Pay Rate (USD/hour)	Overtime Pay Rate (USD/hour)	Position	Pay Rate (USD/hour)	Overtime Pay Rate (USD/hour)
Engineer	*see below	*see below	Machinery Erector	41.00	58.50
Worker Header	66.60	96.25	Painter	34.00	48.00
Steel Bar Worker	41.00	58.50	Crane Operator	66.60	96.25
Concrete Worker	41.00	58.50	Tailer Operator	unknown	unknown
Lift Worker	unknown	unknown	Scaffolding Worker	unknown	unknown
Electrician	56.50	78.30	Helper	30.50	42.75
High Pressure Welder	51.50	74.25	Secretary	34.00	48.00
Structure Welder	37.00	51.00	Safeguard	unknown	unknown
Pipe Erection Worker	48.00	69.00	Driver	34.00	42.75

As Table 4 displays, BMI was not able to identify wage rates for several of the positions. It should also be noted that it is a common practice in many regions, including Nevada, for the State to gather data on Prevailing Wage Rates for non-residential construction (i.e., the median wage paid to workers in a given trade or occupation in a specific region). The prevailing wage rates are then paid to workers employed on public works projects. Since, the construction of a biomass power plant is not a public works project, the wage rates shown above are non-prevailing wage rates.

Regarding wage rates for engineers, it is difficult to make a general estimation because there are numerous types. However, according to RSMeans construction cost data, engineering/design costs typically range between 4.5 and 9 percent of a project's total cost. That information can be compared to information provided by Wellons, Inc. (a boiler manufacturer), which stated that engineering costs (within their scope of work, which was $37.75 million in the case of a 10 MW biomass plant in Lincoln County) are typically 12 to 18 percent of the total turn key cost.