FINAL

CAMPTONVILLE COMMUNITY PARTNERSHIP BIOMASS POWER GENERATION & CHP

Feasibility Study

B&V PROJECT NO. 186534

PREPARED FOR

Camptonville Community Partnership (CCP)

26 AUGUST 2015

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0.0 Executive Summary

Camptonville Community Partnership (CCP) is interested in developing a biomass power plant to generate jobs and remove fire risk woody biomass debris from the forest as outlined more fully in the Introduction below. CCP hired Black & Veatch to review the technical and economic attributes of various technologies for such a plant. In preparation for this work, Black & Veatch solicited budgetary proposals from

- six boiler vendors,
- six steam turbine generator vendors,
- four syngas generator vendors,
- four reciprocating engine vendors,
- two hot combustion gas generators and
- two ORC vendors

Identification of which vendors responded, what pricing they provided, and their commercial status are outlined in Figure 4-1 through Table 4-6. These proposals and vendors were paired up by Black & Veatch based on their pricing or in some cases the vendor providing the proposal included a proposal from its own paired vendor.

Shipping, installation, balance of plant costs were identified by Black & Veatch to obtain an estimated EPC direct cost. Typical indirect costs were estimated by Black & Veatch and added to the EPC direct costs to provide grand total EPC cost estimates, which are summarized in Table 5-2. The operation and maintenance costs were estimated for each technology and are summarized in Table 5-3. A discussion is provided about owner costs that are often not included in engineering studies, but a real cost that should be accounted for when running the economic analysis, and a summary of these estimated costs are presented in Table 5-4.

The financial analysis of the options begins on page 44 with Table 6-1 that outlines the basic economic values used in the analysis that remain unchanged for all options. Table 6-2 provides the financial results without the inclusion of owner's costs and Table 6-3 provides the same information including the owner's costs. The range of revenue required when owners cost are excluded, is $177.6/MWh to $196/MWh, slightly over a 10% spread between the highest and lowest values. Including the owner's cost provides values that range from $182.1/MWh to $200.6/MWh.

Table 6-4 provides sensitivity results for several of the input values to demonstrate the relative effect a given variable has on the revenue required.

Since the economic results for the various technologies and pairings don't provide a clear pathway to the preferred technology, Black & Veatch proceeded to create qualitative evaluation criteria for an assessment of characteristics other than economics. Table 7-1 provides the details of this assessment and shows the steam option earning 89 points followed by ORC with 73 and syngas with 58.

Because of the significant reduction in the LCOE when thermal energy is sold, it is recommended that CCP do all they can to locate and secure a reliable thermal host.

When this qualitative evaluation is combined with the economic results and thermal sales, steam turbine generator technology appears as the preferred technology.

1.0 Project Background Information

1.1 HISTORY

The community of Camptonville, California established some goals for their community that included the following:

- sustainably utilize biomass resulting from forest management and/or harvesting activities,
- protect communities and private property by reducing the risk of catastrophic wildfire on adjacent natural lands and in the wild land - urban interface,
- protect public health and improve air quality by reducing emissions associated with controlled fuel management burns and potential wild land fires, and
- provide direct economic development benefits to the rural communities of the Yuba County foothills region by
    - improving energy self-reliance through local power generation from a renewable source; and
    - supporting forest health improvement by creating a long-term economic market that could drive future land management decisions to treat forested areas

To create structure to allow fulfillment of these goals the Camptonville Community Partnership (CCP), the Yuba Watershed Protection, and Fire Safe Council created the Forest Biomass Business Center Steering Committee (Steering Committee), a collaborative, multi-stakeholder group, to direct the redevelopment of a former sawmill site at Celestial Valley, near Camptonville, California.

1.2 CURRENT STATUS

At the direction of the Steering Committee on behalf of CCP, Black & Veatch has been engaged to commence a study of CCP's planned biomass CHP project, under which the following tasks are being performed:

- Technical feasibility of a biomass power project or combined heat and power project
- Economic feasibility analysis
- Evaluation and selection of technology of a small-scale biomass power or combined heat and power (CHP) generation facility (1-3 MW) at the mill site

This project is funded through a grant from the Sierra Nevada Conservancy through the "Healthy Forests/Abandoned Mine Lands" program. Funding for the grant program is from Proposition 84, passed by California voters in 2006.

A prior study performed by TSS in 2014 for Nevada County, provided a preliminary evaluation of some of the above elements. This study by Black & Veatch addresses the technical and economic feasibility of the project. This study also identifies the challenges associated with implementation of the project.

2.0 Technology Analysis (Task 2)

2.1 OVERVIEW OF CONVERSION TECHNOLOGY

Biomass conversion technologies reviewed in this report include:

- Direct Combustion (stoker, bubbling fluidized bed, or circulating fluidized bed) with a steam turbine generator as the prime mover
- Syngas Generator combined with a reciprocating, internal combustion engine, and
- A Combustion Gas Generator paired with an organic Rankine cycle (ORC) prime mover

These three equipment configurations or technologies have been compared to determine which offers the best solution from a technical performance perspective, and the economic feasibility portion of the report identifies which of the configurations provide a feasible economic solution.

The following sections provide a detailed discussion of biomass energy conversion technologies that could potentially be suitable for CCP's planned biomass CHP project. Following the characterization of these technologies, Black & Veatch presents the relative economic feasibility of the three options along with the benefits and risks of each technology. The best biomass conversion solution will be utilized by CCP to proceed with its development.

2.2 DIRECT COMBUSTION

Direct biomass combustion power plants employ the Rankine steam cycle (not to be confused with the third option, the Organic Rankine Cycle) and utilize the same proven technologies that have been used with coal and biomass combustion for decades. There are nearly 2,000 biomass power plants operating worldwide with a capacity of 22 gigawatts (22,000 megawatts).[1]

In many respects, biomass fired combustion power plants are similar to coal plants. However, as a result of the smaller scale of the plants and the lower heating value of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. There are three common boiler types for biomass Direct Combustion facilities. These are stoker boilers, bubbling fluidized bed (BFB) boilers, and circulating fluidized bed (CFB) boilers. Technical characteristics and parameters of each of these technologies are provided below.

[1] From Renewable Energy Magazine

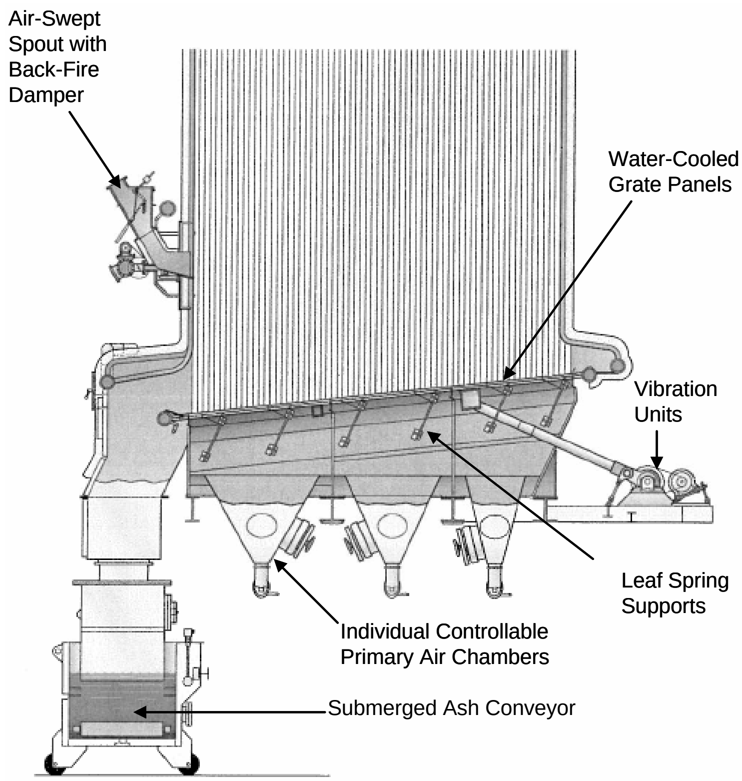


Figure 2-1 Vibrating, inclined Grate Stoker Boiler (Source: Steam, 41st ed., B&W)

2.2.1 Stoker Boiler Technologies

Stoker combustion is a proven technology that has been successfully used with biomass fuels (primarily wood) for many years. In the stoker boiler, fuel feeders (stokers) regulate the flow of fuel down chutes that penetrate the front wall of the boiler above a grate. Mechanical devices or jets of high-pressure air throw the fuel out into the furnace section and onto the grate. Because combustible gases are readily driven off, significant combustion of these gases occurs above the grate. Therefore, a significant portion of the total combustion air is introduced as overfire air (above the grate). The unburned char settles on the grate surface, and char burnout is completed by preheated primary air introduced from below the grate. The speed of the feeders is modulated to maintain output with changing fuel conditions or to respond to load changes.

The grate must be designed to support efficient combustion of the biomass char and allow removal of the ash. There are several types of grates used with stokers:

- **Vibrating Grates** – Water-cooled sloping grate that periodically vibrates to remove ash from the grate surface. This technology is most prevalent today because of its effectiveness, flexibility, and low maintenance.
- **Traveling Grates** – Well-proven air-cooled conveying grate design suitable for most biomass fuels
- **Pin-Hole Grates** – Stationary grate design for low ash fuels such as sugar cane bagasse

- **Dumping Grates** – Relatively old technology for high ash fuels

One of the most commonly used grates in new applications is the vibrating grate, which is shown on Figure 2-1. Compared to traveling grates, vibrating grates require substantially less maintenance and have low excess air requirements that improve boiler efficiency and emissions. Vibration of the grate causes ash to move toward the discharge end of the grate, where it falls into the bottom ash collection and conveying system. The vibration of the grate is not continuous. The frequency, duration, and intensity of the grate vibrations are adjustable. This allows optimization of the ash layer depth on the grate. About 40 percent of the ash will leave the boiler as bottom ash, and 60 percent as fly ash.

2.2.2 Bubbling Fluidized Bed Technologies (BFB)

Combustion of biomass in fluidized bed boilers has been practiced for more than 30 years. In BFB boilers, fuel feeders discharge either to chutes that drop the fuel into the bed or to fuel conveyors that distribute the fuel to feed points around the boiler. The speed of the feeders is modulated to maintain output when fuel conditions or loads change. The fluidized bed consists of fuel, ash from the fuel, inert material (e.g., sand), and possibly a sorbent (e.g., limestone) to reduce sulfur emissions (mostly for coal fired facilities). In most biomass fired applications, the fuel typically has very little sulfur, thus limestone sorbent is not required, and only a sand bed is typically utilized. There are some cases where biomass fuels can have higher sulfur content. For example, the sulfur content of pulping process residues such as spent sulfite liquor is somewhat higher, which may necessitate sorbent injection to control emissions.

An illustration of a BFB is shown on Figure 2-2. The fluidized state of the bed is maintained by hot primary air flowing upward through the bed. The air is introduced through a grid to evenly distribute the air. The amount of air is just sufficient to cause the bed material to lift and separate. In this state, circulation patterns occur, causing fuel discharged on top of the bed to mix throughout the bed. Because of the turbulent mixing, heat transfer rates are very high and combustion efficiency is good. Consequently, combustion temperatures can be kept low compared to other conventional fossil fuel burning boilers. The bed may also be operated in a sub-stoichiometric mode (below the perfect amount of oxygen needed for complete combustion) with additional air added in the freeboard (over-fire or above the bed) to complete combustion. Low bed temperatures and air staging reduces NO_x formation. Low temperature is also an advantage with biomass fuels because they may have relatively low ash fusion temperatures. Low ash fusion temperatures can lead to excessive boiler slagging (large clinkers or chunks of glass hardened ash material from the sand in the fuel).

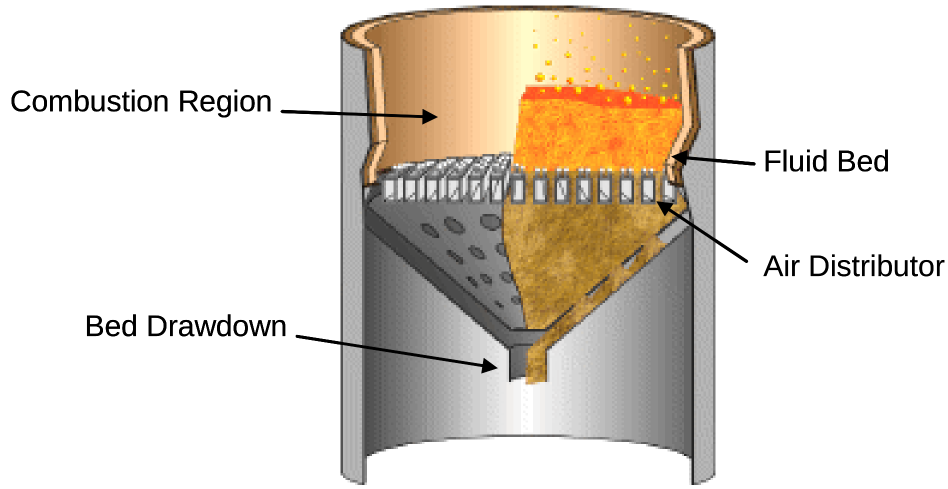


Figure 2-2 Typical Bubbling Fluidized Bed (Source: Outotec)

In a BFB boiler, the unit is generally designed to have flue gas velocities through the bed of less than 10 feet per second. This low velocity minimizes the amount of large solid material entrained in the flue gas stream. Management of tramp material (non-combustibles) and agglomerates in the bed is very important for reliable long-term operation. For example, in the Outotec BFB boiler, there is a bed recycle system that withdraws this unwanted material from the bottom of the fluidized bed. The removed bed material is screened to separate the tramp materials (dirt and other noncombustibles) from the inert bed material, and the reclaimed inert material is recycled back into the bed.

As with a stoker boiler, the combustion gases are rapidly driven from the wood fuel. This results in 55 to 60 percent of the combustion occurring in the bed and 40 to 45 percent occurring above the bed. Overfire air is required to ensure complete combustion of the fuel.

Because of the low combustion temperatures, NO_x emissions from a BFB boiler that burns biomass will generally be less than 0.20 lb/MBtu (million Btu's). In addition, the operating temperature of a BFB is usually within the temperature range that allows an SNCR system (selective non-catalytic reduction) for NOx removal, to be effective. The BFB configuration can accommodate fuels with a wider range of heating value and moisture content than the stoker boiler, if this characteristic is needed. With proper design, BFBs should be able to process a diverse mix of fuels simultaneously (e.g., a mixture of wood waste, agricultural residues, and biosolids). A disadvantage of BFBs compared to stokers is the large auxiliary power requirement for the fluidizing air fan, notably higher capital cost, higher maintenance costs, and more precise fuel preparation requirements.

BFBs traditionally range from 20 to 75 megawatt (MW). BFBs are technically capable of burning a wide variety of biomass fuels as well as coal, provided that the fuel is sized appropriately. BFBs typically have a maximum fuel particle size in any direction of approximately four inches, while the stoker boiler has greater flexibility to handle longer pieces of biomass. This limitation may require more screening and sizing operations to ensure that no dimension of the fuel exceeds the recommended upper limit for BFBs.

One advantage of fluidized bed combustors (both bubbling and circulating) is that the fluid bed medium provides thermal inertia that compensates for variations in nonhomogeneous fuels, including variations in heating value and moisture content. This results in a consistent heat output and flue gas quality. The high heat transfer of the fluid bed medium also provides high carbon burnout.

The typical boiler efficiency for bubbling bed combustion units firing biomass is approximately 70 to 75 percent. NO_x control is required regardless of the fuel, and the prevailing technology for NO_x control is SNCR. Control of PM10 (particulate matter less than 10 microns) would typically be accomplished with a fabric filter.

2.2.3 Circulating Fluidized Bed Technologies (CFB)

As with BFB boilers, CFB units also offer a high degree of fuel flexibility and would be a suitable technology for burning biomass, particularly at larger scales (i.e., 100 MW and greater). As discussed earlier, gas velocities through the bed for BFB systems are typically less than 10 feet per second. In CFB systems, fluidizing air velocity is maintained at 13 to 20 feet per second to prevent a dense bed from forming and to encourage carry-over of solids from the bed. A solids separator (such as a cyclone) is used to recirculate the particles carried over from the furnace. Fuel is typically fed pneumatically into the combustor near the bottom of the unit and/or in the solids return leg.

CFBs share many of the same advantages as BFBs with regard to fuel flexibility, combustion efficiency, and emissions. The technology is better suited for larger sizes than stoker and BFB combustion because injection of fuel and limestone into the circulating media is much easier than evenly spreading the feed across a large grate or bubbling bed. While early CFB units were in the size range appropriate for most biomass plants (i.e., 10 to 50 MW), present use of CFB technology is focused primarily on large fossil fueled units of 200 to 300 MW. Although manufacturers might quote small CFBs, these units generally cost more than other combustion technologies, making them difficult to justify for smaller biomass plants. In general, CFBs are not economically competitive at scales less than 75 to 100 MW.

Large CFBs are ideally suited to burning a broad mix of fossil and biomass fuels. Some CFBs have been designed to burn up to 100 percent biomass or 100 percent coal in the same unit. An example of a successful multi-fuel unit is the 240 MW CFB owned by Alholmens Kraft Ab in Finland. This plant burns a mix of wood, peat, and lignite. This unit, shown on Figure 2-3, was supplied by Kvaerner Pulping and was commissioned in 2001. At the time, this was the largest biomass fired power plant in the world. At this scale, the technology is able to maximize economies and efficiencies of scale, similar to conventional coal plants.

Figure 2-3 Alholmens Kraft Multi-Fuel CFB (Source: Kvaerner)

2.2.4 Comparison of Stoker and BFB Gasification Systems

This subsection provides a detailed comparison of stoker and BFB combustion systems. Either of these systems would be appropriate for the biomass fired cogeneration systems under consideration.

For the majority of the reference plant parameters, the difference between a facility employing stoker boilers and a facility employing a BFB boiler will be slight. The choice of a boiler will not significantly affect the footprint of the boiler island or the design of the steam cycle. Differences in boiler efficiency will affect the biomass consumption rates to a small degree, but these differences are unlikely to affect the design of the fuel yard and fuel handling systems. The most significant differences in the balance of plant (BOP) equipment are likely to be in the selection and design of air quality control (AQC) systems. These differences are due to the disparity in uncontrolled emissions from stoker and BFB systems.

The choice of combustion technology generally has a minor effect on overall plant heat rate. The turbulent action of the bed results in higher combustion efficiencies for fluidized beds than those for stoker boilers. However, this increased combustion efficiency is offset to some degree by the high auxiliary power consumption of the fluidizing air fans. Net plant heat rates for biomass power facilities are much more dependent on steam cycle design. Typically, biomass facilities with nominal capacities of below 5 MW have net plant heat rates in the range of approximately 17,000 British thermal units per kilowatt-hour (Btu/kWh net) to 22,000 Btu/kWh net or even higher.

High-level comparisons of stoker and BFB boilers have been presented by B&W and Metso Power. But these vendors typically offer much larger equipment. Both of these companies offer both types of boilers as part of their standard product lines. It is plausible that the stoker boiler designs of boiler vendors such as Indeck Keystone, FSE Energy and McBurney may offer features and advantages not present in the designs evaluated by B&W and Metso Power.

Key findings of these comparisons are summarized in Table 2-1 include the following:

- **Fuel Selection** – Both BFB and stoker boilers are appropriate for the combustion of wood, bark, and agricultural residues. In previous discussions, B&W has stated that BFB systems are preferred for fuels with high moisture contents, while stoker systems are preferred for fuels with high concentrations of alkali (e.g., poultry litter and crop residues such as rice straw). For the combustion of a relatively homogeneous mixture of woody biomass, B&W has generally recommended BFB technologies.
- **Combustion Temperature** – Stokers operate at significantly higher furnace temperatures than BFBs. Temperatures in the furnace range from 2,200 to 3,000 F for stokers, while the bed temperature of a BFB is typically 1,500° F. Higher combustion temperatures generate greater NOx emissions.
- **Excess Oxygen** – Stokers typically operate with slightly more excess air than BFB systems. Metso Power states that the flue gases from a stoker boiler contain 1 percent more oxygen than the flue gases from a BFB system.
- **Uncontrolled Emissions** – The increased excess air of a stoker boiler, coupled with higher furnace temperatures, lead to significantly greater NO_x emissions from a stoker boiler. B&W states that emissions of NO_x, CO, and volatile organic compounds (VOC) are 10 to 25 percent greater for a stoker boiler than those of an equivalently sized BFB operating with the same fuel. An SNCR (urea injection) system to control NOx is typically required in Cal. for both stoker and BFB boilers to allow either style of boiler to comply with the emission limits.
- **AQC Systems** – At present, both stoker and BFB boiler systems would likely employ SNCR systems for NO_x control. Stoker systems typically employ electrostatic precipitators (ESPs) for particulate control, while BFB systems typically employ fabric filters for this purpose. Knowledge of the specific fuel mixture and discussions with regulatory agencies are required to determine whether the unlikely need for sulfur and acid control technologies would be required.
- **Carbon Conversion** – The carbon conversion rate for BFB boilers is greater than 99 percent, while the carbon conversion rate for stoker boilers is approximately 94 to 96 percent. Stoker systems can employ carbon reinjection systems to increase the carbon conversion rate to 97 to 98 percent. However, this requires increased maintenance and increases the auxiliary power requirements of the system because of an additional blower load.

Table 2-1 Comparison of Stoker, BFB Technologies, and AQC Systems

	STOKER TECHNOLOGIES	BFB TECHNOLOGIES
Combustion System Characteristics		
Combustion Temperature, °F	2,200 – 3,000	1,500
Fuel Moisture Content Range, %	15 – 60	40 – 65
Carbon Conversion Efficiency, %	94 – 96(a)	> 99
Excess Air	Higher	Lower
Operational Stability	Less stable(b)	More stable(b)
Response to Load Variations	More responsive(b)	Less responsive(b)
Furnace Dimensions	Constrained(c)	Optimized(c)
Sand Reclaim/Makeup System	None	Required
Auxiliary (Startup) Fuel	None	Fuel oil or natural gas
Air Quality Control Systems		
Nitrogen Oxides (NOx)	SNCR	SNCR
Sulfur Dioxide (SO2)	Fuel dependent	Fuel dependent
Particulate Matter (PM)	ESP	Fabric filter

Sources:
1. DeFusco, McKenzie, and Fick (B&W). "Bubbling Fluidized Bed or Stoker – Which is the Right Choice for Your Renewable Energy Project?"
2."BFB vs. Stoker," Metso Power presentation.

a) Stoker systems may employ carbon reinjection systems to increase the carbon conversion to 97 to 98 percent. However, these systems require fairly high levels of maintenance and require an auxiliary power load (attributable to an additional blower system).

b) Stokers operate with a relatively small thermal mass (i.e., fuel and ash) on the grate, while the thermal mass (i.e., sand and fuel) of a BFB is considerably larger. The relatively large thermal mass of the fluidized bed provides much more steady operation than that observed in stokers. Fluctuations in the fuel properties (e.g., moisture content, heating value) can result in temporary process upsets and increases in emissions. For these same reasons, however, stokers can more quickly respond to changing load demands, while BFBs respond more slowly.

c) Furnace dimensions for stokers are constrained by the ability of the fuel delivery systems to distribute the fuel evenly across the grate. Based on current design of air-swept spouts, B&W states that the practical limit of furnace width is 26 feet. Once this limit is reached, increases in size become less favorable from an economic perspective. BFB furnace dimensions are not constrained in this fashion; therefore, BFB designs remain optimized and offer economic advantages at larger sizes.

While it is technically possible to select a BFB for this small scale facility, it is clearly on the fringe of the vendors' offerings. BFB's at larger scale offer slightly better combustion efficiencies than stoker boilers, but also have the added burden of higher parasitic load as a result of the blowers needed, thereby nearly offsetting the greater combustion efficiency. The efficiency always suffers at small scale of any technology but a notable efficiency difference between BFB and stoker technologies would not be expected. At this small scale the stoker boiler would likely have a better efficiency than a BFB.

2.3 BIOMASS SYNGAS GENERATORS

Biomass gasification is a thermal process to convert solid biomass into a gaseous fuel (syngas). This is accomplished by heating the biomass to high temperatures in an oxygen-deficient ("fuel-rich") environment. Gasification is a promising process for biomass conversion. By converting solid fuels to a combustible gas, gasification offers the potential of using more advanced, efficient, and environmentally benign energy conversion processes to produce power.

The historical progress of gasification has been sporadic. Near the beginning of the twentieth century, more than 12,000 large gasifiers were installed in North America in a period of just 30 years. These large systems provided gas to light city streets and heat various processes. Moreover, by the end of World War II, more than 1 million small gasifiers had been used worldwide to produce fuel gas for automobiles. However, at the end of the war, the need for this emergency fuel had disappeared. Automobiles were reconverted to gasoline, and the arrival of large interstate natural gas pipelines put many municipal "gasworks" out of business. With the loss of equipment went the majority of the gasification artists – those who operated their generators with practical experience and intuition. In some cases, scientists and developers still struggle to reproduce with state-of-the-art technology what was routine operation half a century ago.

2.3.1 Syngas Fundamentals

Gasification is typically thought of as incomplete combustion of a fuel to produce a syngas with a low to medium heating value. Heat from partial combustion of the fuel is also generated, although this is not considered the primary usable product. Gasification lies between the extremes of combustion and pyrolysis (no oxygen) and occurs as the amount of oxygen supplied to the burning biomass is decreased. Biomass gasification can be described by the simple equation:

$$\text{biomass + limited oxygen} \quad = \quad \longrightarrow \quad \text{syngas + heat}$$

Gasification occurs as the amount of oxygen, expressed in the equivalence ratio, is decreased. The equivalence ratio is defined as the ratio of the actual air-fuel ratio to the stoichiometric (ideal) air-fuel ratio. Thus, at an equivalence ratio of one, complete combustion theoretically occurs. At an equivalence ratio of zero, no oxygen is present and fuel pyrolysis occurs. Gasification occurs between the two extremes and is a combination of combustion and pyrolysis.

A formal definition of gasification might be the process that stores the maximum chemical energy in the gaseous portion of the products. Depending on the fuel and the reactor, the equivalence ratio for this condition can range between 0.25 and 0.35. An equivalence ratio of 0.25 represents the oxidation of one-fourth of the fuel. In most gasifiers, the heat released by burning this portion of the fuel causes pyrolysis to occur on the remainder and produces a low heating value syngas. Below an equivalence ratio of 0.25, char (mostly solid carbon) begins to be produced in substantial quantities, and the gas production begins to taper off. Sales of biochar are still an emerging market and not yet well established. Black & Veatch has a concern that the market may not be as robust as sometime anticipated or presented. For these reasons, we have not given biochar any economic value for this evaluation.

2.3.2 Syngas Quality

The primary product of gasification is a low heating value gas, known as syngas. For air-blown gasification, the heating value of the syngas is typically 100 to 150 British thermal units per standard cubic foot (Btu/scf), whereas the heating value of natural gas is approximately 1,000 Btu/scf. The heating value of the syngas is significantly reduced by the dilution from nitrogen in the process air. For oxygen-blown or steam-blown gasification, the syngas is not diluted by the presence of nitrogen, and the heating value of the syngas is typically 300 to 400 Btu/scf. Black & Veatch used 140 Btu/scf when requesting budgetary proposals from the vendors.

Combustible components of the gas include carbon monoxide (CO), hydrogen, methane, and small amounts of higher hydrocarbons such as ethane and propane. The syngas may also contain varying amounts of carbon dioxide (CO_2) and water vapor. The exact composition of the syngas depends on the operating temperature and pressure as well as the composition of the biomass feedstock. In general, higher pressures tend to produce more methane and water vapor and improve the carbon conversion efficiency of the gasifier. Higher temperatures tend to produce more CO and hydrogen.

The raw syngas exiting the gasifier also contains varying amounts of pollutants and contaminants, including the following:

- Sulfur and nitrogen compounds - hydrogen sulfide (H_2S), carbonyl sulfide (COS), ammonia, and hydrogen cyanide (HCN).
- Vapor-phase alkali.
- Condensable hydrocarbons (tars).
- Particulate matter such as entrained ash.

The syngas must be cleaned of these components before being combusted to produce power or before further chemical processing. The removal of pollutants and contaminants is commonly referred to as gas cleanup.

2.3.3 Syngas Technology Options

A wide variety of gasification technologies exists, including updraft, downdraft, fixed gate, entrained flow, fluidized bed, and molten metal baths. Unlike combustion technologies discussed previously, it is difficult to generally group and categorize gasification technologies because of the wide variety of process variables that differentiate designs. These include the following:

- **Reactor Type** – Many of the same technologies that have been developed for combustion can be adapted for gasification. Some of these technologies can alternately operate between combustion and gasification modes simply by varying the balance and distribution of air and fuel in the reactor. Named for the direction of gas flow in the reactor, small updraft and downdraft gasifiers are more traditional designs and have been widely studied and used. Other types of gasifiers include entrained flow (common for coal gasification) and molten metal baths.

- **Oxygen, Steam, or Air-Blown** – Air-blown gasification produces a syngas with a low heating value, typically 100 to 150 Btu/ ft^3. The heating value of the gas may be increased by using oxygen or steam to gasify the fuel, either of which removes most of the inert nitrogen from the syngas and raises the gas heating value to near 400 Btu/ ft^3. For a biomass power plant at the scale of 3 MW, an oxygen-blown system is not a viable option (the oxygen separation system would cost too much). A steam-blown gasifier is likely to cost roughly 50% more than an air-fired gasifier at the 3 MW scale.
- **Heating Method** – Air-blown gasification partially combusts biomass to provide the heat necessary to drive the gasification reactions. Instead of directly burning part of the fuel, indirect heating can be used to increase the gas heating value. Approaches for providing the heat include gasification in a molten metal bath, combustion of a portion of the syngas in immersed fire tubes, and dual CFBs that circulate solids to transfer heat.
- **Pressure** – Gasification systems can either be near atmospheric pressure or pressurized. Pressurized systems are preferred for applications that require syngas to be compressed (such as Fischer-Tropsch synthesis or gas turbines). However, pressurization complicates material feed and other aspects of the design.

2.3.4 Syngas Conversion Options

The primary advantage of gasification over combustion is the versatility of the gasification product. Gasification expands the use of solid fuels to include practically all of the uses of natural gas and petroleum. Beyond the higher efficiency power generation available through advanced processes, the gaseous product (specifically CO and hydrogen - H_2) can be used for chemical synthesis of methanol, ammonia, ethanol, and other chemicals. Gasification is also better suited than combustion for providing precise process heat control (e.g., for drying or glass making).

The various syngas conversion options include the following:

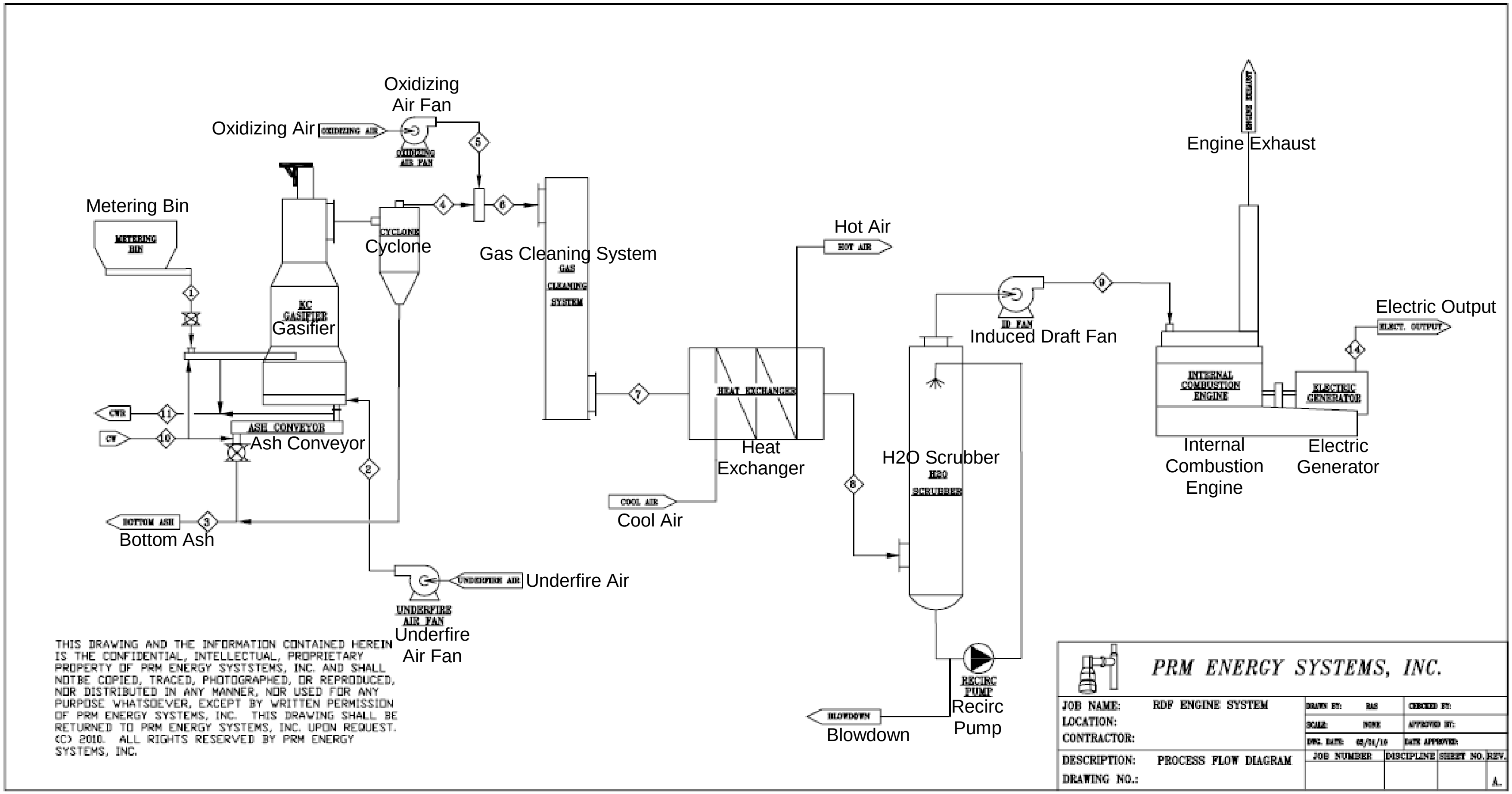
- **Close-Coupled Boilers** – Syngas from gasifiers has traditionally been fired in close-coupled boilers for power generation via a standard steam power cycle. Syngas is combusted in a traditional oil or natural gas boiler to generate steam, which then drives a turbine to produce power. While this is the most conventional method of generating power, it is also one of the least efficient (comparable to direct combustion processes at 20 to 25 percent). A potential advantage of this approach is the removal of ash material prior to the combustion stage. The syngas can also be co-fired in existing fossil fuel boilers with little modification of the boiler required.
- **Internal Combustion Engines and Combustion Turbines** – Gasifier syngas can also be fired in a reciprocating internal combustion (IC) engine or a combustion turbine. Use of syngas in IC engines has been demonstrated, particularly for smaller system sizes. Derivatives of jet engine technology, combustion turbines are more suited for larger

sizes and are the centerpiece of biomass integrated gasification combined cycle (BIGCC) power plants.

2.3.5 Syngas Cycle Diagram

Figure 2-4 below provides a typical cycle diagram for a syngas generator supplying fuel to an internal combustion engine. This figure communicates the significant equipment necessary to clean, cool and scrub the syngas prior to being admitted into the reciprocating engine or combustion turbine.

Figure 2-4 Syngas to Reciprocating Engine Cycle Diagram



2.4 COMBUSTION GAS GENERATORS AND ORGANIC RANKINE CYCLE

The Organic Rankine Cycle (ORC) is a thermodynamic process where heat is transferred to a fluid at a constant pressure. The fluid is vaporized and then expanded in a vapor turbine that drives a generator, producing electricity similar to how water is turned to steam and used in the same way for a traditional steam cycle. The ORC is named for its use of an organic, high molecular mass fluid with a liquid-vapor phase change, or boiling point, occurring at a lower temperature than the water-steam phase change. The fluid allows Rankine cycle heat recovery from lower temperature sources such as biomass combustion, industrial waste heat, geothermal heat, solar ponds etc. The low-temperature heat is converted into useful work that can itself be converted into electricity.

The heat supplied to drive an ORC system is transferred from the biomass combustor through a closed, oil loop system with a heat exchanger in the exhaust gas stream to extract the heat. Another heat exchanger is provided as an integral part of the ORC system and used to release the heat into the ORC's pre-heater and evaporator, shown as items 7 and 8 in the cycle diagram below in Figure 2-5. This figure shows the oil loop as the bright pink circuit.

Figure 2-6 depicts a typical ORC skid's mounted components and Figure 2-7 provides a more complete representation of all equipment necessary for this cycle including the heat sources, the combustor, the closed loop oil system to transfer the heat to the ORC and the need for a cooling cycle.

Figure 2-5 ORC Cycle Diagram

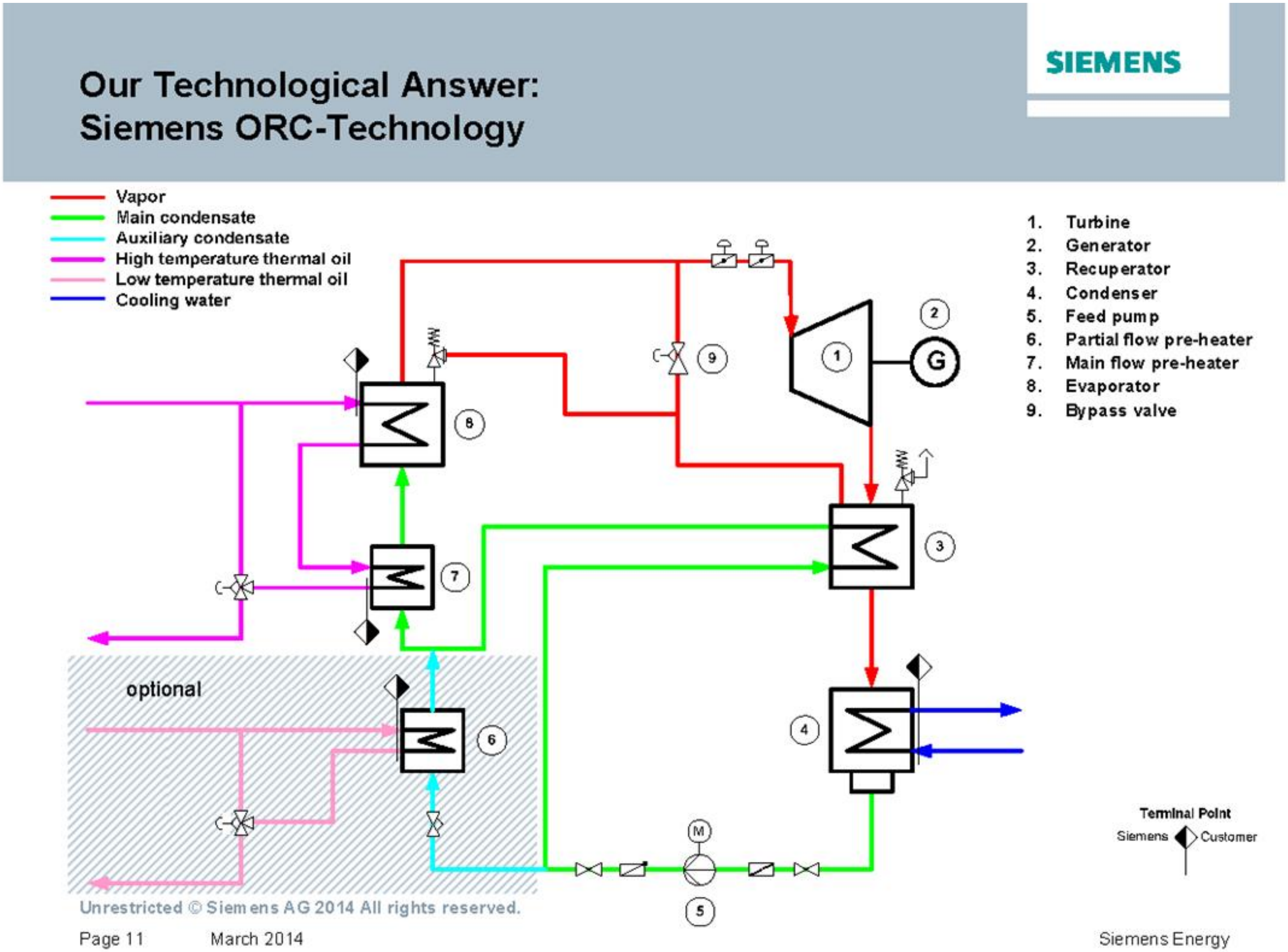


Figure 2-6 Typical Easily Modularized ORC Equipment

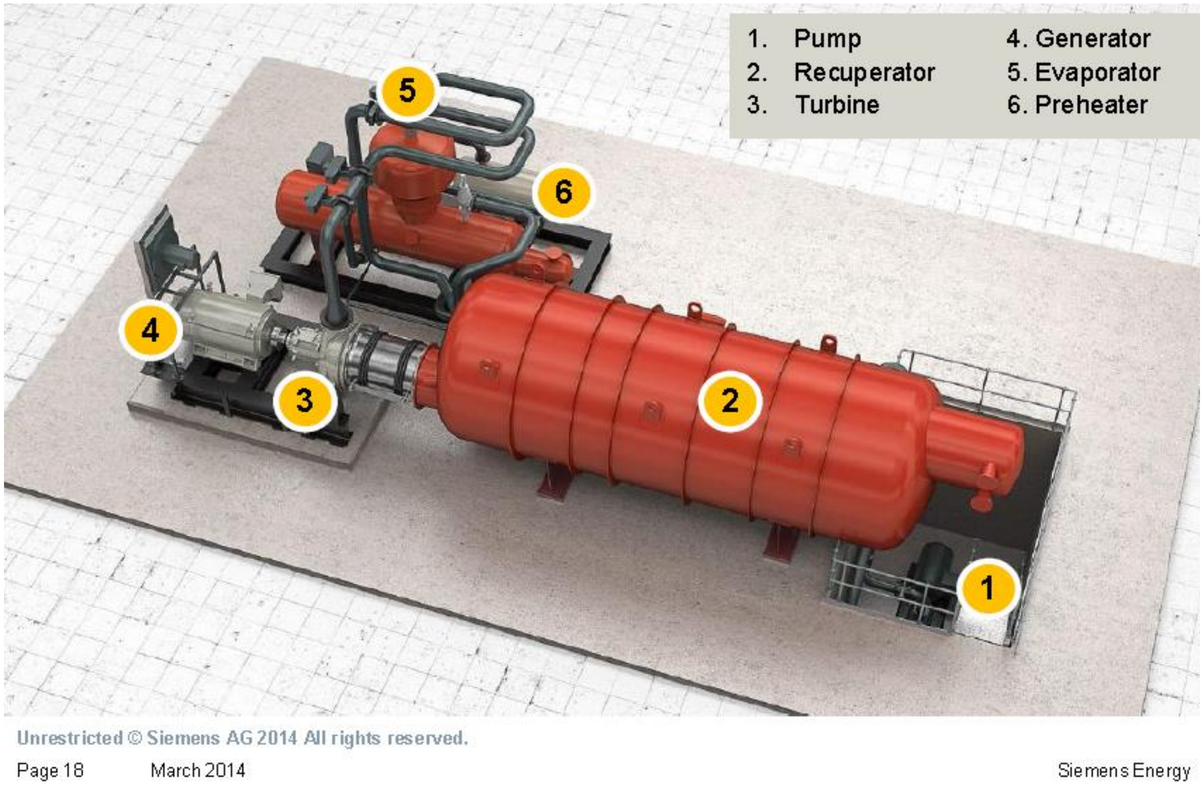
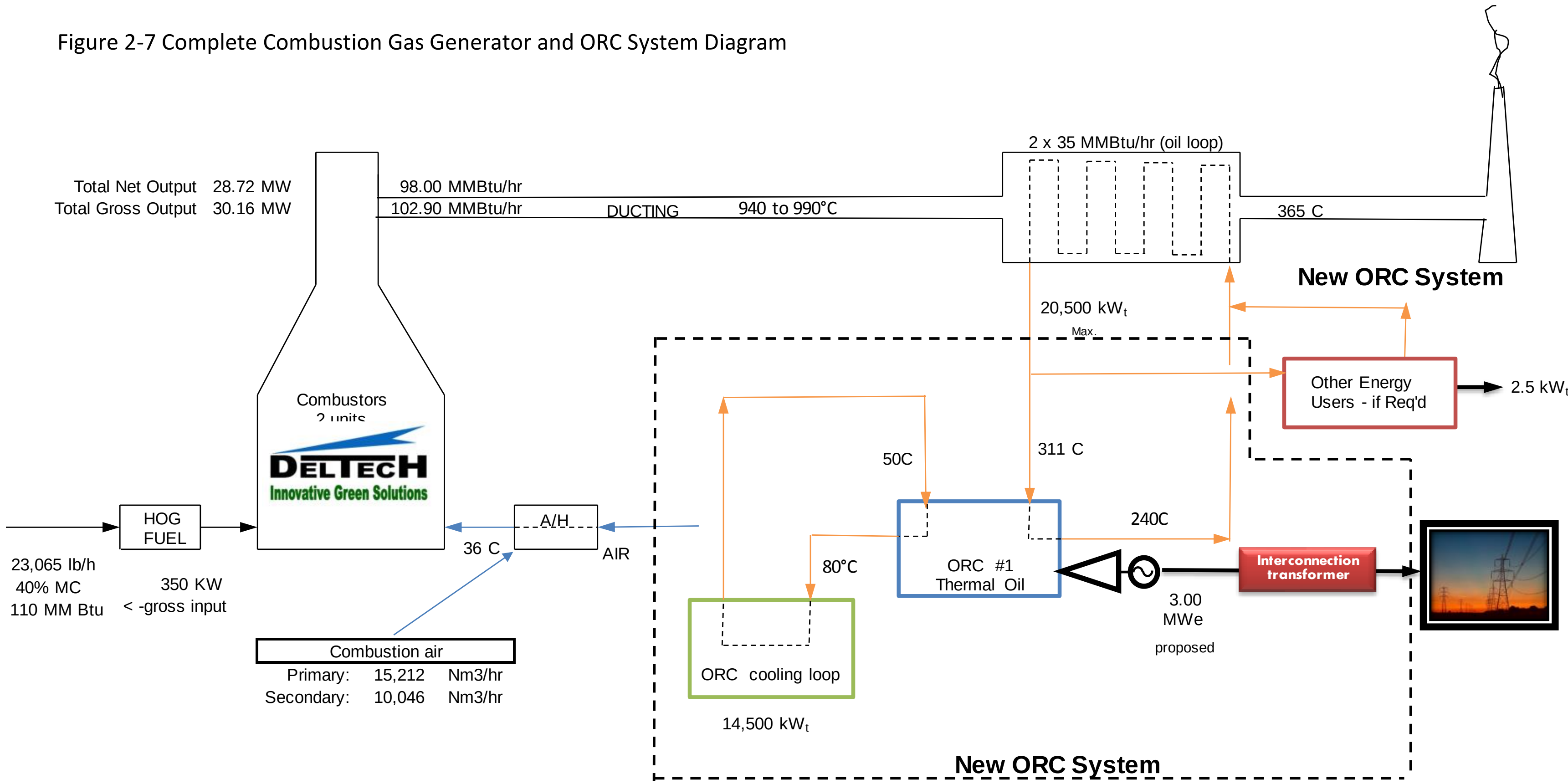


Figure 2-7 Complete Combustion Gas Generator and ORC System Diagram



3.0 Listing of Permits Potentially Required (Portion of Task 2)

The presence of a permit on this list does NOT necessarily mean it is required but rather that it must be evaluated for its applicability. This evaluation will be performed in the next phase of the project development work.

Table 3-1 Permits Potentially Required

AGENCY	PERMIT	REGULATORY CITATION	REGULATORY ACTIVITY	REQUIRED PROJECT PHASE	EXPECTED AGENCY REVIEW TIME	COMMENTS/ISSUES
FEDERAL						
COE	Section 10 Permit	33 CFR 330	Required for work in navigable waters of the US.	Construction	3 - 4 months, NWP 6 - 18 months, IP	May be triggered by project and associated project facilities, such as utility lines or roadways crossing navigable waters.
COE	Section 404 Permit	33 CFR 330	Discharge of dredge or fill material into US waters, including jurisdictional wetlands.	Construction	3 - 4 months, NWP 6 - 18 months, IP	Required if wetlands will be filled on site or along utility right-of-way.
EPA	SPCC Plan	40 CFR Part 112	Onsite oil storage with combined capacity of >1,320 gallons and the potential to discharge to a navigable water.	Construction / Operation	N/A	Required for oil storage. Consider all oil products - fuel oil, transformer oil, equipment lube oils, waste oils, etc., for entire site, during both construction and operational phases. Prepare and implement plan prior to bringing oil on site.
FAA	Notice of Proposed Construction or Alteration	14 CFR 77	Construction of an object which has the potential to affect navigable airspace (height in excess of 200' or within 20,000' of an airport).	Construction	3 - 4 months	FAA may require lighting or marking of stack or temporary construction cranes.

AGENCY	PERMIT	REGULATORY CITATION	REGULATORY ACTIVITY	REQUIRED PROJECT PHASE	EXPECTED AGENCY REVIEW TIME	COMMENTS/ISSUES
USFWS	Endangered Species Act Compliance - Section 7 Consultation	50 CFR 17	Confirmation of no impacts to threatened and endangered species.	Construction	2 - 3 months	Consultation may be required if species and/or habitat on site or within off-site utility interconnection right-of-way may be impacted. Required for compliance with NEPA, CEQA, and NPDES Permits.
USFS (or other applicable federal land agency)	Right of Way Easement / Lease		Approval to use federal lands.	Construction / Operation	9 - 12 months	Right of way approval will be required before a Special Use Permit can be authorized. ROW/Easement subject to NEPA.
USFS (or other applicable federal land agency)	Construction / Use Permit		Approval to construct within an easement / lease	Construction/ Operation	6 - 9 months	
LEAD AGENCY	NEPA		Major federal action affecting the environment.	Construction	10 - 12 months for EA 12 - 48 months for EIS	Federal actions include issuance of a federal permit, activities on federal lands, and federal funding.
CEQA Review	Determinations may include the following: Notice of Exemption; Negative Declaration; DEIR/FEIR		Land use and development in the state of California.	Construction	6 - 18 months	Significant impacts require EIR preparation and review process. (Note: if CEC review is triggered, then the facility will not undergo separate CEQA review.)

AGENCY	PERMIT	REGULATORY CITATION	REGULATORY ACTIVITY	REQUIRED PROJECT PHASE	EXPECTED AGENCY REVIEW TIME	COMMENTS/ISSUES
CALIFORNIA						
FRAQCMD	PSD / Authority to Construct Permit - major/minor sources of air emissions.	New Source Review Construction Permit	Installation, modification, and/or construction of emissions sources.	Construction	12 - 18 months	Yuba County is in attainment with all Federal-level National Ambient Air Quality Standards (NAAQS), but is nonattainment with regard to state-level California Ambient Air Quality Standards (CAAQS) for ozone (both 1 and 8-hour) and PM10. Depending on project location, may require 12 months of pre-construction monitoring.
FRAQCMD	Permit to Operate		Operation of emissions source.	Operation	6 - 9 months	
CVRWQCB	Section 401 Water Quality Certification		Required for federal activities affecting state waters.	Construction	4 - 6 months	Required if COE Section 404 Permit is required.
CVRWQCB	NPDES General Permit for Storm Water (Construct'n) / SWP3		Discharge of storm water runoff from construction sites disturbing 1 or more acres.	Construction	2 months	Project may qualify for coverage under state General Permit.
CVRWQCB	NPDES Permit for Wastewater / Stormwater Discharge / SWP3		Discharge of process wastewater to surface water of the US.	Operation	6 months	
CVRWQCB	Groundwater Protection Permit		Discharge of process wastewater to lagoon.	Operation	6 - 9 months	

AGENCY	PERMIT	REGULATORY CITATION	REGULATORY ACTIVITY	REQUIRED PROJECT PHASE	EXPECTED AGENCY REVIEW TIME	COMMENTS/ISSUES
CVRWQCB	Water Rights		Conservation and of water resources of the State while protecting vested rights, water quality and the environment.	Operation	9 - 12 months	May be required for consumptive water use related to thermal component of project.
CDRRR	Solid Waste Permit		Biomass Ash Disposal	Operation	6 - 12 months	Ash will likely be returned to the forest once it is tested
CDFG	Biological Opinion and Consultation		Confirmation of no impacts to threatened and endangered species.	Construction	3 - 4 months	Required for compliance with CEQA. May require surveys.
CHPO	Section 106 Historical and Cultural Resources Review		Inventory of site for presence of historically and culturally significant features.	Construction	3 - 4 months	Required for compliance with CEQA. May require surveys.
CalTrans	Transportation Permit		Use of federal/state highways for oversize / overweight loads.	Construction	1 - 2 weeks	
CalTrans	Right-of-Way Encroachment Permits		Construction in or along state controlled roadways.	Construction	4 - 6 months	
CalTrans	Access Permit		Driveway access to site from federal or state highways.	Construction	4 - 6 months	
CAL/OSHA	Various non-environmental permits		Employee and construction worker safety, operating safety			
TYPICAL LOCAL						
Planning Department	Site Plan Approval		Site development.	Construction	6 - 12 months	

AGENCY	PERMIT	REGULATORY CITATION	REGULATORY ACTIVITY	REQUIRED PROJECT PHASE	EXPECTED AGENCY REVIEW TIME	COMMENTS/ISSUES
Zoning Department	Land Use Review, Special Use Permit, Variances		Establishment of solar facility as a permitted use.	Construction	9 - 12 months	
Building Department	Building Permits		Construction of facility.	Construction	1 month	Review of construction drawings and inspections.
Building Department	Certificate of Occupancy		Facility operation.	Operation	1 month	
Transportation Department	Oversize Load Permit		Use of County roads for oversize loads.	Construction	1 month	
Transportation Department	Driveway Construction Permit		Access from county roads / maintenance roads.	Construction	2 - 3 months	
Utilities Department	Sewer / Water Hookup		Connection to sewer / water mains.		2 - 3 months	
Health Department	Septic System / Water Well Installation		Construction of septic system or water well.		2 -3 months	
Fire Marshal	Fire Safety Approval		Installation of fire protection system, inspection during construction.	Construction	2 months	

ABBREVIATIONS:

CAL/OSHA - California Occupational Safety and Health Administration

CalTrans -- California Department of Transportation

CDFG -- California Department of Fish and Game

CDRRR - California Department of Resource, Recycling, and Recovery

CEC -- California Energy Commission

CEQA -- California Environmental Quality Act

CHPO -- California Historic Preservation Office

COE- - US Army Corps of Engineers

CVRWQCB - Central Valley Regional Water Quality Control Board

DEIR / FEIR -- Draft Environmental Impact Report / Final Environmental Impact Report

EPA -- Environmental Protection Agency

FAA -- Federal Aviation Administration

FRAQMD - Feather River Air Quality Management District

IP - Individual Permit

NEPA -- National Environmental Policy Act

NPDES -- National Pollutant Discharge Elimination System

NWP -- Nationwide Permit

PSD -- Prevention of Significant Deterioration

ROW - Right of Way

SPCC -- Spill Prevention, Control, and Countermeasures

SWP3 -- Storm Water Pollution Prevention Plan

USFS -- US Forest Service

USFWS -- US Fish and Wildlife Service

4.0 Vendors Considered (Task 3 modified)

This section identifies the vendors contacted for combustion, syngas and hot combustion gas technology (thermal oil loop). A summary of the technology type, system capacities, and commercial status is also provided.

All vendors contacted were made aware of the elevation, annual average temperatures, and the extreme temperatures. These factors were considered by the vendors as they prepared their budgetary proposals and performance. The reciprocating engine vendors confirmed that they have slightly de-rated their equipment because of the elevation.

4.1 BOILER VENDERS CONTACTED FOR DIRECT COMBUSTION TECHNOLOGIES

Direct combustion technologies are offered by a large number of vendors, but only a few of these vendors offer units in the size range under 5 megawatts. A summary of the technologies offered, the maximum potential for electrical generation, and the commercial status of these vendors is presented in Table 4-1. All of the vendors listed have extensive experience supplying commercial combustion systems and each of the vendors has designed and installed more than 50 units.

Table 4-1 Direct Biomass Combustion Boiler Vendors

VENDOR	TECHNOLOGIES OFFERED	POTENTIAL ELECTRICAL GENERATION (MW)	COMMERCIAL STATUS	BUDGETARY PROPOSAL[2] [3]
Chiptec http://www.chiptec.com/	Stoker Gasifier	Modules of 3 MW Each	Commercial	$8,407,000
FSE Energy http://fseenergy.com/	Stoker	100+	Commercial	Too Small-Declined
Hurst (offered by Brad Thompson Co.) http://www.hurstboiler.com/	Stoker	30	Commercial	$7,517,000
McBurney http://mcburney.com/	Stoker	45	Commercial	Did not provide a proposal
Outotec http://www.outotec.com/en/Products--services/Energy/Fluidized-bed-energy-systems/Biomass/	Bubbling Fluidized Bed	40	Commercial	Confidential & not the lowest cost so not used in analysis
Wellons http://wellons.com	Stoker and Thermal Oil for ORC	~ 20 MW	Commercial	Proposal for ORC application

All of the vendors listed above have been in business many years and have established themselves as reputable, reliable suppliers. There are only a few boiler manufacturers that offer biomass units in the size range needed for this project. It should be noted that biomass power facilities are often limited in size because of fuel supply constraints and rarely exceed 100 MW of generation capacity.

These vendor candidates are all suppliers that participate in the niche market of under 20 MW where many other vendors are not competitive. Several of these vendors also offer significantly larger equipment. They offer these smaller units in many cases, because they began their business offering more modest sizes and learned how to provide such units cost effectively. Many of the larger manufacturers with more familiar names are not competitive in the smaller boiler ranges.

[2] Because these are non-binding budgetary proposals, the scope of work for all vendors were not identical. For purposes of comparison, some cost elements from vendor A (i.e. shipping or installation) that were not provided by vendor B, were utilized to build up vendor B's total cost estimate.
[3] All pricing was corrected as necessary to reflect the use of an ESP and SNCR.

- **Chiptec Wood Energy Systems** offers systems up to 3 MW but will provide multiple systems to achieve the required output greater than 3 MW. As a result, they have many units in service in this size range and as a result have fully developed their engineering and manufacturing. For this project, Chiptec could be an attractive application because of the size of Chiptec's standard offering. Their technology utilizes a traditional gasifier directly coupled to a packaged combustion boiler. Chiptec is the only vendor contacted that offers boilers exclusively fired by solid fuels (primarily woody biomass).

Figure 4-1 Chiptec's Gasifier Close Coupled to Package Boiler

- **FSE Energy** originally began their business by supplying boilers primarily to the forest products industry (sawmills) but in the last ten years have expanded their business dramatically offering much larger units and now beginning to offer gasifiers. They offer units regularly to 100 MW. They declined to provide a proposal stating that the project was too small for them to offer a competitive product.

- **Hurst Boiler and Welding Co.** offers units smaller than Outotec, McBurney and FSE Energy, but larger than Chiptec. Hurst's offers boilers in a smaller ranger of sizes, but not offering so many models allows them to lower their costs. In this case, Hurst chose to offer their boiler through Brad Thompson Co. rather than directly to the project as a standalone boiler.

- **McBurney** has been providing boilers for over 100 years and like Hurst, limits the size of boilers offered to reduce the number of options to help keep their costs competitive. A proposal was not received from McBurney in time to be included in the report.

Figure 4-2 FSE Energy Traditional Stoker Boiler

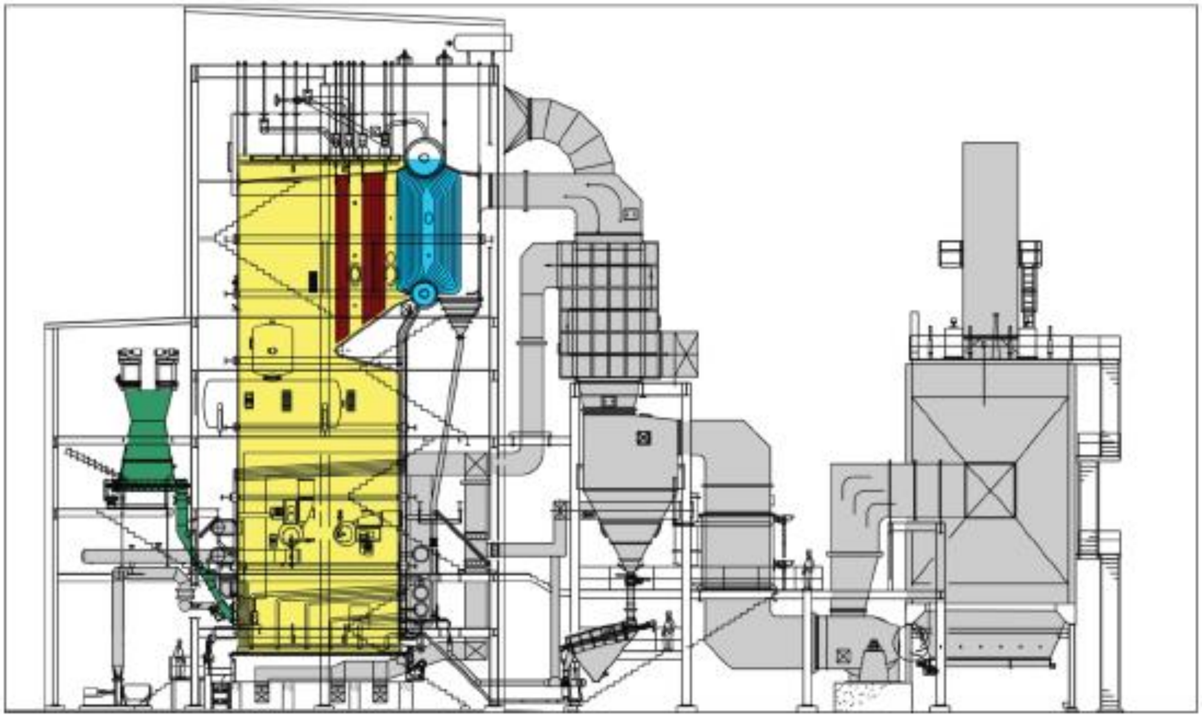


Figure 4-3 Typical Side Elevation of a McBurney Boiler

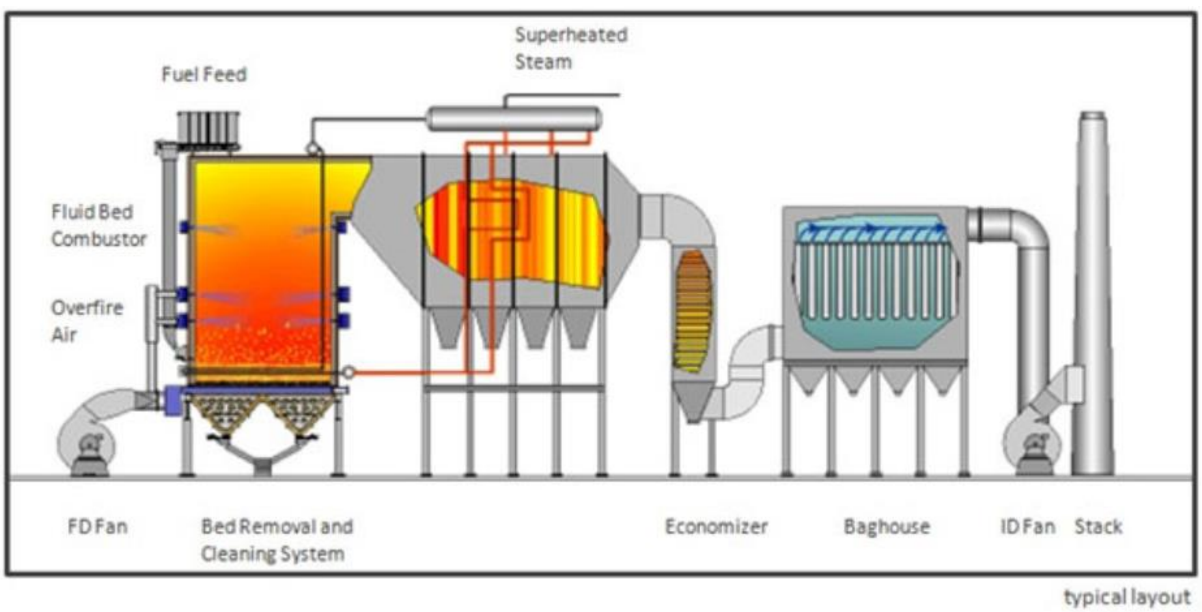


Figure 4-4 Outotec Gasifier

Outotec purchased Energy Products of Idaho (EPI) in 2011. While Outotec offers many products other than energy related products, EPI has a long history within the power sector and is well known within the industry. EPI (now Outotec) has designed and installed numerous biomass fluidized bed combustion units. Outotec offers the greatest flexibility of boilers with both gasification and traditional boilers allowing them to customize their product to the needs of the application.

Figure 4-5 Model of a Fully Assembled Outotec Boiler

Wellons has been incorporated for over 50 years and has 370 biomass units in the field. Like FSE Energy, Wellons began their business supporting sawmills and over time have expanded their offerings well beyond that industry. They are one of the leading vendors offering thermal oil system for many applications including the ORC applications. Wellons did not offer a proposal for a standalone boiler (steam option) but rather offered a proposal for the ORC option. Wellons has the distinction of offering a package boiler, meaning that it arrives in only a few large pieces, making field erection times very short.

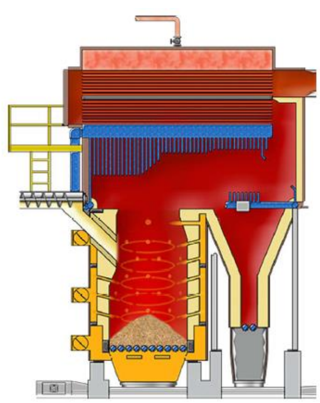


Figure 4-6 Wellons Biomass Package Boiler

4.2 STEAM TURBINE GENERATOR VENDORS CONTACTED

The number of viable steam turbine generator vendors in the market place is considerably fewer than the number of vendors for other equipment supplied. As a result, a high percentage of those contacted offered a proposal. Table 4-2 provides a summary of the steam turbine generator vendor responses.

Table 4-2 Steam Turbine Generator Vendors
(price adjusted for shipping, installation & auxiliaries)

VENDOR	COMMERCIAL STATUS	BUDGETARY PROPOSAL
Air Clean Energy (offered by both Chiptec and Brad Thompson Co) http://www.aircleantech.com/	Commercial	$2,165,000
Dresser-Rand http://www.dresser-rand.com/	Commercial	$2,350,000
Elliott http://www.elliott-turbo.com/	Commercial	$1,744,000
Fincantieri https://www.fincantieri.it/cms/data/pages/000113.aspx	Commercial	Too small a unit for them to be competitive
General Electric	Commercial	Too small - declined
Siemens http://www.energy.siemens.com/hq/en/renewable-energy/biomass-power/steam-turbines-for-biomass-plants.htm	Commercial	$1,815,000

As with the boiler vendors, some potential vendors either don't offer units in this size range or they are not competitive in this size range, so they are unable to offer a proposal. Of the handpicked suppliers listed above in Table 4-2, the number of viable steam turbine generator vendors is considerably few than the number of vendors for other equipment supplied. As a result, a high percentage of those contacted offered a proposal. Table 4-2 provides a summary of the steam turbine generator vendor responses. Only General Electric and Fincantieri declined to offer a proposal.

- **Air Clean Energy** specializes in turbines less than 10 MW. Depending on the application, they utilize turbines from Siemens, Dresser-Rand or Elliott while utilizing their engineering and fabrication capabilities to provide a full package at economic prices.
- **Dresser Rand, Elliott and Siemens** are all well-known long time manufacturers of steam turbine generators of all sizes.
- **Fincantieri** is not as well known by the power industry because their primary products are used for ship propulsion. Ten or 15 years ago they began configuring their well tested equipment for power generation and have been active in the US market. Because ship propulsion steam turbines are typically smaller than large utility power generation steam turbines, they have significant experience in the more modest sizes for power generation and therefore are a formidable competitor. But in this case, they reported that the unit is too small for them to be competitive.

Elliott's pricing was utilized for purposes of the financial modelling.

4.3 SYNGAS TECHNOLOGIES VENDERS

Currently, there are several suppliers of commercial gasification equipment for syngas production, as well as numerous emerging vendors of advanced technologies. In general, commercial systems are fixed and fluidized bed gasification systems that provide low-Btu syngas, which is best suited for combustion in close-coupled boilers. Other processes produce medium-Btu syngas, which would be more appropriate for combustion in gas fired turbines or chemical synthesis. However, these advanced gasification technologies are only now becoming commercially available for power applications and are suitable only for projects with very specific needs for syngas.

Selecting commercially viable and well established syngas generator vendors is a difficult task as this market continues to mature. A short list of candidates anticipated to be the most viable was generated with less than satisfactory results.

Table 4-3 Syngas Vendors
(price adjusted for shipping, installation & auxiliaries)

VENDOR	COMMERCIAL STATUS	BUDGETARY PROPOSAL	COMMENTS
Outotec[4]	Commercial	Only provided a bid for steam option	
PRM Energy	Commercial	$23,010,000 including Caterpillar reciprocating engine	Requires fuel moisture <20% and maximum fuel particle size of 0.4" (10 mm)
Repotec	Commercial	Declined to provide proposal	Not familiar with US codes
Sierra Energy	Not Commercial until 2016	$21,358,000 including reciprocating engine	Not yet commercial.

Only two budgetary proposals have been received, one from Sierra Energy and one from PRM Energy. These proposals allow an economic comparison of this technology with other equipment configurations. However, given the technical restrictions or risks associated with these two vendors reported in Table 4-3 above (see notations in the Comments column), neither of these vendor options are very attractive.

- **Outotec** was already discussed in Paragraph 4.1 because this vendor offers both direct combustion and syngas options.
- **PRM Energy** built several rice straw gasifiers in the 1990's and were recommended by Caterpillar. They have very limiting fuel requirements of less than 20% moisture and sizing less than 0.4" (10 mm), either of which will have a cost impact on the project if this vendor were used in the project.

[4] Also reported in

Table 4-1 Direct Biomass Combustion Boiler Vendors

- **Repotec** offers a good advanced technology for medium Btu applications. They declined to respond, stating that they are unfamiliar US codes.
- **Sierra Energy** is not really an original equipment manufacturer as usually defined because they utilize a gasifier technology from India rather than a technology they developed themselves. They will not have their first commercial unit in operation until 2016.

4.4 RECIPROCATING ENGINE VENDORS

Table 4-4 Reciprocating Engine Vendors
(price adjusted for shipping, installation & auxiliaries)

VENDOR	COMMERCIAL STATUS	BUDGETARY PROPOSAL	COMMENTS
Caterpillar	Commercial	$4.1 million	3 x 1,000 kW, Model G3516C
Cummins	Commercial	Declined to offer proposal	Must have syngas with at least 400 Btu/scf
Jenbacher (owned by GE)	Commercial	$5.4 million	3 x 1,000 kW, Model GE JMS 612
Waukesha	Commercial	Declined to offer proposal	

All of the reciprocating engine manufacturers are reputable entities with a long history of producing quality products. Since utilizing syngas as a fuel is not as common as other fuels, it is a matter of identifying the vendor that has an engine suited for this service at the best price and lowest maintenance cost. Because there are several methods of generating syngas, the energy content (Btu/standard cubic foot) of the resulting syngas can vary considerably. These reciprocating engine vendors have differing requirements and therefore, may or may not be suitable for the application, depending on the syngas characteristics from the chosen supplier.

4.5 ORC TECHNOLOGY VENDORS

Table 4-5 Hot Combustion Gas Generators
(Price adjusted for shipping, installation & auxiliaries)

VENDOR	COMMERCIAL STATUS	BUDGETARY PROPOSAL	COMMENTS
Deltech	Commercial	$14.2 million	Greater scope was included by Deltech. This difference was equalized when entire plant cost was estimated
Wellons	Commercial	$8.9 million	

These hot combustion gas generators also serve the market for steam turbine generator applications. Wellons was considered for the steam option but chose to provide a budgetary proposal for the thermal oil loop and ORC option instead. Wellons is discussed more fully in Par 4.1. Wellons has a long history of thermal oil loops installations.

Deltech is a Canadian boiler manufacturer that has teamed with the ORC industry for many years and has many installations for that technology.

Table 4-6 ORC Vendors
(Price adjusted for shipping, installation & auxiliaries)

VENDOR	COMMERCIAL STATUS	BUDGETARY PROPOSAL	COMMENTS[5]
Ormat	Commercial	$6.55 million	19.4% - 21.3% Gross Electric Efficiency
Turboden	Commercial	$3.6 million	21.3% Gross Electric Efficiency

Both of these vendors have many units in the field with a long successful history of operation. Ormat is especially active in the geothermal industry where the heat source can often be a low temperature source. Black & Veatch understands that Ormat has not paired their equipment with a biomass fueled combustion gas generator. But the source of heat is not important for the technology to operate properly.

Turboden (a group company of Mitsubishi Heavy Industries, Ltd.) has over 100 ORC systems in operation around the world utilizing heat from a biomass fueled hot combustion gas generator. Since beginning to pursue the North America market, they have begun to establish themselves in North America with the following projects:

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[5] Efficiency includes performance of thermal loop of 97%. Turboden's efficiency was adjusted from published values because Turboden uses lower heating value whereas, in the US higher heating value is the standard for biomass estimated efficiency. The difference between higher and lower heating value is generally about 10%. Turboden published value of 24.4% efficiency adjusted by x 0.9 lower to higher heating value x 0.97 for oil loop performance.

- Nechako Lumber Co. Ltd in Vanderhoof, BC Canada has been operating since February 2013
- West Fraser Mills Ltd. in Fraser Lake, BC, Canada is a 2 x 6.5 MW facility that has been operating since November 2014
- West Fraser Mills Ltd. Has a second facility located in Chetwynd, BC Canada that is starting up in the second quarter of 2015.

5.0 Budgetary Proposals & Cost Estimates (Task 6 modified)

5.1 BUDGETARY PROPOSALS

Budgetary proposals were solicited from all vendors listed earlier in this report, each for their technology and equipment offered. Some of these vendors offered proposals for 1) only a boiler, syngas generator, or hot combustion gas generator, 2) only the prime mover for the technology in question (steam turbine generator, reciprocating engine, or ORC package) or, 3) equipment for both options 1) and 2). Brad Thompson Co. offered a full EPC budgetary estimate for the boiler and steam turbine generator option. Black & Veatch paired these proposals by technology to begin building a full technology, cost estimate. While this process was not a comprehensive cost estimating effort, Black & Veatch adjusted the balance of plant (BOP) and installation cost estimates to account for differences in the scope of work supplied by the various vendors or differences in technology requirements (i. e. only the steam option requires a large cooling tower).

No individual proposals were received for the syngas generator, but proposals for both the syngas generator and the reciprocating engine was received from both PRM Energy and Sierra Energy. While the proposals from these vendors can be utilized for cost comparisons to other technologies, these vendors have restrictions or special considerations that don't allow them to be very highly suitable to provide equipment at this point in time. This is discussed more completely above in Table 4-3 Syngas Vendors.

No single vendor offered a package of equipment for the ORC option. The cost estimates for the ORC option were developed by using budget proposals from Deltech and Wellons for hot gas generators and from Ormat and Turboden for the prime mover ORC equipment.

At the point in time that CCP solicits firm bids from various vendors, CCP will find that most vendors will as a matter of routine, provide performance guarantees for the individual components provided by the vendor. Black & Veatch is of the opinion that all vendor proposals would guarantee the performance quoted.

The pricing provided by the vendors, include ESP, SCR, and/or SNCR as appropriate to allow the equipment to meet California air emission requirements.

All of the combinations utilized for cost estimates are summarized in Table 5-2 Vendor Groupings and Costing per Annum. Please refer to the Appendices for copies of the budgetary proposals from all vendors.

5.2 EPC CAPITAL COST

5.2.1 Direct Costs

Black & Veatch's capital cost estimate for the 3.3 megawatt gross biomass project, with different combinations of vendors for each of the three technologies is provided in Table 5-2. The cost estimate assumes the work will be performed under an engineering, procurement, and construction (EPC) contract and, therefore, includes a typical EPC margin of 6 percent of the total capital cost. The total capital cost shown also includes a contingency of approximately 5 percent of the total capital requirement for the biomass power project. Rolling stock (front end loader, maintenance trucks) is not included in the estimate because every operator/owner has a different opinion of what is needed. But truck dumper and conveyors are included in the cost estimate.

5.2.2 Indirect Costs

The EPC cost estimate also includes indirect costs typically included in the EPC cost estimate. All indirect costs used for the cost estimate are summarized in Table 5-1 below.

Table 5-1 Indirect Costs Utilized in the Cost Estimates

INDIRECT COST ITEM	% OF EPC COST (DIRECT & INDIRECT)
Engineering Costs (With G&A)	10.00%
Field Engineering (covered by EPC contractor)	0.00%
Construction Management (covered by EPC contractor)	0.00%
Construction Management-Start-up (covered by EPC contractor)	0.00%
Startup Spare Parts	0.24%
Project Insurance (General Liability)	1.00%
Project Contingency	5.00%
EPC Margin	8.00%
Subtotal - Indirect	**22.2%**

The $18.5 million estimate provided by Brad Thompson Company for a full EPC scope of work for the steam option, was used to develop a balance of plant cost since the boiler and steam turbine costs were provided by the associated vendors. This balance of plant costs was applied to each of the other technologies after being adjusted for differences in the scope requirements of the balance of plant equipment for their respective technologies. The capital cost of the equipment received from the vendors was added to this adjusted BOP cost, along with shipping and installation costs for the major pieces of equipment.

Table 5-2 provides a summary of the capital cost for each of the technologies and vendor pairings. From this table it can be determined that the steam option has the lowest capital cost followed by ORC and then syngas. This is more evident in Table 6-2 and Table 6-3 where the revenue required is identified. But the capital cost does not take into account the operating efficiencies (heat rate) or maintenance costs, which are both covered later in the report first in Table 5-3 followed by more complete information in Table 6-2 and Table 6-3.

5.3 DIRECT & INDIRECT EPC CAPITAL COSTS BY VENDOR

Table 5-2 Vendor Groupings and Costing per Annum

PACKAGER	BOILER SYNGAS HOT GAS VENDOR	PRIME MOVER VENDOR	BOILER SYNGAS HOT GAS COST	PRIME MOVER COST	BALANCE OF PLANT	EPC INDIRECT COSTS[6]	TOTAL EPC CAPEX DIRECT & INDIRECT	EPC COST $/GROSS KW
Steam								
Brad Thompson Co.	Hurst	Air Clean	$7,517,000	$1,744,000 Elliott Used	$5,850,000	3,355,000	$18,466,000	$5,596
Brad Thompson Co.	Hurst	Air Clean	Estimated full EPC cost using Air Clean				$18,467,000	$5,596
Chiptec	Chiptec	Air Clean	$8,407,000	$1,744,000 Elliott Used	$4,350,000	$3,219,000	$17,721,000	$5,370
Syngas Generation								
None	PRM Energy	Caterpillar	$16,100,000		$2,850,000	$4,207,000	$23,157,000	$7,017
None	Sierra Energy	MWM[7]	$14,700,000		$2,850,000	$3,896,000	$21,446,000	$7,073[8]
ORC								
None	Wellons	Ormat	$8,851,000	$6,553,000	$2,850,000	$4,052,000	$22,305,000	$6,759
None	Wellons	Turboden	$8,851,000	$3,606,000	$2,850,000	$3,398,000	$18,705,000	$5,858
None	Deltech	Turboden	$14,175,000[9]	$3,606,000	$0	$3,947,000	$21,728,000	$6,805

[6] Using 22.2% of EPC direct cost
[7] MWM is based in Germany and owned by Caterpillar
[8] Sierra Energy's proposal had a gross MW of only 3.032 MW rather than 3.3 MW causing the $/MW to be greater than PRM Energy
[9] Deltech's scope of work was more comprehensive than the scope of work offered by Wellons, resulting in a large pricing discrepancy.

5.4 OPERATING AND MAINTENANCES COSTS

A summary of the operating and maintenance staffing levels and budget is provided below in Table 5-3. These costs were used in the economic model to generate the cost of generation. The difference maintenance costs for each of the technologies are provided about midway through this table. Typical maintenance costs were obtained from several vendors to assist with estimating these costs. Other than the maintenance cost, all other operating and maintenance costs were held unchanged for each technology.

Contrary to CCP's understanding about the need for "certified" boiler operators for the Steam option, Leonard Tong, Senior Safety Engineer for northern district for the State of California (510-622-3066) stated there is no state requirement for any operator certification or specific training. The Cal. Code does list all the tasks that an operator must be able to perform and must be able to demonstrate this capability when an inspector comes to the site. But these tasks are no more detailed than what any operator should be able to do to satisfactorily operate a boiler.

Black & Veatch also contacted local Union 39 – IUOE Stationary Engineers (415-285-3939), who stated that an operator must be experienced and/or possess the capability to operate a boiler, but there are no specific classes or certification required to perform this task.

Even if there is a certification or license required, Black & Veatch does not believe this would necessarily command significantly higher wages because such certification would likely be relatively straight forward to obtain.

The cost to raise water from the wells has been set to zero because this cost will be quite small, depending on the depth of the wells and which well is used. Going into these details is beyond the scope of this high level assessment. The difference between a technology that uses water and one that does not would hardly be noticed in the pro forma because the cost to pump the water will very modest.

The O&M staffing of plants using these technologies will be very similar. Black & Veatch does not believe it is recommended or practical to operate this facility with any technology with only one operator on shift. Consider that it requires 8 people to have two operators on each of three shifts plus one shift that is on their days off. The other 5 shown in the O&M budget are needed regardless of the technology (manager, vacation relief, admin. and maintenance). However, an option would be to rely on contractors for all maintenance and repairs. But this will mean there will be a waiting time for the contractor to reach the plant. This becomes an owner decision that is difficult for Black & Veatch to specifically make a recommendation.

Table 5-3 Operating and Maintenance Costs

PLANT	EMPLOYEES & MAINTENANCE	SALARY	PAYROLL	SUBTOTAL	TOTAL
			$000 US DOLLARS PER YR		
Wages	13			630	
Control Room Operator	4	50	200		
Assistant Operator and fuel yard operator	4	45	180		
Plant Manager	1	75	75		
Operations Supervisor and vacation relief	1	55	55		
Admin	1	30	30		
Journeyman mechanic	1	45	45		
Electrician & Instrumentation Tech	1	45	45		
Benefits	30%			189	
Overtime	7%			44	
Safety & Production Bonus	3%			19	
Subtotal - Payroll					**882**
Outside Services/Consultants				8	
Consumables/Chemicals				15	
Diesel Fuel				30	
Repair & Maintenance*				85	
Major Maintenance Reserves*				10	
*Above Maintenance & Maintenance Reserves are for Boiler & Steam Turbine. Totals for other technologies follow:	95				
Syngas and Reciprocating Engines	160				
Hot Combustion Gas Generator and ORC	134.2				
SNCR Urea				50	
Materials & Supplies				**3**	

PLANT		EMPLOYEES & MAINTENANCE	SALARY	PAYROLL	SUBTOTAL	TOTAL
				$000 US DOLLARS PER YR		
Ash/Solid Waste Disposal		5%[10]	$5.00		-	
Water & Sewer					-	
	% of yr.	kWh	$/kWh			
Maintenance Power[11]	10%	90	0.13		10	
	Starts	kWh	$/kWh	Hrs/Start		
Maint. Startup Costs[12] - Demand Charge	18	500	0.19	2.5	4	
Maint. Startup Costs – Energy Payment					1.4	
Interconnection Costs					-	
Permits & License Fees					20	
Office Expenses					15	
Operator Fee					-	
Contingency		5%			13	
Subtotal						**297**

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[10] This refers to a maximum ash production of 5% of fuel flow with no more than a $5 per ton cost to haul away. In reality, most of the time, the ash will be 2% – 3% of fuel flow, primarily dependent on how much dirt and sand is on the wood from harvesting. This cost (which is around $4,000 - $6,000 per year) is excluded because B&V anticipates that one of the fuel suppliers will take the material at no cost since it does enhance the tree growth. Contrary to coal ash, Black & Veatch is not aware of any uses for wood ash except for soil amendment and using the bottom ash for road base. Both of these uses should be quite useful to the fuel suppliers, but probably not of sufficient value to justify charging for the material.

[11] Maintenance Power is the cost of the energy purchased from the utility during an outage ($/kWh). The second value is the Demand Charge ($/peak kW demanded) estimate that will be paid by CCP to assure CCP that there is always adequate power available to start the plant.

Formulas for these cells are shown below.

1-Cap Factor	kW	$/kWh	1=Yes 0=No		
10%	90	=(0.135+0.103)/2	1	**9**	=IF(E28=1,C28*D28*(8760-(B30*E30))*B28,0)/1000
# Starts/yr	kW Peak	$/kW Peak/mon	hrs/start		
18	350	=+(10.85+6.29)/2	2.5	**36**	=C30*D30*12/1000

[12] See above footnote. Maintenance Power costs are incurred anytime the plant is not operating. Startup costs are paid every month all year long and are reset any time the Peak Demand reaches a higher level.

PLANT	EMPLOYEES & MAINTENANCE	SALARY	PAYROLL	SUBTOTAL	TOTAL
Subtotal - Plant					**1,179**
			$000 US DOLLARS PER YR		
Administrative					
Insurance				35	
Property Taxes				-	
Land Lease				18	
Legal & Professional				5	
Accounting, Payroll, HR & Audit				8	
Partnership Managem'nt Fee & Development Royalty				-	
Subtotal, Administrative					**66**
Total Estimated Operating Costs (Steam)					**1,245**

5.5 COSTS OFTEN OVERLOOKED BY STUDIES

5.5.1 Owner Costs

Studies similar to this analysis rarely include owner costs for the project. Typically, the reported cost of the project includes only costs associated with an EPC contract (direct and indirect). But there are other costs that will be incurred by the owner to complete the project and these costs should be included in the economic analysis before making a decision about whether the project is economically feasible. Paragraph 6.2 and Table 6-3 provide the estimated revenue required for the project both with and without owner costs included. This provides a reference of the approximate magnitude of the owner costs and the effect this has on the required revenue. Typical owner costs for a project like the CCP project are provided in Table 5-4 Typical Owner Costs below.

Table 5-4 Typical Owner Costs

TYPICAL OWNER COSTS USED IN ECONOMIC ANALYSIS	$ TOTAL
Interest During Construction (ITC), Depends on Capex for each technology – Range	$333,000 - $431,000
Legal	$125,000
Lenders Engineer	$75,000
Permitting (greatly dependent on whether an EIA is required)	$600,000

5.5.2 Return on Equity

The return required by the investors that provide the equity portion of the capital funds is called the return on equity. The magnitude of the return required in any specific instance is affected by several risk factors that include the following:

- Whether there is a power purchase agreement (PPA) or a partial PPA
- The term of the various contracts
- The financial strength of the counterparties or other stakeholders
- Whether the technology is mainstream or emerging
- The leverage used (debt to equity ratio)

Adjusting this return on equity value by one percentage point (i. e. from 10% after tax to 11%) changes the required revenue by 1.7%. This particular financial model input is often not well highlighted in reports even though it is very important to the economics of the project. For this study, 10% after tax return has been utilized as the required benefit equity will likely demand.

5.5.3 Maintenance Power & Maintenance Startup Power

One operating cost that is often overlooked but in some cases can be quite significant, is the cost of startup power that typically includes a sizable demand charge, and maintenance power to maintain the plant during periods when the plant is not generating its own power because of maintenance work or a forced outage. This power is typically purchased from the local utility and in this case is estimated to be approximately $14,000 per year (see details in Table 5-3).

6.0 Financial Analysis (Task 7)

6.1 BASIC ECONOMIC VALUES

The basic (fixed) economic values used for performing the economic analysis for all technologies include the following:

Table 6-1 Basic Values Used in Economic Analysis for All Technologies

MODEL INPUT ITEM	VALUE
Fuel & Plant	
Fuel Cost Delivered - $/Bone Dry Ton	$51.60
Fuel Cost Delivered - $/Ton as Received	$30.96
Plant Capacity Factor	90%
Fuel Heating Value, Bone Dry – Btu/lb.	8,500
Fuel Moisture Content as Received	44%
Fuel Heating Value as Received – Btu/lb.	4,760
Financial	
Debt Percent	75%
Debt Rate	5.0%
Debt Term – Years	15
Depreciation	5 yr MACRS
Composite Tax Rate	38.6%
After Tax Cost of Equity	10%
New Market Tax Credit	No
Investment Tax Credit – ITC	No

6.2 REQUIRED REVENUE BY TECHNOLOGY - EXCLUDING OWNER COSTS

Table 6-2 below provides the revenue required by each technology or equipment configuration to be economically viable, expressed in $/MWh. This analysis provides the results when only the EPC costs are financed (owner costs excluded). Given this is a high level economic analysis, the range of accuracy is likely greater than the relative revenue required by each technology, suggesting that economics is not a fully definitive measurement of which technology to recommend.

Table 6-2 Required Revenue Excluding Owner Costs

TECH	VENDOR PAIR	CAPITAL COST				O&M COST		FUEL COST DELIVERED		FUEL USE		REV REQ'D	% CHANGE
		EPC COST		OWNER COSTS	ALL-IN COST	FIXED	VAR			HEAT RATE	FUEL REQ'D		
		$	$ PER GROSS MW	$	$	$/YR	$/YR	$ PER BDT	$/YR	BTU/ NET KWH	LBS/ HR	$ PER MWH	%
Steam	BTCo	18,466,098	5,596	0	18,466,098	948,000	262,995	51.6	1,487,659	20,931	13,060	177.6	
ORC	Turboden-Wellons	18,705,342	5,668	0	18,705,342	948,000	302,195	51.6	1,679,549	22,884	14,745	182.3	2.66%
Syngas	PRM Energy	23,157,293	7,017	0	23,157,293	948,000	327,995	51.6	1,235,274	17,380	10,844	185.5	4.42%
Steam	Chiptec	17,720,501	5,370	0	17,720,501	948,000	262,995	51.6	1,854,796	26,097	16,283	190.8	7.41%
ORC	Turboden-Deltech	21,728,421	6,584	0	21,728,421	948,000	302,195	51.6	1,679,549	22,884	14,745	192.2	8.23%
Syngas	Sierra Energy	21,446,493	6,499	0	21,446,493	948,000	327,995	51.6	1,174,677	17,989	10,313	192.8	8.52%
ORC	Ormat-Wellons	22,305,926	6,759	0	22,305,926	948,000	302,195	51.6	1,776,870	23,952	15,599	196.0	10.37%

6.3 REQUIRED REVENUE BY TECHNOLOGY - INCLUDING OWNER COSTS

Table 6-3 Required Revenue Including Owner Costs

TECH	VENDOR PAIR	CAPITAL COST				O&M COST		FUEL COST DELIVERED		FUEL USE		REV REQ'D	% CHANGE
		EPC COST		OWNER COSTS	ALL-IN COST	FIXED	VAR			HEAT RATE	FUEL REQ'D		
		$	$ PER GROSS MW	$	$	$/YR	$/YR	$ PER BDT	$/YR	BTU/ NET KWH	LBS/ HR	$ PER MWH	%
Steam	BTCo	18,466,098	5,596	1,168,142	19,634,240	948,000	262,995	51.6	1,487,659	20,931	13,060	182.1	
ORC	Turboden-Wellons	18,705,342	5,668	1,172,714	19,878,056	948,000	302,195	51.6	1,679,549	22,884	14,745	186.7	2.59%
Syngas	PRM Energy	23,157,293	7,017	1,257,783	24,415,076	948,000	327,995	51.6	1,235,274	17,380	10,844	190.3	4.61%
Steam	Chiptec	17,720,501	5,370	1,153,895	18,874,396	948,000	262,995	51.6	1,854,796	26,097	16,283	195.2	7.38%
ORC	Turboden-Deltech	21,728,421	6,584	1,230,479	22,958,900	948,000	302,195	51.6	1,679,549	22,884	14,745	196.8	8.27%
Syngas	Sierra Energy	21,446,493	6,499	1,225,092	22,671,586	948,000	327,995	51.6	1,174,677	17,989	10,313	197.9	8.87%
ORC	Ormat-Wellons	22,305,926	6,759	1,241,515	23,547,441	948,000	302,195	51.6	1,776,870	23,952	15,599	200.6	10.41%

Unless the government renews the ITC, this project will not qualify. If the project did qualify, it would lower the LCOE by $9.50/MWh. If it qualifies for New Market Tax Credit, it would reduce the LCOE only $1.50/MWh. This is so low because with the 5.5 MACRS depreciation, no tax is being paid until the 15th year anyway, and the later the benefit is received (i.e. New Market Tax Credit would start in the 15th year), the lower its impact on the LCOE.

6.4 REQUIRED REVENUE, INCLUDING OWNER COSTS – OTHER SENSITIVITIES

The lowest cost technology pairing was selected to run other sensitivities to provide the relative effect of changes in some of the primary financial model input values.

Table 6-4 Required Revenue Including Owner Costs – Other Sensitivities

TECH	LOWEST PAIR PLUS 10% OF ITEM SHOWN	CAPITAL COST				O&M COST		FUEL COST DELIVERED		FUEL USE		REV REQ'D	% CHANGE
		EPC COST		OWNER COSTS	ALL-IN COST	FIXED	VAR			HEAT RATE	FUEL REQ'D		
		$	$ PER GROSS MW	$	$	$/YR	$/YR	$ PER BDT	$/YR	BTU/ NET KWH	LBS/ HR	$ PER MWH	%
Steam	**BTCo**	**18,466,098**	**5,596**	**1,168,142**	**19,634,240**	**948,000**	**262,995**	**51.6**	**1,487,659**	**20,931**	**13,060**	**182.1**	
Steam	Capital Cost	20,312,708	6,155	1,168,142	21,480,850	948,000	262,995	51.6	1,487,659	20,931	13,060	188.3	3.42%
Steam	Fixed O&M	18,466,098	5,596	1,168,142	19,634,240	1,042,800	262,995	51.6	1,487,659	20,931	13,060	186.2	2.22%
Steam	Variable O&M	18,466,098	5,596	1,168,142	19,634,240	948,000	289,295	51.6	1,487,659	20,931	13,060	183.2	0.62%
Steam	Fuel Cost	18,466,098	5,596	1,168,142	19,634,240	948,000	262,995	56.8	1,636,425	20,931	13,060	188.5	3.49%
Steam	Heat Rate	18,466,098	5,596	1,168,142	19,634,240	948,000	262,995	51.6	1,636,425	23,025	14,366	188.5	3.49%

7.0 Recommended Conversion Technology

7.1 QUALITATIVE COMPARISON

From Table 6-3 it becomes apparent that the relative cost of generation for the three technologies are sufficiently similar that economics alone will not be used as the determinant for selection of the recommended technology. Therefore a qualitative assessment of the technologies was completed to more fully compare the technologies. Table 7-1 provides a summary of such an assessment and identifies the steam option as the most viable when reviewing items other than the resulting cost of power.

Table 7-1 Qualitative Assessment of Technologies

CHARACTERISTIC (SCALE OF 1 – 10 WHERE 10 IS BEST)	STEAM	SYNGAS	ORC	RISK
Efficiency or Heat Rate (amount of fuel required)	10	5	8	Greater fuel cost for lower efficiency
Air Emissions (controlled)	10	10	10	Not really a discriminating criterion since all technologies can be controlled to within limits.
Water Requirements	2	5	5	High water use may not get permitted or could cost more than expected to obtain
Susceptibility to breakdown	5	1	6	Syngas cleanup can be often problematic
Suitability for Scaling Down to 3.3 MW Gross	4	6	8	If a project cannot be scaled down to this small a size it means it could become very expensive or certain aspects of the technology don't work as expected at the new scale.
Staffing Costs	10	10	10	B&V does not see this as a discriminating criterion because we contend that all three technologies require the same staffing levels.
Maintenance Costs ($/year)	10	2	6	Higher maintenance costs are detrimental to the revenue and if high costs are experienced it could mean there will be more unexpected outages.
Sensitivity to Ambient Temperature	8	10	1	If one technology is greatly more sensitive to ambient temperatures than others, this could mean that during unusually warm periods some technologies will not function as expected.
Technology Maturity	10	4	8	Less mature technologies not as well understood providing slightly greater risk than more mature technologies.
Frequency of Use within the Industry	10	1	2	If a technology is seldom or only occasionally utilized, it suggests that the technology is not as sound as others, or works best under very special conditions, which may exist only in certain special projects.
Extent of Commercial Viability	10	4	9	If a technology is not as commercially viable as others that means it will be harder to obtain a profit with that technology.
Total	**89**	**58**	**73**	

The steam option scored high primarily because it has been used for many years and there are so many units in operation that significant risk factors seen by the other technologies are avoided by the steam option. There is a common opinion that capital cost of a steam cycle option cannot easily compete with other technologies. But this analysis does not support that opinion and even offered the lowest capital cost option as presented in Table 5-2.

Syngas is hampered by 1) it's a complicated cycle, 2) the technical and environmental challenge of cleaning the gas stream before combusting it in a reciprocating engine, 3) the high maintenance cost associated with a reciprocating engine cycle, which may not always be fully acknowledged.

The ORC option did not show as well because of its high heat rate (lower efficiency) and somewhat higher maintenance cost when compared to the steam option. This technology's capital costs are not as high as the syngas option, but are still higher than the steam option.

This analysis has shown that the steam option is slightly preferred when economics is the only criterion. But the apparent economic advantage of steam is as small as the margin of accuracy of the values used to obtain this result, so the economics of the three options should be considered nearly equal. However, the qualitative evaluation of the three options as outlined in Table 7-1, demonstrates a significant preference to the steam option.

7.2 FURTHER CONSIDERATIONS FOR TECHNOLOGY SELECTION

7.2.1 Combined Heat and Power (CHP)

The amount of energy or heat available for each technology and the corresponding drop in LCOE if such sales occurred, are provided below in Table 7-3. Since CCP does not have any specific thermal host in mind, the temperature needed by the host is not known. For purposes of the work that follows, it has been assumed that the host could accept thermal energy as low as 85 F (like for a greenhouse), which pretty much maximizes the amount of heat that can be extracted from any technology. It is unclear whether all of the identified heat available will be fully useable, but this still provides some insight into this aspect of each of the technologies.

Table 7-2 presents the cost of CCP's facility to generate heat with and without including the debt service (using BTCo for the example). These values were reviewed to allow a determination of a reasonable price for this energy. For purposes of an example, $5.00/MM Btu has been chosen because theoretically the host could build its own plant and produce heat for the same costs as will be incurred by CCP. So the price offered to the host must lower than the cost for the host to produce its own heat. Table 7-2 identifies the cost for CCP to produce useful heat as a way to know how to price the waste heat (i.e.$5.57 and $8.47).

Table 7-2 Cost to Produce Heat

CURRENT COST TO PRODUCE HEAT	UNITS	VALUE
Without Debt Payment	$/MM Btu	$ 5.57
With Debt Payment	$/MM Btu	$ 8.47
Assumed Sales Price of Heat	$/MM Btu	$ 5.00

Using the above price for heat and the amount of heat available presented in Table 7-3, the theoretical revenue and change in LCOE from heat sales can be calculated (assuming heat can be used as low as 85 F). As shown below in Table 7-3, the thermal sales (with the above assumptions) will lower the LCOE by significant amounts.

Table 7-3 Effect on LCOE of Theoretical Heat Sales

TECHNOLOGY	HEAT AVAILABLE MM BTU/HR	REVENUE/YR		APPROXIMATE REDUCTION IN LCOE WITH THERMAL SALES $/MWH[13]
		MM Btu/yr	$/Yr	
Steam - heat at 85 F Steam – heat at 165 F	44.8 40.7	353,000 320,880	1,760,000 1,600,000	$64.00 $58.60
Syngas – heat at 85 F	12.6	99,340	496,700	$21.80
ORC				Later

Not only does Table 7-3 show a significant reduction in LCOE with thermal sales, but the amount of waste heat available is noteworthy because for the steam option it aligns closely with thermal loads the CCP recently learned to be typical. CCP recently learned, through an independent study, that one use for waste heat is to sterilize used wooden pallets. This would require about 40 MM Btu/hr at a temperature of 160F. Table 7-3 shows that slightly greater than 40 MM Btu's are available even at the higher temperature of 160 F as required by this theoretical thermal host.

7.2.2 Waste Heat vs. Useful Heat

The amount of waste heat provided in Table 7-3 is, in fact, waste heat, meaning it is heat that will be discharged to the atmosphere or in some other way released. If the amount of waste heat available is not adequate to meet the thermal host's needs, the power plant can be configured to provide waste heat plus useful heat. Useful heat is energy that is normally used to produce electricity or syngas which can be diverted to the host to supplement the waste heat to meet the thermal host's needs.

- Steam Cycle
  To provide useful energy in addition to the waste heat to the host, a different steam turbine (condensing turbine with an extraction port) would be utilized that includes an extraction port to bleed off some steam before it travels completely through the steam turbine where its pressure and temperature are reduced by each stage of the steam turbine. This extraction port can be designed to provide steam at higher pressures to meet the host's needs while supplementing the waste heat.

  If waste heat is utilized in some manner, the wet cooling tower could be eliminated or significantly reduced in size. However, it would require that the host operate 24/7 to allow the steam cycle to eliminate the wet cooling tower completely. Perhaps the tower would still be required but would only operate when the host is shut down.

  A larger boiler would be required and a greater fuel demand would result if useful energy is diverted to the host.

[13] This value may be slightly lower if added capex is needed to facilitate moving the energy to the host. But this action would eliminate the need for wet cooling on the steam option.

- Syngas Cycle
  Providing useful energy in addition to the waste heat to the host for this cycle is not quite as direct. A portion of the syngas produced would be directed to a new combustor and heat exchanger (owned either by CCP or the host) to convert the syngas into useful heat. This would require notable capital to implement this approach.

- ORC Cycle
  To obtain useful energy from this cycle a branch would have to be added to the hot oil cycle that would take a small portion of the hot oil to the host. A heat exchanger would have to be purchased to convert the hot oil into useful heat.

Table 7-4 Other Aspects of Each Technology Compared

CHARACTERISTIC	STEAM	SYNGAS[14]	ORC
Feedstock			
Fuel Size	<20% <1/4" <10%>4"	PRM 100% <3/8" PRM < 20% Moisture	Deltec <20% <1/4" <10%>4"
Moisture Content[15]	15 – 60	40 – 65	15 – 60
Ability to handle incidental material in the fuel[1]	Great	Medium	Great
Tons of fuel required per year (as received)	56,000 – 67,000	31,000 – 38,000	59,000 – 73,000
Net kW Efficiency - %	16.616 – 20.2	21.1 – 21.8	16.6 – 20.2
Emissions	All able to meet Cal standards	All able to meet Cal standards	All able to meet Cal standards
Quantity of residuals produced tons/yr.	Ash 1,680 – 2,000	PRM biochar 5,650 – 9,500 Or ash 1,860 – 2,280	Ash 1,800 – 2,900
Amount of water required	Wet Cool 250 gpm Dry Cool 12 gpm	Gen misc. use only	Gen misc. use only
Amount of water discharged	Wet Cool 60 gpm Dry Cool 12 gpm	Gen misc. use only	Gen misc. use only
Operating conditions	650/550 & 450/700 psig/deg F	LHV[17] 6,494 Btu/lb @ 20% moist	45 MMBtu/hr 1975 F 52 MMBtu/hr 1769 F

The moisture and size requirements of syngas vendor PRM will add cost compared to other vendors or other technologies. This is a notable disadvantage. The added costs to meet this requirement have not been included in this analysis.

[14] The correct values will depend on the vendor used. Values shown are for syngas coming from a BFB gasifier.
[15] This item is probably not a discriminating characteristics for the various technologies.
[16] This value is considered quite far from the norm and was dismissed.
[17] LHV stands for Lower Heating Value. In the US HHV (Higher Heating Value) is typically used which is between 5% - 10% higher than LHV.

8.0 Other Considerations/Comments/Risk Assessment

Waste Products and Byproducts

Only direct combustion produces exclusively ash, which can be used as a soil amendment for crops or spread in the forest. The bottom ash can also be utilized as a material for building roads. While these solutions are useful methods for disposal, it is unlikely any revenue will be generated by them. Removal and disposal should not have any cost to the project because the recipient will receive a useful material for the cost of hauling it away.

The other two technologies can produce either ash or biochar or both. When biochar is produced the amount of syngas or hot combustion gases produced will drop (energy extracted in the form of high carbon content biochar). Production of biochar is not a no-cost byproduct, as there will be less useful heat produced for the primary purpose (with a fixed fuel combustion rate). Black & Veatch has concerns that the biochar market may not be as robust as some seem to believe. It may be prudent to consider the generation and sale of biochar as an "upside" rather than a key component of CCP's business plan.

Table 8-1 below provides the anticipated gross income from electricity if no biochar is produced and the gross revenue from biochar if ALL fuel is converted to biochar (only for purposes of comparison), utilizing the pricing provided by CCP. This demonstrates that the relative value of biochar is considerably greater than the revenue from electricity.

Table 8-1 Theoretical BioChar Revenue Compared to Electrical Sales Revenue

ITEM	UNITS	VALUE	COMMENTS
Sales Price	per pound	$0.72	Price mentioned by CCP
Quantity of Fuel Burned	Tons/yr.	34,500	From vendors for syngas, see Table 7-4
Percent of Fuel as BioChar		20%	PRM provided value of 15%-25%
Tons of BioChar per year	Tons/yr.	6,900	34,500 x 20%
Theoretical Revenue from BioChar Sales	$/yr.	9,936,000[18]	$0.72*6,900*2000
Elect Revenue without BioChar	$/yr.	3,976,000	3 MW*178$/MWh*8760*0.85 CF

If the pricing provided by CCP is accurate, and if the market can support additional sales, then there is significant value in biochar. But as previously mentioned, Black & Veatch has concerns that the biochar market may not be as robust as some seem to believe. Having said that, it is worth mentioning that some potential biochar producers believe biochar can be used as a filler material for plastics, which if technically and economically feasible, would increase demand for biochar significantly. Such a use should be considered as being in the experimental stage. A scenario that includes production of biochar would require a greater fuel consumption rate. The amount that the fuel consumption would increase for any given scenario of biochar production, would have to be obtained from the syngas vendors.

[18] This assumes ALL fuel is used to produce biochar (which of course would not be done) only to compare the revenues from electricity if all fuel is used for generation of power.

Energy Demand

The Feed-In Tariff (FIT) available to CCP and the small size of the project (1 to 3 megawatts) will likely remove any barriers regarding adequate energy demand to support the project. (The project represents a very small percentage of the local grid capacity.)

Biomass Resource

Given the proximity of the project to the forest products industry and timber stands in the area, it places this project in an advantageous location. Further, the TSS study of 2014 for Nevada County concluded that biomass resource availability is more than adequate for the CCP project. This should not be an issue adverse to its success.

Technology

There is more than one technical solution for a plant like the one planned by CCP. Black & Veatch has evaluated the options in this report. But even if this recommendation is not the final design, there are other acceptable solutions that will not cause technology to become a concern for the project to proceed.

Site

CCP is planning to utilize an existing industrial site (location where a sawmill had operated in the past), which has adequate size for the planned project. Utilizing an existing industrial site typically provides ready access to infrastructure items, good vehicular access, and utilities necessary for a power plant. Using this site will significantly reduce the chances there are any fatal flaws for this location. In addition, the owner of the site has shown a strong interest in working to facilitate the development of a biomass CHP installation at this location.

Environmental and Permitting

The permits required and basic environmental impacts are well understood and documented for a project like the one planned by CCP. The fact that the site is somewhat remote, that it is planned to be located on an existing industrial site, and the project's relatively small size, all contribute to a reasonably straight forward permitting process with few surprises expected. Any environmental challenges regarding such things as flora and fauna, endangered species, migratory bird patterns, nearby airports, cultural heritage sites, etc. were likely addressed when the site was first permitted for industrial use, likely removing these as significant concerns now. CCP has shown a strong awareness of the key issues and barriers that need to be addressed with respect to local stakeholder concerns and acceptance issues for the CHP project.

Traffic Impact

The traffic impacts of the project will be very limited. The amount of traffic and truck trips will be very modest because of the small size of the project. This small level of traffic increase, the site's existing status as an industrial site (and past use for a lumber mill), and its remoteness, all contribute to negligible traffic impacts noticed or perceived by the local residents or impacts on the integrity of the roadways.

Regulatory

The regulatory impacts are anticipated to be insignificant and are well understood. This element is not expected to be a concern for the project's success.

Developmental Impact

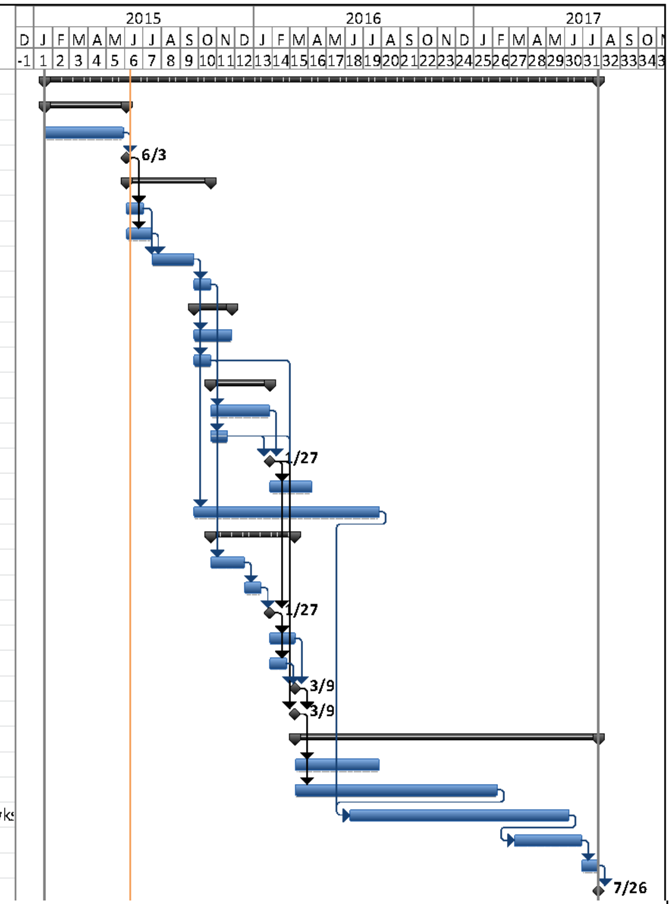
As stated before, siting this project on an existing industrial site significantly reduces any perceived or real impact resulting from the development and construction of the project.

9.0 Schedule

Below is a high level implementation schedule outlining the major steps and approximate duration to develop this project. Informally, a more conservative schedule was provided to CCP that included many owner tasks not directly related to engineering, permitting or construction. The durations and many of the tasks were originated by CCP and represented a worst case scenario.

Figure 9-1 Typical Schedule

ID	Task Name	Duration	Start	Finish	Predecessors
1	**Camptonville Development and Constructon**	**131.6 wks**	**Mon 1/19/15**	**Wed 7/26/17**	
2	**Black & Veatch Feasibility Study**	**19.6 wks**	**Mon 1/19/15**	**Wed 6/3/15**	
3	B&V Perform Feasibility Study	19 wks	Mon 1/19/15	Fri 5/29/15	
4	B&V Present Findings	0 wks	Wed 6/3/15	Wed 6/3/15	3FS+3 days
5	**Developer/Owner Selection**	**20 wks**	**Thu 6/4/15**	**Wed 10/21/15**	
6	Prepare List of Developer Candidates	4 wks	Thu 6/4/15	Wed 7/1/15	4
7	Prepare & Issue RFP to Developers	6 wks	Thu 6/4/15	Wed 7/15/15	4
8	Developers Prepare & Submit Proposals	10 wks	Thu 7/16/15	Wed 9/23/15	7,6
9	Evaluate & clarify proposals-tentative selection	4 wks	Thu 9/24/15	Wed 10/21/15	8
10	**Bid into PG&E's FIT Tariff Process**	**9 wks**	**Thu 9/24/15**	**Wed 11/25/15**	
11	Uncertain tasks and timing (CCP to research)	9 wks	Thu 9/24/15	Wed 11/25/15	8
12	Negotiate PPA and Execute	4 wks	Thu 9/24/15	Wed 10/21/15	8
13	**Developer Contract**	**14 wks**	**Thu 10/22/15**	**Wed 1/27/16**	
14	Developer - Contract Negotiated	14 wks	Thu 10/22/15	Wed 1/27/16	12
15	Draft Developer Contract	4 wks	Thu 10/22/15	Wed 11/18/15	12
16	Developer Contract Signed	0 wks	Wed 1/27/16	Wed 1/27/16	14,15
17	Developer Negotiate/Execute Elect Interconnect Agree	10 wks	Thu 1/28/16	Wed 4/6/16	16
18	Permitting & EIA (shorter if EIA not required)	44 wks	Thu 9/24/15	Wed 7/27/16	8
19	**Financing**	**20 wks**	**Thu 10/22/15**	**Wed 3/9/16**	
20	Contact Lenders & Obtain Proposals	8 wks	Thu 10/22/15	Wed 12/16/15	9
21	Negotiate Lenders' Terms	4 wks	Thu 12/17/15	Wed 1/13/16	20
22	Select Lender	0 wks	Wed 1/27/16	Wed 1/27/16	21,16
23	Lender's Due Diligence	6 wks	Thu 1/28/16	Wed 3/9/16	22
24	Prepare Closing Documents	4 wks	Thu 1/28/16	Wed 2/24/16	22
25	Financial Close	0 wks	Wed 3/9/16	Wed 3/9/16	23,15,24,12
26	Developer Given Notice to Proceed	0 wks	Wed 3/9/16	Wed 3/9/16	25,16
27	**Developer Implementation of Project**	**72 wks**	**Thu 3/10/16**	**Wed 7/26/17**	
28	Detailed Design	20 wks	Thu 3/10/16	Wed 7/27/16	26
29	Procurement (including delivery time)	48 wks	Thu 3/10/16	Wed 2/8/17	26
30	Construction	52 wks	Thu 6/9/16	Wed 6/7/17	29FS-35 wks,18FS-20 wks
31	Startup and Commissioning	16 wks	Thu 3/9/17	Wed 6/28/17	30FS-13 wks
32	Utility Performance Test	4 wks	Thu 6/29/17	Wed 7/26/17	31
33	Full Commercial Operation	0 wks	Wed 7/26/17	Wed 7/26/17	32



Project: CCP High Level Implemen
Date: Wed 6/10/15

Task, Split, Milestone, Summary, Project Summary, External Tasks, External Milestone, Inactive Task, Inactive Milestone, Inactive Summary, Manual Task, Duration-only, Manual Summary Rollup, Manual Summary, Start-only, Finish-only, Deadline, Progress

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Appendix A: Boiler Budgetary Proposals

Appendix B: Steam Turbine Proposals

Appendix C: Syngas Generators

Appendix D: Reciprocating Engines

Appendix E: Hot Combustion Gas Generators

Appendix F: ORC Vendors