Clearwater County Biomass Energy Report

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ACRONYMS AND ABBREVIATIONS

24/7	24 Hours Per Day, 7 Days Per Week
APC	Air Pollution Control
ARRA	American Recovery and Reinvestment Act of 2009
ASTs	Above Ground Storage Tanks
Avista	Avista Corp.
BCAP	Biomass Crop Assistance Program
BMPs	Best Management Practices
BOOM	Construction and Demolition
C&D Rule	Construction & Development Effluent Limitations
CAA	Clean Air Act
CADD	Computer-aided Design and Drafting
CC	Carbon Credits
CCC	Commodity Credit Corporation
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CESQG	Conditionally Exempt Small Quantity Generator
CGP	Construction General Permit
CHP	Combined Heat and Power
CIG	Conservation Innovation Grants
CINRAM	Center for Integrated Natural Resources & Agricultural Management
CO	Carbon Monoxide
CO2	Carbon Dioxide
C-P TPA	Clearwater-Potlatch Timber Protective Association
CROP	Coordinated Resource Offering Protocol
CVHC	Clearwater Valley Hospital and Clinic
CWA	Clean Water Act
D/F	Dioxins/furans
DEQ	Department of Environmental Quality
EHSs	Extremely Hazardous Substances
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPCRA	Emergency Planning and Community Right-to-Know Act
EQIP	Environmental Quality Incentive Program
ESA	Endangered Species Act
ESCO	Energy Services Company
FARR	Federal Air Rules for Reservations
FERC	Federal Energy Regulatory Commission
FIPs	Federal Implementation Plans
FRP	Facility Response Plan
FS	Feasibility Study
HAPs	Hazardous Air Pollutants
HCl	Hydrogen Chloride

Hg	mercury
HIS	Idaho Historical Society
IC	Interconnection Customers
ICI Boilers	Industrial Commercial and Institutional Boilers and Process Heaters
ICI-O	Idaho Correctional Institution-Orofino
IDL	Idaho Department of Lands
IDWR	Idaho Department of Water Resources
IERA	Idaho Energy Resources Authority
IRR	Internal Rate of Return
kWh	Kilowatt-hours
LUST	Leaking Underground Storage Tank
MACT	Maximum Achievable Control Technology
MBF	Thousand Board Feet
MSDSs	Material Safety Data Sheets
MSGP	Multi-Sector General Permit
MSW	Municipal Solid Waste
MW	Megawatt
N2	Nitrogen
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service
NSPS	New Source Performance Standards
NSR	New Source Review
NTU	Nephelometric Turbidity Units
OHS	Orofino High School
pH	Potential of Hydrogen
Plant	Power Plant
PM	Particulate Matter
PPA	Power Purchase Agreement
PPP	Public-private Partnership
PSD	Prevention of Significant Deterioration
PSTF	Petroleum Storage Tank Fund
PTE	Potential to Emit
PURPA	Public Utility Regulatory Policy Act
QF	Qualifying Facility
QFs	Small Power Production Facilities
RCRA	Resource Conservation and Recovery Act
REAP	Rural Energy for America Program
REAP/EA/REDA	Rural Energy for America Program Grants/Energy Audit and Renewable Energy Development Assist
REC	Renewable Energy Credits

REEZ	Renewable Energy Enterprise Zone
RFQ	Request for Quotation
ROI	Return on Investment
RQs	Reportable Quantities
SAR	Surrogate Avoided Resource
SHN	State Hospital North
SHPO	State Historic Preservation Office
SPCC rule	Spill Prevention, Control, and Countermeasure, or SPCC Plan
SWPPP	Stormwater Pollution Prevention Plan
Syngas	Synthetic Gas Fuel
T&D	Transport and Dispose
TAS	Treatment as a State
TCLP	Toxicity Characteristic Leaching Procedure
Tetra Tech	Tetra Tech NUS, Inc.
TMDL	Total Maximum Daily Loads
TPD	Tons Per Day
TPQs	Threshold Planning Quantities
TRI	Toxic Release Inventory
USACE	U.S. Army Corps of Engineers
USDOE EIA	US Department of Energy's Energy Information Administration
USFWS	U.S. Fish and Wildlife Service
USTs	Underground Storage Tanks
VAP	Value-Added Producer
VAPG	Value-Added Producer Grant
VRV	Variable Refrigerant Volume
WQC	Water Quality Certification
WTE	Waste-to-Energy

Executive Summary

This study was prepared by Tetra Tech NUS, Inc. ("Tetra Tech") for Clearwater County, Idaho, to evaluate the technical, regulatory, logistical and economical feasibility of a Woody Biomass Combined Heat and Power Plant (Plant) in Orofino, Idaho. The project intent is to utilize local biomass to lower public facility operating expenses and support job growth in the county, specifically in Orofino, the largest town in the county. This prospective biomass power plant project is envisioned to provide stable and competitively priced utility services to local public facilities, to supplant electric grid powered heat, and to sell electricity to the grid, while adding value to the local timber industry and providing local job opportunities.

The city of Orofino contains a number of public facilities, including Idaho Correctional Institution-Orofino (ICI-O), the Clearwater Valley Hospital and Clinic (CVHC), Orofino High School (OHS), and Idaho State Hospital North (SHN). This facility complex, anchored by ICI-O, is envisioned to be the primary project beneficiary.

Clearwater County is 92% forested and supports a strong local logging industry. Logging industry residues and secondary products are envisioned to be the feedstock material for the plant. Feedstock supply is the single most important aspect of a biomass energy project, and volume and price are the key variables to biomass feedstock. Logging residues, in the form of in-woods grindings, are anticipated to be the primary feedstock. Within a 30-mile area surrounding Orofino, over 141,000 tons of logging residue is estimated to be produced annually. Of this amount, the logging residue available to the project is estimated to be **40,000-50,000 tons** annually, considering competition and access limitations. Feedstock supply in the area is ample, as shown in the table below.

Table ES-1 –Total Biomass Potential in the Orofino, ID Region

Feedstock	Annual Tonnage Available to the Project (tons)	Baseline Delivered Price ($/ton as received) (delivered, not dried)	Baseline Delivered Price ($/ton dry basis) (delivered & dried price)
Logging Residue	40,000-50,000	$25.00	$35.00
Mill Residue	3,500	$20.00	$28.50
Thinning / Stewardship	35,000	$35.00	$50.00
Chip wood	22,000+	$40.00+	$55.00+
Total	**100,500**		

The secondary project feedstock is anticipated to be mill residues. Although it is an easily-accessible feedstock, this product is currently utilized in other industries. Tetra Tech anticipates mill residues averaging **3,500 tons** will be available per year as shown above.

Stewardship and thinning contracts may also be acquired to procure feedstock material for the project at estimated supply of over **35,000 tons** per year, based on 5-yr future contracts. However, due to the limited current thinning and stewardship practice, it is not recommended as a long-term or consistent feedstock. Chip wood or pulpwood is available as a potential project feedstock, but is also not recommended except in times of lean supply of due to its higher value for use in making pulp and paper products.

An energy audit of ICI-O illustrates that it should be the anchor facility to receive thermal energy produced from the prospective Plant. The existing facility steam and hot water boilers appear to be inefficient and outdated. Electrical energy consumed to generate the thermal requirements at ICI-O alone is over 3 million kilowatt-hours (kWh), of the approximately 4.5 million kWh total used by the facility annually. This thermal requirement can be furnished with steam supply from the proposed biomass plant at very good interconnection points at each ICI-O building.

Other facilities in the complex were reviewed as optional additional thermal energy users to supplement the demand from ICI-O. CVHC was determined to be the likely secondary thermal energy customer. Approximately half of the CVHC heating and cooling system is powered by dual fuel-oil fired boilers, centrally located for straightforward interconnection with Plant-provided thermal energy. Proposed additions to CVHC can also integrate to the piping system at less cost than installation of stand-alone energy-generation equipment. OHS is a third candidate for use of thermal load as the school is facing a complete upgrade of its existing heating and cooling system. SHN is currently overhauling its entire facility HVAC system, and thus is not considered a viable candidate for interconnection. The total expected thermal energy demand in the area from these prospective users is expected to be 6.185 million kWh/yr at a 775kW load, equivalent to 21,113 MMBTU/yr.

Tetra Tech determined the optimum location for the proposed Plant based upon land availability, permitting, access, utility inputs, and product off-take (i.e., steam / hot water and electricity). The most desirable site is on SHN property between the ICI-O and water towers. From the prospective site, it is feasible to interconnect piping to prospective thermal energy customers ICI-O, CVHC, and OHS. It is also feasible to interconnect with the Orofino Substation, owned and operated by Avista Corp, which approximately ½ mile away. Avista believes the substation has the capacity to upload and redistribute up to 5 to 6MW of produced power from a dedicated line from the Plant. These initial conclusions can be confirmed through Avista's official interconnection application process, which includes a detailed review of substation equipment and capacity.

Based upon commercially available biomass conversion technologies, advanced combustion or gasification technology providing combined heat and power (CHP) is most suitable conversion technology for this Plant. Two plant-scale scenarios were designed and modeled for side-by-side comparison analysis; one facility utilizing 20 wet tons of woody biomass feedstock per day and producing slightly less than 1MW of total electrical energy output, and a larger-scale system utilizing 40 wet tons of feedstock per day and producing approximately 2MW of nominal electrical power. The proposed electric generation capacity of the plant was severely limited in that the local thermal demand is much lower than what would be generated from a larger plant. That is, a larger plant (3 to 6 MW) is viable based upon available feedstock and buyback prices, but without users/buyers of the thermal energy the financial viability of a larger plant is less favorable.

Total project capital cost for the 1MW CHP biomass power plant is projected to range between $7MM and $10MM, with a median estimate of **$8,319,718**. The 2MW CHP biomass power plant is projected to cost between $10MM and $15.4MM, with an estimated median cost of **$11,872,940.**

The prospective biomass power plant is envisioned to be a public service project. As such, a public-private partnership (PPP) with ownership by Clearwater County and a private firm partner appears to be a plausible and advantageous approach to operate the project under a performance-based contract. A PPP would allow the project to utilize the benefits provided by both public and private sectors, while sharing the potential risks and rewards of the project. The facility financial model assumes ownership by a public entity, with facility operations handled by a private entity on a contract basis. The contract will likely include specific performance and efficient guarantees that the private entity is required to maintain. Although this model chosen assumes that the private entity will only carry a minimal project financing burden, and will not be expected to cover facility ownership, it is likely that this should be evaluated further by the County based upon their interests. Financing of the project is expected to be accomplished primarily through raising of a bond, supplemented by available grant funding and a small capital investment from the partner private entity. The funding would likely be covered by a state general-obligations bond, housed under the IERA Renewable Energy Generation Bond Program.

Economic and financial modeling analysis evaluated a biomass-fed, advanced combustion unit coupled with and internal combustion generator set, based upon vendors solicited. Analysis included two scales, corresponding to approximately 1MW and 2MW of electrical output. Both scenarios are expected to produce electrical energy uploaded to Avista utility electrical grid and thermal energy to be consumed by local facilities. Electrical energy is expected to be sold to Avista at a scheduled rate set by the Idaho Public Utilities Commission, based on the number of years in the Power Purchase Agreement (PPA) contract. Thermal energy is expected to be sold equal to the rate facilities currently pay for the electricity used to power boilers.

Tetra Tech conducted the financial analysis to determine if the proposed biomass power plant project is economically feasible to pursue, and to identify key project parameters that most affect the viability of the project. The Tetra Tech Life Cycle Cost Model produces 11-year operating forecasts (1 year of construction plus 10 years of operation) for the projects including a balance sheet, income statement, and cash flow statement, and calculates thirty-year project operational internal returns in investment. The impacts of critical project variables have been determined and the viability of the projects with regard to each has been evaluated. Table ES-2 summarizes the major project metrics produced by the financial model for each project scale, assuming a scenario in which ICI-O is the sole thermal recipient of thermal energy.

Table ES-2 – Summary Results of Baseline Financial Analysis

Baseline Scenario		
Clearwater County 112C03170 Financial Projections Summary	**1MW CHP**	**2MW CHP**
10-year Average Annual ROI	-1.4%	-0.5%
30-year Internal Rate of Return	-N/A-	-N/A-
Simple Payback in Years	-N/A-	-N/A-
Average Annual Income	($62,585)	($4,136)
Equity Investment	$1,327,887	$749,176
Debt	$4,991,831	$7,123,764
Grants	$2,000,000	$4,000,000
Total Project Investment	**$8,319,718**	**$11,872,940**

This project result produces an untenable financial situation. The limited thermal energy demand by ICI-O is the primary variable negatively affecting financial performance. The majority of the thermal energy produced by the 2MW CHP scenario has no sale outlet and will have to be vented to the atmosphere. As well, a significant portion of the thermal output of the 1MW CHP plant goes unused, but a portion of that energy can be used to dry incoming feedstock and improve plant operations and efficiencies. Additional thermal energy users/buyers in the local area would greatly improve plant financial performance and return.

An additional financial model was produced by Tetra Tech to illustrate a financially positive scenario. This scenario includes other facilities in the local complex as thermal energy customers, determined to be a logistically feasible option through the facility energy audits. The revenue produced by sale of the additional thermal energy (approximately $200,000 annually) results in a long-term viable financial project. Table ES-3 summarizes this scenario.

Table ES-3 – Summary Results of Financial Analysis with Optional Facilities

Maximized Thermal Energy Use Scenario		
Clearwater County 112C03170 Financial Projections Summary	**1MW CHP**	**2MW CHP**
10-year Average Annual ROI	1.2%	1.5%
30-year Internal Rate of Return	-5.4%	-6.4%
Simple Payback in Years	15.47	21.68
Average Annual Income	$122,297	$180,437
Equity Investment	$1,549,503	$973,788
Debt	$5,324,255	$7,460,682
Grants	$2,000,000	$4,000,000
Total Project Investment	**$8,873,758**	**$12,434,470**

When additional thermal energy users are included in the analysis, both the 1MW and 2MW scenarios are estimated to be cash-flow positive through the project life span. The projects produce a nominal return rate (ROI), resulting in a sub-par 30-yr IRR. Average annual income, after operations, maintenance, and debt service, are calculated at $132,361 for the 1MW scenario, and $191,159 for the 2MW scenario.

Other parameters that need to be considered for successful project implementation and financial performance include feedstock purchase price, electrical and thermal energy sale prices, capital cost, and others. The risks associated with variation of these parameters are shared to large degree by all prospective biomass power plants. The project is very sensitive to variations in biomass feedstock pricing. Clearwater Paper located in Lewiston, ID is the primary market buyer of current logging residuals as well as pulpwood in Clearwater County. The risk associated with competing in the market place should be mitigated. Clearwater Paper representatives contacted see the value in this project and are willing to work as community member in this project to achieve reasonable market pricing. The project also appears to be moderately sensitive to electrical and thermal energy sale prices which can be further addressed in PPAs and off-take agreements, respectively. Risks associated with technology performance and capital costs can be mitigated via refined pricing and performance guarantees as part of the engineering procurement, and construction (EPC) phase. Requirement for subsidies in the form of grants (and/or guaranteed loans) as noted in Table ES-2 are also significant risks that should be addressed early in the planning stages.

In summary, the financial viability of a proposed Plant and the scenarios evaluated is not definitive. There is significant value to the economic conditions in the County by bringing in a secure, self-sustaining electrical and heat source to the community. Conversely, these systems are essentially cost-neutral; that is, they achieve the benefits to the community of a biomass-based renewable energy generation system, but at a similar cost to conducting business as it is currently. Project stakeholders will need to evaluate intrinsic project benefits (e.g., support of local logging industry, maintaining the local employers presence in Orofino, job creation, protection against unspecified energy cost increases, and energy independence, etc.) against financial costs to determine whether the project is in the best interest of all parties involved.

1.0 Introduction

This Feasibility Study (FS) was prepared by Tetra Tech NUS, Inc. ("Tetra Tech") for Clearwater County, Idaho, to evaluate the logistical and economic feasibility of installed a Woody Biomass Combined Heat and Power Plant in Orofino, Idaho. The project is funded under the American Recovery and Reinvestment Act of 2009 (ARRA), with the intention of creating a Renewable Energy Enterprise Zone (REEZ) in the Orofino area. Clearwater County created a project Oversight Committee, consisting of Clearwater County Commissioners, the Idaho Correctional Institution-Orofino (ICI-O), and the Idaho Department of Energy, to organize and oversee the study.

1.1 BACKGROUND

The Clearwater County Board of Commissioners is interested in pursuing development of a Combined Heat and Power (CHP) generation facility, offering a proactive renewable energy source to the community that offers a positive economic impact on local facility operations and that opens a new complementary market opportunity for the County's timber industry. Accordingly, a preliminary FS was performed in 2006 in partnership with the Fuels for Schools program. It was anticipated that the outcome of this project would identify and develop a mechanism to lower operating expenses at local facilities, thus maintaining and perhaps supporting potential job growth in the County.

In the preliminary FS (CTA Architects Engineers, 2006), the Idaho Correctional Institution-Orofino (ICI-O), State Hospital North (SHN), Clearwater Valley Hospital and Clinic (CVHC), and Orofino High School (OHS) were evaluated to consider the value of converting from electric service to woody biomass generated hot water/steam for heating, cooling and hot water. This initial effort also considered the opportunity of locating a central woody biomass boiler to serve all of the facilities needs for heating, cooling and hot water.[1]

Recognizing the opportunity and need for a sustainable supply of feedstock, the Clearwater County local economic development team sets out to determine if the ninety-two percent (92%) forested county would have ample raw material available. A detailed analysis of public lands resource offerings (i.e. timber sales) was developed, which indicated an average of 50,000 tons of biomass removal from the local landscape per year over the next five years. Additionally, an evaluation of past harvest of local private forestlands suggested an average of 104,000 tons per year of available slash for processing hog fuel is available.

A fuel supply analysis effort was completed, identifying that regional sources of woody biomass materials could sustain a 15 megawatt (MW) facility from forest management activities and wild fire hazard mitigation forest clearing. This preliminary FS indicated that the opportunity exists to save significant funds by utilizing wood as a fuel source for the ICI-O, and suggested that a wood chip/hog fuel boiler system could reach a positive cash flow in year one following

[1] CTA Architects Engineers, 2006

conversion (CTA Architects Engineers, 2006). A more detailed analysis was recommended, which is the driving force behind this project.

1.2 PROJECT ORGANIZATION

This project was structured to address four key aspects that were not addressed in the preliminary FS, to determine the financial and technical viability of this project. These tasks are summarized in brief below:

- Task 1 included an assessment of the woody biomass (feedstock) availability in the region in terms of an amount available under long-term contract, and the cost for the feedstock at the source location and/or delivered; the facility site location considerations; permitting requirements; and utility issues.
- Task 2 included (a) detailed breakdown of electricity demand for heating, domestic hot water generation, cooling, lighting and power at the ICI-O; and (b) an estimate of the feedstock requirements for the correctional facility heating and hot water system as well as a combined heat and power (CHP) facility.
- Task 3 included a conceptual design of the heating, hot water and the CHP system, including permitting, utility interconnection, operational range, capital and operational costs, energy savings and revenues.
- Task 4 included this final project Report.

The findings from Tasks 1, 2, and 3 have been submitted in technical memorandums. These memorandums were compiled, expanded, and included into this final report.

1.3 REPORT ORGANIZATION

This report was prepared to address objectives of each of the four project tasks as well as other items identified in the scope of work. This report contains the following sections:

- An executive summary was prepared to summarize the findings of this FS.
- Section 1 includes this introduction to the project that provides the background and explains the scope and purpose of this FS.
- Section 2 provides an assessment of the woody biomass (feedstock) availability in the region and how much may be obtained under long-term contract for this project, including the cost for the feedstock at the source location and delivered for use on this project. An estimate of the feedstock requirements for the facilities of the ICI-O heating and hot water system and a CHP facility.
- Section 3 includes a detailed breakdown of electricity demand for heating, domestic hot water generation, cooling, lighting and power at the ICI-O.

- Section 4 includes a project site selection and the interconnections that would be needed to support a viable project.
- Section 5 includes an evaluation of technologies, selection the best type for this project and a preliminary engineering design. This includes a selection of the facility site location and utility issues such as grid access and interconnection.
- Section 6 includes an estimation of the capital and operational costs, energy savings and revenues for the most likely facility operational range. These estimates are included into a financial model for the site which includes a financial sensitivity analysis.
- Section 7 includes a discussion of the local, state, and federal regulatory and permitting requirements and how these requirements may influence the project.
- Section 8 includes discussion on project funding mechanisms including identification of ownership, management & operational agreement options, construction funding sources, required construction permits, cost evaluation, energy savings and revenue analysis.

Acknowledgement: This material is based upon work supported by the Department of Energy under Award Number DE-EE000141.

2.0 Biomass Feedstock Assessment

Feedstock supply is the single most important aspect of a biomass energy project, and volume and price are the key variables to biomass feedstock. Consistent volumes of attractively-priced fuel are critical to a project operational and financial health. In this task, Tetra Tech has analyzed the feedstock supply potential in and around Orofino, Idaho.

The methodology necessary for a comprehensive analysis of feedstock availability for a prospective biomass power plant includes a review of total available volumes, which at times needs to be calculated if volume statistics were not available, sourcing and supply accessibility to the project site, and current and future projected feedstock pricing.

The following section quantifies the available and accessible volume of biomass supply in the Orofino Region, as it pertains to the feedstocks logging slash, stewardship and thinning biomass, mill residues and pulp wood/chip wood.

2.1 FEEDSTOCK SUPPLY OVERVIEW

Initial Feedstock Scoping

Feedstock analysis for the project focused primarily on woody biomass products harvested in conjunction with timber operations in the local region. Potential feedstocks for preliminary screening included:

- Logging residues (slash)
- Stewardship and stand thinning products
- Chip wood (meeting industry standard chip specification)
- Mill residues (sawdust and other waste)
- Agricultural residues
- Fuel wood
- Municipal solid waste (MSW)

The viable potential feedstocks for the prospective facility have been narrowed down to include logging residues, forest stewardship and stand thinning products, chip wood, and mill residues. These feedstocks present the greatest abundance, processing, and pricing advantages to the project. Abundance, supply logistics, and product pricing are discussed in further detail in this section.

Other potential feedstocks for the project, including agricultural residues, fuel wood, and MSW did not present the same project advantages in the preliminary screening stage; therefore, were not further reviewed for this project:

Agricultural residues, while abundant in the local area, are more expensive to collect and transport than woody biomass, at $60-100/ton. In addition, additional front-end processing equipment is required to manage fibrous plant material.

The **fuel wood** market in the local area appears to be dominated by small contractors. The large volumes of feedstock required by the proposed biomass energy plant would likely upset the current economic supply/demand and apply significant upward pressure to product pricing.

The subset of **MSW** feedstock that is applicable to the processing equipment being considered in this project is organic and woody biomass derived from municipal trash and construction and demolition (C&D) waste. This feedstock is abundant in the county and significant expense is incurred to collect it in Orofino and transport and dispose (T&D) of it to a landfill in Missoula, Montana. Because this material is not separated (e.g., organic from non-organic material) and the inclusion of this feedstock that would alter the technologies used to convert woody biomass to energy inclusion of this feedstock would impact project development timelines for the proposed biomass power plant. For this and other reasons, this feedstock was not included in the evaluation. Further evaluation may be of value in future analysis, if needed.

Orofino Regional 'Woodbasket'

Idaho is nearly 50% wooded, and its forestlands are amongst the state's most productive. The area surrounding Orofino, Idaho is heavily wooded, and supports a significant portion of the state timber industry. As stated in Section 1, Clearwater County is more than ninety-two percent (92%) forested and there is likely an ample raw material supply available. Figure 1 shows the distribution of forest types in the area surrounding Orofino. The majority of wooded acreage is to the east and north of the community.

Figure 1 – Forest and Tree Species Surrounding Orofino, ID

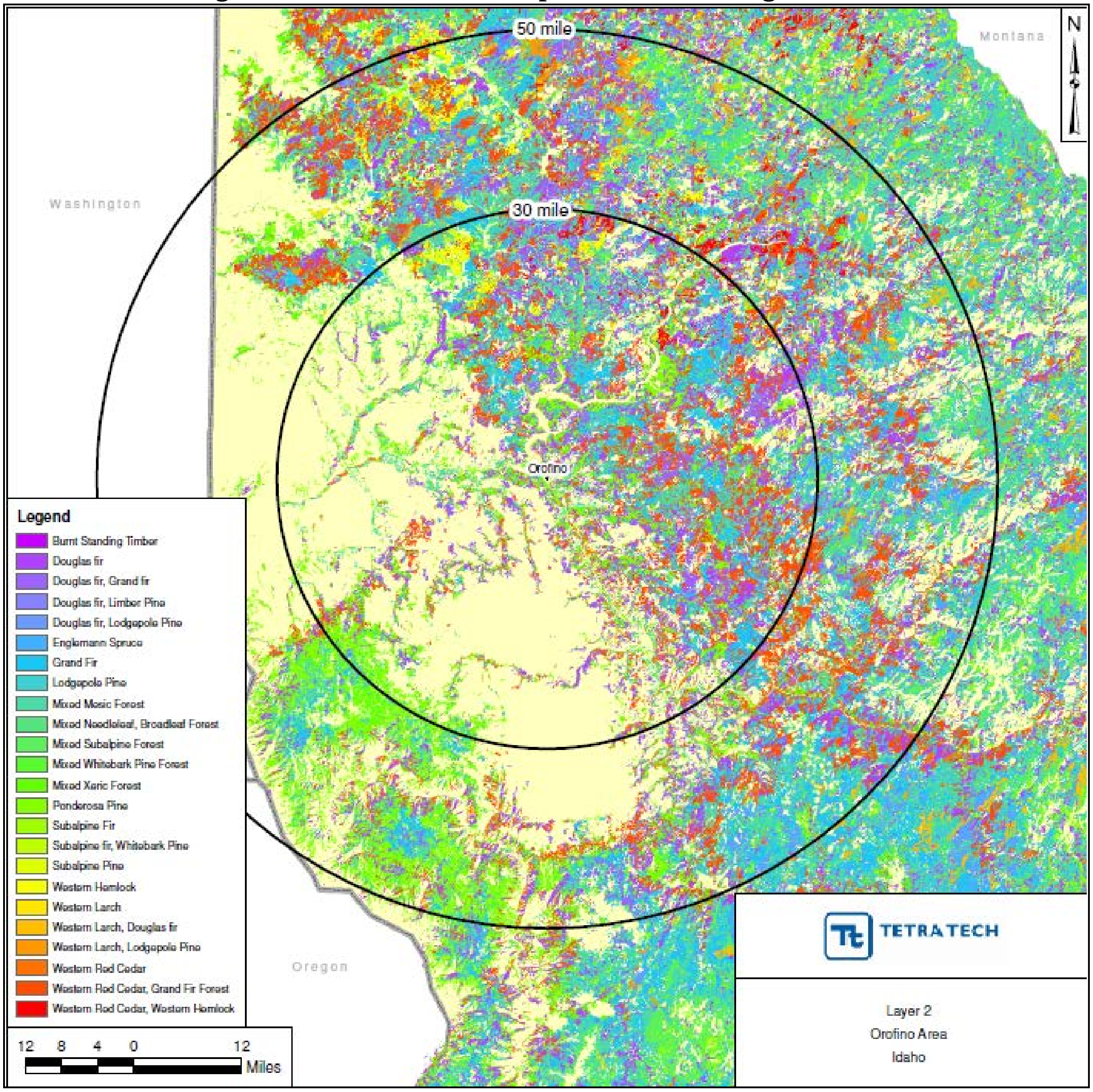
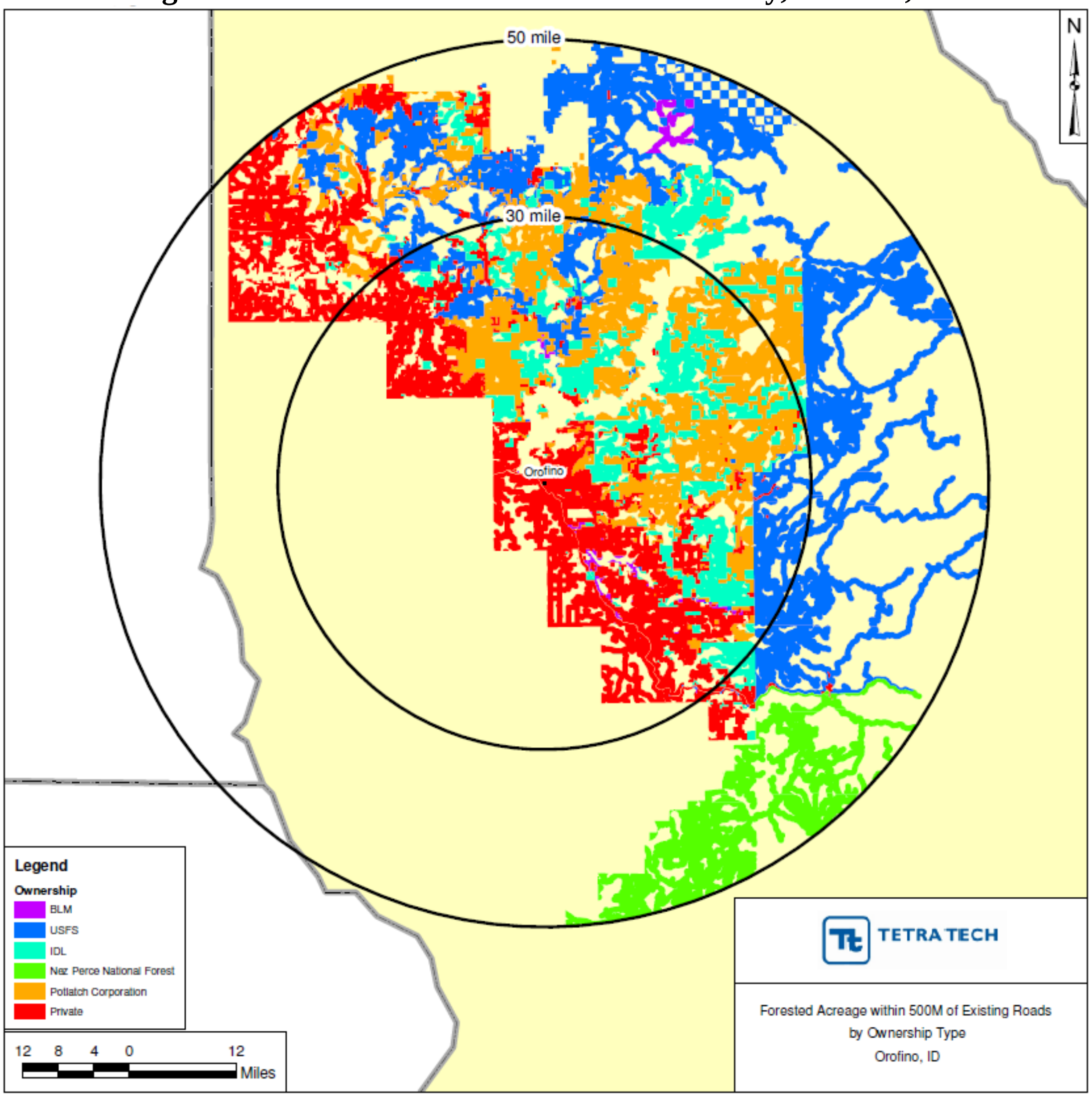


Figure 2 and Table 1 show the ownership of the forested lands near Orofino. The graph further categorizes the acreage of forestland within 640 feet (500 meters) of an existing road. As shown in the graphic, forested land is predominantly to the northeast and southeast of Orofino.

Table 1 – Accessible Forest Acreage near Orofino, ID

Landowner	Acreage of harvestable forestland within 30 mi	Acreage of harvestable forestland within 50 mi
USFS	96,975	568,134
Potlatch Corp.	294,643	475,096
BLM	5,392	13,208
IDL	180,965	246,133
Private (Other)	297,276	442,802
Nez Perce Nat'l Forest	-	164,817
Total	**875,251**	**1,910,190**

Figure 2 –Forestland within 500m of a roadway, Orofino, ID



Forested land ownership within 30 miles of Orofino is dominated by state-owned land (Idaho Department of Lands) and private ownership lands. The largest private owner is Potlatch Corp and multiple smaller private owners. Statewide, IDL and private landowners supply more than 90% of timber harvested annually[2]. Over 875,000 acres of accessible forestland is within 30 miles of Orofino. Further to the east of Orofino (30 to 50 miles), land ownership is dominated by U.S. and Nez Perce Forest Service-owned lands. Nearly 2 million acres of harvestable forest land are within 50 miles of Orofino.

2.2 BIOMASS SUPPLY - LOGGING RESIDUES

Logging Residues Volume Availability

Logging residue, also known as logging slash, is the woody biomass material left over from timber harvesting operations. This includes State regulations required mitigation of potential fire hazards caused by logging activities. Residual biomass is the portion of a tree that is not considered 'merchantable', and includes crowns, bole tips, and material above a 3-inch merchantable top. Idaho Department of Lands (IDL) further defines the non-merchantable logging product designated as 'fuel wood' or 'biomass' as "*any limb, chunk, log, top, longbutt or tree designated for harvest, which does not contain merchantable sawlog, pulpwood or cedar product material.*"[3]

The available volume of logging residues in the region was calculated by Tetra Tech for this analysis. The product is not consistently traded in the region, and therefore tracking data is limited or nonexistent. Two sources of data were utilized; historical harvest data, gathered from various public and private agencies, and forward-looking public agency timber offering data, gathered from the Coordinated Resource Offering Protocol (CROP) database. The resulting biomass residual volumes are shown in Table 7 and Table 8, and the basis of the calculation is presented below.

The following analysis uses the green weight (in pounds) of tops of trees cut for timber harvesting, assuming a "merchantable top diameter" of 3 inches. An estimate can be made of the weight of tops, crowns and cull wood by species by tree based on research conducted in Montana and Idaho (shown in Table 2). In addition to the tops, branches (crown) and defective portions of the tree are included. The tables refer to DBH, which is the diameter of the tree (outside the bark) at breast height (4.5 feet above the surface of the ground on the uphill side). Grand Fir and Douglas-fir are the most commonly available trees in the region.

[2] O'Laughlin, J. et al. "Wood Bioenergy: Homegrown Baseload Energy for Idaho." Report of the Forestry Task Force Idaho Strategic Energy Alliance (June 2009).

[3] ILD Proposed Special Terms of Sale, CR-30-0587, Old Style Timber Sale. 12/28/2010

Table 2 – Weight of Logging Slash Residual by Species

Pounds of Biomass in Tree Tops Above the 3-inch Merchantable Top							
PP	LP	WL-WP	DF	GF	AF	WC-WH	ES
16.3	14.2	16.1	22.8	25.9	22.9	19	22.9

Pounds of Biomass in Tree Branches and Defect up to the 3-inch Merchantable Top								
DBH (inches)	PP	LP	WL-WP	DF	GF	AF	WC-WH	ES
4	35	29	31	40	45	37	34	40
5	48	36	36	51	60	47	44	53
6	66	46	43	64	77	61	56	69
7	87	59	52	80	97	79	70	87
8	113	74	62	97	120	100	86	108
9	143	92	72	116	146	125	104	131
10	177	112	84	137	175	154	124	156
11	216	133	97	160	207	187	145	183
12	259	155	110	184	242	226	168	213
13	307	179	125	210	281	269	193	246
14	359	205	140	239	324	319	220	280
15	416	233	156	269	270	375	249	317
16	478	262	173	301	422	437	280	257
Source: (Brown, Kendall Snell, & Bunnell, 1977), Table 1. Weight Per Tree by DBH of All Material for Crowns and Unmerchantable Bole Tips to a 3-inch top.								

PP = Ponderosa Pine
LP= Lodgepole Pine
WL-WP =Western Larch and White Pine
DF = Douglas-fir
GF= Grand Fir
AF=Subalpine Fir
WC-WH = Western Redcedar and Western Hemlock
ES=Engelmann Spruce

The weights of the biomass included in the tables above are considered “green weight” meaning that the woody material still retains waters. The biomass needs to be measured as air dry weight, the material that can be processed in a biomass power plant. To determine the air dry biomass weight, a calculation can be used by subtracting the weight of the moisture based on the moisture content. The formula for calculating the dry weight of the biomass is as follows:

Green weight * (1 – % moisture content) = air dry weight

Based on the weight information in the tables above, the average dry weight per tree per species can be calculated. The table below shows the air-dry biomass of tops, crowns, and defect for a 12-diameter tree by species, displayed in short tons (2,000 pounds).

Table 3 – Air-Dry Weight of Logging Slash

Weight of Tops (3-inch diameter)					Weight (pounds) in crowns of average 12-inch DBH trees			Total
Species	Green Weight (pounds) of 3-inch DBH top	green weight (tons)	Air Dry		Green Weight (pounds) of Crown/Cull	green weight (tons)	Air Dry	Total Air Dry Wt. per Tree (Tons)
PP	16.3	0.0082	0.005		259	0.130	0.081	0.086
LP	14.2	0.0071	0.005		155	0.078	0.058	0.063
WL-WP	16.1	0.0081	0.006		110	0.055	0.042	0.049
DF	22.8	0.0114	0.010		184	0.092	0.079	0.089
GF	25.9	0.0130	0.008		242	0.121	0.071	0.079
AF	22.9	0.0115	0.007		226	0.113	0.067	0.073
WC-WH	19	0.0095	0.007		168	0.084	0.059	0.066
ES	22.9	0.0115	0.007		213	0.107	0.063	0.070

In order to determine enough woody biomass would available near Orofino, the information above can be used to calculate approximately how many trees by species would be needed. If one 12-inch DBH Grand Fir would produce 0.079 air dry ton then:

$1 \div 0.079$ = the number of Grand Fir needed to produce 1 air dry ton.

Table 4 shows the number of 12” DBH trees of each species required to be harvested, in order to produce one air-dry ton of logging slash available at the logging site.

Table 4 – Tree Harvest Required for 1 Ton of Biomass

Species	Total Air Dry Ton per tree of Tops and Crowns of 12-inch DBH trees	# of 12-inch DBH trees needed to make 1 Air Dry Ton
PP	0.086	12
LP	0.063	16
WL-WP	0.049	21
DF	0.089	11
GF	0.079	13
AF	0.073	14
WC-WH	0.066	15
ES	0.070	14

To calculate the number of trees needed within a given distance reasonable for transporting to Orofino, the trees were converted to thousand board feet (MBF) and compared to an associated timber harvest level. This will indicate whether enough timber is harvested in the area to meet potential biomass demand for this project.

Table 5 – Scribner Board Feet MBF Volume Table

Scribner Board Foot Volume Table								
Total Tree Height								
DBH (Inches)	**50**	**60**	**70**	**80**	**90**	**100**	**110**	**120**
Thousand Board Feet (MBF)								
12	30	50	70	90	100	120	140	160
14	50	70	140	130	160	180	200	220
16		100	170	170	200	240	260	300
18			210	220	260	290	330	370
20				260	310	360	400	440
22				310	370	420	470	520

Using the same average 12-inch diameter tree that is 80 feet tall, the harvesting level needed by species is shown in the table below.

Table 6 – Harvest in MBF Required for 1 ton of Biomass

Species	Number of trees per ton of biomass (air-dry)	Board feet per tree	Board Feet needed for a ton of air-dry biomass	Thousand Board Feet *(MBF)*
PP	12	90	1051	1.1
LP	16	90	1431	1.4
WL-WP	21	90	1852	1.9
DF	11	90	1015	1.0
GF	13	90	1139	1.1
AF	14	90	1226	1.2
WC-WH	15	90	1361	1.4
ES	14	90	1294	1.3
Average	**14.4**	**90**	**1296.1**	**1.3**

The average harvest needed to produce one ton of air-dry logging residue is 1.3 MBF. This is a conservative estimate for the dominant species mix in the area, considering only 1.0 MBF of Douglas-fir and 1.1 MBF of Grand Fir yield one ton of logging residue.

This figure is compared to historical harvest figures in the local region surrounding Orofino, ID to produce a calculated annual biomass residual potential, shown in Table 7. A total of 141,000 tons of logging residue, on a dry weight basis, is available in the Orofino region.

Table 7 – Historical Logging Slash Potential in the Orofino, ID Region

Calendar Year	Private Lands in Clearwater County[2]	Tribal lands in Clearwater County[1]	USFS (Lochsa District-Clearwater National Forest) [3]	Idaho Department of Lands (Clearwater and Maggie Creek Areas) [4]	Annual Total MBF
Thousand Board Feet (MBF)					
2005	125,138	2,672	10,226	43,219	181,255
2006	122,849	2,765	7,359	47,947	180,920
2007	131,635	3,359	3,796	63,377	202,167
2008	116,855	2,773	1,155	54,302	175,085
2009	113,508	3,135	10,498	52,211	179,352
5-year total	**609,985**	**14,704**	**33,034**	**261,056**	**918,779**
Annual Average	**121,997**	**2,941**	**6,607**	**52,211**	**183,756**
Annual Biomass Residual Potential (tons)	**93,844**	**2,278**	**5,082**	**40,163**	**141,367**

Notes:

1. Data grouped Tribal and private owners together. For the purposes of comparison with the CROP data, the Tribal volume was assumed to be equal to 5% of the agency total (Forest Service and IDL). This assumption is based on the predicted 1% to 12% of the total for 2010-2013 of Tribal offerings compared to the total of US Forest Service Lochsa Ranger District and IDL Clearwater and Maggie Creek Areas.
2. Idaho Department of Lands (IDL) "Private timber harvested per year" for years 2005-2009 for Clearwater County. This report includes all volume purchased by mills over 25,000 board feet from private and tribal lands (does not include state or federal lands). County volumes reported are from lands within the county. Totals included sawlog and pulp volumes.
3. Forest Service "Cut and Sold" reports. Figures used include the cut volumes reported for calendar years 2005-2009 for the Clearwater National Forest, Lochsa District. Totals included sawlog and pulp volumes.
4. IDL "CY Harvest Recap" for 2005-2008 for the Clearwater and Maggie Creek Areas. Totals included sawlog and pulp volumes. (The report for CY 2010 is not available).

The information in the table above can be used to observe recent trends in timber harvesting and therefore, likely available biomass. Timber harvesting levels are dependent on market conditions and availability. Timber purchasers will use whatever flexibility they have to time their harvests for optimal market conditions. This is indicated in the available data by an upward trend until 2007, followed by the downward trend in 2008 and 2009 when the housing market declined significantly. This above estimate of logging residue availability in the Orofino, ID region concurs with other estimations of logging residue potential that have been conducted in the area.

Forward-looking woody biomass resource data is also available for the Orofino region. The Coordinated Resource Offering Protocol (CROP) was designed so multiple agencies could enter their planned forest activities and users can download data across different scales and agencies. The outputs from the CROP database reports what agencies expect to offer for sale in the next 5 years, beginning in 2009. Data for Tribal lands, US Forest Service Lochsa Ranger District, and the IDL Clearwater and Maggie Creek Supervisory Areas are reported in the table below. CROP does not include data from private lands.

Table 8 – 5-yr Forecast Logging Slash Potential in the Orofino, ID Region

Calendar Year	Private Lands in Clearwater County[1]	Tribal lands in Clearwater County[2]	USFS (Lochsa District-Clearwater National Forest)	Idaho Department of Lands (Clearwater and Maggie Creek Areas)[3]	Annual Total MBF[4]
Thousand Board Feet (MBF)					
2009	NA	NA	596	70,197	70,793
2010	NA	500	9,370	49,000	58,870
2011	NA	3,300	41,040	49,000	93,340
2012	NA	3,300	8,045	49,000	60,345
2013	NA	3,300	5,334	49,000	57,634
5-year total[4]	**NA**	**10,400**	**64,385**	**266,197**	**340,982**
Annual Average	**NA**	**2,600**	**12,877**	**53,239**	**68,196**
Annual Biomass Residual Potential (tons)	**NA**	**2,000**	**9,905**	**40,953**	**52,459**

Notes

1 Information on offerings from private lands is not included in the CROP data.
2 Information on Tribal land for 2009 is not included in the CROP data. The total includes the 4 years instead of 5, and the annual average is based on 4 years instead of 5.
3 CROP data indicated the planned offering for Maggie Creek declines from 35 MMBF annually to 16 MMBF beginning in 2010.
4 Totals do not include any offerings from Tribal lands in 2009.

Source: Coordinated Resource Offering Protocol (CROP, 2011) Available online at http://www.crop-usa.com/nc_idaho/program_overview.php.

Unfortunately, CROP data does not include private timber offerings. Private landowners are often the most responsive to market conditions, and are highly likely to vary timber harvests according to the current value of the product. As private timber is by far the largest subset of the harvest in the local area, this points to a potential project risk. However, overall trends between historical and forward-looking data show a relative consistency in logging slash supply across the 10-year period, balanced by the multiple sources of material.

Because the table above reports what agencies expected to offer, it cannot be compared to past volumes of cut and removed timber. Timber offered (and sold) in 2009 may be cut in 2009 or any time within the next few years, depending on sale contract requirements. The overlap of 2009 data in the two tables proves this out. For example, the Lochsa Ranger District expected to offer 596 MBF in 2009, but reported that 12,552 MBF was cut. It is extremely difficult to project specific harvest by location or owner, but on an aggregate basis, and averaged over time, the harvest volumes are fairly consistent. Facilities will need to account for a reasonable buffer for year-to-year variations in product supply.

The vast majority of the logging residue currently produced is not marketed or sold. Some of this material is simply spread over the logging site, some is broadcast burned, and some is piled and burned in areas inaccessible to chipping machinery. A large portion of the material is inaccessible or otherwise not cost-effective to remove. Slash piles are managed under Idaho Forestry Act and Fire Hazard Reduction Laws[4], which apply the laws of the Forest Practices Act. Currently the majority of these slash piles are burned for fire mitigation.

Figure 3 – Logging Slash Piles near Orofino, ID

Conservatively estimating that 50% of logging residues are inaccessible, it can be assumed that 70,000 tons per year are available and accessible for removal and use as biomass fuel feedstock for all users in the Orofino region. Competition for the material is discussed below.

[4] Idaho Code Title 38, Chapters 1 & 4

Logging Residue Supply Logistics

Diversion of accessible slash piles is the anticipated mode of supply for the biomass power plant. Figure 3 shows a logging slash pile, photographed on IDL land near Orofino. The mix of tops, branches, ends and whole logs is representative of the logging residue material available in the Orofino area. This particular slash pile was reportedly slated for burning. Below it is a picture of another, nearby slash pile, in the process of being burned by the Clearwater-Potlatch Timber Protective Association (C-P TPA).

A limited quantity of logging residue is currently being processed and removed from forests for use in existing biomass power plants. This process is called in-woods grinding, and represents a small but growing industry in the area. These in-woods grinding operations have established procedures and have purchased specialized grinders, chippers, and other equipment to economically process and transport logging residues from the forest to the project site. Due to the high bark content and inconsistent particle size of the material, in-woods grinding material is known as hog fuel. Hog fuel is predominantly used as boiler feedstock material.

Three chipping operations in the local area represent the majority of the existing supply channel for acquisition of biomass residuals, including Jack Buell Trucking, Ray Moss Trucking, and ABCO Wood Recycling. Other chipping operations may also exist in the area.

Figure 4 shows a photo of a local chipping contractor's in-woods grinding operation, photographed near Orofino.

Figure 4 – In-woods Grinding Operation near Orofino, ID

The Clearwater Paper plant located in Lewiston, ID is the primary market buyer of current logging residuals as well as pulpwood. Acquisition of logging residue supply from west of Orofino is unlikely due to limited forested acreage and the draw from the paper plant. The Clearwater Paper biomass power plant is currently operating at 50MW+, requiring a total feedstock supply of over 1,000 tons per day (tpd). Much of this is supplied as a byproduct of the facility's paper mill, but must be supplemented with in-woods grinding derived biomass. Clearwater Paper is by far the largest consumer of biomass material in the area, and while on one had they are competition for raw materials, their position presents an advantage to the project. Much of Clearwater Paper's biomass fuel comes from east of Orofino, and passes through town on its way to the plant in Lewiston. The shorter transportation distance to the prospective Orofino biomass power plant will be attractive to chipping operations seeking additional outlets for their product. In this regard, working with this large buyer will be advantageous to this project. Clearwater Paper's existence provides stability for in-woods grinding operations, and at times they may be able to sell their feedstock surplus to the project. It is expected to be advantageous to Clearwater Paper because this project will benefit the community in which they do business. Initial conversations with Clearwater Paper representatives suggest they are willing to work as a team member in this project.

A portion of the available and accessible feedstock is also being removed and sold as feedstock for other biomass power plants in the area. In 2010, IDL's Clearwater Supervisory Area sold 16,300 tons of logging residual as biomass fuel in two separate projects of 12,500 and 3,800 tons each. Local chipping operations contacted reported approximately 50,000 tons of logging residual material sold as biomass fuel in 2010, though this included removal from areas outside of the Orofino region, and also included the material removed from IDL lands. 20,000-30,000 tons per year of logging residues are assumed to be currently utilized in the Orofino region.

Accounting for the currently-utilized material and materials not cost-effective to remove, Tetra Tech estimates there are **40,000-50,000 tons per year** of available and accessible logging residues within the Orofino region.

2.3 BIOMASS SUPPLY - FOREST THINNING AND STEWARDSHIP

Forest Thinning and Stewardship Biomass Volume

Additional biomass feedstock supply may be obtained from thinning, stewardship, and unmerchantable log harvests, identified within the CROP database as 'Biomass Offerings' (trees less than 7" DBH). On average from year 2010-2014, 60,000 green tons annually of biomass will be available for contract removal from IDL, USFS, and the Nez Perce Tribe (Table 9). CROP also reports biomass removal projects that agencies plan to make available. The table below shows the reported amount of biomass to be offered from CROP data. The air dried tons was calculated using an average 30% reduction in weight from green to air dried. Note in 2014 offering level is much less, likely due to a lack of reporting interest in the resource rather than a reduction in availability.

Table 9 – 5-yr Forecast Stewardship and Thinning Biomass Volume

Calendar Year	Private Lands in Clearwater County[1]	Tribal lands in Clearwater County[2]	USFS (Lochsa District-Clearwater National Forest)	Idaho Department of Lands (Clearwater and Maggie Creek Areas)	Annual Total Tons
Green Tons					
2009	NA	NA	16	49,700	49,716
2010	NA	1,300	5,023	37,620	43,943
2011	NA	4,000	22,800	37,620	64,420
2012	NA	4,000	4,293	37,620	45,913
2013	NA	4,000	2,730	37,620	44,350
5-year total	**NA**	**13,300**	**34,861**	**200,180**	**248,341**
Annual Average Green Tons	**NA**	**3,325**	**6,972**	**40,036**	**49,668**
Air Dried Tons[3]	**NA**	**2,328**	**4,880**	**28,025**	**34,768**

Notes

1 Information on offerings from private lands are not included in the CROP data.
2 Information on Tribal land for 2009 is not included in the CROP data. The total includes the 4 years instead of 5, and the annual average is based on 4 years instead of 5.
3 Weight reduction between green and air dried due to moisture loss by species. (Toolbox, 2011)

DF	14%
S	41%
GF, AF	41%
LP	26%
PP	38%
WC-WH	29%
WL-WP	23%

Sources: Coordinated Resource Offering Protocol (CROP, 2011) Available online at http://www.crop-usa.com/nc_idaho/program_overview.php.
Toolbox, The Engineering. 2011. http://www.engineeringtoolbox.com/weigt-wood-d_821.html. 2011.

Thinning and Stewardship Contracts and Acquisition

Acquisition of biomass from thinning and stewardship operations is logistically similar to acquisition of logging residuals. However, thinning and stewardship biomass contracts are a primary logging contract, as opposed to a secondary product from a logging contract made for sawlogs or pulpwood. However, purchase of this material differs from logging residues because thinning and stewardship operations are stand-alone timber sales, as opposed to secondary sales from existing logging operations. The owner of the biomass power plant will have to enter into agreement with IDL, USFS, or the Nez Perce Tribe to gain access to these materials as stand-alone timber sales, and must also hire a logging firm to remove the materials and deliver to the plant site. This structure allows for as-needed supply of product, but adds logistics and manpower requirements. Competition for these products is on case-by-case, according to the perceived value of the stand for other uses (sawlogs, pulpwood, etc).

There is an estimated supply of over **34,000 tons** per year of forest thinning and stewardship biomass product available in the Orofino region. However, due to the limited practice of thinning and stewardship harvest removal in Idaho, this product is not recommended as a primary feedstock source for the proposed biomass power plant. Tetra Tech recommends acquiring forest thinning and stewardship contracts and feedstock only to supplement plant needs in times of limited supply of other feedstocks.

2.4 BIOMASS SUPPLY - MILL RESIDUES

Mill residues are generally considered an over-utilized resource in Idaho. Most sawmills are already under contract to sell sawdust, hog fuel, and other residues to pulp-and-paper mills and established biomass power plants. Other mills utilize residues on-site to produce thermal energy for kiln drying and other processes. Whether sold to existing biomass power plants or used by the mills for their internal thermal energy needs, the fuel value of this resource has been understood for many years in the state. According to the Idaho Strategic Energy Alliance's Forestry Task Force, "mill residues are already used either for biomass energy production or in pulp/paper manufacturing (e.g., Lewiston ID, Wallula WA, and Missoula MT). Almost all mill residues in the state are fully utilized (Nicholls et al. 2008, citing Morgan et al. 2004) and thus not available to produce additional bioenergy[5]."

Despite the existing demand for mill residues, they present a low-cost opportunity feedstock for the project. Mill residues are pre-processed and are ready to use, and have the benefit of reduced logistics of delivery from local mills. Because mill residues are produced and aggregated in a localized area (the mill itself), the logistics of acquisition and transport are far simpler than logging residues.

[5] O'Laughlin, J. et al. "Wood Bioenergy: Homegrown Baseload Energy for Idaho." Report of the Forestry Task Force Idaho Strategic Energy Alliance (June 2009).

Mill Residue Supply, Competition, and Availability

Tetra Tech interviewed several mills in the Orofino region to determine the supply produced, availability, and pricing of mill residues. The mills in the Orofino region include:

Tri-Pro Forest Products PO Box 1208 2705 Michigan Avenue Orofino, Idaho 83544 County: Clearwater P: 208-476-4597 F: 208-476-7799	**Bennett Lumber Products** PO Box 49 Highway 6 Princeton, Idaho 83857 County: Latah P: 208-875-121 F: 208-875-0191	**Empire Lumber Company** Kamiah Mills PO Box 638 Highway 12 Railroad St Kamiah, Idaho 83536 County: Idaho P: 208-935-2536 F: 208-935-0460	**Empire Lumber Company** PO Box 206 206 Sixth Avenue East Weippe, Idaho 83553 County: Clearwater P: 208-435-4113 F: 208-435-4663

Of the mills interviewed, all had existing uses for sawdust residue product. Several used residue in in-house steam boilers, and the remainder sold product to existing biomass power plants, primarily Clearwater Paper in Lewiston, ID. Contracts for that product preclude competitive buying. There is, however, less demand for mill residue in the form of hog fuel in the Orofino region. Hog fuel product is of lower quality and is less consistent than sawdust.

Several mills do not have contracts in place to off-take hog fuel residues, and indicated willingness to sell product to the proposed biomass power plant. While this availability is dependent on the overall supply in the region and the spot pricing for the project, Tetra Tech estimates the average available supply to be in the range of 20-30 tons per day (tpd) at 35% moisture, or 7,000-10,500 tons per year. Due to existing competition, the proposed project can only expect to draw a portion of this supply. Assuming 50% of the available (not contracted) supply can be drawn to the proposed project, the supply availability for the proposed biomass power plant is conservatively estimated at **3,500 tons per year.**

2.5 BIOMASS SUPPLY – PULPWOOD/CHIPWOOD

Pulpwood Supply, Competition, and Availability

Chip wood has an established market structure. Chip wood or pulpwood is used in the paper manufacturing process, and while secondary to sawlogs in terms of market value, chip wood is produced and sold through common supply chain mechanisms. Chip wood has an established product specification, strictly limiting bark content, fines, and other impurities.

A portion of the total volume of timber removal analyzed above is sold as pulpwood. Table 10 shows the volumes of timber sold specifically as chip wood or pulpwood in the local area. Approximately 15% of total volume of logging contracts are sold as pulpwood or chip wood.

Table 10 – Historical Chip Wood Biomass Potential in the Orofino, ID Region

Calendar Year	Private Lands in Clearwater County[1]	Tribal lands in Clearwater County[1]	USFS (Lochsa District-Clearwater National Forest)[2]	Idaho Department of Lands (Clearwater and Maggie Creek Areas)[3]	Calculated Annual Total
Thousand Board Feet (MBF)					
2005	20,005	427	725	5,114	26,271
2006	19,639	442	1,059	6,385	27,525
2007	21,043	537	0	11,993	33,573
2008	18,681	443	44	11,121	30,289
2009	18,129	518	346	10,227	29,219
5-year total	**97,496**	**2,367**	**2,174**	**44,840**	**146,877**
Annual Average (MBF)	**19,499**	**473**	**435**	**8,968**	**29,375**
Annual Average (tons)	**14,999**	**364**	**334**	**6,898**	**22,596**

Notes

1 Data was not available regarding pulp volume of private and tribal lands harvesting, so a calculation was made based on the percent of the total volume on National Forest and IDL land and applied to the private and tribal lands. The average percentage of volume in pulp used was 15%.
2 From the Forest Service Cut and Sold reports for 2005-2009.
3 From the IDL Harvest Reports for 2005-2009.

Additional unknown volumes may have been reported sold as sawlogs, but diverted to pulp and paper mills. Due to competing uses for the product, the volume of chip wood below is not an indication of the volume of chip wood that is available for use by the proposed plant. Tetra Tech recommends that chip wood be considered an as-needed feedstock source. The existence of an established, consistent market greatly reduces the risk of facility under-supply.

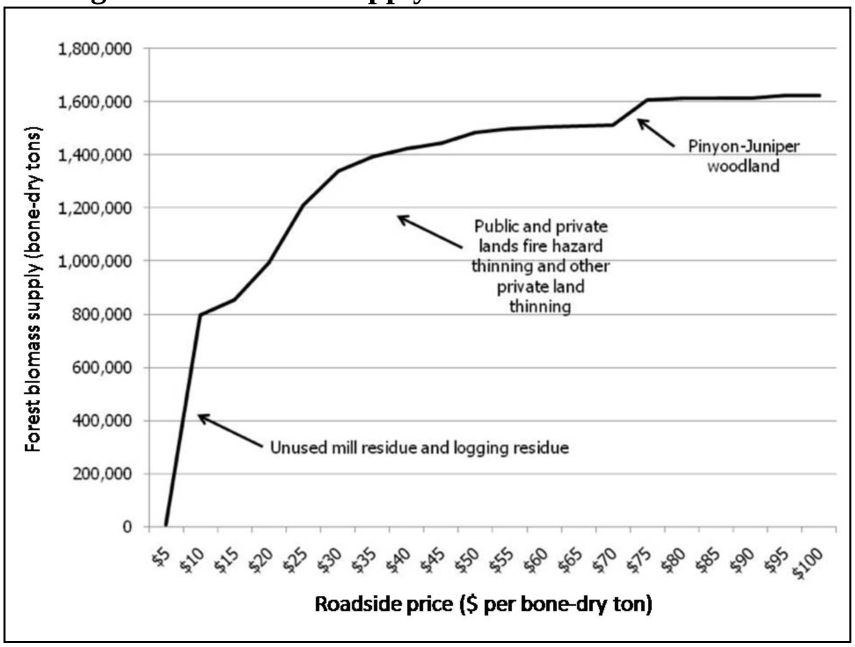
As an additional consideration, chip wood is commonly delivered as whole logs. A chipper at the facility site is included in the plant conceptual design, but is primarily designed for size reduction of pre-ground hog fuel. Whole-tree chipping or grinding will require purchase of equipment or hiring a contractor at additional product cost.

2.6 FEEDSTOCK SUPPLY PRICING ESTIMATION

Pricing for forest products is rarely static; varying in regards to season, current economic conditions, and most importantly, available supply and the market demand for that supply. Further compounding the problem, logging residue, which are the anticipated primary feedstock for the project, have until recently had little value and are not a commoditized product. The value of thinning contracts and mill residue, the project's secondary feedstocks, have more established supply chains and therefore somewhat simpler pricing methodology.

Evidence gathered in 2009 by the Idaho Strategic Energy Alliance's Forestry Task Force determined a pricing supply curve for biomass feedstocks in Idaho (Figure 5). As indicated in the graph, biomass price is a function of supply. A larger plant scale and associated feedstock supply need may trigger competition for the resource (thereby upsetting the current supply and demand economics) and/or require more expensive extraction techniques (thereby increasing the cost to the project).

Figure 5 – Price vs. Supply Curve for Idaho Biomass[6]



Logging Residue Pricing

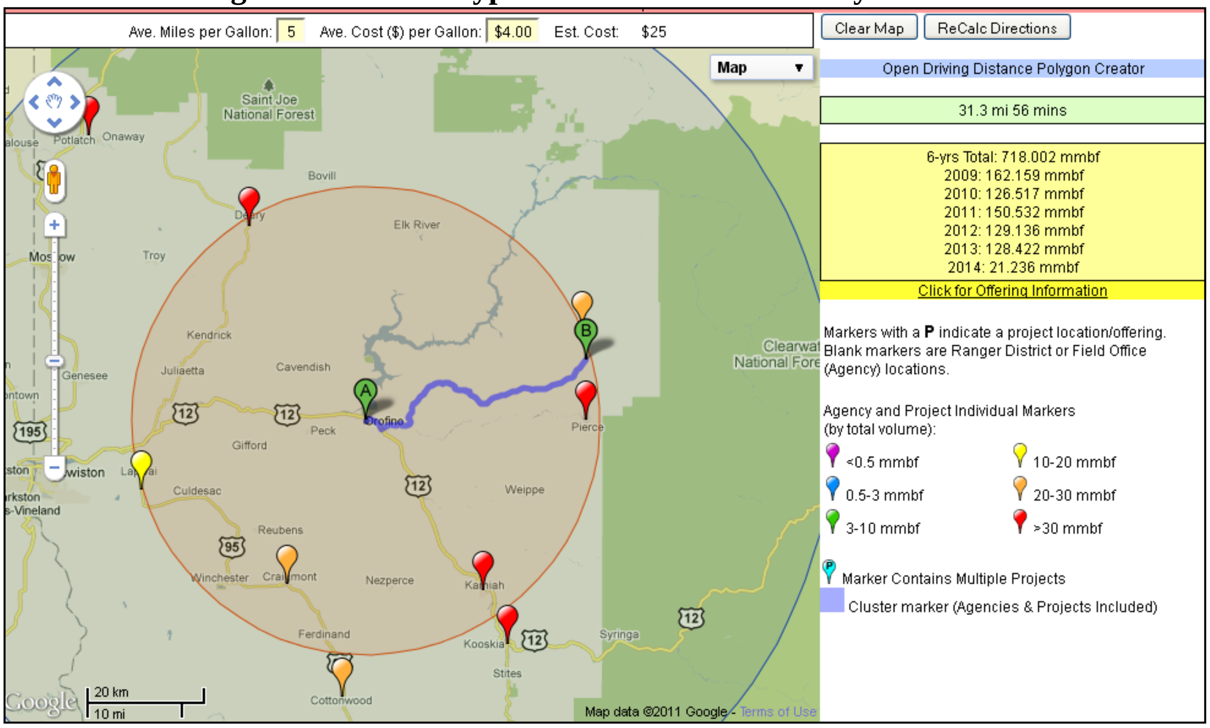
Based on the material availability and supply determined in the previous section, Tetra Tech anticipates that a significant volume of logging residual biomass will be available to the proposed facility with little or no pricing disruption. In other words, below a certain volume, the price for logging slash can be assumed to be the cost of collecting and transporting the product to the plant. This assumption that the feedstock supply is readily available allows for a brief decoupling of the price vs. supply dichotomy.

The CROP Interactive Haul Distance Mapping Tool was used to assist in estimating the transport distance and delivery price of the project's feedstocks. Within 25 miles of Orofino there are four 'Agency and Project individual markers', representing two offerings of 20,000-30,000 MBF of

[6] O'Laughlin, J. et al. "Wood Bioenergy: Homegrown Baseload Energy for Idaho." Report of the Forestry Task Force Idaho Strategic Energy Alliance (June 2009).

timber between 2009 and 2013, and two offerings of over 30,000 MBF in that same timeframe. In addition, two agencies are just beyond the 25-mile radius, with offerings in the next five years of another 50,000-60,000 MBF.

Figure 6 – CROP Hypothetical Biomass Delivery Scenario[7]



A hypothetical feedstock delivery scenario was created using the database. CROP estimates a delivery distance of 31 miles from a representative logging site situated amongst the offerings, and the Biomass Power Plant (Point A to Point B in Figure 6). The majority of the trip is on windy, dirt roads, and CROP estimates it takes 1 hour to traverse this distance. CROP further estimates the fuel surcharge cost at $25.00 for the delivery, based on $4.00/gallon diesel fuel. Common transport charges are $2.00/mile for vehicles and labor, which equates to $125 for the hypothetical haul model example. With fuel surcharge added in, this results in a delivery price of $143, rounded to $150 charge per load. Conservatively estimating 20 tons per load, the as-received transport charge is estimated at $7.15/ton. Delivery distance up to 50 miles adds an extra 38% to delivery charges, resulting in a conservative estimate delivery price of $9.80/ton.

The Idaho Strategic Energy Alliance's FTF report estimates the cost of logging residue slash at the roadside to be approximately $8.00/ton, and an additional $2.00/ton stumpage price for public land harvest. However, the material still needs to be chipped. Equipment and labor for

[7] Source: CROP Interactive Haul Distance Mapping Tool: http://www.crop-usa.com/Interactive_Haul_Distance_map_all_offerings.php

operation of an in-woods grinding operation was quoted at $400/hr, producing 200 bone dry tons of material daily (25 tons/hr). That equates to $16.00/ton for finished loaded material.

Adding the estimated delivery charge calculated above arrives at an estimated delivered price of $35/ton for logging residue feedstock on a dry ton basis, or $25.06/ton as-received condition. Table 11 indicates the supply chain breakdown of in-woods grinding and delivery of logging residue feedstock for the Clearwater area. Increases in hauling distance, difficulty of material access for grinding, or other factors can quickly increase delivered material cost.

Table 11 – In Woods Grinding Delivered Feedstock Cost

In-Woods Grinding Supply Cost (Readily- Available Material 30-50 mi)			
Supply Chain	**Cost**	**Unit**	**Cost /ton**
Raw Logging Residue (roadside)[1]			$8.00
Stumpage[1]			$2.00
Chipping Cost[2]	$400	hour	$16.00
	25	tons/hr	
Transport[3]	$2.00	mile + fuel	$9.80
		Total ($/dry ton)	**$35.80**
		Total Cost ($/ as received)	**$25.06**

Notes
1. O'Laughlin, J. et al. "Wood Bioenergy: Homegrown Baseload Energy for Idaho." Report of the Forestry Task Force Idaho Strategic Energy Alliance (June 2009)
2. Jack Buell Trucking/JMF Co. Inc. - St. Maries, Idaho and other in-woods grinding companies
3. CROP Interactive Haul Distance Mapping Tool: http://www.crop-usa.com/Interactive_Haul_Distance_map_all_offerings.php

Table 12 shows the results of a study of harvesting methods conducted by the University of Minnesota's Center for Integrated Natural Resources & Agricultural Management (CINRAM). The report was an in-depth survey multiple harvest sites and methods. The report estimates that the total delivered cost of logging residues are currently between $26-$32/ton, incorporating various harvest types, forwarding, chipping, and transport to mills.

Table 12 – CINRAM Biomass Harvesting Costs by Activity[8]

	Cords/Acre	Tons /Acre	Harvesting	Forwarding	$ to Chip /Ton	Transport to Mill	$/Ton Stumpage	Total Price/Ton
Selective Cut - Hardwood, small area of clearcut Aspen	14 cords/acre 75% - Hardwood 14% -Aspen 11% -Balsam	11 tons	$0/ton	$12.30/ton	$5/ton	$9/ton	$0/ton	$26.30/ton
Land Clearing, Mainly Hardwood	29 cords/acre 84% - Hardwood 16% -Pine/Fir	33 tons	$0/ton	$9.20/ton	$5/ton	$12/ton	$0/ton	$26.20/ton
Shelterwood Harvest - Oak and Red and White Pine Left, Hardwood, Aspen, and Jack Pine Cut	12 cords/acre 40% -Hardwood 41% -Aspen 19% -Jack Pine	8 tons	$0/ton	$14.80/ton	$5/ton	$12/ton	$0/ton	$31.80/ton

The delivered price of slash calculated above, and the provided analysis by CINRAM, is consistent with the median pricing estimated by Clearwater County-area stakeholders Tetra Tech has contacted throughout the project. These stakeholders include public and private loggers, forest consulting firms, and local land management agencies. Pricing estimates solicited from these stakeholders varied widely, from $8.00/ton to over $40.00/ton, but the consensus opinion coincided with the calculated feedstock supply estimate. This pricing is assumed to be the same for acquisition of feedstock from public and private lands.

The calculations presented above are an empirical analysis of the cost of logging residues. In Idaho, logging residues are primarily sold on a delivered basis, calculated from the distance of the logging operation to the plant site. The quality and quantity of the logging residual existing at the logging operation, and most importantly, and the ease in which logging material can be removed from the logging operation site, impact product pricing. At present, in-woods grinding depends on the economic and logistical viability of removal of slash from the forest as opposed to *in situ* burning.

Short-term opportunities may become available for advantageous pricing, reported by one stakeholder to be in the range of $15/ton, but in times of tight supply higher than normal pricing may be experienced. Once the cost of logging residue reaches a certain price ceiling, other products such as stewardship and thinning products or chip wood become financially viable alternatives.

$25/ton will be assumed for the delivered price of logging residue on a wet or as-received basis, corresponding to $35.71 per dry ton. This pricing can be assumed for the volume of available logging residue as calculated above, approximately 40,000 tons per year. Should the plant draw volumes above that amount, significant pricing increases can be expected.

[8] Source: “Economics of Biomass Harvest” CINRAM

Thinning and Stewardship Biomass Pricing

Thinning and stewardship feedstock is acquired through the same logistical pathways, therefore pricing for that material is assumed to be equal. However, the administrative costs, stumpage price, and cost of logging can be assumed to add $10/ton to the feedstock price, resulting in a delivered price of **$35/ton** on a wet basis, or $50/ton on a dry basis.

Mill Residues Pricing

Mill residues in the form of hog fuel are the least-expensive feedstock product available in the area. However, due to the significant competition for mill residues in the state, pricing of mill residues is highly variable. Discussions with one local mill produced the following pricing structure for mill residues, which can be extrapolated to the available volumes from other local mills.

Table 13 – Mill Residue Pricing by Product Type

Type	Volume	Pricing	Availability
Hog Fuel	25 tpd	$20/ton green	25-50%
Sawdust	25 tpd	$25/ton green	None
Chips	25 tpd	$30/ton green	Limited

As discussed above, sawdust and chip wood from mills are competitively sought in the local area. Hog fuel is more available for use at the prospective biomass plant, and also has the benefit of being the lowest cost feedstock product. For the limited volume available in the local area, $20/ton on a green basis will be assumed for mill residue feedstock.

Chip Wood Pricing

Northwest Management, Inc. produces a quarterly Log Market Reports of wood product sales and prices in the Pacific Northwest region. The 1st Quarter 2011 report indicates pulpwood pricing at $35/ton, delivered on a dry basis in the nearby Lewiston and Nez Perce region, and $40/ton to the north near Spokane and Stevens. Pulpwood pricing is not available in the Clearwater region.[9] Pulpwood prices are unnaturally low with the shortage of construction material needs in the U.S., and can be expected to rise as the market improves.

Chip wood pricing is expected to range from $40-$60/ton. The price for the purposes of this analysis will be assumed at $55/ton on a dry basis, equivalent to $40/ton as-received.

[9] http://www.consulting-foresters.com/?id=market

2.7 SUMMARY AND FEEDSTOCK SOURCING PLAN

It is apparent from data available that required volumes of biomass feedstock material are available in the Orofino region to supply the Plant. This feedstock requirement can be met entirely with residual logging, and can be supplemented with mill residues, stewardship/thinning biomass, and occasional chip wood that can be obtained at advantageous pricing. Idaho Department of Lands (IDL) and Private Foresters, including Potlatch Corp and independent operations, are expected to be the primary sources for the material.

Table 14 below shows the total volume of biomass available and accessible for the prospective biomass power plant.

Table 14 – Orofino Regional Feedstock Supply and Pricing

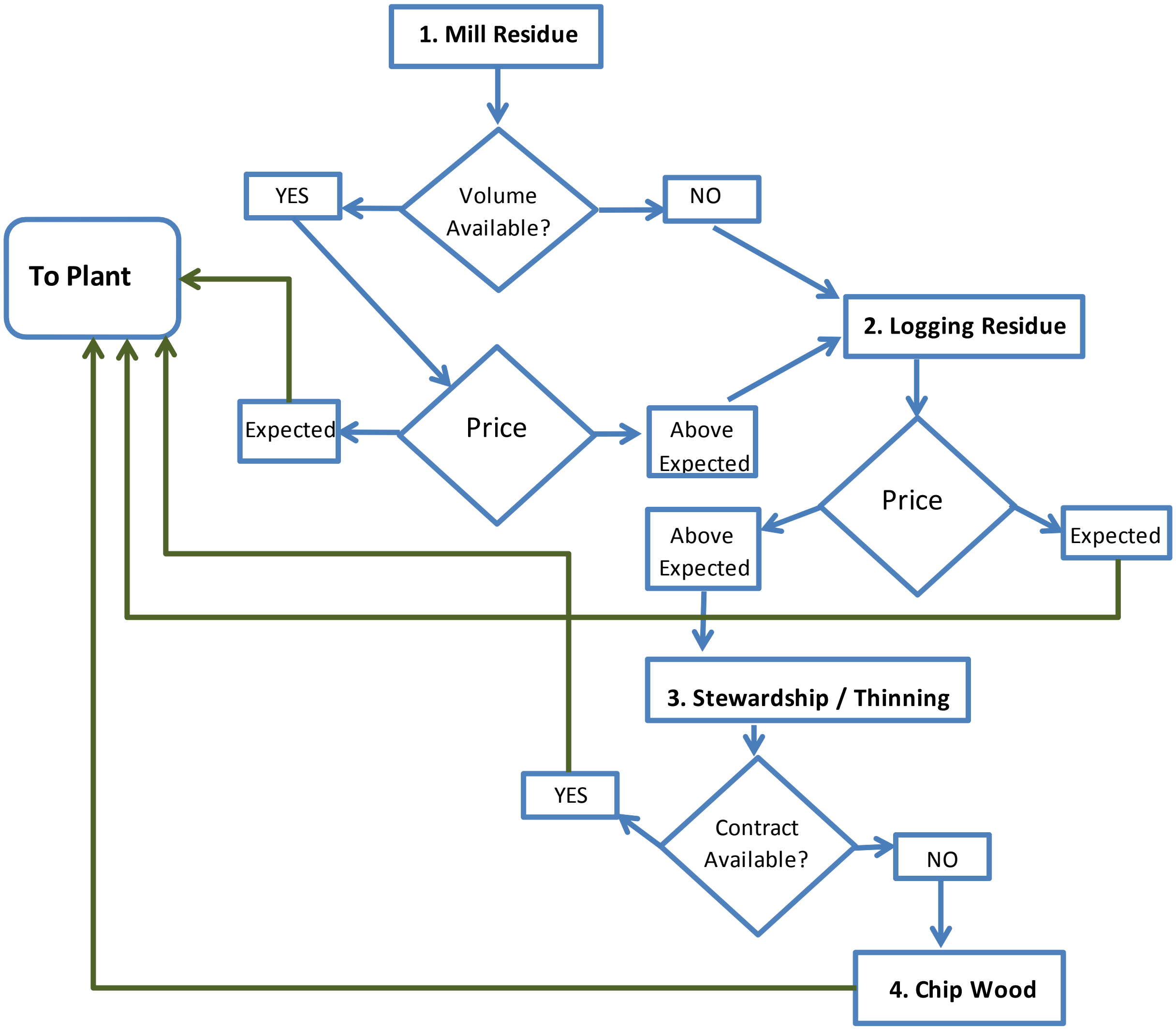
Product	Annual Tonnage	Baseline Delivered Price ($/ton as received)	Baseline Delivered Price ($/ton dry basis)
Logging Residue	40,000-50,000	$25.00	$35.00
Mill Residue	3,500	$20.00	$28.50
Thinning / Stewardship	35,000	$35.00	$50.00
Chip wood	22,000+	$40.00+	$55.00+
Total	**100,500 tons**		

Feedstock Sourcing Plan

Acquisition of feedstock for the Plant will focus on the lowest cost materials available with the least logistical difficulty for delivery. Though specific conditions will vary as market forces change in the area, the following is a brief description of the process the Plant's feedstock buyer can be expected to take in the acquisition process.

Figure 7 below maps the fuel supply plan flowchart for the prospective biomass power plant.

Figure 7 – Fuel Supply Plan Flowchart



The lowest cost and easiest feedstock to acquire in the Orofino area is mill residues. However, supply of mill residues is limited, and competition is high. The project should first seek available and competitively-priced mill residues. If pricing and/or volume do not meet the feedstock requirements of the biomass power plant (a likely common scenario), the buyer should then look to logging residues for supply.

For logging residue, one or several of the local in-woods grinding operations should be contacted for supply and pricing. Supply is not anticipated to be a problem with the large quantity of logging residue available in the region; product pricing is the primary variable that will fluctuate according to market conditions. Alternatively, one of the larger biomass power plants (i.e., Clearwater Paper) can also be contacted for purchase of oversupply material if available.

In normal market conditions, mill residue and logging residues should fully supply a biomass power plant. However, in times of low supply availability, forest thinning contracts or chip wood may be purchased for the facility.

Feedstock Contracts and Long-Term Pricing

As noted above, mill residues or a combination of mill residues and logging residues should be sufficient to fully supply the feedstock needs of the Plant. Assuming this, the baseline feedstock purchase price for the plant will be set to the price of logging residues, or $25/ton on an as-received basis ($35/ton on dry basis). This is considered the 2011 pricing basis. Pricing will vary and likely increase over time, and is discussed below.

The market for forest products in Idaho is closely linked to national trends in lumber demand. Sawlogs are the primary forest product in the area, and logging of timber in the region is dependent on the demand for construction materials in the larger market. Pulpwood is the next highest value product removed from the forests, but is also often dependent on sawlog timber sales for product availability. The byproducts of logging, of which the proposed biomass power plant is entirely dependent, follow suit.

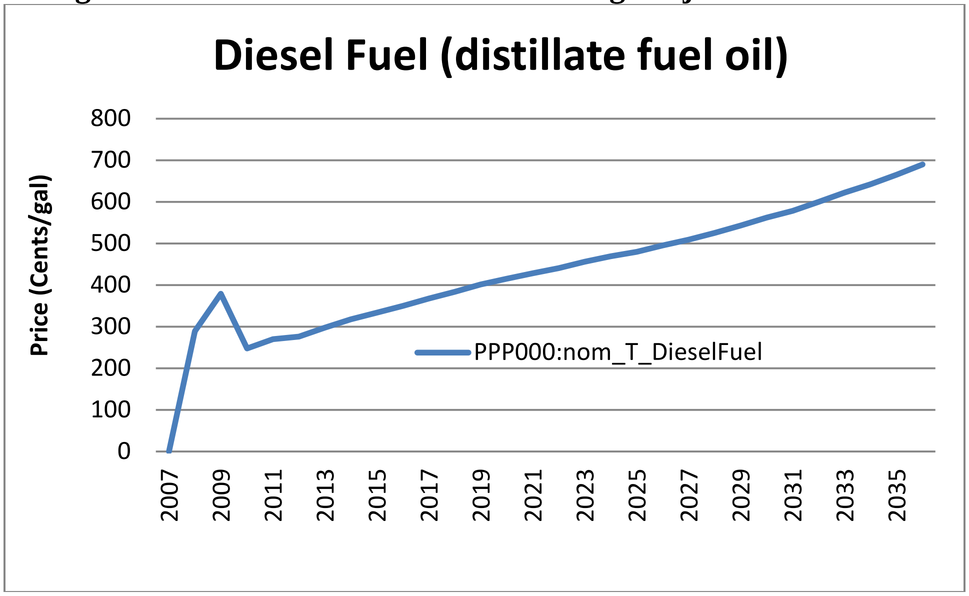
The volatile market for forest products does not lend itself well to long-term pricing structures or supply contracts. Most pricing is determined when a timber sale is purchased, akin to a spot market. Stewardship and thinning contracts, and to a lesser extent mill residues, represent feedstock acquisition avenues for the proposed plant that are independent of the sawlog market volatility. At the standpoint of the proposed biomass power plant, however, several indicators give confidence that feedstock availability is assured for the project.

The relative abundance of logging residue allows for pricing to be determined through the cost of removal, as calculated in preceding sections. Therefore, at smaller plant feedstock requirements, expected pricing over time can be established. At higher plant scales, other market forces come into play and will disrupt pricing. This can be projected into the future though a link to the diesel fuel index, which is the most volatile variable of the logging residue supply chain. Diesel fuel accounts for approximately 30% of the price impact of logging residues acquisition.

The US Department of Energy's Energy Information Administration (USDOE EIA) projects fuel pricing as a portion of its Annual Energy Outlook[10]. Forecasted pricing for on-road diesel fuel is shown in Figure 8 below.

[10] U.S. Department of Energy, Energy Information Agency, Annual Energy Outlook 2010 (http://www.eia.gov/forecasts/aeo/)

Figure 8 – USDOE EIA Diesel fuel Pricing Projection 2007-2035



Assigning the price of diesel fuel in 2010 a value of '1', the price impact of diesel fuel can be applied to the expected delivered price of logging residues. Table 15 shows the expected diesel fuel price impact over time and its effect on the delivered price of logging residue, assuming a base price of $25/ton for feedstock. Escalation of diesel fuel pricing over time raises the delivered price of logging residue to $29.41/ton by 2020, and $36.66/ton by 2035. These values will be used in the financial evaluation of the project in Section 6.

Table 15 – Projected Feedstock Delivery Price 2010-2035

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Diesel Price	270.0	276.2	297.6	317.9	334.0	350.2	368.0	384.1	401.6	415.4	428.7
Diesel Index	1.00	1.02	1.10	1.18	1.24	1.30	1.36	1.42	1.49	1.54	1.59
Diesel Fuel Impact	7.50	7.67	8.26	8.83	9.28	9.73	10.22	10.67	11.16	11.54	11.91
Total Feedstock Price	25.00	25.17	25.76	26.33	26.78	27.23	27.72	28.17	28.66	29.04	29.41

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
441.0	456.5	468.9	480.1	495.2	509.4	525.1	542.7	562.5	578.2	600.1	622.2	642.4	665.0	689.9
1.63	1.69	1.74	1.78	1.83	1.89	1.94	2.01	2.08	2.14	2.22	2.30	2.38	2.46	2.55
12.25	12.68	13.02	13.33	13.75	14.15	14.59	15.07	15.62	16.06	16.67	17.28	17.84	18.47	19.16
29.75	30.18	30.52	30.83	31.25	31.65	32.09	32.57	33.12	33.56	34.17	34.78	35.34	35.97	36.66

To assist in negotiating the volatility of the forest product market, a feedstock supply manager (buyer) is recommended for the proposed biomass plant. If the plant is constructed at a small scale that does not allow for the financial burden of a full-time buyer, agreement with a larger buyer in the area for product, such as Clearwater Paper, is recommended.

2.8 BIOMASS FEEDSTOCK CHARACTERIZATION

The prospective biomass power plant will use hog fuel from various sources and tree species as its primary fuel source. Hog fuel contains significant bark and fines, as well as inconsistent particle sizes (up to 4" square). These characteristics are problematic for processing equipment, and make the product undesirable for all uses except as fuel source. Bark has a higher Btu content than wood, but also has higher ash content. Foliage (needles, etc) contain the highest ash content and other impurities, and should be minimized whenever possible.

The physical characteristics of hog fuel, whether in the form of in-woods grinding from logging residue, stewardship or thinning products, or mill residue, are shown below([11], [12], [13], and other references). These characteristics are utilized in the conceptual biomass power plant design presented further in the study.

[11] Wilson, Et.al, Fuelwood Characteristics of Northwestern Conifers and Hardwoods (Updated). USDA PNW-GTR-810 (2010

[12] O. Kitani and C. W. Hall: Biomass Handbook, Gordon and Breach science publishers, New York (1989)

[13] Susott, R. A., For. Sci. 28, 404 (1982) and Biorenewable Resources (2003) - Robert C. Brown

Table 16 – Project Feedstock Composition

SPECIES	HEATING VALUE (dry) HHV BTU/lb	HEATING VALUE (dry) LHV BTU/lb	PROXIMATE ANALYSIS (%wt.,dry) Volatile	Ash	Fixed C	ULTIMATE ANALYSIS (%wt.,dry) C	H	O	N	S	Cl
Douglas Fir											
Douglas Fir - Wood	8,884	8,336	83.3	0.6	16.1	51.28	6.27	41.70	0.11	0.02	
Douglas Fir - Bark	9,465	8,948	73.3	0.9	25.9	56.20	5.90	36.70			
Douglas Fir - Foliage	9,587			4.3							
Douglas Fir - Rotten Wood	9,910			0.2							
Douglas Fir - Stems	9,622			2.6							
Avg	**9,494**	**8,642**	**78.3**	**1.69**	**21.0**	**54**	**6.1**	**39.20**	**0.11**	**0.02**	
Grand Fir											
Grand Fir - Wood	8,641	7,653	83.2	0.3	16.6	49.00	5.98	44.75	0.05	0.01	0.01
Avg	**8,641**	**7,653**	**83.2**	**0.25**	**16.6**	**49**	**5.98**	**44.75**	**0.05**	**0.01**	**0.01**
Ponderosa Pine											
Ponderosa Pine - Wood	8,826	8,209	82.9	0.3	16.9	50.25	6.20	43.20	0.06	0.02	0.01
Ponderosa Pine - Bark	9,540		73.4	0.6	26.0						
Ponderosa Pine - Foliage	9,556			2.7							
Ponderosa Pine - Dead Foliage	9,850			3.8							
Avg	**9,443**	**8,209**	**78.2**	**1.82**	**21.4**	**50**	**6.20**	**43.20**	**0.06**	**0.02**	**0.01**
Western Larch											
Western Larch - Wood	8,403			2.0							
Western Larch - Bark	8,835			1.6							
Avg	**8,619**			**2**							
Engelmann Spruce											
Engelmann Spruce - Bark	8,712			2.5							
Avg	**8,712**			**2.5**							
Average Feedstock Composition	**8,982**	**8,168**	**79.9**	**1.6**	**19.7**	**51.0**	**6.09**	**42.38**	**0.074**	**0.017**	**0.010**

3.0 Energy Audit - Local Energy Demand

Several facilities in Orofino have been identified as potential project customers, to utilize the thermal and/or electrical energy produced by the prospective Plant. They include the Idaho Correctional Institution-Orofino (ICI-O), the Idaho State Hospital North (SHN), Orofino High School (OHS), and the Clearwater Valley Hospital and Clinic (CVHC). The ICI-O has been identified as the primary recipient of energy from the proposed plant, and the largest energy load off-take. Tetra Tech has performed a detailed Energy Audit on ICI-O facilities to determine the existing energy demand for heating, domestic hot water generation, cooling, lighting, and power, and their potential for interconnecting with the proposed biomass power plant. This section discusses the most important aspects and conclusions of this audit. Specific data are shown on the following tables and figures in this section. A complete data set generated as part of this task is included in Appendix A of this report.

3.1 ICI-O FACILITIES AND ENERGY USES

The following section describes the power consumed at the ICI-O facility, located at 23 Hospital Drive, Orofino, Idaho. Energy information and building information used for this task was collected directly from ICI-O. All information and data were provided and used under the direct permission from Warden Carlin and Facilities Director Chris Manfull. Energy data were provided from the period July 2009 through September 2010. Additional information (e.g., plot plans, line diagrams) and data were obtained from ICI-O staff and used to assist in this facility analysis.

Figure 9 – View of ICI-O from Southeast

In reviewing the historical data collected, there are eleven different electric metering points where power is brought into the ICI-O facility. This power is used to operate heating and cooling equipment, create hot water, and operate lights, locks, computers, and all other electrically-powered equipment at the facility. The facility uses electricity for all of its energy needs, except for diesel-powered emergency backup generators. The metering points are not dedicated to specific uses; therefore, the various uses of electricity (heat, hot water, cooling, lights/locks, etc) were calculated formulaically in the following sections. While this fact made this task much more challenging, it does suggest some inefficiencies of the current system.

Of those eleven metering points, three represent the large majority of electrical power consumed at ICI-O. These three metering points primarily serve A-Block, McKelway Hall, and Givins Hall. All of the power supplied to ICI-O is from Avista Corp.

The ICI-O is owned by the State of Idaho, and is an IDL endowment recipient. It was originally constructed as a part of the state mental hospital, and later repurposed as a correctional facility. The facility has an aging HVAC and hot water system, with equipment installed over the past 30+ years. The ICI-O consists of three major buildings and several ancillary structures and operations. The three primary buildings at the ICI-O campus are identified as A-Block, Givins Hall, and McKelway Hall. Each of these buildings has independent HVAC and hot water systems. Each of these, and other structures at ICI-O, are shown in Figure 10 below.

Figure 10 – Facility Site Map, ICI-O

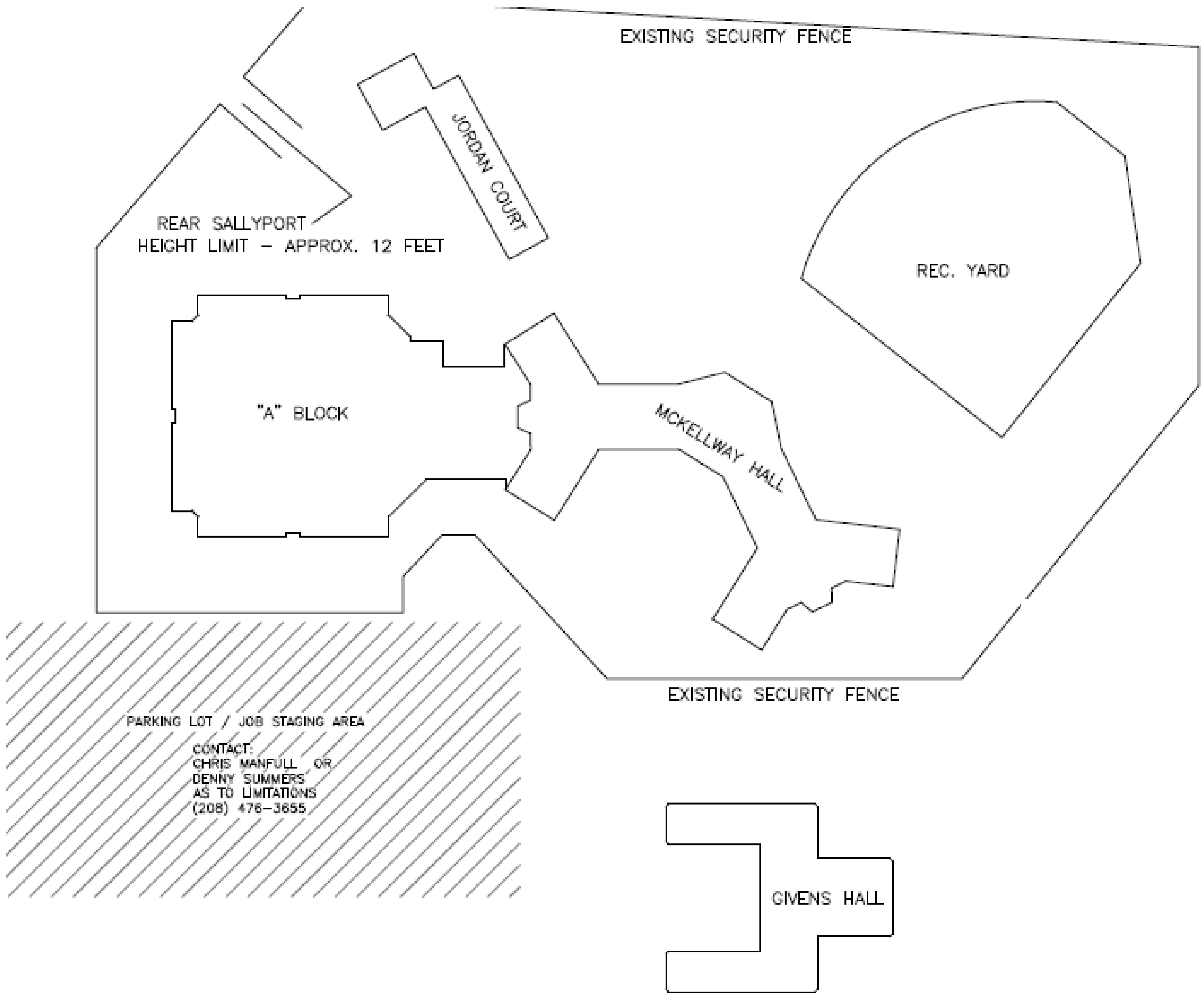
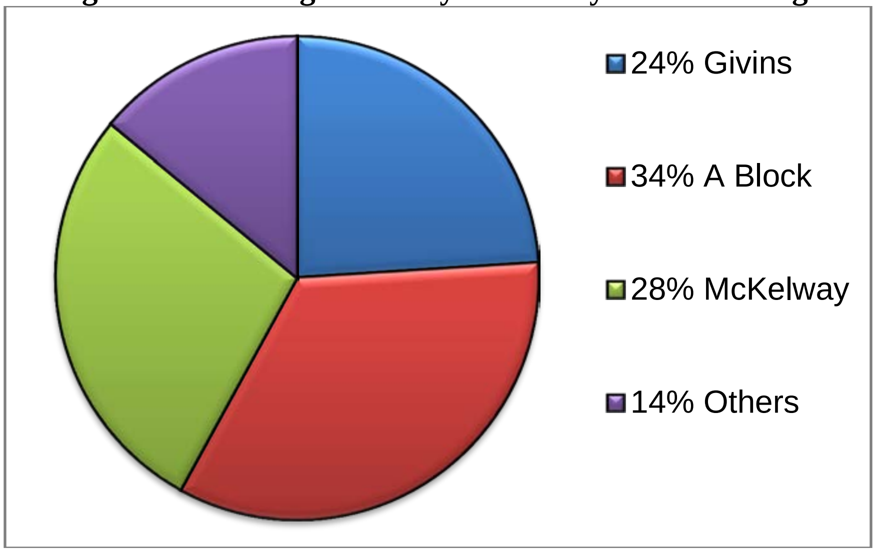


Figure 11 below shows the percent breakdown of energy use at the three primary buildings, A-Block, McKelway Hall and Givins Hall, and ancillary buildings that make up the ICI-O, averaged over the period of July 2009 to September 2010. A-Block is the largest consumer of energy at ICI-O, followed by McKelway Hall, Givins Hall, and lastly the ancillary facility buildings.

Figure 11 – Average Monthly Electricity Use Percentage



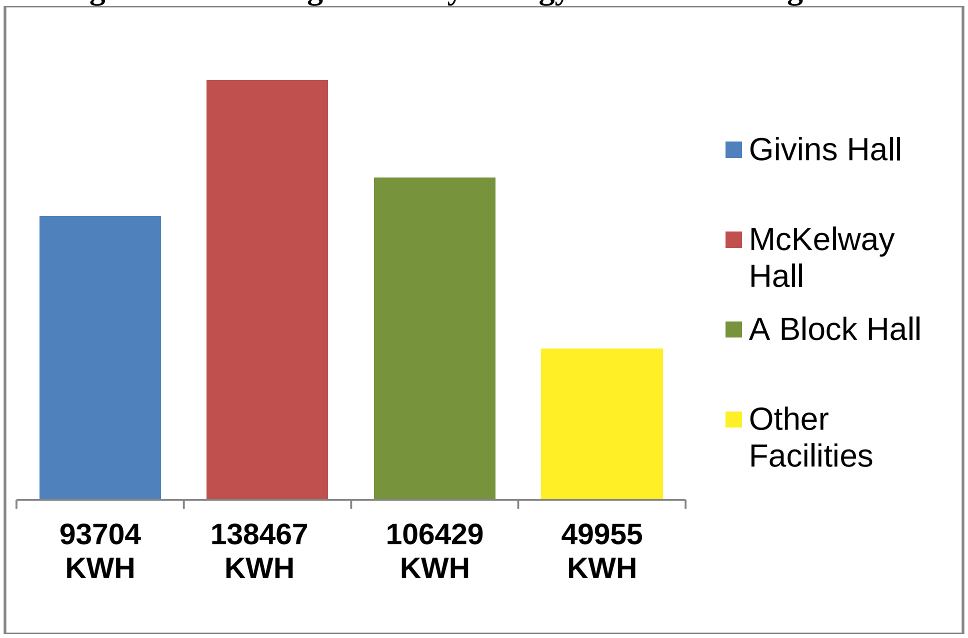
Heating requirements and other operations at the facility vary electrical demand throughout the year. Actual energy use as well as the ratio of energy used in each building also changes. From the usage percentages above, the three primary buildings consume approximately eighty-six percent of the total energy use on average, eighty-nine percent during the winter months, and eighty-three percent during the summer months. Figure 12 below shows the monthly average total energy use at each of the facility buildings. The ancillary ‘other facilities’, including garages, outbuildings, and other unknown users of power from the remaining eight of the facility’s eleven meters, have a negligible impact on overall energy consumption.

A-Block Hall Thermal Energy System Configuration

A-Block was built in 1988, and has 44,211 square feet of heated space. A-Block is a two-story building constructed of cinder block with a hypolon roof. The insulation values are unknown and may require further study (a separate scope) but appear to be insufficient, contributing to the building’s high thermal energy use. A-Block is provided with hot water heat via a hydronic system. The water is presently heated using electricity.

Facility information obtained from ICI-O was used to model A-Block with the assistance of computer-aided design and drafting (CADD) tools. This representation was used as the template for energy modeling for the McKelway Hall and Givins Hall.

Figure 12 – Average Monthly Energy Use All Buildings ICI-O

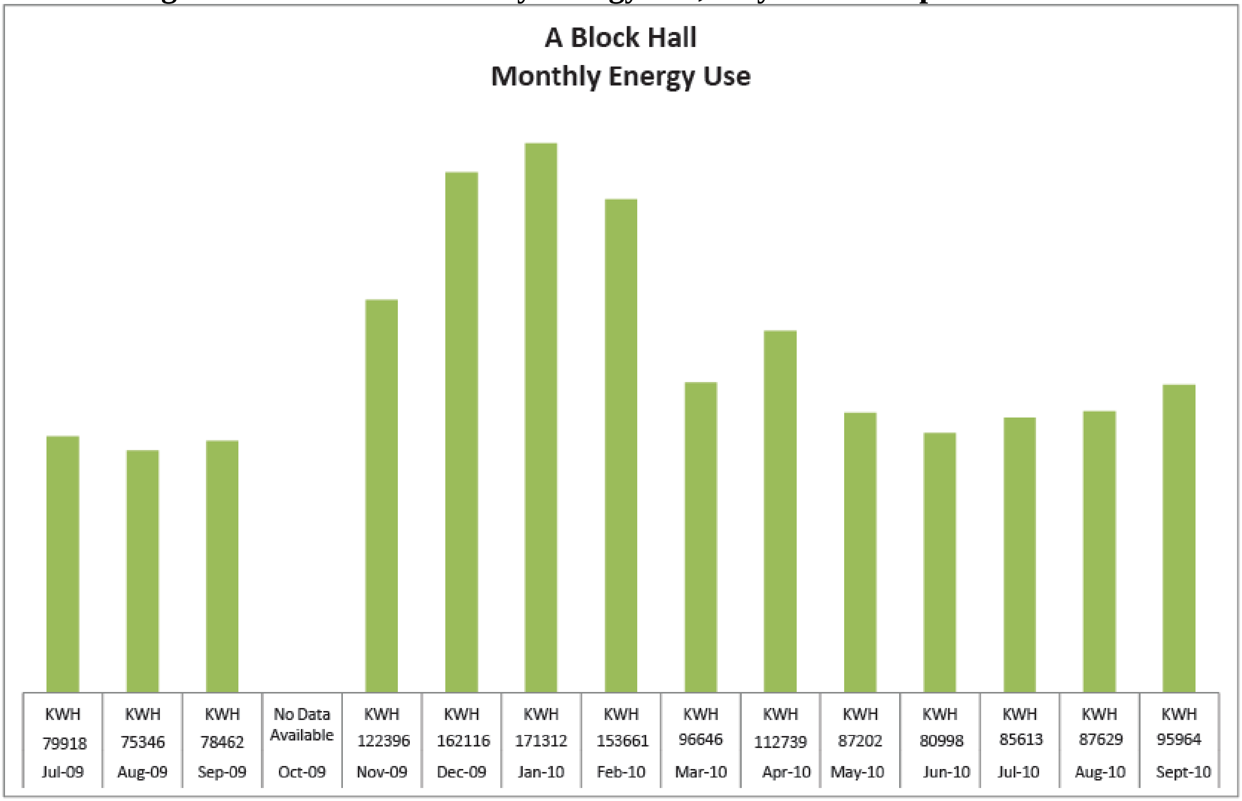


The building's steam and water needs are currently met by a thirty year old steam boiler and water heater (installed in 1988), at 450kW and 120kW, respectively. Several swamp coolers were installed approximately five years ago for cooling duties, and are currently working to design specifications. The building also has a thirty year old diesel-powered generator system backup power supply.

The A-Block boiler room is the core of existing steam and hot water piping networks that travel throughout the building. Piping system operating condition may require additional review to determine suitability for integration with the proposed biomass power plant. The boiler room has an exterior wall along the north side of the building that would likely be the location where steam and/or hot water would presumably enter the building from the proposed biomass power plant.

A-Block is the largest consumer of power at ICI-O, averaging approximately thirty-eight percent of total during the winter months, and thirty-one percent during the summer months. Although smaller than McKelway Hall, A-Block consumes more energy. This is partially due to A-Block's outdated and inefficient heating system, but also to a significant degree the configuration of A-Block (large, multi-story open spaces which are difficult to heat) and lack of proper insulation contribute to excessive energy use for the building. Figure 13 shows A-Block energy use over time.

Figure 13 – A-Block Monthly Energy Use, July 2009 to September 2010



McKelway Hall System Configuration

McKelway Hall was constructed in 1950, and has 58,260 square feet of heated space. McKelway Hall is a three-story building constructed of brick, and has a ballasted roof. The insulation values are unknown and may require further study. Major renovation of the facility has not occurred since 1984.

McKelway Hall utilizes three identical Coates Heater Co. electric powered steam boilers for its heating needs, each one with a 210kW load capacity. The boilers were installed during the renovations in 1984, and are located in the building's central boiler room. Figure 14 below shows two of the three McKelway steam boilers.

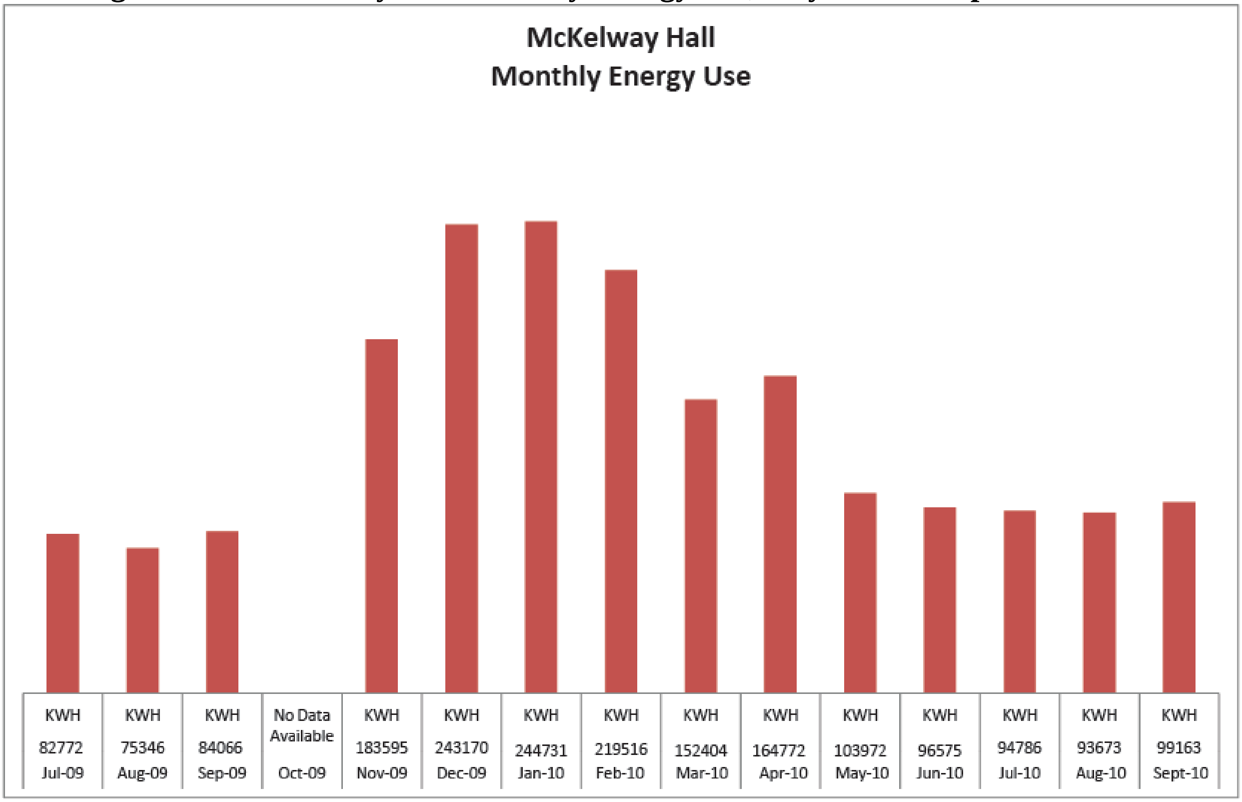
Figure 14 – ICI-O McKelway Hall Steam Boilers

As with A-Block, McKelway Hall has an existing network of steam piping originating in the boiler room, and the boiler room has an exterior wall to facilitate project integration. During site visits it was mentioned by the Warden and her staff that the heating system at McKelway Hall currently requires a substantial upgrade and possible full-system reengineering. This primarily relates to the thermal energy production equipment, but may also indicate the condition of facility piping. Piping networks were not reviewed as a part of this audit.

The boiler room also has two hot water heaters, installed in 2010. There are four other dispersed hot water heaters, drawing 36kW each. Facility cooling is accomplished through four large evaporative cooling units, commonly known as swamp coolers, located on the building roof. These replace multiple window-mounted evaporative coolers and air conditioners. Ductwork was installed to pipe cool air through the building.

McKelway Hall consumes approximately twenty-eight percent of electrical power in the winter months and twenty-seven percent during the summer months. Figure 15 shows the building energy use from July 2009 thru September 2010.

Figure 15 – McKelway Hall Monthly Energy Use, July 2009 to September 2010

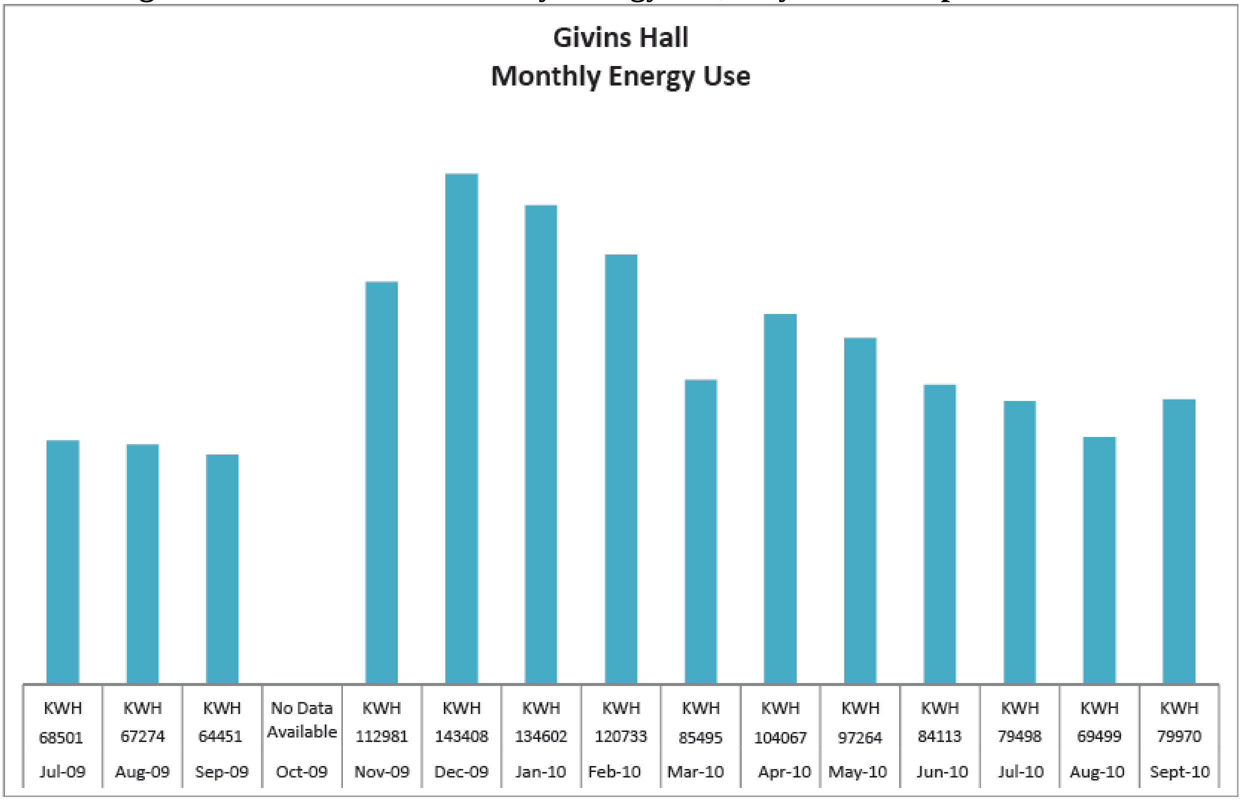


Givins Hall System Configuration

Givins Hall is the smallest building of the ICI-O facility, with 25,907 square feet of heated space. Givins Hall was constructed in 1938, but had major renovations in 1996. Givins Hall is a three-story building constructed of brick with a ballasted roof. The insulation values and unknown and may require further study. An upgrade of the building's heating and cooling system is currently under construction.

HVAC duties are handled by a set of heat pumps, installed within the past five years. Five 54kW hot water heaters, all located in the boiler room, provide water to the building, ranging from 30+ years to five years old. A central water piping system in a single boiler room with exterior wall access allows for integration of project hot water supply lines. This equipment was installed in a 1996 renovation of the facility, and is in better working order than the other buildings. Heat is distributed using hot water baseboard-wall heaters. Givins Hall consumes approximately twenty-three percent of electrical power in the winter months and twenty-five percent during the summer months. Figure 8 shows Givins Hall energy use from July 2009 thru September 2010. Domestic hot water is produced for use in lavatories, kitchens, showers, and laundries. This is produced using electric energy and is reflected in the graph below.

Figure 16 – Givins Hall Monthly Energy Use, July 2009 to September 2010



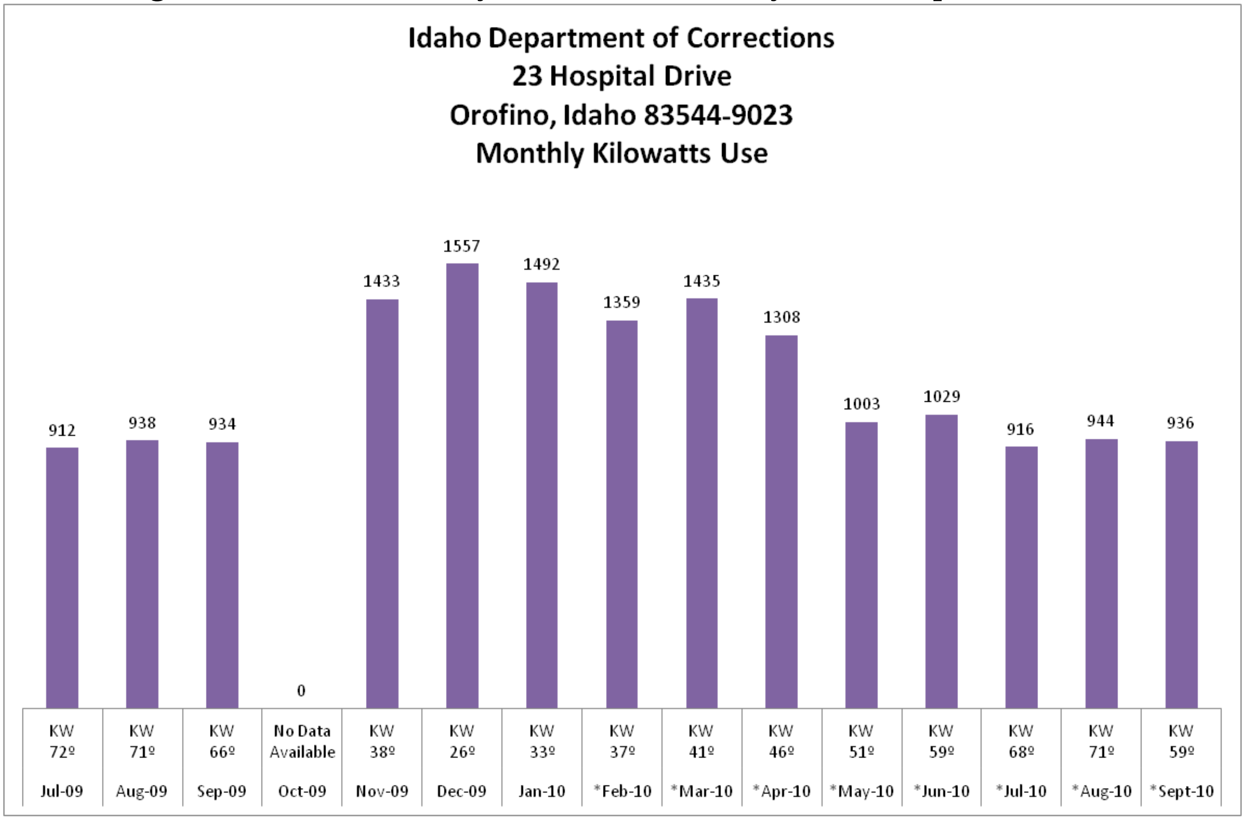
3.2 BREAKDOWN OF FACILITY ELECTRICITY DEMAND, ICI-O

Electricity use data at ICI-O was collected from utility supplier Avista, for a 15-month period from July 2009 to September 2010. Using this data and information gathered from facility inspections and equipment, Tetra Tech analyzed the electrical demands and consumption at ICI-O.

Facility Energy Consumption and Demand

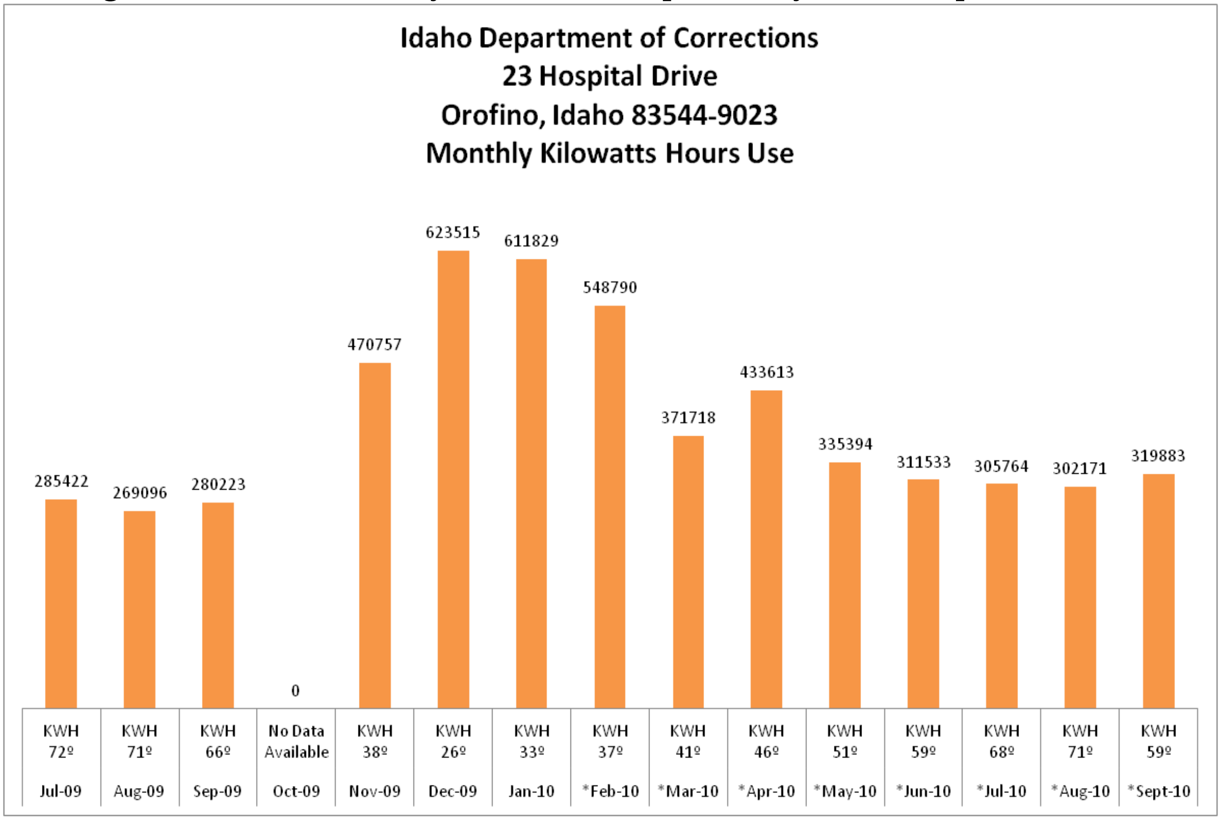
Electrical 'load' or 'demand' is a measure of the amount of power required to operate a device. It is independent of time, and is measured in watts, kilowatts (kW), or megawatts (MW). Power demand at the entire ICI-O facility averaged 1,157 kW between July 2009 and September 2010, with a maximum load of 1,557 kW in December 2009, and a minimum load of 912 kW in July 2009. Figure 17 shows monthly power load at ICI-O.

Figure 17 – ICI-O Monthly Power Demand, July 2009 to September 2010



Power ‘consumption’ is the amount of electricity used to operate a device or devices over time, and is commonly measured in kilowatt-hours (kWh). Monthly power usage at ICI-O averaged is 390,693 kWh between July 2009 and September 2010, with a maximum of 623,515 kWh in December 2009 and a minimum of 269,096 kWh in August 2009. Figure 18 shows monthly power consumption at ICI-O.

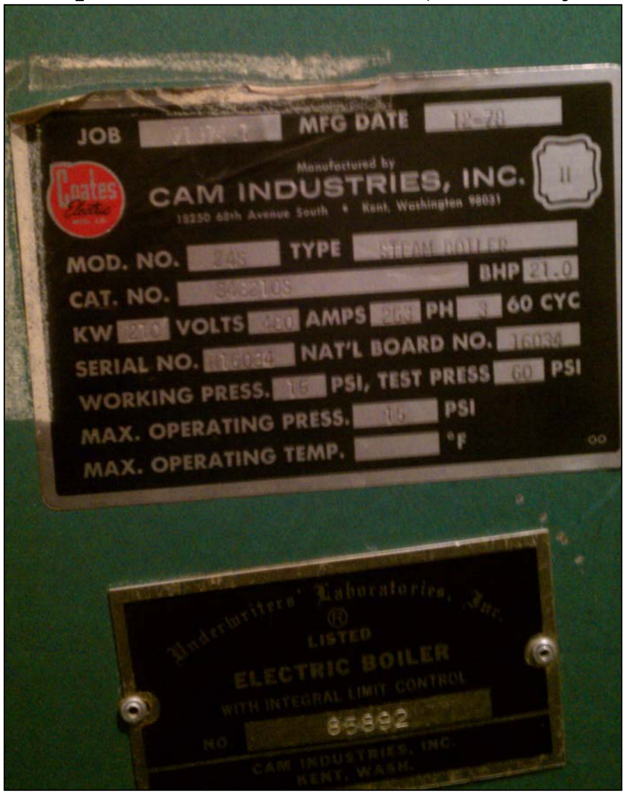
Figure 18 – ICI-O Monthly Power Consumption, July 2009 to September 2010



Facility Energy Uses Categorization by Type

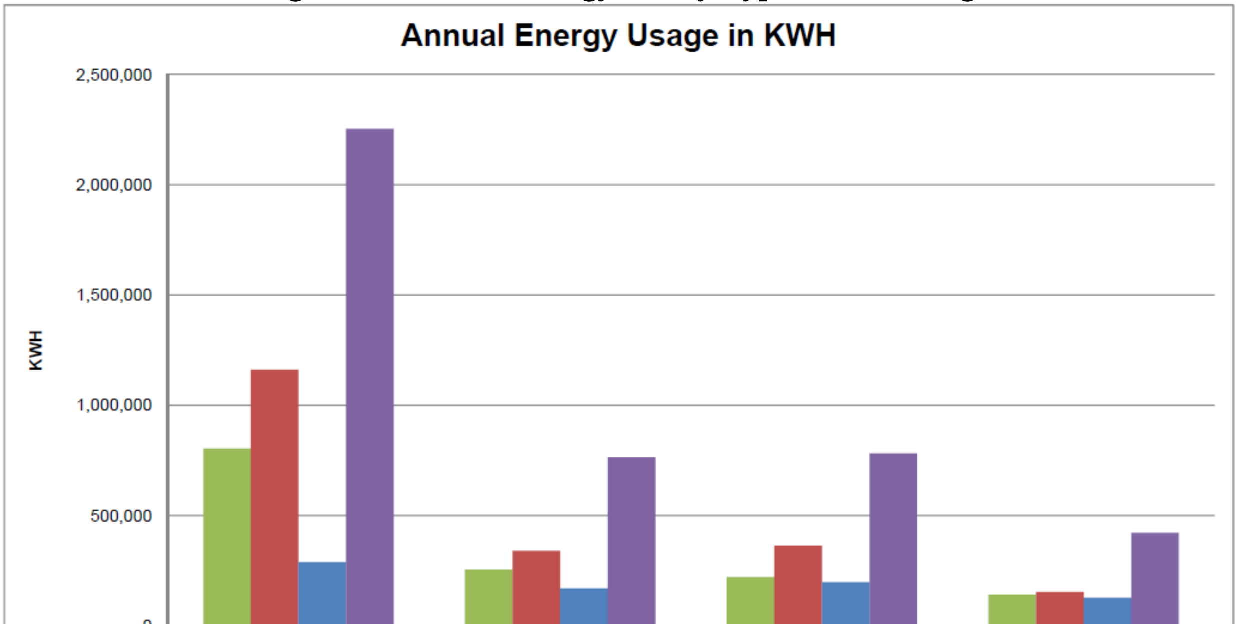
Energy use at the three primary facility buildings was further categorized by specific usage type such as heating, cooling, hot water, and electricity for lighting, locks, and other power consumption. Facility heating and hot water production loads were developed from the demand requirements of steam and hot water boilers onsite. Operating parameters for major equipment, including kW demand, volts, and amps, is commonly posted on a plate attached to the equipment, as shown in the sample photo in Figure 19. Actual consumption is a calculated using the stated loading information and a commonly-accepted operating timeframe (10 hours/day for 5 months for heating equipment, 6 hours/day year-round for water heaters). Using this methodology, electrical consumption accuracy is expected to be 80-90%. Metering equipment attached to each hot water heater and steam boiler is required for a more accurate measurement. While this was not required or conducted in this analysis, it is recommended prior to final design and construction of the biomass power plant.

Figure 19 – Representative Boiler Plate (McKelway Hall ICI-O)



Cooling loads are not available at the level of analysis in this study, and were therefore derived from the difference in energy consumption for the facilities between summer months and other seasons when facility cooling is not assumed to be required. Electricity use for lights, locks, and other equipment was based on facility square-footage. Figure 20 shows the breakdown of power use by type at each of the primary buildings.

Figure 20 – ICI-O Energy Use by Type and Building

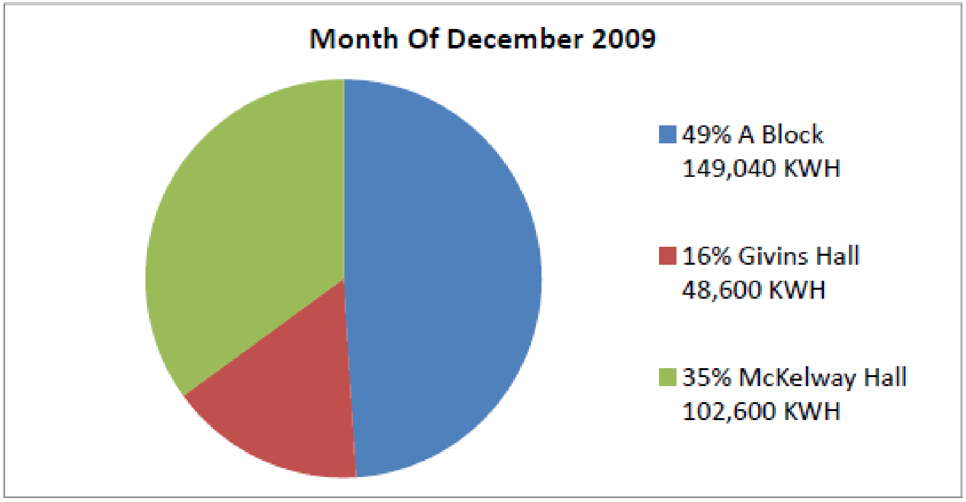


	Heat/ Steam	Cooling	Hot Water	Lighting/ Small Power
A-Block	803,250	254,465	220,320	140,675
McKelway Hall	1,160,250	339,779	363,528	153,848
Givins Hall	289,170	170,000	198,288	127,500
Total	2,252,670	764,244	782,136	422,023

Energy consumption at ICI-O for the production of steam for building heat is by far the largest draw on energy at the facility, at 2,252,670 kWh per year. Annual energy use for hot water production facility-wide is another 782,136 kWh. Annual energy use for cooling ICI-O buildings is estimated to be 764,244 kWh, and annual use for all other electricity at the facility is 422,023 kWh. The proposed biomass power plant can be configured to displace steam and hot water production at the facility, equal to 3,034,806 kWh annually. The planned upgrade of Givins Hall may reduce the potential to utilize energy produced at the biomass power plant. However, as shown above, the energy use at Givins Hall is far less than other buildings and is likely to have a small to negligible affect if the renovated design is not able to accept waste heat from the proposed biomass power plant.

Peak loading requirements of thermal energy use at ICI-O was also analyzed. This is necessary in order to properly size a biomass power plant. According to the analysis, peak thermal energy usage at ICI-O occurs in the month of December. As shown in Figure 21, steam and water heating utilized 300,240 kWh for December 2009. The total facility energy use in the month time frame was 623,515 kWh.

Figure 21 – ICI-O December 2009 Steam / Hot Water Use



Steam and hot water production at ICI-O accounted for forty-eight percent of the total electrical energy consumption for the facility in the month of December. That electricity could be replaced by capturing low pressure steam from the biomass power plant. The electrical energy invoice for December, 2009 was $47,170.21. Therefore the calculated savings for one month would be $22,641.70. Annually, the electricity cost that could be replaced by the biomass power plant is approximately $240,000, depending on variations in the utility electricity rate schedule. This brief analysis only assumes savings of purchased electricity, and does not account for the potential cost of operating the biomass power plant or purchase of steam from the biomass power plant.

Facility Upgrades and Planned Expansions

Future facility expansions and additions identified by ICI-O facility operations staff were reviewed to gauge the projected energy load changes. Musgrove Engineering of Boise, ID, has designed an HVAC system renovation of Givins Hall, which is currently being installed, with an esxtimated completion date of November 2011. The system will incorporate a primary variable refrigerant volume (VRV) heat pump managing HVAC duty for the basement and first floor, combined with 7 rooftop heat pump units for the second floor. The system upgrade was too far through the design phase to facilitate integrate with the prospective Plant, but pipeline retrofits for hot water and peak load thermal heating and cooling could conceivably be installed down the line.

Upgrades are not planned at any other facility buildings at ICI-O, though it was mentioned that in all cases these upgrades are needed. In the long term, McKelway is slated for a full heating and cooling system upgrade but plans for these upgrades have not be established. Also, construction of a new ‘B-Block’ (structurally similar to A-Block) has been considered but not yet officially planned or funded according to ICI-O personnel.

3.3 SUPPLEMENTAL THERMAL ENERGY DEMAND

Tetra Tech also reviewed the other publicly-owned facilities adjacent to ICI-O, also within the facilities complex area to the west of downtown Orofino. These facilities are also potential candidates to utilize the excess thermal energy produced by the biomass power plant.

Clearwater Valley Hospital and Clinic

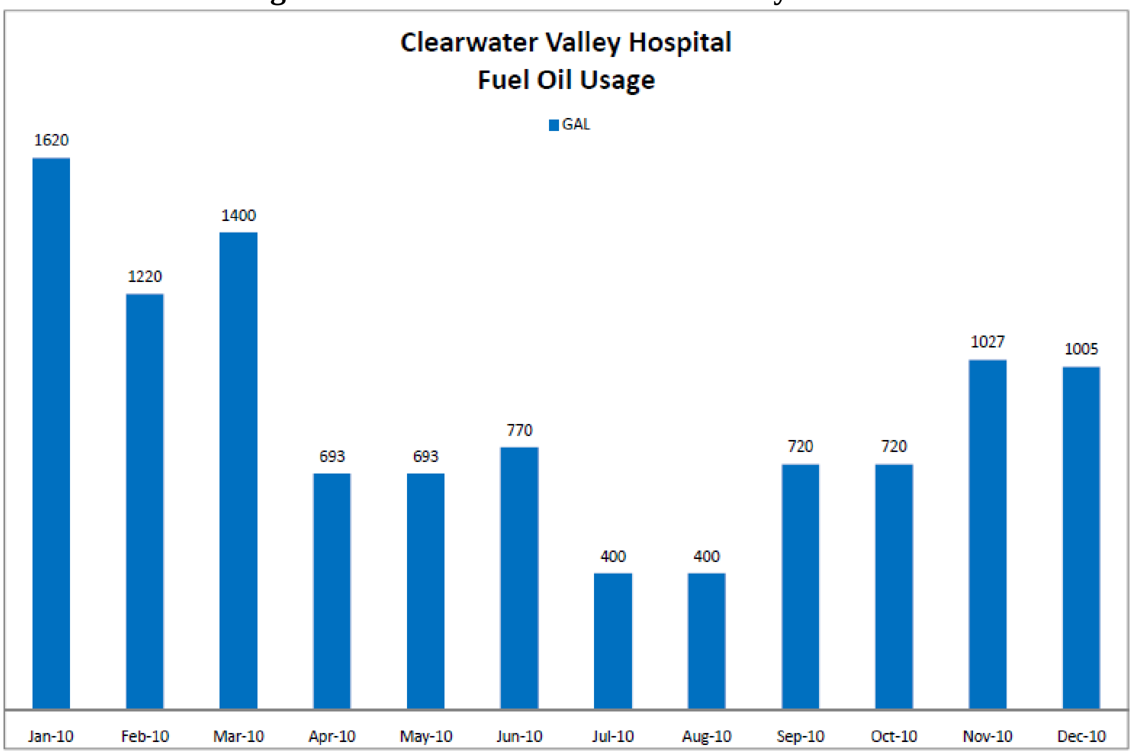
The Clearwater Valley Hospital and Clinic (CVHC) sits approximately 1,000 meters to the south-southeast of ICI-O. The site is leased from Clearwater County, and the clinic itself is owned and operated by St. Mary's Hospital and Clinic of Cottonwood, ID. The CVHC hot water and HVAC system was originally operated through two diesel fuel oil-powered steam boilers, both of which are over 50 years old. Figure 22 is a photo of one of the boiler units.

Figure 22 – Photo of CVHC Fuel Oil Boiler

Some of the facility HVAC work has been converted to heat pumps, via a system 16 rooftop-mounted units installed at various times over the past 10 years. The diesel fuel oil boilers are still operational, however, providing the majority of the heating and cooling duties for the hospital and hot water for the entire facility. Maps of the facility heating system are provided in Appendix B.

CVHC facility data were gathered from Pat Walker, Facilities Director. In 2010, the facility burned 10,668 gallon of diesel fuel, at a cost of $34,460. This is equivalent to 407,903 kWh of energy use on a Btu basis, at a load of 46.56 kW. Fuel cost during the year averaged $3.63, and is expected to approach $4.00/gallon in 2011. Even 2010 fuel oil prices are equivalent to average electricity costs of 8.4¢/kWh, assuming equal efficiency of electricity and fuel oil, much higher than the standard electricity price in the area. Fuel oil sage is highly season-dependent, as shown in the monthly delivery results of Figure 23. Because of differences in delivery date, the delivery volumes are not perfectly representational of fuel oil consumption, but there is a definite and expected reduction in usage in the summer months.

Figure 23 – CVHC 2010 Fuel Oil Use by Month



CVHC is an excellent candidate for integration with the prospective biomass power plant. The most-likely project integration avenue is into the facility hot-water system, centrally-located in the boiler room, with access through an outer wall. Integration with the thermal energy supply system is expected to cost only a few thousand dollars for connecting equipment and valves within the boiler room itself, Steam, hot water, and cold water piping systems are already in use throughout the facility, though they are aging. The minimal cost of system will likely be paid for in a few years with monthly savings in heating bills.

CVHC personnel clearly identified the need for a potential integration to meet requirements for the facility to remain a 'critical access hospital'. There are no specific guidelines for this, but the hospital must be available with energy systems on-line at all times. In this regard integration with the biomass power plant will provide redundancy for HVAC systems, as one or both of the boilers are recommended to be kept in place.

CVHC is currently in the planning stage of an expansion project for the hospital, and an entirely new clinic building. Combined, the expansions will add 28,000 square footage of heated space to the facility grounds. This expansion is an excellent opportunity for integration with the prospective biomass power plant. The building can be designed to optimize use of the power plant-produced thermal energy and allow for ground-up integration of steam and water systems. New construction integration of piping and control systems is extremely cost-effective, and can cost less than half of stand-alone HVAC generating units such as boilers or heat pumps.

Orofino High School

The Orofino High School was constructed in 1968-69, and is also an IDL endowment recipient for its funding. OHS is owned by Clearwater County. The HVAC system for the high school was installed when the building was constructed, and consists of over thirty in-room electric heaters with 480v coils. The gymnasium has another two oversized heaters. The high school possesses the last 10 Trane Co. heating coils ever made for these heaters; the heaters will need to be replaced once the backup coils run out, estimated to be within 1-2 years.

Roof-mounted A/C units over each room provide cooling for the facility. Hot water for the building is provided by four 480v commercial water heaters, two located in the central boiler room and two additional of the same size, plus one residential 65-gal hot water heater in the basement. Access to all HVAC and hot water supply systems and piping is only available through the building roof. Based on the nameplate output of the existing units, the annual electrical load for space heating is calculated at 821,100 kWh, and the electrical load for water heating is calculated to be 16,560 kWh per month or 149,040 kWh annually. Total demand for thermal energy at OHS is calculated to be 970,000 kWh.

It is generally understood that the facility is due for an upgrade of its HVAC system. At present, plans for upgrade of the high school heating system have not been detailed nor sent out to bid. The most likely system according to tetra Tech interviews with school maintenance staff, is to install replaces the roof-mounted A/C units with heat pumps providing heating and cooling. This is estimated to cost around $8,000 per room; replacement of the entire facility-wide existing HVAC systems is in the range of 300,000-$400,000. Because installation of piping and registers throughout the facility is required for a building-wide retrofit for integration with the prospective biomass power plant, this may approach an equal cost. However, operational costs would be greatly reduced with the integrated system. A detailed engineering review of the interior of the facility is recommended to determine the most cost-effective route for the high school and the community.

OHS has discussed plans for facility expansion and inclusion of a separate Jr. High at several times in the building’s history. A bond issue has been raised but defeated in past elections. The facility is at capacity at present, and there is a realistic possibility of a bond being raised and project moving forward in the next five years. An addition on the building would result in approximately 20% more heated space. Integration with the prospective biomass power plant would allow for ground-up design of integrated heating system. As with CVHC's potential expansion plans, integration of power plant-provided energy would be much cheaper than installation of energy-generating units.

State Hospital North

The State Hospital North was constructed in 1995, and is also an IDL endowment recipient. SHN is in the process of implementing a system-wide HVAC retrofit, scheduled for completion in mid-2011. HVAC duties will be performed by 40 roof-mounted air/air heat pumps. Hot water for the facility used to be created by 37 different ceiling-mounted hot water heaters, but that system has recently been changed out with a single 12-gal hot water heater that services the entire facility. SHN is not recommended as a candidate for integration with the prospective biomass power plant.

Future Facility Installations

The future addition of facilities to the complex has been discussed as a method to achieve greater thermal energy use from the biomass power plant. Several facilities have been discussed as additional thermal energy users, including an aquatic center and an industrial-scale greenhouse operation. Both aquatic recreation centers and greenhouses require significant thermal energy input for operations; in greenhouses energy is the second most expensive input behind labor. The type and scale of such a facility has not yet been determined, thus the associated thermal energy demand is not known at present. However, the biomass power plant provides an attractive sales proposition, allowing the facility to eliminate the cost of boilers or other thermal energy generation equipment.

3.4 SUMMARY LOCAL AREA ENERGY DEMAND

The biomass power plant is expected to produce thermal energy in the form of steam and hot water, which can be used to displace electrical-powered heating at nearby facilities. These facilities include ICI-O, CVHC, OHS, and SHN. ICI-O is the primary recipient of thermal energy from the biomass power plant, and CVHC and OHS have been identified as potential secondary users. Due to the very limited thermal energy demand from ICI-O, additional facilities using thermal energy are recommended to utilize the energy produced by the biomass power plant.

Thermal energy use by the prospective users of produced thermal energy from the biomass power plant, including ICI-O, CVHC, and OHS, is presented below along with a contingency factor to account for potential future construction of additional facilities deriving thermal energy from the biomass power plant.

Table 17 – Local Area Thermal Energy Demand

Orofino Area Thermal Energy Demand			
		kWh/yr	*MMBTU/yr*
Primary Facility	ICI-O	3,034,806	10,358
Additional Facilities *Optional*	CVHC	1,181,112	4,031
	OHS	970,040	3,311
	Future Installation	1,000,000	3,413
	Totals	**6,185,958**	**21,113**
		773.24	kW Load

As shown in the table, the total expected thermal energy demand in the area is 6.185 million kWh/yr at a 775kW load, equivalent to 21,113 MMBTU/yr. ICI-O is the largest single energy user, consuming approximately half of the total energy demand of the area (10,385 MMBTU/yr). CVHC is the next-largest user (figure includes expansion plans), followed by OHS. As mentioned, an additional 1MM kWh/yr to account for a future energy user is included in the figure.

Thermal energy produced by the prospective Plant is expected to be sold to the identified energy users, at a rate equal to the current electrical energy purchase price on a BTU basis. In other words, at the current thermal energy usage levels, ICI-O and OHS will pay the same amount for the lifespan of the project as they do currently, with a minor price escalation over time to account for future price increases. The current electricity rate of 6.5¢/kWh is equivalent to $19.04/MMBTU. CVHC heats its current buildings with more-expensive diesel fuel (equivalent to 8.4¢/kWh), and will realize a lower heating cost from inclusion in the prospective project. Facilities with minimal integration costs (ICI-O, CHVC current building and especially the planned expansion, and the potential future installation) will see immediate monetary benefits due to reduced capital costs and maintenance costs for their HVAC systems.

Additionally, if all of the listed facilities agree to integrate with and purchase power from the prospective biomass power plant, over 6 million kilowatt-hours of electricity will be saved annually, with an equivalent reduction in carbon emission from utility-scale power plants.

4.0 Site Selection and Facility Interconnects

This section reviews the various potential parcels of land available for siting the prospective Plant. The section also reviews the equipment and infrastructure necessary for interconnection of piping for thermal energy off-take and electrical off-take at the most viable site.

4.1 SITE ASSESSMENT

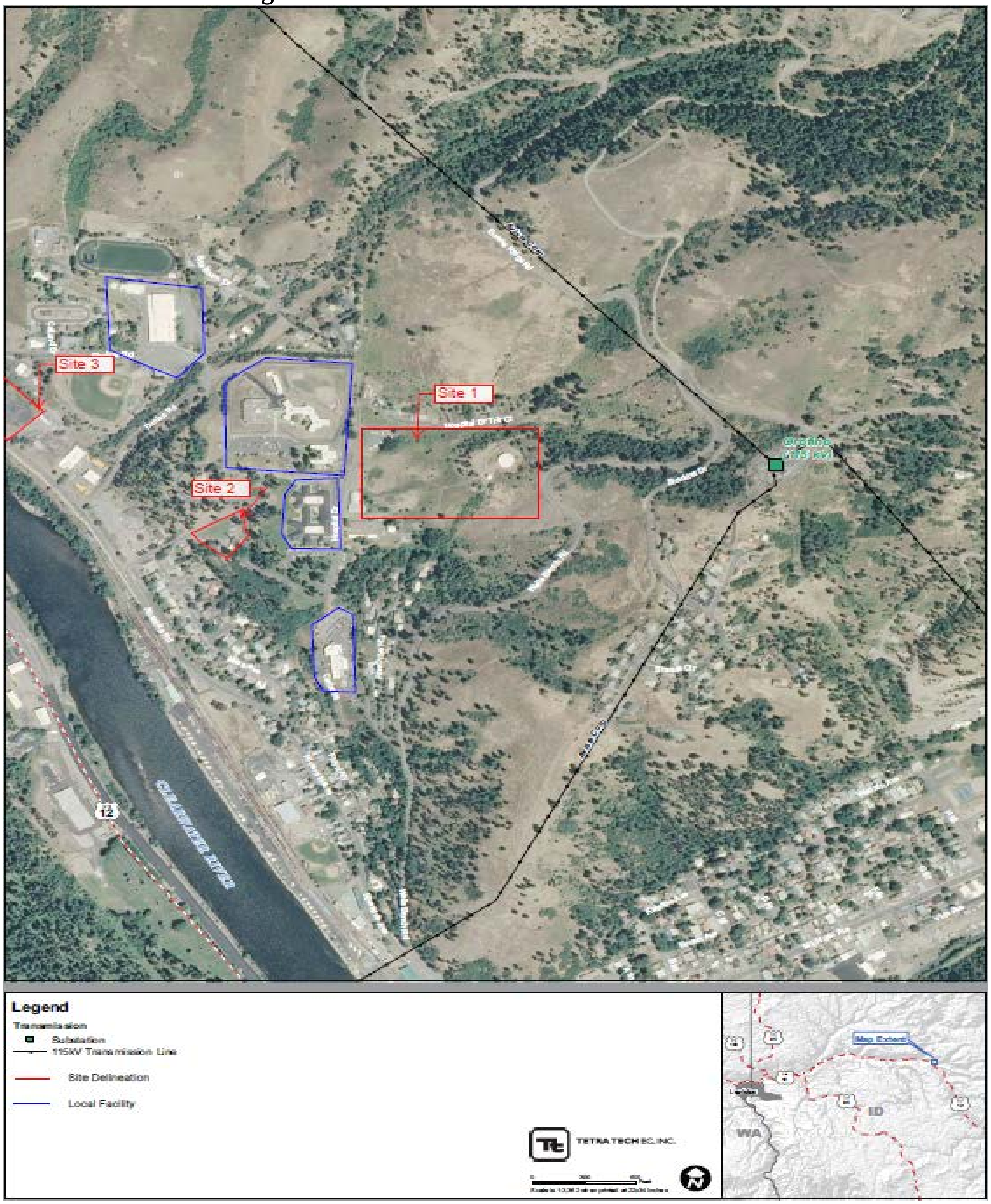
Several potential project sites were inspected by Tetra Tech's permitting and siting staff on November 8-9, 2010. All sites are within ½ mile of the SHN / ICI-O / OHS / CVHC complex to facilitate thermal energy off-take from the biomass power plant. The site selection process has been formulated using the following basic criteria:

- Proximity and supply of feedstock (both near-term and long-term)
- Transportation – road access for feedstock delivery trucks
- Utility availability – electricity, substation access
- Water supply and wastewater treatment options
- Community infrastructure, such as electrical, mechanical services

The selection of a proper site encompasses many issues as indicated above but also should take into account issues such as the environmental impact, the status of current and future production technology, the ability to expand production as required and more. While the environmental impact of a biomass power plant is minimal, there still remains a need to ensure that such a facility does not negatively impact the community. While technology exists and is being implemented in most new plants to mitigate any harmful emissions and odors from biomass power plants, it remains an important consideration for site selection.

Figure 24 below illustrates the prospective plant sites, in relation to the Orofino utility substation and the facilities complex. The three most promising sites are listed in the following sections.

Figure 24 – Biomass Power Plant Site Selection



Site 1) Greenfield site east of State Hospital North facility
Site 2) Former State Hospital North Central boiler plant
Site 3) Orofino High School parcel adjacent to Highway 7, Former Forest Service site

Site 1 – SHN Greenfield Site east of ICI-O and SNH

The most desirable site is on State Hospital North grounds between the ICI-O and water towers (shown as Site 1 in Figure 24). The SHN site presents the most advantageous for the plant, in that it has the most area, it has good access to input water from SHN and ICI-O water towers, it is in an area that is not easily seen from Orofino, it is less than approximately 1,000 feet to potential thermal energy users, and is within ½ mile of the Orofino Substation. According to the county assessor's records, the site is parcel number 36N02E064200A. This parcel is approximately 83 acres and is currently zoned as Low Density Rural District F1. Rezoning may be required in order to build a power plant on the site. The rezoning of this parcel of land can be accomplished through spot zoning, rezoning the entire 83 acres, or a conditional use permit as outlined in Clearwater County's Zoning Ordinances Article XI.

The potential SHN grounds site is located east of Hospital Drive North and south of Hospital Drive Trailer Court and would be built south of the State Hospital North and ICI-O water towers. It is worth noting, that the State Hospital North grounds site between the ICI-O and water towers have some initial environmental and construction constraints, but the site is most desirable due to the accessibility of existing infrastructure, the availability of utilities (water and electrical substation), and close proximity to potential steam users. Potential site constraints include: significant site work would be required to alleviate the slope of the land, an ephemeral drainage located west of the site leads to a potential wetland area, and a new road would potentially need to be constructed off Dent Bridge Road. Due to the elevation of the site and stack height, air emissions are not anticipated to be a concern. Dealing with these constraints is not a formidable task. If provided ample time, appropriate planning should alleviate these constraints.

Potable and make-up water would be available from either the ICI-O water tank or by tapping into the city of Orofino's main water line. Wastewater treatment is also available through the Clearwater County Wastewater Treatment Plant. The capacities and capabilities of the wastewater treatment facility are approximately 880,000 gallons per day. Currently, the demand load is estimated to be only 300,000 gallons per day, so the site could accommodate a larger facility, at least from a water/wastewater perspective. The potential site is located 43 minutes east of Lewiston, Idaho and within 5 miles of the city of Orofino and possesses all the desirable community services: electrical, maintenance, machine shops, pipefitting and plumbing, hospital, airport, schools, and fire protection. Long-term, the State Hospital North grounds site is located within abundant feedstock resources from a healthy timber industry.

The primary disadvantages of this location are the slope of land, requiring site work and regarding, and the lack of log or chip truck access road to the site. A stem road would have to be built from Wells Bench Road. Further, a small wetland appears to exist on the far eastern edge of the site, currently used as a water catchment. If this site is selected it may be possible to configure the plant site without affecting this feature. Land is available for a mid-size (1-5MW) biomass power plant and associated feedstock storage, but due to site grading issues it may prove less expensive to lease off-site storage land. This would need to be further evaluated from a cost and operational standpoint as this will require handling the feedstock twice.

Figure 25 is a photograph of the site from the water towers looking west, with ICI-O and SHN clearly visible in the background.

Figure 25 – Photo of Project Site 1, SHN Parcel No. 36N02E064200A

Site 2 – SHN Former Central Boiler Plant

The former SHN Boiler Plant (shown as Site 2 in Figure 24) is considered secondary to Site 1. Previous use as a boiler will make zoning and permitting relatively simple, but existing buildings and equipment may prove to be costly to retrofit to current power facility code and plant scale desired. The building is currently used by the Clearwater County Sherriff's office as a vehicle maintenance building.

The former State Hospital North Central Boiler Plant potential site is located southeast of Hospital Drive, south of the ICI-O and west of State Hospital North. This site is considered to be our second most desirable site due to the accessibility of existing infrastructure, the availability of utilities (water and electrical substation), and close proximity to potential steam users. The site is an approximately one acre site owned by State Hospital North which contains an existing boiler building, an emission stack, and completed sitework, including drive-through truck access. The site is well positioned with access to Idaho State Highway 7 and significant site work would not be required. The site is roughly equal distance to the facilities complex that would be using its steam / hot water output as Site 1. The steam pipeline system to ICI-O from the former plant has been plugged with cement to discourage prison escapes, and is unusable.

The major constraints associated with this site would be space limitations and retrofitting costs. Currently, the site is approximately one acre in size and would require a secondary storage location for the storage and transportation of woody biomass products. Secondly, the costs associated with retrofit to current power facility code may out-weight the positives of the site. The stack is the largest concern. Dismantling of the existing stack and construction of a new stack would be a significant project cost. The stack was not subjected to a full engineering review for this study.

Figure 26 shows a photograph of the boiler plant.

Figure 26 – Photo of Former SHN Boiler Plant Site

Site 3 – OHS former Forest Service Ranger Station

The Orofino High School parcel (Site 3 in Figure 24) has adequate land requirements and excellent transportation access via Idaho State Highway 7. The site has been graded for its former use as a Forest Service ranger station. The site lacks access to potable water and wastewater, and would require 1.5-2x the steam/hot water piping as the other two sites to provide thermal energy to ICI-O and CHVC.

In the opinion of the project team, environmental constraints such as potential plant emissions and odors, and truck traffic and noise concerns, the residence adjacent to Site 3 is too close to allow the plant to be permitted. The residence appears to be owned by OHS, however, and with relocation of the residents and razing of the building the site would be suitable for construction of a biomass power plant.

Site Selection Summary and Land Acquisition

The existing infrastructure provided by the State Hospital North grounds (Site 1), make it the logical choices of sites among those evaluated. Should the project move forward, it would be the recommendation of this report that the State Hospital North Grounds site between the ICI-O and Water Towers and the State Hospital North Central Boiler Plant site be given primary consideration over the other sites for development. It also should be noted that all potential sites are located within the boundaries of the Nez Perce Indian Reservation. Should the project move forward, it is recommended that the Nez Perce Tribe be consulted in site selection to determine if sites are located in areas which have traditional cultural significance.

The land at the prospective site necessary for construction of the biomass plant scale selected would need to be acquired from SHN prior to plant construction. At this point it is undetermined whether a land lease or purchase will be required, dependent on the ownership structure selected for the biomass power plant. The land is currently unused and considered ‘surplus’ by SHN. IDL formerly managed land use by various state government agencies, but has as of late decided to allow individual agencies to determine their own sale price and conditions.

SHN is currently involved with a land sale deal to CVHC for that facility’s expansion plans, a convenient case study for sale structure and pricing. The as-yet incomplete land sale is valued at $6,250/acre; for the 9.5 acres planned for the 2MW biomass power plant scenario comes to approximately $60,000. For the 1MW power plant scenario the land purchase price is expected to be in the range of $40,000. These values are included in the biomass power plant financial analysis. It is important to note that the structure and pricing of deals is assumed to be a government-to-government deal; pricing and process would be more difficult and likely more expensive for sale of government property to the private sector.

Tetra Tech recommends proceeding with the State Hospital North greenfield site (Site 1) as the primary option, but continue to pursue options associated with retrofit of the former Central Boiler Plant site (Site 2) as well as Site 3 as back-up plans.

4.2 STEAM / HOT WATER PIPING AND FACILITIES INTERCONNECTION

Thermal Energy Interconnection to Facility Energy Users

Assuming the primary site identified is selected for plant construction, the following analysis was conducted to determine interconnection to the various facilities evaluated as potential thermal energy customers.

Underground piping is the likely mode to transport thermal energy to facility users. 4” steel steam piping is conservatively estimated for use, and is the most expensive option. Smaller piping, aboveground routing, or use of hot water pipe as opposed to steam will all bring down cost, which will be determined in detailed engineering of the plant. This type of pipe is estimated to cost $200/ft.

The primary facility identified as a thermal energy user is ICI-O. From the plant site to the boiler room adjacent to A-Block and McKelway Hall is 852 feet. A spur route to Givins Hall is an additional 103 feet.

Additional facilities that are optional thermal energy customers include CVHC and OHS. Pipe from Site 1 to CVHC is estimated at 1,448 feet, and 703 feet of pipe will be necessary to connect OHS to the ICI-O trunk line. 1,000 feet is estimated for interconnection to a potential future facility using produced thermal energy (i.e., aquatic center). While all facilities are included in the base case financial analysis as energy users, only piping to ICI-O, CVHC, and OHS are included in the plant capital costs for the financial scenario that includes those facilities. The future potential facility is assumed to cover costs of connection to its facility.

Table 18 summarizes piping distance to each potential thermal energy user.

Table 18 – Biomass Power Plant Thermal Energy Interconnection

Thermal Energy Piping Summary			
Primary Thermal Energy Supply: (ICI-O)	4"Steam Pipe CHP plant to ICI-O	852	ft
	Secondary Pipe to Givins Hall, ICI-O	103	ft
	Primary Piping Total:	**955**	**ft**
Optional Thermal Energy Supply:	4"Steam Pipe CHP plant to CVHC	1448	ft
	4"Steam Pipe ICI-O to OHS	703	ft
	4" Steam Pipe to Potential Future Customer	1000	ft
Grand Total:		**4,106**	**ft**

4.3 ELECTRICAL GRID INTERCONNECTION

Tetra Tech has compiled the following prospective interconnection procedure and equipment. This is required for proposed configurations of the facility that produce combined heat and power and plan to upload power to the electrical grid.

Electricity Off-take and Power Purchase Agreement

Tetra Tech has investigated various usage options for the electrical energy produced by the prospective biomass power plant. One option considered is an off-grid system, which involves producing and directly routing power to facility energy users, including ICI-O, CVHC, SHN and/or OHS. The second option involves uploading produced power to the utility electrical grid system for sale.

Initial review of federal and Idaho State interconnection procedures and power purchase rates was conducted. As stipulated by the Idaho Public Utilities Commission, and pursuant to the Public Utility Regulatory Policy Act (PURPA), qualifying renewable energy generating systems can obtain a scheduled Power Purchase Agreement (PPA) rate for power produced. Assuming interconnection is feasible, utilities are required to purchase produced electricity at a fixed rate from renewable energy generating systems such as the prospective biomass power plant.

"Pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA) and the implementing regulations of the Federal Energy Regulatory Commission (FERC), the Idaho Public Utilities Commission (Commission) has approved a Surrogate Avoided Resource (SAR) methodology for calculation of the avoided cost rates paid to PURPA qualifying cogeneration and small power production facilities (QFs) by Idaho Power Company, Avista Corporation and PacifiCorp. Avoided cost rates are the purchase price paid to QFs for purchases of QF capacity and energy."[14]

The scheduled rates are nearly $0.02/kWh better than the rate paid by current users, or a 26% increase in revenue if sold to grid instead of directly to users. Due to the advantageous pricing associated with power purchase agreements, Tetra Tech recommends upload and sale of produced electrical energy to the utility grid if the viability of interconnection is confirmed.

Interconnection Customers (IC's) are those intending to install generation that connects into the utility electrical grid system. IC installations on the utility electrical grid system require that both the utility and the IC meet certain minimum requirements for operation and safety. The specific circumstances of each installation must be taken into account. The utility and the licensed professional engineer for the IC will follow the requirements of the target utility and the regulatory authorities when planning such an installation. The equipment and protection listed in the attached diagram represent examples from which a final installation can be developed and approved. It is very important that the targeted utility review interconnections between IC equipment and the utility electrical grid system early in the design stage.

All generation installations and their interconnections must adhere to applicable national and local codes, standards, rules and regulations and receive applicable approvals from all appropriate governing bodies and be designed and constructed in accordance with Good Utility Practice.

The targeted utility for interconnection for this project is Avista Corp. (Avista). Avista requires an application be submitted before determining interconnection points, amount of power that can be uploaded, and specific equipment required for interconnection. The application is called the Small Generator Interconnection Request (Application Form). A copy of the application form will be incorporated into the final project report for reference. The interconnection application can only be submitted in advanced stages of project development, once the developers have

[14] Idaho Public Utilities Commission, Case No. GNR-E-10-01, Order No. 31025 (3/16/2010).

obtained control of a prospective plant site and have determined exact facility scale and output, equivalent to approximately 50% final detail engineering completion. The study itself, not including any utility engineering or construction, is estimated to take six months to a year to complete. It is recommended that the interconnect process be conducted in parallel with final facility engineering, and before any project construction commences. Initial application fee is $1,000, and final fees will include any additional survey or engineering required.

Developers of the prospective Plant will also need to file an application with the Federal Energy Regulation Commission (FERC) to obtain Small Generator Qualifying Facility (QF) status. This status allows a facility to avoid negotiations for power purchase and instead receive the advantageous scheduled avoided cost rates for produced electricity. The application, FERC Form 556, will also be incorporated into the final project report for reference. The Plant as proposed herein adheres to the requirements stipulated for a Small Generator QF.

Interconnection Procedure and Estimated Equipment Required

Avista Corp. owns and operates the Orofino utility substation, located approximately 500m from the proposed plant site. This is the targeted location for facility interconnection. The next nearest interconnection point is in the town of Ahsahka, approximately 4 miles away. The regional electrical transmission grid, and location of the prospective interconnection point, is shown in Appendix C.

The Orofino substation operated by Avista consists of four transmission lines, one going to Moscow, ID, one going to the Dworshak utility station, one going to Nez Perce, and a radial line returning to source. The substation operates at 115kW, and has two transformers, a 7.5mva unit transferring power to Clearwater Power, and a 20mva transformer feeding Orofino.

Tetra Tech investigated the possibility of interconnection with the Orofino substation. Avista's representatives indicated that this substation is the most suitable location for interconnection in the local area. The substation is likely capable of handling up to 5-6MW of power production using a dedicated line from the biomass power plant. Confirmation of the interconnection potential, and specific equipment required for interconnection, can only be accomplished through Avista's application process. The interconnection procedure described below is based on preliminary discussion with Avista and Tetra Tech's estimation of process and equipment required.

In planning Interconnection Customers (IC) installations, proposed facilities can be categorized into one of two major groups, One Way Power Flow and Two Way Power Flow. The proposed installation for Clearwater County is defined as a Two Way Power Flow facility. An IC generation facility is classified as a "two way power flow" installation if the facility is configured such that its load is sufficiently variable or smaller than the generating capacity and the IC proposes to export its excess power. This type of installation provides for normal power flow in either direction, with the Avista system delivering power to the IC or the IC exporting power into the Avista system.

Note: Typically the two way power flow category also covers installations whose normal power flow is only into the accepting system (Avista), with no power received from the accepting system (Avista) to the IC.

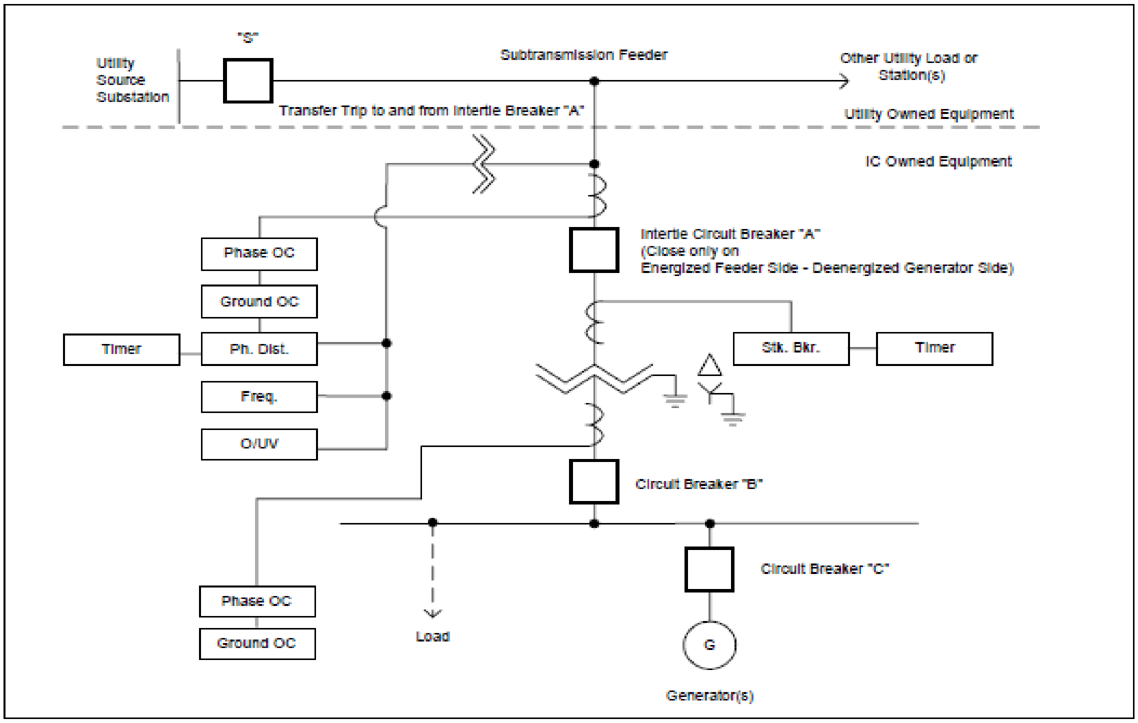
The type of generation equipment used by the IC along with the power flow requirements determines what type of protective equipment and switching requirements are needed. Generation installations may use either Synchronous Generators or Signal Dependent Generators. The Clearwater installation is expected to use a Synchronous Generator.

Synchronous Generators are capable of operation independent of any signal from Avista and can supply power to the IC's load when the Avista supply is unavailable. Special protection must be installed to ensure that synchronous generators do not keep an isolated part of the Avista system energized when the supply feeder's circuit breaker is open at the Avista source station. This condition is called "islanding" and is not permitted under any situation to ensure public safety, the safety of Avista employees and to prevent possible damage to other equipment. Two Way power Flow installations most frequently use synchronous generators.

In the case of two-way power flow installations, Avista must be able to absorb the power proposed to be received into the Avista system. The effect of power flow from IC generator installations on Avista's load flows must be studied, and may affect the design of the interconnection station, including interconnection location and voltage, as well as the IC's generation system.

The following schematic is typical of similar installations. The proposed equipment and operating sequence is subject to review and acceptance by Avista Corp. A completed application for interconnection will be required to confirm viability of electricity upload, as well as to determine equipment required for interconnection.

Figure 27 – Electrical Interconnect Schematic (Preliminary)



Protection	Trips Breaker	Typical Settings
Over/Under Frequency (FREQ)	A	61Hz Overfrequency 59Hz Underfrequency
Over/Under Voltage (O/UV)	A	110% of Nominal Overvoltage 80% of Nominal Undervoltage
Primary Phase Overcurrent (Phase OC)	A	200% of Transformer Rated Current
Primary Ground Overcurrent (Ground OC)	A	100% of Transformer Rated Current
Phase Distance & Timer (Ph. Dist.) (Timer)	A	80% of Impedance to "S" @ 0 seconds Time Delay 150% of Impedance to "S" @ 0.5 seconds Time Delay
Secondary Phase Overcurrent (Phase OC)	A or B	200% of Transformer Rated Current
Secondary Ground Overcurrent (Ground OC)	A or B	100% of Transformer Rated Current
Stuck Breaker & Timer (Stk. Bkr.) (Timer)	B or C and Transfer Trip to S	200% of Transformer Rated Current @ 0.25 sec. Time Delay

Notes: 1. Required metering is not shown.

FIGURE "C" -Two Way Power Flow – Subtransmission
Synchronous Generator
Typical Installation

--PRELIMINARY--PRELIMINARY-- PRELIMINARY--PRELIMINARY--PRELIMINARY--

5.0 Preliminary Engineering Design

Tetra Tech reviewed major heating and power options that are applicable to the general project conditions thus far determined for the prospective Plant. The following section identifies the most likely process technology for the biomass power plant and describes the conceptual plant design.

5.1 TECHNOLOGY EVALUATION

The options evaluated included advanced combustion, gasification, and pyrolysis. As proposed, each of these technologies was evaluated in a down-select mode to determine the most viable technology platform to pursue in the conceptual engineering phase of the project. The goal is to determine which technology platform can most cost-effectively utilize the available woody biomass fuel source, is fairly easy to implement considering the site operations and location, and is commercially available for full scale operation. Evaluations are based on previous experience with comparable projects. Ultimate selection of technology may depend on the preferred vendor, as vendors may include specific proprietary improvements, modifications, and interpretations to each given technology.

Advanced Combustion

Combustion can be defined as the burning of fuel to produce power and heat. The combustion process is highly developed commercially and is available in numerous vendor specific designs. It has been used throughout the world for power generation and heating. Incineration technology is well-established and easy to use, and systems using this process have evolved to be robust and long-lasting investments. Combustion occurs with oxygen in slight stoichiometric excess to rapidly complete the thermal oxidation reaction. Waste products are an ash residue and an off gas made up of predominantly nitrogen (N_2), carbon dioxide (CO_2), and water vapor. The off gas must be treated to meet regulatory requirements for chemical pollutants and particulates. The emissions will vary considerably from one vendor to another. As stated in Section 1.3, most vendors prefer to select and design specific Air Pollution Control equipment that addresses pollution and particulate for each project to meet air requirements.

Combustion is a highly exothermic (net heat output) process; therefore the technology lends itself to heat recovery in many applications. Heat generation can be used in boilers or converted to power via turbines. It is critical to maintain correct airflow and exposure of the fuel bed to ensure complete, clean, and efficient combustion. This is done by a combination of methods, including rotating kilns, fluidized bed reactors, and traveling grates. All of the systems work in conjunction with any number of controlled air flow systems including induced draft, forced air, and over fire/under fire systems.

Recent advances in combustion technology approach the system complexity and precision of gasification. In these advanced combustion processes, a “synthetic gas fuel” (syngas) is created from the woody biomass in an oxygen starved pre-burn chamber. The syngas is immediately burned in a second combustion chamber or used as a fuel in an attached combustion device. The combustion device may be a boiler to generate steam or an internal combustion engine or gas turbine used to power a generator producing electricity. This second destruction stage results in higher conversion of the fuel, and improved environmental and energy performance.

Utilizing aspects of gasification theory, combined with a specific gas combustion chamber, results in higher combustion efficiency and less air emissions as compared to traditional incineration/combustion. These systems approach gasification on the spectrum of technology complexity, and are sometimes referred to as gasification processes by equipment vendors. While this is not technically incorrect, the systems will be referred to in this study as advanced combustion because the end result is complete combustion of the feedstock fuel rather than downstream processing of the syngas.

Gasification

Gasification is defined as partial combustion that takes place in an oxygen-deficient atmosphere. That is, the oxygen level is controlled to use less than the amount needed stoichiometrically to complete the combustion process. The resulting products from a gasification process using air are a carbon-rich ash and a syngas stream. The syngas stream by volume contains approximately: 10% CO_2, 20% CO, 15% H_2, 2% CH_4, and the balance N_2.[15] When the oxidant used is air, the expected energy content of the syngas stream, is estimated to be approximately 4.8-6.7 MJ/m^3 (128 to 180 Btu/ft^3).[16] Gasification processes that use pure oxygen are able to obtain higher syngas energy content (300 – 380 Btu/scf) as a result of the elimination of the nitrogen present in atmospheric air. The syngas composition and energy content is dependent upon the composition of the feedstock fuel fed to the unit, but is commonly more pure than advanced combustion syngas streams.

There are different methods used to process material for gasification, as there are with combustion systems. Plasma energy gasification, reforming with steam vs. partial oxidation with oxygen, and various reactor types are also employed (e.g., entrained flow and fluidized bed).

Reactions that take place during the gasification process are both endothermic and exothermic, so that some heat input is generally required to keep the reaction ongoing. The benefits of gasification are considered to be increased efficiency, greater variety of end products, and fewer back-end pollution control requirements.

The resultant syngas may be further processed and used in downstream energy generation or chemical synthesis. This is what sets gasification apart as a distinct technology platform. In more sophisticated conversion processes, the syngas can be converted to ethanol, methanol, and hydrogen and then further refined to other liquids. Conversion via Fisher-Tropsch or other

[15] Perry's Chemical Engineers' Handbook, 7th Edition, 1997

[16] U.S. Department of Energy – National Energy Technology Laboratory

catalytic processes can also be used to generate materials such as gasoline or diesel. The syngas stream can also be used to directly fuel a boiler or generate electricity. These simplified systems are labeled by equipment vendors as a gasification system, but are essentially indifferentiable from advanced combustion systems.

Gasification has achieved a higher level of commercial acceptance over the past 10 years due to improvement in available technologies such as control systems and high temperature materials of construction. While gasification is a more complex technology, and typically more expensive than conventional combustion, it allows for the recovery of value products (i.e., syngas) which can be used to synthesize other chemicals (fuels, alcohols, etc.).

Pyrolysis

Pyrolysis is defined as the thermal breakdown of higher chain organic molecules (cracking) into smaller organic components. This thermal cracking is done in the absence of oxygen, sometimes with the addition of a catalyst. The resulting products from the pyrolysis process are:

> **Char:** Consists of high carbon content solids. Also, any inorganics that might be contained in the waste stream, and catalysts that were added and carried through the process.
> **Non-condensable Gas:** Made up of hydrogen, methane, carbon monoxide and other non-condensable gases. Can be burned similar to natural gas.
> **Liquid Fuel:** Made up of dozens of organic chemicals. Can be used similar to a #4 Fuel Oil, but pyrolysis oil typically requires additional processing.

Most organic compounds can be broken down to basic components using the pyrolysis process. As a result, many experimental and pilot plant programs have been done using pyrolysis to process products such as animal offal, used tires, agricultural field residue, and manure. The process is endothermic, requiring significant support fuel to maintain the reaction, and is difficult to control because of variations in feed make-up. Therefore, the product quality has a tendency to be inconsistent.

The theoretical advantage of pyrolysis is that close to 100 percent of the mass feed is recovered and reused as fuel for consumption. The process also has very low air emissions as a result of the recycling and condensing done during the liquid recovery phase. In the case of the char, it is reprocessed as a carbon replacement (in some cases activated) or used as a soil enhancement. In practice, the products are inconsistent, requiring further complicated processing. The char tends to contain inorganic components that limit its usefulness. Most of the issues related to product inconsistency result from the inability to control the make-up of the feed to the unit.

More recently, there has been some success in at pilot scale processing animal wastes, such as turkey and chicken litter. A potential benefit of the pyrolysis process in this particular application is that the woody biomass could be partially converted to a liquid fuel that could be more readily stored for usage during the winter months, eliminating the need for a large stockpile of hog fuel.

Commercially, when compared to combustion, there have not been many successful pyrolysis ventures. Capital costs and operating costs tend to be higher due to the complexity of the process and additional processing requirements. There have been a handful of commercial ventures successful in processing used tire shreds.

Combined Heat and Power (CHP)

Each of the proceeding technologies can technically be integrated with electrical generating equipment to provide a combination of electrical power and heat. In practice, however, advanced combustion is more often combined with CHP units than pyrolysis or gasification units.

Combustion is typically used in a boiler to generate high pressure steam, which in turn is used to drive a steam turbine connected to an electrical generator. The steam turbine can be designed as either a backpressure turbine or a condensing turbine, depending on whether or not there is a need for steam. Steam turbines are mature technology that has been proven reliable over a century of use.

Gas turbines and reciprocating (internal combustion) engines can also be used to drive electrical generators. Gas turbines are typically used with a clean gaseous fuel, such as natural gas, but can be used with synthesis gas such as that produced in a gasifier. "Dirty" fuels can create issues with build-up on the turbine blades, so the synthesis gas typically needs to be cleaned prior to injection into the turbine. Reciprocating engines can burn liquid or gaseous fuel and are also a mature technology with many successful installations.

Technology Evaluation Matrix

A technical analysis and decision matrix using a set of critical factors as proven on other projects has been used to assist in the determination of the leading technology platform for the proposed biomass power plant. Primary and secondary criteria outlined in Table 19 below are directly related to the technical, environmental, and social goals and objectives of Clearwater County in the development of the facility. Technology evaluation scale is the small to mid-size scale being considered for the Clearwater facility (1 to 10MW). These criteria form the basis of a SWOT and "decision tree" evaluation process. The matrix evaluation is based on Tetra Tech's past experience working with the technology platforms analyzed, and does not contain information specific to any one vendor or technology supplier.

The technology selection matrix uses a scale of 1-10 for each factor; a value of 1 means the system satisfies the criteria very poorly, while a score of 10 means the system is very well designed to accomplish the intended goal.

Table 19 – Technology Selection Decision Matrix

Implementation	Advanced Combustion	Gasification	Pyrolysis
Commercialization status and risk	9	7	3
Process complexity and upset risks	8	6	4
Siting, zoning, and permitting issues: Permitability Public acceptability Infrastructure requirements	7	7	7
Footprint and stack/building height requirements	7	7	7
Proximity to woody biomass sources	9	9	9
On-site storage potential	8	8	8
Ability to synergize with existing woody biomass and recycling operations	8	8	8
Subtotal	**56**	**52**	**46**

Effectiveness (Technical)	Advanced Combustion	Gasification	Pyrolysis
References from suppliers	9	7	6
Energy production	7	8	5
Conversion efficiency	7	9	7
System flexibility	7	7	8
Technology availability	8	6	3
Ability for expansion Scalability Modularity	8	7	7
Ability to integrate Pre-processing Emissions control	8	8	8
Parasitic loads(1)	8	7	7
Subtotal	**62**	**60**	**51**

Financial Analysis	Advanced Combustion	Gasification	Pyrolysis
Cost analysis	8	6	5
Degree of localized content (2)	7	6	6
Degree of automation	7	7	7
Federal, State, and Local Incentives	7	7	7
Money market value (Certified Emissions Reductions (CERs) and Carbon Offsets	7	7	8
Subtotal	**36**	**33**	**33**

Environmental Impact	Advanced Combustion	Gasification	Pyrolysis
Regulated and toxic emissions	8	8	8
Byproducts and residual wastes Generation of ash and disposal options Air emissions Carbon / GHG Footprint Overall impact on human health, safety, nuisance, and visual	6	8	9
Subtotal	**14**	**16**	**17**

Social Analysis	Advanced Combustion	Gasification	Pyrolysis
Employment generation	6	6	6

Ability to locate in populated area	6	6	5
Any local constraints or objections	6	6	6
Impacts – Noise, smog, odor, and visual impacts	6	8	5
Subtotal	**24**	**26**	**22**

Comprehensive Evaluation	Advanced Combustion	Gasification	Pyrolysis
TOTAL SCORE	**192**	**187**	**169**

Notes:

'Parasitic load' is the energy consumed by the process equipment to operate the system.
'Degree of localized content' refers to ability of process equipment to be constructed and operated by existing local workforce.

Technology Recommendation

As the matrix evaluation indicates, advanced combustion and gasification technology platforms most closely fit the goals and objectives of the project, with scores of 192 and 187, respectively. The Clearwater site and project objectives make pyrolysis a suspect choice of technology. Theoretically, the advantage of pyrolysis is that a waste can be converted into marketable products. In Idaho there is currently not a profitable established market for pyrolysis oils, therefore it makes little sense to pursue the technology at present.

Both advanced combustion and gasification are very similar to one another in that a syngas is created from the woody biomass in an oxygen-starved pre-burn. In the advanced combustion process, this syngas is immediately burned in the combustion chamber, whereas in the gasification process the syngas is more likely to be used to fuel a downstream process or be condensed and refined. The higher quality syngas created in most gasifiers is not required for CHP process that will be utilized in this system, and the commonly higher capital cost associated with gasification make it the less favorable technology for consideration.

The Decision Matrix favors advanced combustion, but the final project decision will need to be based on factors specific to each equipment vendor, as received through final bids for project construction. Technical evaluation of competing vendors' bids is the next step in the engineering process. Tetra Tech recommends Clearwater pursue discussions with equipment vendors manufacturing advanced combustion technology, as well as those producing simplified gasification technologies that directly create combined heat and power, for the prospective biomass power plant.

5.2 BIOMASS CHP FACILITY PROCESS DESCRIPTION

Tetra Tech recommends using advanced combustion combined with a CHP system to process biomass feedstock at the Clearwater project site, and has prepared the following conceptual process design based upon advanced combustion technology. The plant design is engineered and tailored to conditions specific to the site, at a conceptual engineering level corresponding to standard engineering practices of approximately 10% of system design. In several cases as noted below, Tetra Tech has completed additional measures that provide more detail than the standard 10% design.

Process equipment required for the combustion of biomass feedstock material to electrical and thermal energy includes: hog fuel shredder, feedstock drier, 2-stage combustion chamber, gas conditioning and clean-up, electrical generator, heat exchanger for thermal energy recovery, and an air pollution control system. It is important to note that equipment is specifically engineered / chosen to operate at a high level utilizing hog fuel feedstock (e.g., inclusion of dedicated shredder), understanding that the composition and physical characteristics of hog fuel differ from higher value feedstocks meeting specific quality specifications, such as chip wood.

All of the supplied equipment is proposed to be of “modular” design. This will allow the equipment to be easily shipped and installed at this moderately remote location.

Biomass Power Plant Process Flow

The system process flow is described in sequence in the following section. A corresponding process flow diagram is supplied below as Figure 28.

- Feedstock will be transported to the site via chip trucks where they will be off loaded. The fuel will be stored on a paved area to minimize mud and the resultant mixing with inert particles and dampness. The fuel storage area is designed to store enough fuel to operate for 3 months. This will allow for onsite drying, blending of various grades of feedstock materials, and winter storage when source chipping, removal from the source, and transportation to the site is difficult. The lower heat value of the feedstock fuel processed at the facility is expected to be approximately 6300 Btu/lb, and the moisture content as received is expected to be approximately 30%.

- The feedstock will be moved from the storage by a front loader from the on-site storage pad to a shredder where it will be reduced in size to enable consistent flow through the equipment. Shredding also will mix the fuel for a more consistent heating value throughout the fuel stream.

- The sized fuel will be transported via belt conveyor to a drier. Extracting heat generated from the process, moisture will be evaporated from the fuel. The drier will increase the overall efficiency of the process by using heat that might otherwise be wasted, and improving the conversion efficiency of the combustion process. Recovered heat from power generation will fuel the dryer. Once dried, the fuel will be conveyed to a feed hopper.

- The dried fuel will be conveyed and metered into the combustion chamber through an airlock system. The airlock system enables the air to be maintained at a very low oxygen level during the combustion process. The combustion process generates syngas. The solid material remaining is the ash waste product. The syngas is removed via piping overhead, and the ash is continuously removed from the bottom of the gasifier.

- The syngas is conditioned or cleaned prior to being ignited during the electrical generation process.

- Electrical generation can be accomplished through two methods using currently-available technology:

    The syngas stream is directly ignited using an internal combustion engine or gas turbine to drive a generator. This in the recommended pathway in this specific situation.

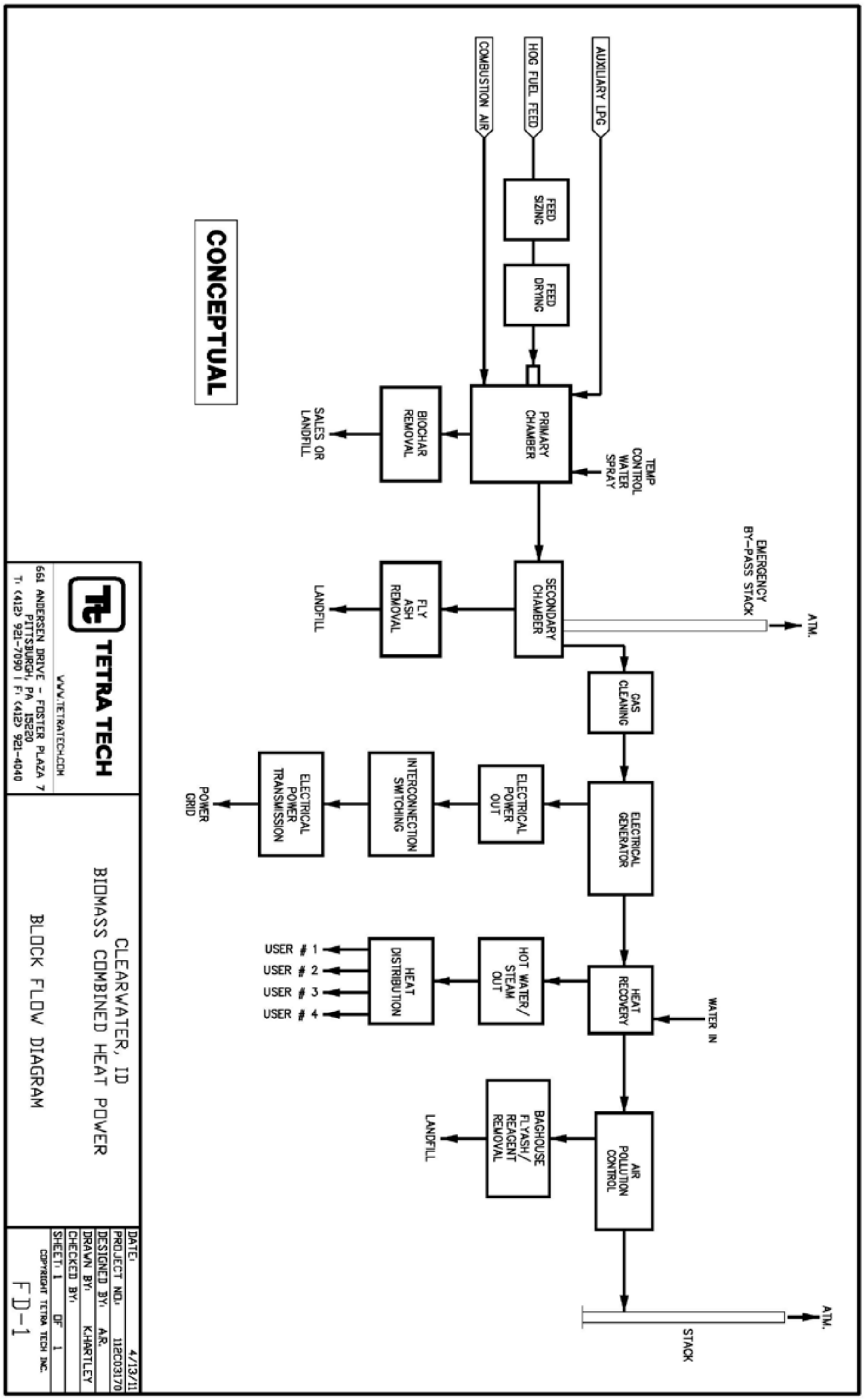
    The syngas stream is ignited in a steam boiler, with the produced steam driving a steam turbine generator.

- Heat recovery for building heat will be accomplished with a heat exchanger that uses either the exhaust from the internal combustion engine or the low pressure steam that remains from the steam turbine. Steam and/or hot water is piped to local facility energy users, including ICI-O, CVHC, OHS, and additional potential thermal energy users. These are identified as Users #1-4 in the process flow diagram below.

- Ash (also known as 'fly ash') produced by the various processes is classified as non hazardous if woody biomass feedstock is used exclusively. It can be sent to residual landfill as a waste product. Alternately, ash can be further processed as a soil amendment, known as biochar. Biochar has been proven to enhance soil quality by adding nutrients (calcium, potassium, magnesium, etc.) to the soil when properly processed and added to soils in the correct ratio with other fertilizers. A market outlet must be available to utilize the product, and at present one does not exist in the local area. However, with the agriculture in the area it is likely that it can be handled in this way, at first given away to local farmers to test soil amendment properties and later sold as the beneficial properties of biochar become known. The amount of ash produced is likely range from 2 to 10 percent of the original feedstock. The amount of ash is dependent on the feedstock, moisture content and the transformational process noted above. For example, whole tree chip wood including bark will have higher ash content.

- Air Pollution Control is the final treatment of the gas stream prior to release into the atmosphere. Air emissions will be required to meet regulations determined by the Federal EPA and State environmental regulatory agency.

Figure 28 – Biomass Power Plant Block Flow Diagram



Air Pollution Control Systems

An important component of any thermal treatment system is the treatment of the final off-gas prior to its being emitted to the atmosphere. Individual vendors tend to favor an APC specific to their process. Manufacturers need to address site-specific regulations for air emissions of various chemicals (i.e., NOx, SOx, dioxin, and furans).

APCs can be categorized into two types: wet or dry. Both types use chemical addition, adsorbents and absorbents, and filters to bind the chemical pollutants, then subsequently trap the particulate emissions through the use of bag house filters. The wet systems have a 'blow-down' stream and a 'make-up' stream that will need to be considered. The blow-down stream is dried, discharged to outfall, or reused in the manufacturing process. A dry system will have filters that collect particles. In this the particles can be dislodged from the filters and disposed of, and the filters reused. The given process is acceptable for point-source emissions from most APC systems on the market. It is standard practice for process equipment vendors to partner with APC firms as part of the Engineering, Procurement, and Construction (EPC) contract, allowing them to provide a guarantee that local emissions standards will be met by the constructed system. General permitting and regulatory requirements for air emissions are presented in Section 7.

Biomass Power Plant Operational Considerations

The Plant will require an area approximately 9.5 acres in size. This includes the plant, pre and post processing including a storage area for feedstock large enough to store 3 months for winter supply, a truck offloading and turning area, and a pole building to enclose the entire process.

The system is designed to operate 24 hours per day, 7 days per week (24/7). It will therefore need to be manned 24/7 in order to maintain the feed and monitor the operations. The estimated man power will allow a manager to oversee day to day operating, feedstock purchasing, off-take management (e.g., electricity sales) environmental monitoring, management of truck traffic in and out, and scheduling of repairs and down time. One process operator will be on each eight hour shift to monitor and adjust the operating parameters of the process to ensure safe, efficient and environmentally sound operations. He will also assist with monitoring and maintenance duties, as needed. The maintenance mechanic, who can also be a shift operator, will be present during daylight shift to provide additional assistance for preventative and repair maintenance, as needed. At a smaller plant scale (1MW CHP), feed hoppers can be used to reduce onsite man hours, and reduce full-time employees of the facility to three.

Scheduled maintenance will need to be conducted on the system at periodic intervals. The biomass power plant is assumed to have 90% uptime, corresponding to approximately 330 days per year of consistent operation.

It is noted that the operation of the prospective biomass power plant will require regulatory oversight. A facility such as this comes under oversight by many authorities including: US EPA, Idaho EPA, OSHA, DOLI, DOT and others. Operating the proposed facility to the highest level of regulatory compliance should be a primary goal of Clearwater County.

The major variables for facility operation and modeling of financial performance of the project include product yields, product and raw material pricing, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the plants and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs. Major facility parameters for both plant configurations are shown in Table 20. The scenarios are labeled according to the nominal electrical output load, 1MW and 2MW, respectively.

Table 20 – Biomass Power Plant Facility Operation Parameters

Biomass Power Plant Facility Parameters		1 MW CHP	2 MW CHP
Plant Inputs			
Feedstock	tons/day (wet)	20	40
	tons/year (wet)	6,600	13,343
	tons/year (dry)	4,620	10,675
Physical parameters of feed stock		Chipped hog fuel	Chipped hog fuel
Lower Heating Value (LHV)	Btu/lb	6,268	6,268
Auxiliary fuel required	gal/year diesel	0	0
Plant Outputs			
Gross electrical energy produced	MW	0.9	1.8
Parasitic load to process equipment	%	15%	15%
Net electrical energy produced	MW	0.77	1.53
	kWh/yr	6,058,800	12,117,600
Net thermal energy available	MMBTU/yr	33,264	66,528
Thermal energy utilized by facilities	MMBTU/yr	21,113	21,113
Excess thermal energy	MMBTU/yr	12,151	45,415

Figure 29 illustrates a conceptual view of the biomass power plant configuration at the project site.

Figure 29 – Clearwater Biomass Power Plant Facility Configuration

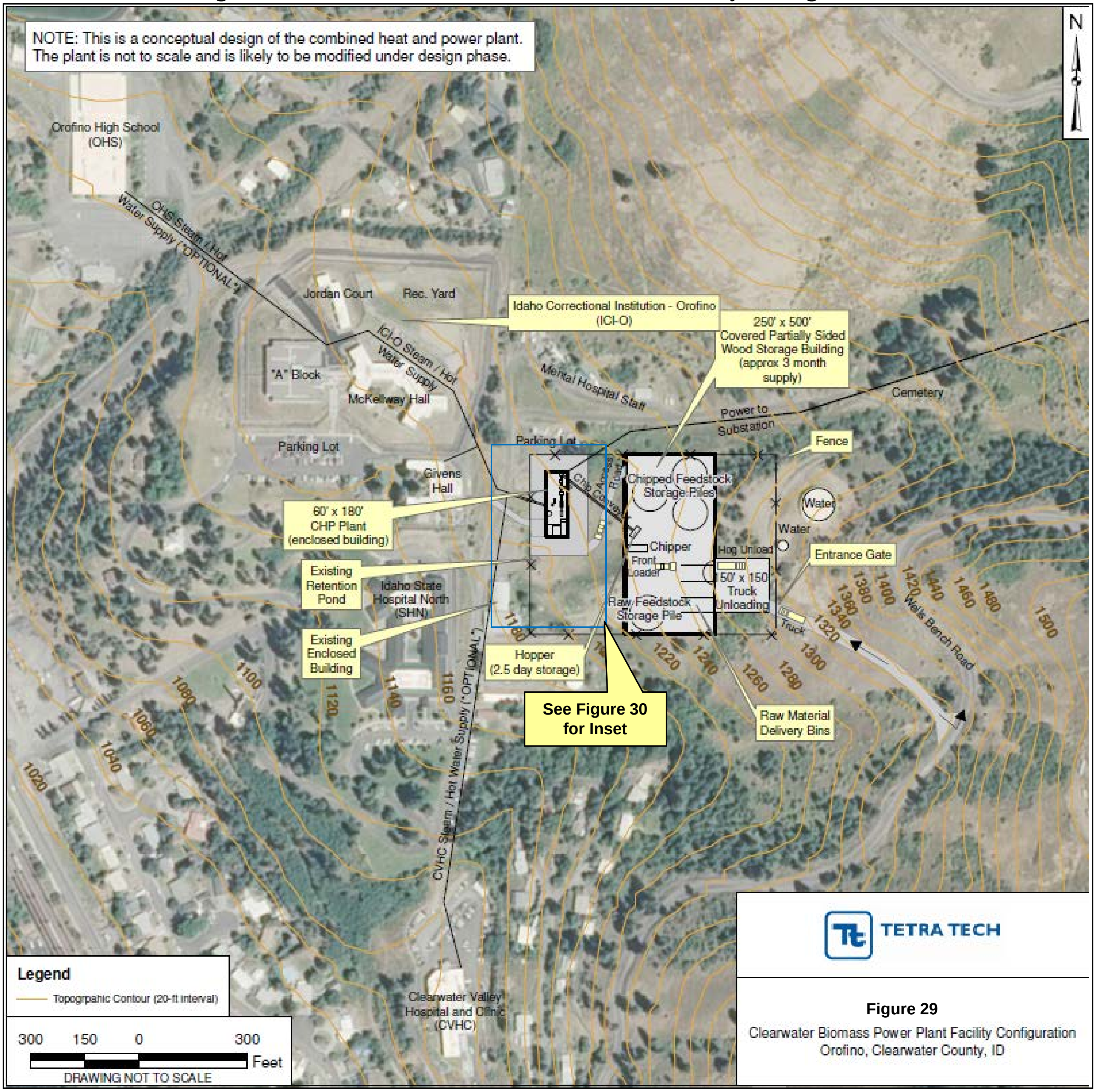
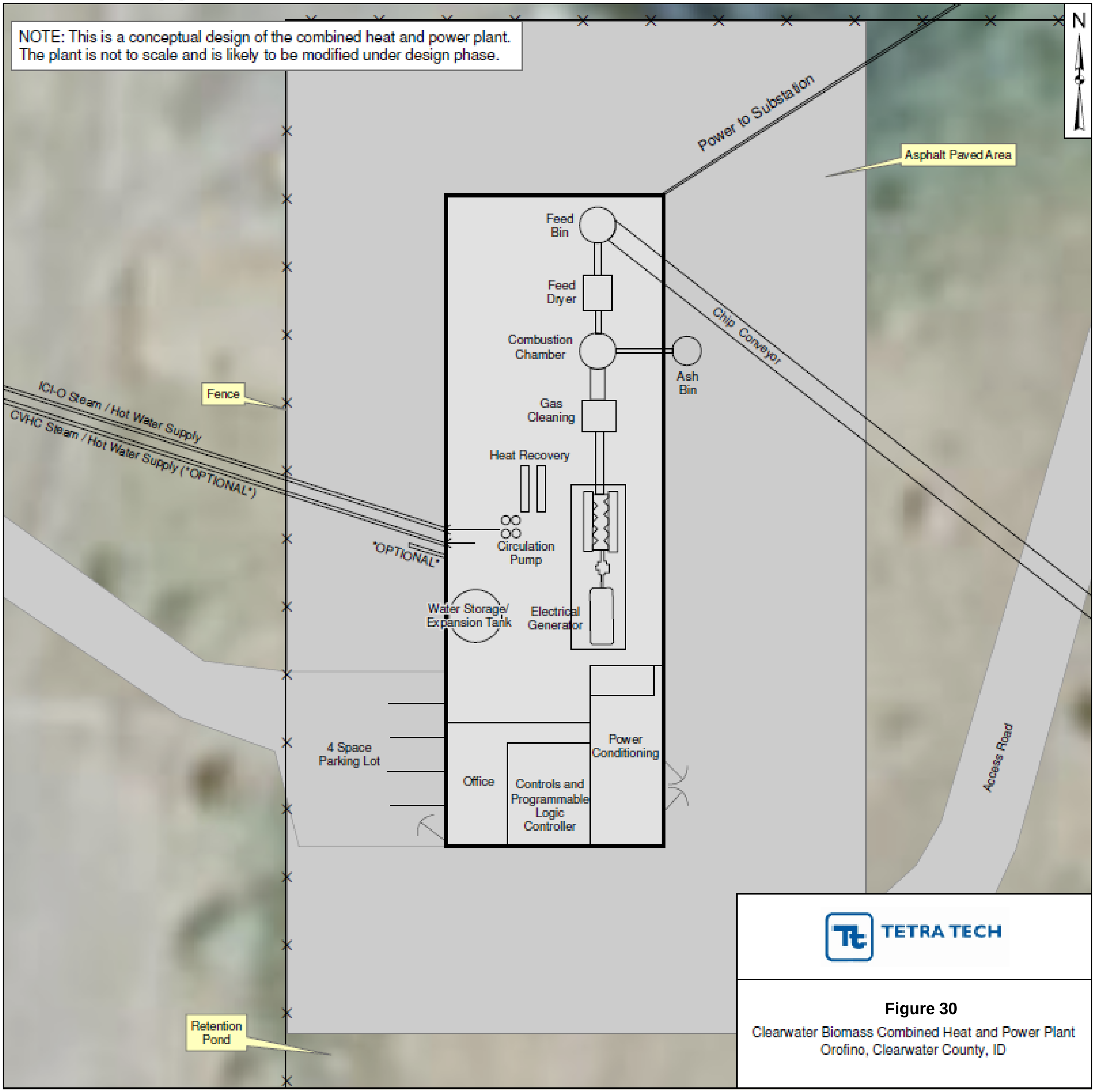


Figure 30 – Clearwater Biomass Power Plant Process Equipment



6.0 Project Financial and Economic Analysis

Tetra Tech prepared financial modeling and economic performance projections of the prospective biomass power plant, using the company's proprietary economic modeling software. The models evaluate the project conditions evaluated in the study. When possible, Tetra Tech solicited cost and operational parameters from equipment providers, and supplemented that information with internal engineering analysis. Product yields, product and raw material pricing, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the plants and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs, and other facility parameters for 1MW CHP and 2MW CHP facilities are presented in this report.

6.1 FACILITY CAPITAL COSTS

Tetra Tech prepared and released a budgetary-level Request for Quotation (RFQ) to gather information regarding project construction costs and equipment operational parameters. This information was used to supplement internal databases. Four equipment quotes were solicited by Tetra Tech for the biomass power plant. The companies solicited included:

ZeroPoint Clean Tech, Inc.
P.O. Box 1406
Princeton, NJ 08540

Waste2Energy Holdings, Inc.
1 Chick Springs Road
Greenville, SC 29609

Nexterra Systems Corp
1300-650 W. Georgia St.
P.O. Box 11582
Vancouver, BC V6B 4N8

Spinheat Limited
1222 Bronson Road
Fairfield, CT 06824-2824

Tetra Tech reviewed the supplied information from the vendors and developed capital costs for the proposed operating ranges of the facility. The facility capital costs included information supplied in vendor responses, as well as costs and operational parameters derived from internal investigation of the facility. The capital cost below is therefore not representative of any single bid or vendor's equipment profile. Clearwater will need to obtain final construction bids from prospective vendors to confirm final project capital cost.

Table 21 – Schedule of Equipment

Clearwater County 112C03170 Equipment Schedule		1 MW CHP		2 MW CHP	
Item	**Description**	**Qty**	**Units**	**Qty**	**Units**
Site Preparation					
Grading		1	lot	1	lot
Access Roadway	800 LF x 24 ft wide asphalt	19200	ft2	19200	ft2
Retaining Walls	200 LF x 20 ft high	4000	ft2	4000	ft2
Catch basins		1	lot	1	lot
Backfill		150	yd3	150	yd3
Retention Pond		1	lot	1	lot
			yd3		yd3
Asphalt		15000	ft2	45000	ft2
Building Requirements					
Building Floor Area		**6250**	**ft2**	**10800**	**ft2**
Foundations, floor slab	8" slab	153	yd3	264	yd3
Footers		115	yd3	115	yd3
			ft2		ft2
Building Shell	Insulated Metal Building - 25' Height	6250	ft2	10800	ft2
Truck doors	Overhead doors with operators	4	ea	4	ea
Fire Protection System					
Fire Protection	Sprinkler system and alarms	6250	ft2	10800	ft2
Material Handling Equipment					
Front Loader		1	each	1	each
Fork Trucks	2 ton fork trucks	1	each	1	each
Process Equipment					
Renewable CHP Solution		1	lot	1	lot
Gasification Unit					
Gas cooling and heat recovery					
Gas Cleaning					
Blower					
Reciprocating Engine/generator		1	each	1	each
Chipper		1	each	1	each
Utility Equipment and Piping					
Water/gas tie-ins		1	lot	1	lot
Cooling Tower	8 MM Btu/hr			1	lot
Sewage		1	lot	1	lot
Ash Removal		1	lot	1	lot
Ash storage		1	lot	1	lot
Air Compressor		1	lot	1	lot

Electrical and Instruments					
Transformer	240/120 single phase	1	lot	1	lot
Supply	Underground run from new transformer	200	LF	200	LF
Lighting/power		1	lot	1	lot
Switchgear & connection to grid	switchgear and power conditioning for interconnection to grid, and transmission line	1	lot	1	lot
Controls					
PLC & related hardware			each		each
Software	PLC and Interface Software		lot		lot
Panels	I/O and Control Panels		each		each
Cables and Wiring	Interface cables and network wiring		lot		lot
MMI	Operator Interface Panels		each		each
Programming	PLC and MMI programming		lot		lot
Emission, HVAC & Ventilation					
Building Heat	Electric radiant	6250	ft2	10800	ft2
Ventilation	Fresh air blowers and ductwork	1	lot	1	lot
Other costs					
Installation Labor		1	lot	1	lot
Rental equipment		1	lot	1	lot
Indirect Costs					
Permitting	Permitting fees and related costs	1	lot	1	lot
Engineering	Detailed Design Engineering	1	lot	1	lot
Surveying	Site survey	1	lot	1	lot
Soil Testing	Building #1 Expansion	1	lot	1	lot
Construction Support Services	On-site construction support	1	lot	1	lot

The vendors solicited preferred a 2MW scale for their base equipment package. The vendors did not quote systems producing 1MW output, but remained available to design and build application to that scale. The preference of larger systems is likely due to the efficiencies associated with the larger process scale. Tetra Tech produced the 1MW capital cost estimate using standard engineering equipment scaling formulas when necessary to supplement internal databases. As is standard when scaling equipment down in size, the 1MW system is estimated to be more than 50% of the cost of the 2MW system despite being 50% of the size, due to economies of scale.

Table 22 shows the estimated capital cost breakdown for process equipment, building costs, development costs, startup, and contingency.

Table 22 – Biomass Power Plant Capital Cost Estimate

Clearwater County 112C03170 Capital Expenditure Summary	1MW CHP	2MW CHP
Process Equipment & Construction Costs		
Primary Process Unit	$1,517,434	$2,300,000
Power Generator	$1,715,360	$2,600,000
Utility Grid Interconnection	$824,705	$1,233,000
Steam / Hot Water Piping	$191,000	$191,000
Chipper / Shredder	$197,926	$300,000
Installation Cost	$720,000	$720,000
Total Equipment and Construction Cost	**$5,166,425**	**$7,344,000**
Development and Start-up Costs		
Engineering	$250,000	$250,000
Total Land, Site Development and Building	$719,188	$1,108,210
Inventory - Feedstock	$15,000	$30,000
Inventory - Spare Parts	$150,000	$150,000
Start-up Costs	$7,400	$9,600
Land	$40,000	$60,000
Fire Protection & HVAC	$57,375	$93,320
Rolling Stock & Shop Equipment	$70,000	$70,000
Organizational Costs & Permits	$300,000	$50,000
Construction Bond & Financing Costs	$420,230	$738,570
Working Capital/Risk Management	$27,000	$50,000
Total Development and Start-up Costs	**$2,056,193**	**$2,609,700**
Contingency 20%	$1,387,000	$1,979,000
Total Uses	**$8,319,718**	**$11,872,940**

The capital cost supplied above is a budgetary estimate, corresponding to the level of engineering detail that has been conducted at this stage of the project. Budgetary quotes are defined by engineering's governing body, AACE International, as 10-15% design completion of the facility, and as such can only be held to a +30% to -15% accuracy level. Adhering to this international standard, the 1MW biomass power plant all-in capital cost is projected to fall in the range of **$7MM-10.8MM**. The 2MW CHP biomass power plant is projected to cost between **$10MM-15.4MM**.

Note that a 20% contingency factor is also applied to the capital cost to account for additional cost overruns. Actual costs will vary depending on the technology provider and general contractor chosen for the project, material costs, and other factors in further facility engineering and procurement stages.

6.2 FACILITY OPERATIONAL PARAMETERS

Facility Ownership and Funding Structures

Several business structures are available to Clearwater County to finance and operate a biomass power plant. The structures include ownership wholly by Clearwater County, ownership by a private entity under contract to provide the services to the facilities, or a partnership between public and private ownership and operation of the project under a negotiated contract.

One such system is known as a public-private partnership (PPP) to build, own, and operate the facility A PPP is a contractual agreement between a public entity that will own and will be receiving the benefits of the project, such as Clearwater County or the City of Orofino, and a private entity service provider that may design, build, and/or operate the facility for a scheduled period of time. 15 or 20-yr operation contracts are common in this financial structure. Equity investment can be monetary (injection of capital) or in-kind (engineering, construction management, etc services for the project).

Another structure of PPP is known as a BOOM – Build, Own, Operate, and Maintain. In this structure, a private third party finances, and operates the system as well as retaining ownership, The third-party receives its return from selling power and thermal energy to end users at a negotiated rate. These are often arranged as a performance-based operations contract, or an Energy Services Performance Contract. In this system, an Energy Services company (ESCO) arranges financing for a project, develops and installs equipment, and receives a portion of profit from energy sold as well as the revenue from monetizing carbon credits for the energy produced. These projects often require significant energy efficiency programs to be implemented in conjunction with a biomass power plant to improve carbon credit values.

Alternatively, the local public entities can join forces in the creation of a special utility district encompassing ICI-O, CVHC, OHS, and SHN. Each entity would invest in the project, whether through injection of capital, in-kind donations of land or other resources, and/or contractual obligations to use produced energy from the project. A third-party can be brought in to operate the plant for a negotiated fee.

The prospective Plant is envisioned to be a public service project, providing stable and competitively priced utility services to the local facilities while at the same time adding value to the area timber industry and providing local job opportunities. As such, a PPP with ownership by Clearwater County with a private firm partner to operate the project under a performance-based contract is a likely and advantageous financial approach to the project. A PPP would allow the project to utilize the benefits provided by both public and private sectors, while sharing the potential risks and rewards of the project.

For the purposes of this financial analysis, the prospective Plant project is the product of a PPP contract. The facility financial model assumes ownership by a public entity, with facility operations handled by a private entity on a contract basis. The private entity operating the facility will be responsible for day-to-day oversight of the facility, maintenance, and production of established quantities of thermal and electrical energy. The contract will likely include specific performance and efficient guarantees that the private entity is required to maintain. The private entity will only carry a minimal project financing burden, and will not be expected to cover facility ownership.

Financing of the project is expected to be accomplished primarily through raising of a bond, supplemented by available grant funding and a small capital investment from the partner private entity. The funding would likely be covered by a state general-obligations bond, likely housed under the IERA Renewable Energy Generation Bond Program. Standard period is 30-yr, current rate is 4.49% for Idaho general obligations bonds. Grant funding is available and assumed in the project modeling to reduce capital expenditure. Grant funding mechanisms are discussed in Section 8.

Performance-based contacting for operation of the facility sometimes also includes negotiated distribution of project earnings, much like distribution to shareholders. This can be contracted on a percentage basis, where both parties are able to benefit from profits in the system. Conversely, in this structure both parties are liable for project losses.

The estimated financing structure for the two plant scales are outlined in Table 23 below. Grant funding is expected to be used to supplement capital costs, and a small equity amount is assumed to be applied to the project expenditure, whether through monetary investment or in-kind expenditure.

Table 23 – Project Financing Summary

Project Financing Summary	1MW CHP	2MW CHP
Percent Equity	17%	8%
Percent Senior Debt	60%	60%
Equity	$1,549,503	$973,788
Total Grants	$2,000,000	$4,000,000
Senior Debt	$5,324,255	$7,460,682
Total Source of Funds	**$8,873,758**	**$12,434,470**

Financial Modeling Assumptions

Tetra Tech prepared a two financial models for the project, based upon the best information available at present and corresponding to the two plant scale conceptual designs, at 1MW and 2MW nominal power output. To maintain project transparency, and to facilitate adjustments to project goals as the project moves further in the development phase, an explanation of the inputs used in the financial forecasts that have the greatest impact on the project risk and return follows. The project inputs that have the greatest impact on project operations and financial returns are:

- *Project Construction and Facility Operational Year.* The facility was assumed to be constructed and operational in the year 2014. The construction period is expected to consume 13 months following project financial close, then ramp up to full operations in months 14 and 15.

- *Feedstock Input.* For the 2MW CHP operational scenario, feedstock input is assumed to be 13,343 wet tons per year at 30% moisture (10,675 dry tons/yr), at a rate of 40 wet tons per day input. For the 1MW CHP scenario, feedstock input is 20tpd or 6,600 tons per year on an as-received basis, or 4,620 tons per year on a dry basis.

- *Feedstock Input Cost.* Feedstock input cost throughout the project lifespan is projected into the future using a USDOE EIA projected diesel fuel price index basis. This basis assumes a baseline feedstock cost of $25 per wet ton cost in 2010 rising in accordance with the diesel index basis. Table 24 shows the projected feedstock cost throughout the lifespan of the project. Projection of feedstock price inflation over time is further described in Section 6.3 below.

Table 24 – Project Feedstock Pricing

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Diesel Price	270.0	276.2	297.6	317.9	334.0	350.2	368.0	384.1	401.6	415.4	428.7
Diesel Index	1.00	1.02	1.10	1.18	1.24	1.30	1.36	1.42	1.49	1.54	1.59
Diesel Fuel Impact	7.50	7.67	8.26	8.83	9.28	9.73	10.22	10.67	11.16	11.54	11.91
Total Feedstock Price	25.00	25.17	25.76	26.33	26.78	27.23	27.72	28.17	28.66	29.04	29.41

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
441.0	456.5	468.9	480.1	495.2	509.4	525.1	542.7	562.5	578.2	600.1	622.2	642.4	665.0	689.9
1.63	1.69	1.74	1.78	1.83	1.89	1.94	2.01	2.08	2.14	2.22	2.30	2.38	2.46	2.55
12.25	12.68	13.02	13.33	13.75	14.15	14.59	15.07	15.62	16.06	16.67	17.28	17.84	18.47	19.16
29.75	30.18	30.52	30.83	31.25	31.65	32.09	32.57	33.12	33.56	34.17	34.78	35.34	35.97	36.66

- *Energy Savings.* The Plant is expected to produce thermal energy in the form of steam and hot water, which can be used to displace electrical-powered heating at nearby facilities. The project assumes the maximum available thermal energy load is serviced by the Plant. Thermal energy use by the prospective users of produced thermal energy from the biomass power plant, including ICI-O, CVHC, and OHS, is presented below along with a contingency factor to account for potential future construction of additional facilities deriving thermal energy from the Plant.

Table 25 – Orofino-Area Facility Thermal Energy Demand

Orofino Area Thermal Energy Demand			
		kWh/yr	*MMBTU/yr*
Primary Facility	ICI-O	3,034,806	10,358
Additional Facilities *Optional*	CVHC	1,181,112	4,031
	OHS	970,040	3,311
	Future Installation	1,000,000	3,413
	Totals	**6,185,958**	**21,113**
		773.24	kW Load

Table 26 shows that the maximum expected thermal energy load from all potential local facilities is 773kW, or approximately 21,000 MMBTU/yr. The load from ICI-O is approximately half of this total, at 10,358 MMBTU/yr. Unsold thermal energy will either be used for feedstock drying or vented to atmosphere. A sensitivity analysis will also be included to determine the effect of increases or decreases in thermal energy sold by the project.

- *Thermal Energy Sale Value.* Thermal energy produced by the biomass power plant is expected to be sold to the identified energy users, at a rate equal to the current electrical energy purchase price on a BTU basis. CVHC heats with more-expensive diesel fuel, and will realize a lower heating cost from inclusion in the prospective project. The value of thermal energy produced by the system is set at a cost of $19.00/MMBTU. Thermal energy sales are expected to increase by 1.5% annually to account for future increases in electricity pricing in the area. A sensitivity analysis will also be included to determine the effect of variations in thermal energy sale value.

- *Electrical Energy Sale Value.* For a power-producing facility coming online in 2014, the scheduled Power Purchase Agreement (PPA) rate for electricity off-take is $71.41—$91.89/MWhr, depending on the length of contract (See Table 26). For a 10-year contract, the scheduled rate is $82.40/MWhr, or $0.0824/kWh. A 10-yr contract is assumed for conservative estimate of electricity rate. A better rate can be achieved with a longer contract signing but at present it is deemed prudent to include a more conservative rate. The value used in the base financial model is ¢8.24/kWh. A sensitivity analysis will also be included to determine the effect of variations in electrical energy sale value.

Table 26 – AVISTA Power Purchase Rate Schedule[17]

AVISTA
AVOIDED COST RATES FOR NON-FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 15, 2010
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2010	2011	2012	2013	2014	2015	CONTRACT YEAR	NON-LEVELIZED RATES
1	56.94	60.32	64.06	67.60	71.41	75.50	2010	56.94
2	58.56	62.11	65.76	69.43	73.37	76.63	2011	60.32
3	60.25	63.80	67.49	71.29	74.74	77.71	2012	64.06
4	61.87	65.47	69.25	72.73	75.94	78.80	2013	67.60
5	63.47	67.16	70.70	73.98	77.07	79.87	2014	71.41
6	65.09	68.60	71.97	75.15	78.16	80.93	2015	75.50
7	66.50	69.87	73.15	76.26	79.21	82.01	2016	77.85
8	67.76	71.05	74.26	77.31	80.27	83.10	2017	80.16
9	68.92	72.16	75.31	78.36	81.34	84.20	2018	82.68
10	70.02	73.20	76.35	79.40	82.40	85.30	2019	85.15
11	71.05	74.22	77.37	80.44	83.46	86.40	2020	87.71
12	72.05	75.23	78.38	81.47	84.51	87.45	2021	90.73
13	73.03	76.21	79.37	82.48	85.52	88.47	2022	93.88
14	73.99	77.18	80.36	83.46	86.50	89.46	2023	97.15
15	74.93	78.13	81.30	84.40	87.45	90.42	2024	100.55
16	75.84	79.04	82.21	85.31	88.37	91.35	2025	104.08
17	76.72	79.92	83.09	86.20	89.26	92.29	2026	107.09
18	77.57	80.76	83.94	87.05	90.16	93.21	2027	110.18
19	78.39	81.58	84.76	87.91	91.04	94.11	2028	113.37
20	79.17	82.37	85.58	88.75	91.89	94.99	2029	116.67
							2030	120.06
							2031	124.62
							2032	128.62
							2033	132.76
							2034	137.04
							2035	141.48

- *Ash and Biochar.* The fly ash byproduct of the biomass power plant is assumed to be disposed of in several ways. Some of the product will have to be landfilled at a fee, some can be sold to farmers as biochar soil amendment, but likely the majority will be given away as a combination of soil amendment and filler. The financial analysis assumes a zero-cost for ash disposal based on this combination of potential product uses.

- *Project Investment and Bond Financing.* Financing of the project is expected to be accomplished primarily through raising of a bond, supplemented by available grant funding and a small capital investment from the partner private entity. The interest rate is set at the current Idaho general obligations bond financing rate, 4.49%.

- *Depreciation and Amortization.* 20-year straight line depreciation is used to depreciate the installed cost of the WTE facility major equipment, and 30-yr straight line depreciation for process buildings. Process equipment depreciation is based on the minimum lifespan of the equipment as reported by the respective equipment vendors, and takes into account maintenance and overhaul costs. Depreciation and amortization costs are based on the equity investment into the project.

[17] Idaho Public Utilities Commission, Case No. GNR-E-10-01, Order No. 31025 (3/16/2010).

- *11-year Return on Investment (ROI) calculation.* Return on Investment calculation is based on an 11-yr run of the financial model (1 year of construction and 10 years of operation), on a pre-tax income basis.

- *30-year Internal Rate of Return (IRR) calculation.* Internal Rate of Return calculation is based on a 20-year run of the financial model (11 years of the base model plus 19 years of additional end-of-year cash flow). The additional years allow for the IRR calculation to account for the full 30-yr project period.

- *Annual Inflation.* Annual inflation for project parameters is as follows.

Table 27 – Financial Modeling Parameters Inflation

Financial Modeling Parameters Inflation	
Feedstock Purchase Price	Index
Electricity Sale Price	0.00%
Thermal Energy Sale Price	0.00%
Fresh Water Purchase Price	1.00%
Waste Effluent Disposal Price	1.00%
Maintenance Materials & Services	1.50%
Insurance	3.00%
Salary Inflation	2.50%
Inflation for All Other Expense Categories	2.00%

- *Operational Costs Summary*. Table 28 shows the major costs assumed for facility operations, including expected input feedstock cost, value of electrical and thermal energy sold. Steam value is set equal to current facility energy cost on BTU basis (i.e., it is assumed this as it is unlikely that local facility users will not agree to an increase in their expenses however, it is possible they may want lower costs.) This will be further evaluated in the sensitivity analysis in the final report.

Table 28 – Biomass Power Plant Facility Operation Costs and Revenue

Clearwater County 112C03170 Operational Expenditures Summary	
10-yr Avg. Feedstock Cost ($/ton as received)	$28.74
10-yr Avg. Feedstock Cost ($/ton dry)	$41.06
10-yr Avg. Sold Electricity Value ($/kWh)	$0.0824
10-yr Avg. Thermal Energy Value ($/MMBTU)	$19.04
10-yr Avg. Thermal Energy Value ($/kWh)	$0.065

- *Project Operating and Maintenance Expenditure*. Project Operating and Maintenance costs were estimated by Tetra Tech, based on information provided by vendors. In the event of performance-based operations contracting with a third-party, these costs will be paid as part of the contract. Each scenario is assumed to have One (1) Operations Lead, who will also serve as facilities manager. The 2MW CHP scenario assumes 3 Shift Operators, assuring 24/7 manning of facilities, while the 1MW CHP scenario takes advantage of feedstock hoppers and the project PLC to use only 2 Shift Operators. The 2MW scenario also assumes the hiring of a Commodities Manager to handle feedstock purchasing. The average salary for employees is $58,125/yr, including 25% overhead and benefits. Maintenance for each scenario is assumed to be 2% of the equipment capital costs, annually. Operating and maintenance costs will form the basis of an operations contract, should that be the chosen mode of facility operation.

6.3 PRO FORMA FINANCIAL MODELING AND PROJECTED RETURNS

Tetra Tech prepared two preliminary financial scenarios to evaluate the installation of a biomass power production system at the prospective plant site. The economic modeling analysis evaluated a biomass-fed, advanced combustion unit coupled with an internal combustion genset. This scenario is based upon information received from the technology suppliers solicited and also from internal analysis. The analyzed installation is considered at two project scales, corresponding to approximately 1MW or 2MW of electrical energy output. The facilities are expected to produce electrical energy uploaded to the Avista Corp. utility electrical grid, and thermal energy to be consumed by local facilities.

Tetra Tech conducted the financial analysis to determine if the proposed biomass power plant project is economically feasible for Clearwater County to pursue, and to identify key project parameters that most affect the viability of the project. The Tetra Tech Life Cycle Cost Model produces ten-year operating forecasts for the projects including a balance sheet, income statement, and cash flow statement. Complete 11-year proformas (one year of construction and ten years of operation) for the scenario is included in the appendixes. The Life Cycle Cost Model also produces 30-year project return calculations. The impacts of critical project variables have been determined and the viability of the projects with regard to each has been evaluated.

Table 29 summarizes the major project metrics produced by the financial model, assuming ICI-O as the only thermal energy user. The results of the scenario fail to produce positive financial returns throughout the project lifespan. As the project does not produce positive cash flow, the internal rate of return (IRR) calculation cannot produce a viable metric, and the plants do not pay off their initial investment (i.e., simple payback period = N/A).

Table 29 –Results of Baseline Scenario Financial Analysis

Baseline Scenario		
Clearwater County 112C03170 Financial Projections Summary	**1MW CHP**	**2MW CHP**
10-year Average Annual ROI	-1.4%	-0.5%
30-year Internal Rate of Return	-N/A-	-N/A-
Simple Payback in Years	-N/A-	-N/A-
Average Annual Income	($62,585)	($4,136)
Equity Investment	$1,327,887	$749,176
Debt	$4,991,831	$7,123,764
Grants	$2,000,000	$4,000,000
Total Project Investment	**$8,319,718**	**$11,872,940**

Tetra Tech also produced a viable financial model scenario for the operation of the project, which incorporates all available thermal energy users to produce additional thermal energy revenue (approximately $200,000 annually). The $430,200 in additional piping to connect the additional facilities can be paid back in a little over 2 years. Table 30 shows the results of that analysis.

Table 30 –Results of Financial Analysis with Optional Thermal Energy Users

Maximized Thermal Energy Use Scenario		
Clearwater County 112C03170 Financial Projections Summary	**1MW CHP**	**2MW CHP**
10-year Average Annual ROI	1.2%	1.5%
30-year Internal Rate of Return	-5.4%	-6.4%
Simple Payback in Years	15.47	21.68
Average Annual Income	$122,297	$180,437
Equity Investment	$1,549,503	$973,788
Debt	$5,324,255	$7,460,682
Grants	$2,000,000	$4,000,000
Total Project Investment	**$8,873,758**	**$12,434,470**

As shown in Table 30, the 1MW CHP scenario is cash-flow positive throughout the project lifespan with the additional thermal energy users. The project produces a positive 11-yr average annual return on investment (ROI) of 1.2%. The 30-yr internal rate of return (IRR) is projected at -5.4% due to the relatively long project payback period. Simple payback of capital expenditure occurs just before Year 16 of operation. These results are based on the investment capital injected into the project. Bond financing is paid at the scheduled rate.

The 2MW CHP scenario is also cash-flow positive once additional thermal energy users are included in the project, producing an 11-yr average annual ROI of 1.5%, and an IRR based on equity investment of -6.4%. Simple payback of capital equipment does not occur until the equipment is fully depreciated, at 22 years of operation.

The limited thermal energy load provided by local facilities is the primary variable negatively affecting financial performance of the biomass power plant. Even with additional facility thermal energy users included, the majority of the thermal energy produced by the 2MW CHP scenario has no sale outlet and will have to be vented to the atmosphere. As well, a significant portion of the thermal output of the 1MW CHP plant goes unused, but a portion of that energy can be used to dry incoming feedstock to improve plant operational efficiency. Additional thermal energy users in the local area would greatly improve plant financial performance. If all of the produced thermal energy could be sold to local users, the project would be financially viable without subsidization. Even if all of the facilities listed become customers of the biomass power plant, the use is below the usual standard supply from a biomass power plant. The ideal thermal energy demand to justify a CHP system is usually in the range or 10,000 lbs/hr of steam, or over 100,000 MMBTU/yr.

Again assuming thermal energy use can be maximized within the local facilities, the 2MW CHP project scenario still sees diminishing returns throughout the project lifespan. This is primarily due to rising feedstock costs. Year 2 of operations is the healthiest year as modeled. Figure 31 shows projected annual project earnings, after interest, depreciation, and other expenses are paid. The 1MW project scale scenario averages $121,905 annual net income, while the 2MW project scale averages $180,437 over the initial 10 years of facility operation. As shown in the graph, and likely due to increases in feedstock cost over time, the 2MW project scale earnings begin to slip over time while the 1MW plant holds profitability, increasing earnings slightly over time.

Figure 31 – Clearwater Project Net Earnings for Distribution

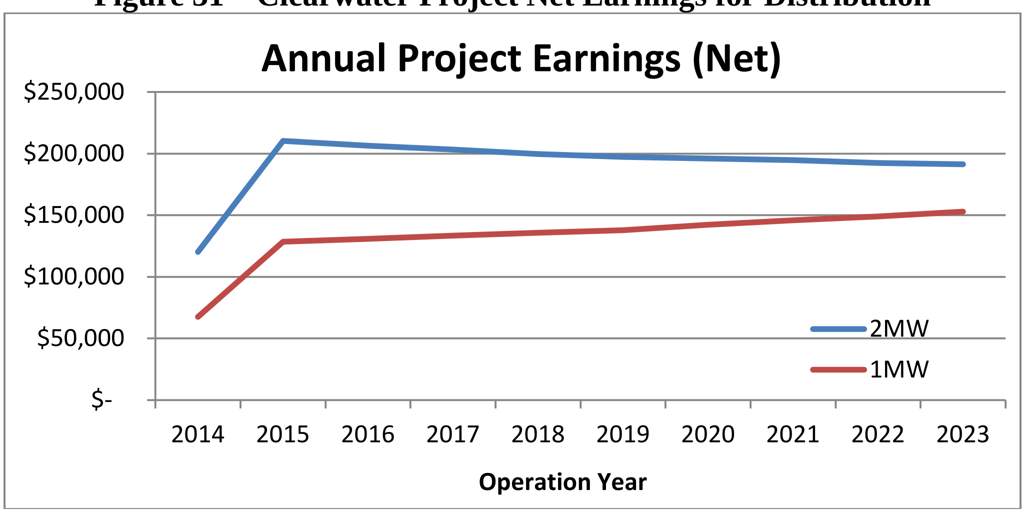


Table 32 shows a summary Proforma Income Statement for the two baseline production scenarios. Table 33 shows a summary Proforma Income Statement for the production scenarios that include additional thermal energy users. The summaries display projected financial metrics in Year 2 of facility operation, assumed to be the first year of stable facility operations. Additional project sensitivity analyses are presented in the following section.

Appendices D and E displays complete financial proformas for scenarios incorporating additional thermal energy users.

Table 31 – Baseline Summary Proforma Income Statement

Clearwater County 112C03170	Baseline Scenario			
Proforma Income Statement for Year 2	2MW CHP		1MW CHP	
Net Revenue	**$/Year**	**$/ton Feedstock**	**$/Year**	**$/ton Feedstock**
Heat	$200,225	$21.44	$200,225	$42.87
Power	$995,452	$106.58	$497,726	$106.58
Total Revenue	**$1,195,677**	**$128.02**	**$697,951**	**$149.45**
Production & Operating Expenses				
Feedstocks	$363,286	$38.90	$181,643	$38.90
Electricity	$0	$0.00	$0	$0.00
Makeup Water	$1,582	$0.12	$791	$0.12
Wastewater Disposal	$190	$0.01	$95	$0.01
Operations Cost	$231,266	$24.76	$177,453	$38.00
Total Production Costs	**$596,323**	**$63.85**	**$359,982**	**$77.08**
Gross Profit	**$599,354**	**$64.17**	**$337,969**	**$72.37**
Administrative & Operating Expenses				
Maintenance Materials & Services	$149,083	$15.96	$104,878	$22.46
Repairs & Maintenance - Wages & Benefits	$0	$0.00	$0	$0.00
Property Taxes & Insurance	$0	$0.00	$0	$0.00
Admin. Salaries, Wages & Benefits	$69,828	$7.48	$0	$0.00
Office/Lab Supplies & Expenses	$6,120	$0.66	$6,120	$1.31
Total Administrative & Operating Expenses	**$225,031**	**$24.09**	**$110,998**	**$23.77**
EBITDA	**$374,322**	**$40.08**	**$226,971**	**$48.60**
Less:				
Interest - Senior Debt	$312,659	$33.47	$219,089	$46.91
Depreciation & Amortization	$36,047	$3.86	$64,032	$13.71
Current Income Taxes	$0	$0.00	$0	$0.00
Year 2 Net Earnings Before Income Taxes	**$25,617**	**$2.74**	**($56,150)**	**($12.02)**
11-Year Average Annual Pre-Tax Income	**($4,136)**	**($0.44)**	**($62,585)**	**($13.40)**
11-Year Average Annual Pre-Tax ROI	**-0.48%**		**-1.38%**	
30-Year Internal Rate of Return (IRR)	**-N/A-**		**-N/A-**	

Table 32 – Maximized Thermal Energy Use Summary Proforma Income Statement

Clearwater County 112C03170	Maximized Thermal Energy Use Scenario			
Proforma Income Statement for Year 2	2MW CHP		1MW CHP	
	$/Year	$/ton Feedstock	$/Year	$/ton Feedstock
Net Revenue				
Heat	$408,124	$43.70	$408,124	$87.39
Power	$995,452	$106.58	$497,726	$106.58
Total Revenue	**$1,403,576**	**$150.27**	**$905,850**	**$193.97**
Production & Operating Expenses				
Feedstocks	$363,286	$38.90	$181,643	$38.90
Electricity	$0	$0.00	$0	$0.00
Makeup Water	$1,582	$0.12	$791	$0.12
Wastewater Disposal	$190	$0.01	$95	$0.01
Operations Cost	$231,266	$24.76	$177,453	$38.00
Total Production Costs	**$596,323**	**$63.85**	**$359,982**	**$77.08**
Gross Profit	**$807,253**	**$86.43**	**$545,868**	**$116.89**
Administrative & Operating Expenses				
Maintenance Materials & Services	$157,816	$16.90	$113,611	$24.33
Repairs & Maintenance - Wages & Benefits	$0	$0.00	$0	$0.00
Property Taxes & Insurance	$0	$0.00	$0	$0.00
Admin. Salaries, Wages & Benefits	$69,828	$7.48	$0	$0.00
Office/Lab Supplies & Expenses	$6,120	$0.66	$6,120	$1.31
Total Administrative & Operating Expenses	**$233,764**	**$25.03**	**$119,731**	**$25.64**
EBITDA	**$573,489**	**$61.40**	**$426,137**	**$91.25**
Less:				
Interest - Senior Debt	$327,446	$35.06	$233,679	$50.04
Depreciation & Amortization	$46,787	$5.01	$74,613	$15.98
Current Income Taxes	$0	$0.00	$0	$0.00
Year 2 Net Earnings Before Income Taxes	**$199,256**	**$21.33**	**$117,845**	**$25.23**
11-Year Average Annual Pre-Tax Income	**$180,437**	**$19.32**	**$122,297**	**$26.19**
11-Year Average Annual Pre-Tax ROI	**1.54%**		**1.17%**	
30-Year Internal Rate of Return (IRR)	**-6.4%**		**-5.4%**	

6.4 PROJECT RISK IDENTIFICATION AND SENSITIVITY ANALYSES

Every project carries with it a set of risks that apply to financial underperformance, logistical issues, or other detrimental project conditions. Prior to project funding and construction, these risks must be identified and quantified to the degree possible at each stage of project development.

In this section Tetra Tech seeks to identify the common project risks associated with biomass power plant development and operation. While the risks presented below are the most likely to affect project performance as evaluated at this point, the project team should diligently pursue further identification and quantification of project risks in further project development stages.

Project risks are quantified below using sensitivity analyses. The variables that have the greatest impact on the project's profitability are the delivered feedstock price and the finished product selling price. This is the case for all biomass facilities, not just the proposed projects. A series of sensitivity analyses were run to examine the effect of critical parameters on the projected 11-year Average Annual After-Tax ROI. The parameters analyzed include:

- Feedstock Purchase Price
- CHP-generated Electrical Energy Sale Price
- CHP-generated Thermal Energy Sale Price
- Thermal Energy Utilization
- Capital Cost

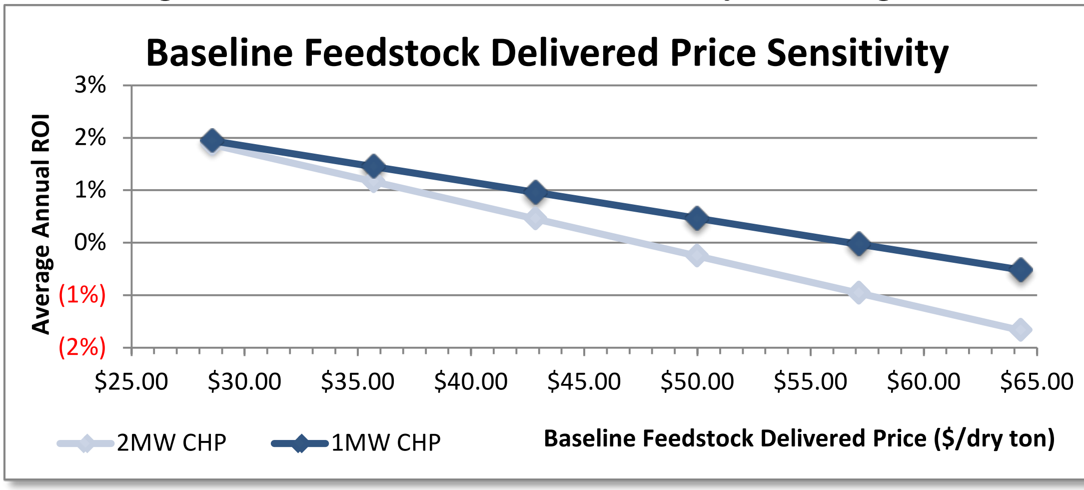
The results of these parameter studies are shown in the graphs that follow. Each of the sensitivity figures assumes that only one variable is changing and that all others are constant as listed in the financial assumptions towards the beginning of this section.

Risks Associated with Feedstock

For this project, feedstock risk is primarily associated with product pricing. Feedstock supply has been determined to be ample, but the plant cannot to utilize high-priced material and continue to operate at a profitable level. Because the primary project feedstocks are all sourcing from secondary markets, the plant has very little price control. As well, being a 1MW or 2MW facility in a region dominated by 40-50MW facilities, project operators will have limited bargaining power when sourcing feedstocks.

A sensitivity analysis was conducted to determine the project's tolerance to feedstock price variation. The variable adjusted in the financial model is baseline feedstock delivered price, on a dry ton basis. The model assumed a baseline price of $35.71/dry ton, increasing over time as linked to the diesel price index. Figure 32 shows the effect on project ROI for each plant scenario when the baseline feedstock price is moved up or down. The sensitivity to feedstock price shows that the 2MW CHP plant scale reacts more strongly to variations in feedstock price than the 1MW CHP scenario. The ROI break-even point is when feedstock prices are $57/ton for the 1MW CHP plant scale scenario, and $47/ton for the 2MW CHP scales. This result is the somewhat surprising, as usually larger-scale plants are more tolerant of feedstock price rises. The result may be due to the utilization and sale of the facilities' finished products, specifically thermal energy use.

Figure 32 – Effect of Feedstock Price on 11-year Average ROI



Feedstock quality control is also a risk that must be addressed. Low-quality material with high levels of dirt, bark, or other contaminants can foul process machinery and reduce product yields. Potential feedstock issues include:

- Feedstock may be wetter than expected, which may reduce operating efficiencies since more process heat must be used to dry the hog fuel.
- Feedstock may contain non-biomass debris (soil, rocks, metal waste) that may cause problems with the feed and/or ash handling systems.
- Feedstock piles may become inaccessible due to weather conditions
- Feedstock piles may catch fire

Risks Associated with Product Sale and Utilization

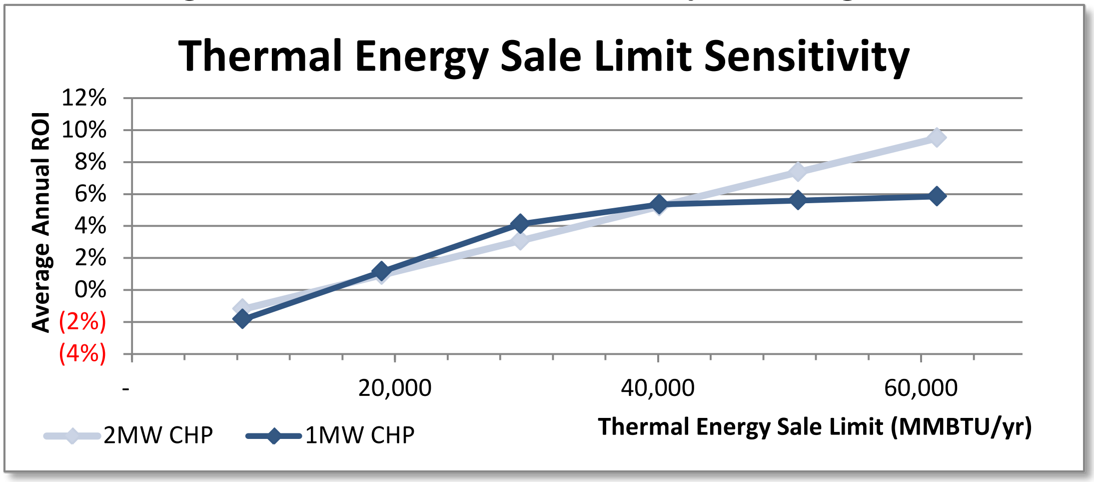
The primary risk associated with the sale of finished products from the prospective biomass power plant is the amount of thermal energy utilized by the local area facilities. This risk can be fully quantified prior to plant construction, however. Contracts will be in place for each of the local facility energy users at the time of contraction, and the exact volume of thermal energy bought and utilized by those facilities will be established.

At present, however, the number of local facilities that will engage with the project and purchase the thermal energy produced by the prospective Plant is unknown. A sensitivity analysis was conducted to analyze the effect on project returns resulting from additional (or fewer) facilities utilized the produced thermal energy.

Figure 33 illustrates the advantage of attracting more customers for thermal energy use. The 2MW CHP facility has the capacity to produce over 66,000 MMBTU of usable thermal energy, and if all is sold the project ROI reaches almost 10%. The 1MW CHP facility ROI levels off at

5.5% when it hits its peak production at 33,000 MMBTU/yr. Both facility scales break even financially at a minimum of 15,500 MMBTU sold annually.

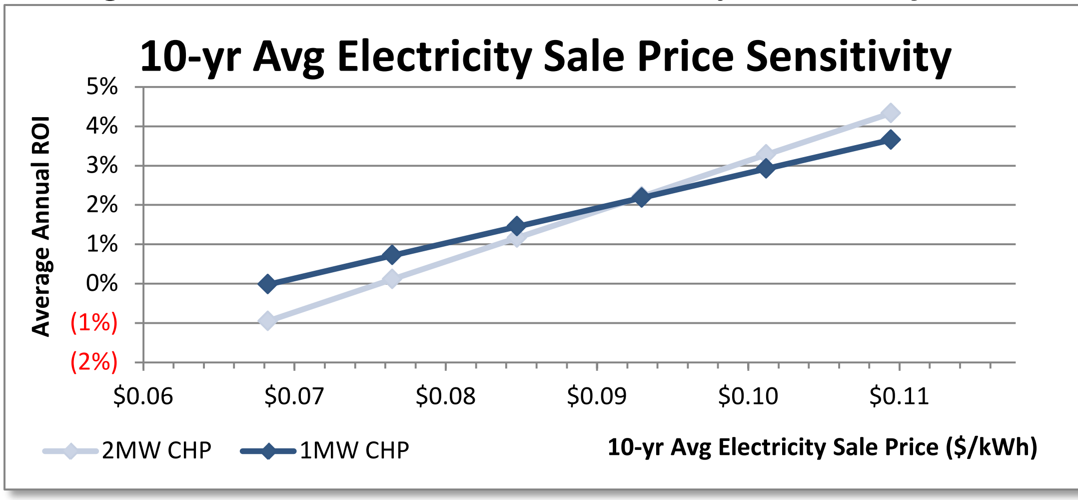
Figure 33 – Effect of Pellet Price on 11-year Average ROI



The value at which finished products are sold is a risk in any new venture. In this project, the finished products for sale are electrical power uploaded to the utility grid, and thermal energy piped to local facilities. This risk can also be fully quantified prior to project construction with power purchase agreements and thermal energy off-take contracts. Sensitivity analyses were conducted to review the effect of various values for sale of power and thermal energy.

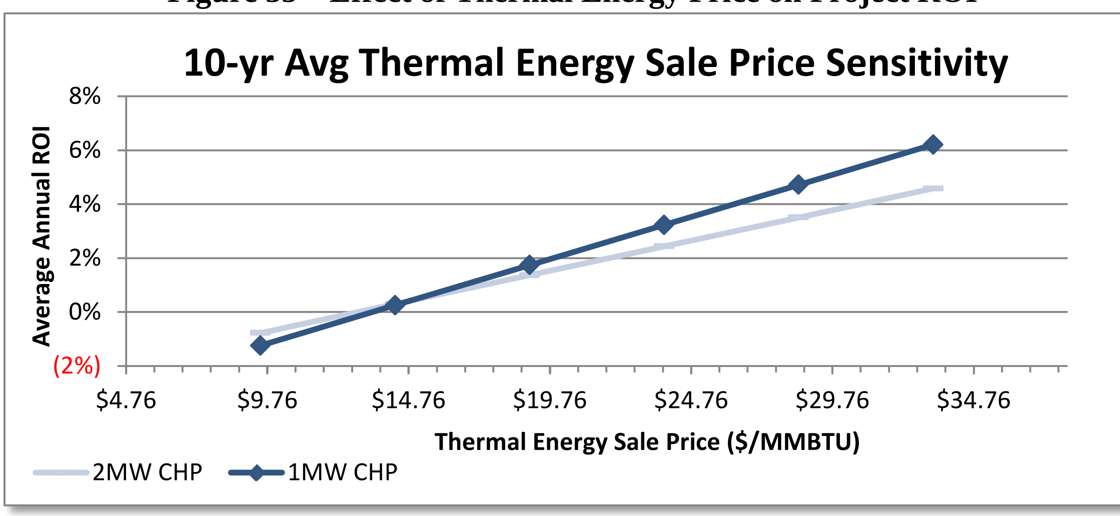
The primary sale product of CHP plants is electricity, and the CHP plants are highly sensitive to the final sale price of electricity (Figure 34). The smaller plant scale can sell electricity at 6.6¢/kWh and break even financially, while the larger plant scale can sell electricity at a minimum price of 7.6¢/kWh without producing negative returns. At 11¢/kWh, both plants have improved their profitability to the 3-4% ROI range.

Figure 34 – Effect of CHP-Generated Electricity Price on Project ROI



The Plant will also derive revenue from the sale of thermal energy. The base case financial model sets thermal energy sales equal to the current electricity purchase price (on a Btu basis) at $19.04/MMBTU, equivalent to 6.5¢/kWh electricity price. Figure 35 shows the plants' sensitivities to thermal energy sale price. Both plant scales break even at a thermal energy sale price of $14.76/MMBTU, equivalent to 5.04¢/kWh. ROI climbs steadily at thermal energy sale prices up to $30/MMBTU, or 10.2¢/kWh.

Figure 35 – Effect of Thermal Energy Price on Project ROI



This also brings up project hedging risk. The biomass power plant will be locked into a long-term price structure for power sold to the grid via a power purchase agreement, and may also have established thermal energy sale price limits for thermal energy customers. Should feedstock prices rise above the anticipated amount, the plant may be forced to produce at a loss. There are two ways to address this risk; one is to link thermal energy sale price to feedstock purchase price to guarantee the plant produces at a profit or break-even status, and the second is to establish a long-term feedstock pricing agreement to lock in feedstock prices. The second route is the most advantageous to the project, by eliminating price risk on both the plant inputs and outputs, but as determined in the feedstock analysis the woody biomass industry commonly operates on a spot basis. Long-term agreements for feedstock supply are difficult if not impossible to establish in this industry.

Risks Associated with Technology Performance and Capital Cost

Biomass CHP systems have a level of inherent complexity, and although some consider the technology mature, there is still some degree of experimentation in the industry. As with any of the emerging industries there are a number of players with a number of promising products, not all of which will perform up to their design. The problem can be caused by a weakness or failure in any of numerous subcomponents. Potential issues with CHP systems include:

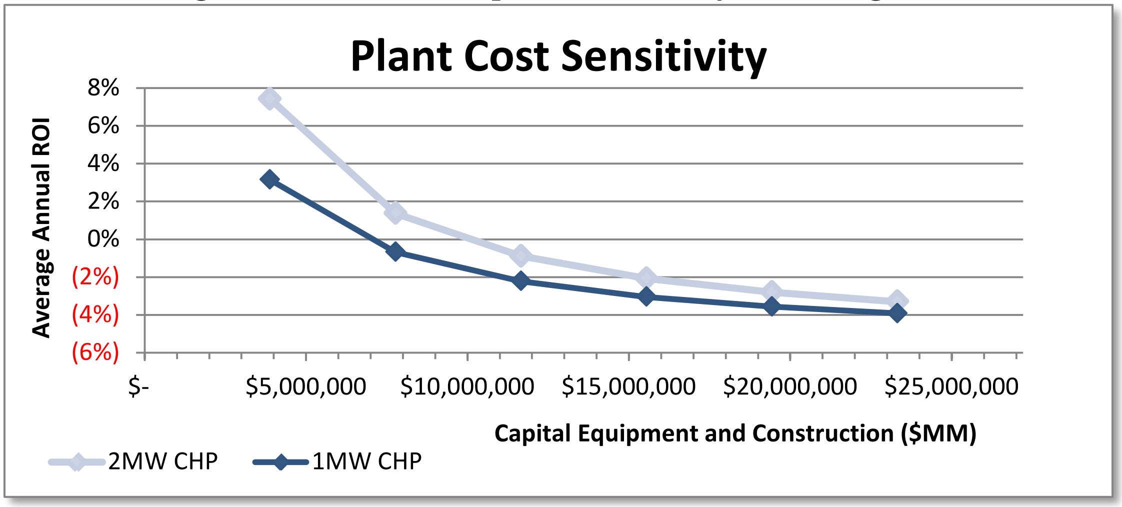
- System may not achieve design output
- System may not achieve expected efficiencies
- System may require higher maintenance costs or experience more downtime than anticipated
- System may not achieve pollution limits
- System may fail due to operator errors
- System may fail due to natural occurrences

Many of the risks can be mitigated by including performance guarantees and penalty clauses in the various procurement contracts, but it must be kept in mind that there may be similar penalty clauses in contracts obtained from heat or power customers. Operator error can be minimized by proper training. Engineering design account s for a reasonable level of natural disaster (i.e., earthquake, flooding, lighting strikes).

Equipment capital cost is a major project risk, though one that can be quantified and mitigated prior to plant construction with firm fixed-price engineering, procurement, and construction (EPC) contracts. As noted above, capital cost figures are presented as budgetary in the study, due to the price variation between technology providers, site requirements, and other costs that cannot be projected at present. Contingency factors are included to account for these unknown factors, however final plant construction costs may differ significantly from estimated values. Budgetary quotes are defined by engineering’s governing body, AACE International, as 10-15% design completion of the facility, and as such can only be held to a +30% to -15% accuracy level.

A sensitivity analysis is included to quantify the effect of higher or lower capital costs on the profitability of the Plant. Figure 36 shows the effect of changes to the Capital Equipment and Construction Cost of the two plant scales. The base case values are $5,596,625 for the 1MW plant, and $7,774,200 for the 2MW plant. The plants appear to be able to sustain reasonable increases in capital cost and remain profitable; the 1MW plant breaks even at a capital equipment cost of $7.5MM, an increase over projected facility construction costs of nearly 50%, while the 2MW plant breaks even at a capital equipment cost of $10MM, an increase of 28%.

Figure 36 – Effect of Capital Cost on 11-year Average ROI



7.0 State and Federal Policy, Regulatory Requirements, and Permitting

Based on the proposed sites under consideration, developing a biomass power plant project in Idaho would require coordination with tribal, federal, state, and county personnel. Permitting can be one of the biggest obstacles to the development of any industrial plant. As in the case of any industrial facility, construction and operation must be preceded by the acquisition of a broad range of regulatory permits and approvals.

Permitting required for developing the prospective biomass power plant should not be a formidable task. It should also not be considered trivial. Obtaining the proper permits is not expected to be difficult, provided ample time and planning are incorporated into the process from the start.

Based on our experience, Tetra Tech assumes that the project will likely trigger several environmental permits. These permits may include various federal, state and local environmental, construction and land use permits. Examples of permitting concerns may include issues related to air quality, solid and hazardous waste, water quality, water use, wastewater disposal, tank registration as well as various other local permits, such as local building, transportation and other special use permits. The following section addresses the anticipated regulatory actions associated with the development of a biomass power plant in Idaho, within the boundaries of the Nez Perce Indian Reservation.

7.1 LOCAL ENVIRONMENTAL PERMITS & REGISTRATIONS

State and local building and fire code departments address related safety issues such as exhaust temperatures, venting, fuel storage, space limitations, vibration, and steam piping, and building structural issues. Building departments are often part of a city's planning division. It is anticipated that the construction of a biomass power plant would require the submittal of a building permit application. Clearwater County building permit applications can be accessed at: http://www.clearwatercounty.org/?PermitApplications

Zoning & Building Permits. County and city planning bureaus govern land use and zoning issues. Idaho Zoning Ordinance (Code 67-6511) gives the county or municipality legal authority to control the use of property and physical configuration of development upon tracts of land within their jurisdiction. According to the county assessor's records, our most desirable site, the State Hospital North Grounds between the North Idaho Correctional Institution of Orofino (ICI-O) and Water Towers is parcel number 36N02E064200A. This parcel is approximately 83 acres and is currently zoned as Low Density Rural District F1. A satellite photo of project site parcel parameters was supplied by the Clearwater County Assessor's Office to assist in project analysis.

The zoning process must be based on comprehensive plans and are enacted for the protection of public health, safety and welfare. The rezoning of this parcel of land may be accomplished through spot–zoning, rezoning the entire 83 acres, or would require a conditional use permit as outlined in Clearwater County's Zoning Ordinances Article XI. Clearwater County's Zoning Ordinances can be accessed at http://www.clearwatercounty.org/?OrdinanceIndex. It is also recommended that the Nez Perce Tribe be consulted during the rezoning process.

Building permit requirements vary widely within the state and may be the deciding factors in selecting a site. Depending upon the jurisdiction there may be various fees, prior approvals by various departments such as the Fire Marshal, and local highway authority, and a hearing before the planning and zoning authority. Once there is zoning compliance and approval, potential developers must also obtain building permits from the local planning authority. Clearwater County building permit applications can be accessed at:
http://www.clearwatercounty.org/?PermitApplications

Local Community Impacts. Community impacts that may require evaluation include visual impact assessments, noise, and possible odors as well as increased truck traffic due to the deliveries of woody biomass feedstock.

Boiler Licensing. Until recently, the Idaho Department of Administration, Division of Building Safety was responsible for boiler licensing and inspections. However, with the approval of the 2010 Idaho Legislature, the administrative rules related to Boilers and Pressure Vessels (Chapters 1 through 5 of IDAPA 17, Title 06) have been repealed. While the licensing and inspection of boilers is no longer the responsibility of the Division of Building Safety, it may be a condition of the building owner's liability insurance.

Endangered Species Act (ESA). The Endangered Species Act (ESA) is a means for listing native animal and plant species as endangered and giving them and their habitats limited protection. The ESA [16 USC §1531 et seq. (1973)] is jointly administered by the U.S. Fish and Wildlife Service (USFWS), the National Oceanic and Atmospheric Administration, (NOAA), and the National Marine Fisheries Service (NMFS). The ESA requires federal agencies, in consultation with the USFWS and/or the NMFS, to ensure that their actions are not likely to jeopardize the continued existence of any listed species or result in adverse effects on designated critical habitat of such species. It also prohibits any action that causes a "taking" of any listed species of endangered fish or wildlife; the removal of any endangered plant from an area under federal jurisdiction.

The discovery of an endangered or threatened species on or near your site can cause significant delays in a construction project. Prior to final site selection, discussions with the appropriate state, tribal and/or federal agencies and review of Clearwater County's endangered and threatened species should be completed. This information can help avoid, but not guarantee, that this will not be an issue for the construction and operation of a biomass power plant. The full suite of ESA regulations promulgated by the USFWS is available at 50 CFR 17. The full suite of ESA regulations promulgated by the NMFS is available at 50 CFR 216-296.

Archaeological Resources and Historic Structures. Cultural resources relate to the remains and sites with human activities and include the following: Prehistoric and Ethnohistoric Native

American archaeological sites; Historical archaeological sites; Historic buildings; and elements or areas of the natural landscape which have traditional cultural significance. Known archeologically sites should be avoided when siting a Biomass CHP plant. The discovery of an archeological site on or near your site can cause significant delays in a construction project.

Prior to final site selection, the Nez Perce Tribe's Department of Natural Resources, Cultural Resources Division should be consulted as well as a review of files maintained by the Idaho Historical Society ("IHS"), the Idaho Historic Preservation Council, and the Idaho State Historic Preservation Office ("SHPO"). Tribal consultation and file review is can help avoid, but not guarantee, that this will not be an issue for a biomass power plant. An archeological survey may be required prior to the start of construction and should be performed before final site selection.

7.2 CLEAN WATER ACT (CWA)

U.S. Army Corps of Engineers - Section 404 Permits. The basic premise of Section 10 of the Rivers and Harbors Act of 1899 and Section 404 of the Clean Water Act is that dredged or fill material cannot be discharged into waters if the nation's waters would be significantly degraded or if a feasible alternative exists that is less damaging to the aquatic environment. The proposed plant site contains a small water catchment depression on its western edge, which may be classified as a wetland area. If it is determined that backfill of this catchment pond is required for plant construction, the following permitting and regulatory requirements will be in effect.

The Walla Walla District Regulatory Office of the U.S. Army Corps of Engineers (USACE) is responsible for administering and enforcing Section 10 of the Rivers and Harbors Act of 1899 and Section 404 of the Clean Water Act in the State of Idaho. In Clearwater County including the Nez Perce Indian Reservation, the USACE Coeur d' Alene Regulatory Office is responsible for administering and enforcing Section 10 of the Rivers and Harbors Act of 1899 and Section 404 of the Clean Water Act and are overseen by the EPA.

Some activities may fall within the guidelines of previously authorized categories and a nationwide or regional permit can be issued with no further Corps approvals required. Other activities may fall within the guidelines of an abbreviated permit processing, requiring a letter of permission to authorize the activities in less than 30 days. Other activities may require a Public Notice to be issued, where notification of Federal, state, and local agencies, adjacent property owners, and the general public allows the opportunity for review, comment, or to request a public hearing. Most applications involving Public Notices are completed within four months and many are completed in as little as 60 days.

The processing of an application begins immediately upon receipt of all required information, which includes a completed application, vicinity map, plan view and section view drawings, adjacent property notification (if required), and any other project specific information.
Below is an outline of the basic application process, based on submission of a typical and complete application:

- Pre-application consultation – optional
- Applicant submits Joint Application for Permit to appropriate office
- Application is received and assigned to a Project Manger
- Incomplete applications are returned for correction/completeness
- Application is reviewed and assigned an identification number
- If activities fall within nationwide or regional permit guidelines/categories, permit issued
- If activities qualify for an abbreviated permit processing, a letter of permission is required
- If activities require a public notice, within 15 days of receiving all information - Federal, state, local agencies, special interest groups, the general public, etc. are notified via Public Notice Announcement
- Corps considers all comments received
- Other federal agencies are consulted, if appropriate
- Corps may ask applicant for additional information
- Public hearing held, if needed
- Corps makes a final decision
- Permit issued or denied – applicant advised of reason(s)

The full suite of Clean Water Act regulations related to permits for the discharge of dredge and fill material into waters of the United States is available at 33 CFR 323.

Water Quality Certification - Section 401. A USACE permit that involves a discharge of dredged or fill material cannot be issued until a State Section 401 Water Quality Certification has been issued or waived. Each state and authorized tribes have the responsibility of setting its own water quality standards. Under the Clean Water Act, Section 401 certificates of compliance with state or tribal water quality standards is required for any discharge of dredge and fill material into waters of the United States. All individual or general permits issued by the Corps of Engineers require a Water Quality Certification, under Section 404 of the Clean Water Act.

Tribes may receive Section 401 Water Quality Certification authority when they apply for and receive Treatment as a State (TAS) status which is often at the same time as EPA approval of their water quality standards. Presently, the Nez Perce Tribe's Natural Resource Department, Division of Water Resources only has TAS for implementing Section 106 and Section 319 of the Clean Water Act. Section 106 address water quality monitoring and Section 319 address Non-Point Source Pollution. Section 106 and Section 319 of the Clean Water Act are briefly discussed below. Since the Nez Perce Tribe does not have TAS for Section 401 Water Quality Certification, Region 10 of the Environmental Protection Agency (EPA) will be responsible for administering and enforcing Section 401 Water Quality Certification (WQC). Once submitted, EPA has up to one year to grant, waive, or deny a Section 401 Water Quality Certification. However, a typically Section 401 Water Quality Certification takes approximately 60 to 90 days to receive. For surface waters not located within tribal boundaries, the Idaho Department of Environmental Quality (DEQ) Water Quality Division is responsible for issuing Section 401 Water Quality Certifications.

Clean Water Act Section 106. Under Section 106 of the Clean Water Act, the Nez Perce Tribe can conduct watershed assessments and can maintain and improve their capacity to implement water quality programs through monitoring, assessments, planning and standards development. Additionally, the tribe can participate in program activities related to the restoration of impaired watersheds such as Total Maximum Daily Loads (TMDL); implementation of integrated wet weather strategies in coordination with nonpoint source programs; and development of source water protection programs.

Clean Water Act Section 319. Under Section 319 of the Clean Water Act, the Nez Perce Tribe can implement a Non-Point Source Management Program. The goal of the Non-Point Source Management Program is to reduce Non-Point Source pollution on the Nez Perce Reservation, restore and maintain degraded systems/habitats, preserve natural ecosystems, and educate landowners and the general public.

National Pollutant Discharge Elimination System (NPDES) Permit – Storm Water

To prevent pollutants in storm runoff from entering surface waters, the federal Clean Water Act requires that stormwater discharges from construction, industrial and municipal sources obtain National Pollutant Discharge Elimination System (NPDES) permit coverage. In Idaho including Indian Reservations, the EPA, Region 10, is the NPDES permitting authority and as such, is responsible for issuing NPDES stormwater permits. Permits for stormwater discharges can be classified as either a General Permit for Storm Water Discharges Associated with Large and Small Construction Activity or can be classified as a Multi-Sector General Permit for Storm Water Discharges Associated with Industrial Activities. Each permit program is described in more detail below.

EPA Construction General Permit. Construction activities in Idaho and on Indian reservations are covered by a general permit for stormwater discharges from construction sites. The NPDES stormwater program requires construction site operators engaged in clearing, grading, and excavating activities that disturb 1 acre or more, including smaller sites in a larger common plan of development or sale, to obtain coverage under an NPDES permit for their stormwater discharges. Where EPA is the permitting authority, construction activities are regulated under the Construction General Permit (CGP). The CGP outlines a set of provisions construction operators must follow to comply with the requirements of the NPDES stormwater regulations. Construction operators intending to seek coverage under EPA's CGP will have to develop a Stormwater Pollution Prevention Plan (SWPPP), complete an endangered species determination for the project site, file a Notice of Intent (NOI), and implement Best Management Practices (BMPs). Text of the NPDES General Permit for Stormwater Discharges from Construction Activities can be accessed at: http://www.epa.gov/npdes/pubs/cgp2008_finalpermit.pdf.

By June 30, 2011, EPA will issue a new CGP, which will incorporate new Construction & Development Effluent Limitations (C&D Rule) and New Source Performance Standards (NSPS) to control the discharge of pollutants from construction sites. All construction sites required to obtain permit coverage must implement a range of erosion and sediment controls and pollution prevention measures.

Beginning on August 1, 2011 the C&D Rule will require all sites that disturb 20 or more acres of land at one time to comply with the turbidity limitation. On February 2, 2014 the limitation applies to all construction sites disturbing 10 or more acres of land at one time. These sites must sample stormwater discharges and comply with a numeric limitation for turbidity. The limitation is 280 NTU (nephelometric turbidity units). Supporting documents addressing the Construction & Development Effluent Limitations can be accessed at:
http://water.epa.gov/scitech/wastetech/guide/construction/index.cfm

EPA Multi-Sector General Permit. The federal regulations, in 40 CFR 122.26(b)(14)(i)-(xi), identify 11 categories of stormwater discharges associated with industrial activity required to be covered under an NPDES permit. Clearwater County's proposed Biomass CHP Plant has the potential to fall under Category Seven (vii): Steam Electric Power Generating Plants. EPA's Multi-Sector General Permit (MSGP) is the general permit currently available to facility operators in Idaho. If this general permit is not applicable to a specific facility, the facility operator must obtain coverage under an individual NPDES permit.

On September 29, 2008, EPA announced publication of the final 2008 Multi-Sector general permit (MSGP). This permit replaces the 2000 MSGP which expired on October 30, 2005. The 2008 MSGP specifies steps that facility operators must take prior to becoming eligible for permit coverage, including submitting a NOI, installing stormwater control measures to minimize pollutants in stormwater runoff, and developing a SWPPP. A general two-page fact sheet summarizing the final 2008 MSGP can be accessed at http://www.epa.gov/npdes/pubs/msgp2008 generalfs.pdf. Text from the 2008 MSGP for stormwater discharges associated with industrial activities can be accessed at: http://www.epa.gov/npdes/pubs/msgp2008_finalpermit.pdf.

Water Supply Approval. In the event that the proposed Biomass CHP plant is served by an existing public water supply, there will likely be little or no additional permitting requirements imposed. Potable and make-up water would be available from either the ICI-O water tank or by tapping into the City of Orofino's main water line. Wastewater treatment is also available through the City of Orofino Wastewater Treatment Plant. The capacities and capabilities of the wastewater treatment facility are approximately 880,000 gallons per day. Currently, the demand load is estimated to be only 300,000 gallons per day, so the site could accommodate a larger facility, at least from a water/wastewater perspective.

The Clearwater County's Wastewater Treatment Plant NPDES permit currently places limitations on the chemical make-up of receivable wastewater. The current NPDES permit places limitations on amount of total dissolved solids, potential of hydrogen (pH), chlorine, biological oxygen demand, and E. coli that can be discharged back into the Clearwater River. Prior to establishing a sewer line to the wastewater treatment plant the chemical make-up of the wastewater should be determined.

In the event that the construction of the Biomass CHP plant is at location where there is not a convenient access to a licensed public water supply, it may result in the need for the development and licensing of a new water right meeting the requirements of the Idaho Department of Water Resources (IDWR). Additionally, permitting under Section 316(b) of the Clean Water Act may be required if a surface water-intake is required.

Storage Tanks. Storage tanks are divided into above ground storage tanks (ASTs) and underground storage tanks (USTs). In Idaho, including Indian Reservations, Region 10 of the EPA enforces ASTs and USTs regulations. Above ground storage tanks are regulated by the EPA in accordance with the Clean Water Act, as amended by the Oil Pollution Act. The text of the regulation is found at 40 CFR Part 112. Although DEQ does not regulate ASTs on Indian reservations, state rules require that the agency be notified within 24 hours of the time of release if an AST has a release to the environment.

The Clean Water Act as amended by the Oil Pollution Act establishes requirements for facilities to prevent oil spills from reaching surface waters. The rule applies to facilities that have an aggregate storage capacity greater than 1,320 gallons or a completely buried storage capacity greater than 42,000 gallons; and could reasonably be expected to discharge oil in quantities that may be harmful into surface waters. The regulations apply specifically to a facility's storage capacity, regardless of whether the tank(s) is completely filled.

Regulated facilities are required to have a fully prepared and implemented Spill Prevention, Control, and Countermeasure, or SPCC Plan (SPCC rule) and a Facility Response Plan (FRP). A licensed professional engineer must certify the SPCC Plan. The SPCC Plan is required to address the facility's design, operation, and maintenance procedures established to prevent spills from occurring, as well as countermeasures to control, contain, clean up, and mitigate the effects of an oil spill that could affect navigable waters. In addition, facility owners or operators must conduct employee training on the contents of the SPCC Plan. An FRP is a plan for responding to the maximum extent practicable, to a worst case discharge of oil and to a substantial threat of such a discharge. The Plan also includes responding to small and medium discharges as appropriate. Administration of the regulations is done through the EPA Boise, Idaho office and further information can be obtained at www.epa.gov/oilspill.

In EPA Region 10, the UST / Leaking Underground Storage Tank (LUST) Program, authorized under Subtitle I of the Resource Conservation and Recovery Act (RCRA), works to prevent the release of petroleum and other products stored in USTs. Unlike environmental statutes such as the Clean Air Act or the Clean Air Act, RCRA contains no provision for the delegation of regulatory authority to tribes. In Region 10, EPA, not the state, conducts inspections at UST facilities, which includes facilities on Indian reservations owned by non-Indians.

EPA has promulgated technical performance standards designed to insure safe design, operation, maintenance, and closure of USTs. The standards encompass design, construction, and installation; operation; release detection; release reporting, investigation, and confirmation; corrective action; closure, and financial responsibility**.** RCRA Subtitle I - Underground Storage Tank (UST) Regulations are contained in (40 CFR Parts 280, 281, 282).

Federal law requires owners to carry pollution liability coverage for regulated USTs to demonstrate they have the resources to pay for cleanup and compensatory costs. Idaho's Petroleum Storage Tank Fund (PSTF) operates as a nonprofit insurance company and is responsible for administering the Idaho Petroleum Clean Water Trust Fund. The petroleum liability insurance policies issued to owners and operators of regulated USTs through the PSTF satisfies the federal financial responsibility requirements. The PSTF also provides insurance coverage to owners of all eligible unregulated above ground petroleum storage tanks. Further information on the Idaho State Insurance Fund can be found at www.idahosif.org.

7.3 CLEAN AIR ACT

For Indian reservations in Idaho, EPA has not yet approved any Tribal air programs, and State and local air agencies are not approved to administer Clean Air Act (CAA) rules on Indian reservations.

On April 8, 2005, EPA adopted regulations (70 FR 18074) codified at 40 CFR Parts 9 and 49, establishing Federal Implementation Plans (FIPs) under the CAA for Indian Reservations in Idaho. The FIPs, commonly referred to as the Federal Air Rules for Reservations (FARR), establish federal air quality regulations to protect health and welfare on Indian Reservations in the Pacific Northwest. The FARR applies to all residents (both tribal members and non-tribal members) and businesses located within the boundaries of reservations in Idaho or other reservation lands as specified in 40 CFR Part 49 Subpart M.

FARR includes air quality regulations for industrial sources and places limits on a facility's visible emissions, particulate matter, fugitive particulate matter, and sulfur dioxide. Emission limits are discussed below in more detail. In addition to the emission limits, FARR establishes a Non-Title V Operating Permit, and requires the annual registration of air pollution sources and reporting of emissions.

Visible Emissions. 40 CFR 49.124 sets limits for visible emissions produced by certain air pollution sources that operate within an Indian reservation. Visible emissions occur when particulate matter is present in an amount large enough to be seen by the human eye. Visible emissions include particulate matter. The limit on visible emissions is 20 percent opacity over any consecutive 6 minute period.

The rule allows two exceptions to the 20 percent opacity limit: The limit may be exceeded if the only reason that the limit cannot be met is because of the presence of water or steam in the visible emissions and visible emissions from an oil-fired or solid fuel-fired boiler that continuously measures opacity with a continuous opacity monitoring system can exceed the 20 percent opacity limit during start-up, soot blowing, and grate cleaning.

This limit can be exceeded for a single time period of up to 15 consecutive minutes in any 8 consecutive hours. However, the opacity can't exceed 60 percent at any time. The final rule is available at the EPA Region 10 FARR website at: www.epa.gov/r10earth/FARR.htm

Particulate Matter. 40 CFR 49.125 sets limits on the amount of particulate matter that can be produced by certain air pollution sources that operate within an Indian reservation. This rule applies to anyone who owns or operates an air pollution source that is a combustion source stack, a wood-fired boiler, a process source stack, or any other stack that produces, or could produce, particulate matter that is released into the air.

Particulate matter from a wood-fired boiler stack can't exceed an average of 0.46 grams per dry standard cubic meter (0.2 grains per dry standard cubic foot), corrected to 7 percent oxygen during any 3-hour period. The final rule is available at the EPA Region 10 FARR website at: www.epa.gov/r10earth/FARR.htm.

Fugitive Particulate Matter. 40 CFR 49.126 sets limits on the amount of fugitive particulate matter that can be produced by air pollution sources that operate within an Indian reservation.

The rule has three main requirements. First, air pollution sources must take actions to prevent and minimize fugitive particulate matter emissions. Second, the rule describes various methods that air pollution sources can use to prevent and minimize the emissions. Third, air pollution sources must perform a survey yearly to see if any fugitive particulate matter emissions are being produced. The final rule is available at the EPA Region 10 FARR website at: www.epa.gov/r10earth/FARR.htm.

Sulfur Dioxide. 40 CFR 49.129 sets limits on the amount of sulfur dioxide that can be produced by combustion source stacks. Sulfur dioxide emissions from a combustion source stack can't exceed an average of 500 parts per million by volume, on a dry basis, and corrected to 7 percent oxygen, during any 3-hour period. The final rule is available at the EPA Region 10 FARR website at: www.epa.gov/r10earth/FARR.htm.

Registration of Air Pollution Sources. 40 CFR 49.138 requires sources of air pollution within Indian reservations to register those sources with EPA and to report air pollutant emissions annually. The rule does not apply to air pollution sources that do not have the potential to emit more than 2 tons per year of any air pollutant.

A new air pollution source must submit register with EPA within 90 days after beginning operation. After the initial registration, the owner or operator must re-register the source by February 15 of each year. The information to be provided during initial and annual re-registration includes facility identification information; contact information for persons responsible for source compliance; identifying information for all emission units including a facility plot plan; descriptions and quantities of fuels and raw materials consumed at the source; the source operating schedule; estimates of total actual emissions; and, estimated efficiencies of air pollution control equipment.

All registrations and reports must include a certification signed by the source owner or operator testifying to the truth, accuracy, and completeness of the submittal. The final rule is available at the EPA Region 10 FARR website at: www.epa.gov/r10earth/FARR.htm.

Non-Title V Operating Permit – Part 70. 40 CFR 49.139 establishes an operating permit program for owners and operators of air pollution sources who want to request federally-enforceable limits on the source's actual emissions or potential to emit (PTE). A facility's PTE is based on the maximum annual operational (production, throughput, etc) rate of the facility taking into consideration the capacity and configuration of the equipment and operations. The primary reason for requesting federally-enforceable limitations is to reduce a facility's PTE to below major source thresholds, therefore avoiding certain federal Clean Air Act requirements.

The major source threshold for any "air pollutant" is 100 tons/year and major source thresholds for "hazardous air pollutants" (HAP) are 10 tons/year for a single HAP or 25 tons/year for any combination of HAP. The analyzed biomass power plant sizes, and associated emission profiles, are expected to be below this threshold and therefore will be subject to Non-Title V Operating Permit procedures.

An owner or operator of an air pollution source who wishes to set federally-enforceable limitations on the source's emissions or PTE must submit a Non-Title V Operating Permit application to the EPA. Within 60 days of receiving the application, the EPA will determine if the application is complete. Once complete, the EPA will prepare a draft permit to operate.

Along with the draft permit to operate, the EPA will prepare a draft technical support document. This document will describe the proposed limitations and the effect of these limitations on the air pollution source's actual emissions or potential to emit. The owner or operator will have the opportunity to meet with EPA to discuss these documents. EPA will also consult with the Nez Perce Tribe's Environmental Restoration & Waste Management Department, Air Quality Division and allow the tribe an opportunity to comment on the draft operating permit.

The EPA will also provide the public with an opportunity to comment on the draft permit to operate. A copy of the permit application, draft permit, draft technical support document, and supporting information will be made available for the public to review. A 30-day comment period will be provided. After this time, the EPA will review the comments and prepare a final permit to operate and a final technical support document.

The information that the owner or operator of the air pollution source must provide on the Non-Title V Operating Permit application includes facility identification information; contact information for persons responsible for source compliance; description of the proposed limitations and the effect of these limitations; identifying information for all emission units including a facility plot plan; descriptions and quantities of fuels and raw materials consumed at the source; the source operating schedule; estimates of total actual emissions; estimates of allowable emissions or potential to emit that would result from the proposed limitations;

estimated efficiencies of air pollution control equipment; and proposed testing and monitoring to show that the proposed limitations are met.

Region 10 Federal Air Rules for Reservations, 40 CFR 49.139, Non-Title V Operating Permit Application Forms can be accessed at:
http://www.epa.gov/region10/pdf/farr/non_tv_application_122408.pdf.

Federal Operating Permits – Part 71. 40 CFR 71.3 establishes a Title V Operating Permit program (also known as Part 71 permits) to sources operating on Indian reservations. If a facility has actual or potential emissions that meet or exceed major source thresholds they are required to apply for a Title V Operating Permit. The major source threshold for any "air pollutant" is 100 tons/year and major source thresholds for "hazardous air pollutants" (HAP) are 10 tons/year for a single HAP or 25 tons/year for any combination of HAP. Clearwater County is not expected to exceed the Title V Operating Permit thresholds; the following information is presented for reference purposes.

A part 71 source applying for the first time is generally required to submit an application within 12 months of the effective date of the part 71 permitting program or within 12 months of the source commencing operation, whichever occurs later. If you already have a part 70 permit, you do not have to apply for a part 71 permit until the part 70 permit expires. Part 71 sources are required to pay emissions-based fees when they initially apply and then subsequently on an annual basis. For Part 71 programs administered by EPA, the effective fee rate during calendar year 2011 is $46.00 per ton.

Applicants must retain records, materials, worksheets, or other support material used in the preparation of any required forms for a period of at least 5 years from the date the information is submitted to EPA.

Initial application forms used to initially apply for a permit or for a renewal are presented below as Table 34.

Table 33 – EPA Title V Operating Permit Forms

EPA Form #	Form Name
5900-78	Instruction Manual
5900-79	**GIS,** General Information and Summary
5900-80	**EUD-1,** Emissions Unit Description for Fuel Combustion Sources
5900-81	**EUD-2,** Emissions Unit Description for VOC Emitting Sources
5900-82	**EUD-3,** Emissions Unit Description for Process Sources
5900-83	**IE,** Insignificant Emissions
5900-84	**EMISS,** Emissions Calculations
5900-85	**PTE,** Potential to Emit Summary
5900-03	**FEE,** Fee Calculation Worksheet
5900-06	**FF,** Fee Filing Form
5900-86	**I-COMP,** Initial Compliance Plan and Compliance Certification
5900-02	**CTAC**, Certification of Truth, Accuracy, and Completeness
5900-01	SIXMON, Six-Month Monitoring Report
5900-02	CTAC, Certification of Truth, Accuracy, and Completeness*
5900-03	FEE, Fee Calculation Worksheet *
5900-06	FF, Fee Filing Form
5900-04	A-COMP, Annual Compliance Certification
5900-05	PDR, Prompt Deviation Report

Before issuing a permit, EPA must publish a newspaper notice and send out individual notices to persons on a mailing list for each draft permit. EPA must advertise in the public press that the public can request to be on the mailing list. The notice must tell you where the permit file is located, when it is available for public inspection, and that all data submitted by the facility are publicly available. Anyone (including the permitee) can make comments on the draft permit during the public comment period and may request a public hearing. Public hearings will be held if there is a significant degree of public interest or at the discretion of EPA.

In addition to FARR, and EPA-issued operating permits, portions of the CAA regulations potentially applicable to energy development activities on tribal lands include New Source Review (NSR) permit requirements, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPs).

New Source Review (NSR) Permits (40 CFR 51-52). New Source Review (NSR) Permits are permit regulations, which are incorporated into requirements for state and tribal implementation plans, requiring that all new stationary sources of air pollution be permitted before construction begins. There are three types of NSR permits: (1) Nonattainment NSR permits (40 CFR 51), which may apply to new major sources or major modifications of existing sources located in areas that are not in attainment with the NAAQS; (2) Prevention of Significant Deterioration (PSD) permits (40 CFR 52.21), which may apply to new major sources or major modifications of existing sources located in attainment areas or unclassifiable areas with respect to the NAAQS;

and (3) Minor NSR permits, which may apply to facilities not requiring either a PSD or Nonattainment NSR permit. The EPA's New Source Review Web page provides more information about these permit requirements and can be accessed at: http://www.epa.gov/air/nsr/info.html

New Source Performance Standards (NSPS) (40 CFR 60). New Source Performance Standards (NSPS) are regulations issued by the EPA establishing air pollution emission standards for new stationary sources of emissions. NSPS have been established for a number of individual categories related to energy development including steam generators. Depending on the scale of the Biomass CHP plant and potential to emit, emission standards may be regulated under 40 CFR part 60, Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units or 40 CFR Part 60, Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Text on these subparts can be viewed at the Electronic Code of Federal Regulations at: http://www ecfr.gpoaccess.gov.

National Emission Standards for Hazardous Air Pollutants (NESHAPs) Regulations (40 CFR 63). National Emission Standards for Hazardous Air Pollutants (NESHAPs) are regulations issued under Section 112 of the CAA (40 CFR Part 63) that regulate 187 hazardous air pollutants from particular industrial sources. These industry-based NESHAPs are also called Maximum Achievable Control Technology (MACT) standards.

Sources subject to MACT standards are classified as either **major sources** or **area sources**. **Major sources** are sources that emit 10 tons per year of any of the listed HAPs, or 25 tons per year of a mixture of HAPs. **Area sources** consist of smaller-size facilities that emit less than 10 tons per year of a single HAP or less than 25 tons per year of a combination of HAPs.

On April 29, 2010, EPA issued NESHAP or new Maximum Achievable Control Technology (MACT) standards for industrial commercial and institutional boilers and process heaters (ICI Boilers). The rule, if finalized as proposed, will impose stringent emission limits and monitoring requirements on biomass-fired boilers by the end of 2013, and on any new boilers constructed after the rule becomes final. EPA is currently reviewing to determine whether to finalize the rule as proposed or revise the scope of the rule and/or its limitations.

The MACT establishes very stringent emissions standards for eleven subcategories of boilers based on fuel and process type. The rule addresses HAPs emissions by imposing limits on five "surrogate" pollutants, namely mercury (Hg), hydrogen chloride (HCl), particulate matter (PM), carbon monoxide (CO), and dioxins/furans (D/F). Depending on the scale of the Biomass CHP plant and potential to emit, Clearwater County's Biomass CHP Power Plant may be regulated under 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. Text on this subpart can be viewed at the Electronic Code of Federal Regulations at: http://www ecfr.gpoaccess.gov.

7.4 STATE OF IDAHO

Air Permitting. Currently, all proposed sites for the biomass power plant are located within the boundaries of the Nez Perce Indian Reservation and as such EPA Region 10 will be the permitting authority for air quality permits. It is recommended the Nez Perce Air Quality Division be informed of all permitting activities.

In the event that initial site locations are not viable and an alternative site is located outside the boundaries of the Nez Perce Reservation, then the DEQ will have permitting jurisdiction.

Outlined below is a DEQ Permit to Construct Application Checklist for Small Wood-Fired Boilers. The checklist is designed to aid the applicant in submitting a complete permit to construct application for a wood-fired boiler with a rated input capacity of over 1.0 million Btu/hr and less than 10 million Btu/hr that will be located at a minor facility. Combustors of less than 1.0 million Btu/hr are not required to obtain a permit to construct (IDAP 58.01.01.222.02d). Applications for a permit to construct will be processed in accordance with the Procedure for Issuing Permits (IDAPA 58.01.01.209), which specifies the amount of time for DEQ processing of permit applications, as follows:

> Thirty (30) days to review the application for completeness.
>
> Sixty (60) days (after completeness determination) to prepare the permit for issuance or to prepare the proposed permit for public comment if a public comment opportunity is requested.
>
> If a public comment period is requested, DEQ must issue or deny the permit within 45 days of the start of the 30-day public comment period, unless the Director determines that additional time is required to address comments received.

Actions Needed Before Submitting Application. Consult with DEQ Representatives. It is recommended that the applicant consult with DEQ to discuss application requirements before submitting the permit to construct application. This step often saves the applicant time and effort.

Submit a Dispersion Modeling Protocol. (Dispersion modeling is sometimes called ambient air quality modeling.) It is suggested that a dispersion modeling protocol be submitted to DEQ at least two (2) weeks before the permit to construct application is submitted.

Application Content. Application content should be prepared using the checklist below. The checklist is based on the requirements contained in IDAPA 58.01.01.202 (*Application Procedures).*

> *Apply for a Permit to Construct.* Complete and submit the following forms from DEQ's website at: http://www.deq.idaho.gov/air/permits_forms/forms/forms.cfm#PTC, under Application Forms:

- Cover Sheet (Form CS)
- General Information (Form GI)
- General Emission Unit (Form EUO)
- Plot Plan (Form PP)
- Modeling Information Workbook (Form MI)

Permit to Construct Application Fee. A $1,000 permit to construct application fee must be submitted when the original application is submitted. Refer to IDAPA 58.01.01.224. Note that a permit to construct processing fee will be required to be paid prior to the permit issuance. Refer to IDAPA 58.01.01.225.

Process Description and Process Flow Diagram. The process or processes for which the construction permit is requested must be described in sufficient detail and clarity such that a member of the general public not familiar with air quality can clearly understand the proposed project. A process flow diagram is required that includes the boiler and fuel feeding system; the description provided must describe the boiler's design (e.g., single chamber, dual chamber, combustion air, supplemental fuel, etc.) and how the fuel feeding system operates and is controlled.

Equipment List. All equipment for which the construction permit is requested must be described in detail. Such description includes, but is not limited to, manufacturer, model number or other descriptor, serial number, maximum combustion rate, proposed combustion rate, maximum heat input capacity, stack height, stack diameter, stack gas flow rate, stack gas temperature, etc. All equipment for which the construction permit is requested must be clearly labeled on the process flow diagram.

Emission Inventory. Submit the uncontrolled emission inventory that does not consider restrictions on emissions such as air pollution control equipment, hours of operation, or limiting wood combustion rates below the design combustion rate capacity of the burner. Also submit a controlled emission inventory that does consider operational restrictions. Any physical or operational limit on emissions given in the application will become a limitation in the permit to construct.

Applicants must use the most representative emission data available for the combustor type that is proposed to be installed. When source specific emissions test data are not available, the Environmental Protection Agency's AP-42 emissions factors are often used to estimate emissions. Listed below is the emission data that DEQ knows is available:

Messersmith Single Combustion Chamber - Council, Idaho (March, 2007) and Vermont Source Test Data (April, 1996)

Chiptec Dual Combustion Chamber - Vermont Source Test Data (April, 1996)

EPA, AP-42: Compilation of emission factors

The Vermont source test data may found at the following link:
http://www.nrbp.org/pdfs/pub14.pdf

EPA's compilation of emission factors (AP-42) may be found at the following link:
http://www.epa.gov/ttn/chief/ap42/index.html

Emission Inventory and Modeled Ambient Concentration for All Regulated Air Pollutants. All proposed emission limits and modeled ambient concentrations must demonstrate compliance with all applicable air quality rules and regulations. Regulated air pollutants include criteria air pollutants, toxic air pollutants listed pursuant to IDAPA 58.01.01.585 and 586, and hazardous air pollutants listed pursuant to Section 112 of the 1990 Clean Air Act Amendments.

Describe in detail how the proposed emissions limits and modeled ambient concentrations demonstrate compliance with each applicable air quality rule and regulation. Calculations, assumptions, and documentation for emissions estimates must include sufficient detail so DEQ can verify the validity of the emissions estimates.

When estimating emissions, thoroughly document the source of the emissions factors that were used to estimate emissions. Be sure to use the most representative data available. Contact DEQ to determine what emissions data are known to be available for use in these estimates.

Toxic Air Pollutant Compliance Demonstration. Complete and submit the Toxic Air Pollutant Preconstruction Application Completeness Checklist. (The checklist can be found at:
www.deq.idaho.gov/air/permits_forms/forms/ptc_checklist_TAP_completeness_13Apr09.doc).

Particulate Matter Grain Loading. Demonstrate compliance with the fuel burning equipment particulate matter grain loading standard (0.200 grams/dscf @ 8% O2, corrected for altitude). Refer to IDAPA 58.01.01.677 & 680.

Procedures Manual. Prepare and submit a procedures manual that details how the combustor will be operated and monitored to assure combustion efficiency is maintained. Combustion efficiency can be influenced by combustion temperature, combustion air, fuel type, fuel moisture content, fuel feeding procedures and idle or pilot operating conditions. At a minimum the procedures manual is expected to address each of these. The procedures manual purpose is to assure that wood is combusted under optimum conditions (i.e. temperature and combustion air) and to describe the ongoing monitoring that will be undertaken to assure these conditions are maintained.

Currently, DEQ does not have a large wood-fired boiler PTC checklist. Should Clearwater choose to build a facility greater than 10.0 MMBTU/hr, it is recommended that the applicant consult with DEQ to discuss large wood-fired boiler application requirements before submitting the permit to construct application.

7.5 HAZARDOUS CHEMICALS AND HAZARDOUS MATERIALS

The use of certain hazardous chemicals above regulated quantities will trigger the Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986. EPCRA establishes requirements for Federal, State and local governments, Indian Tribes, and industry regarding emergency planning and "Community Right-to-Know" reporting on hazardous and toxic chemicals. EPCRA regulations are codified in Title 40 of the Code of Federal Regulations, Parts 350 to 372.

EPCRA consists of four major provisions and include the following.

Sections 301 to 303. Emergency Planning: Local governments are required to prepare chemical emergency response plans, and to review plans at least annually. State governments are required to oversee and coordinate local planning efforts. Facilities that maintain Extremely Hazardous Substances (EHSs) on-site in quantities greater than corresponding Threshold Planning Quantities (TPQs) must cooperate in emergency plan preparation. Appendix A to 40 CFR Part 335 lists EHSs and their TPQs.

Section 304. Emergency Notification: Facilities must immediately report accidental releases of EHS chemicals and "hazardous substances" in quantities greater than corresponding Reportable Quantities (RQs) defined under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to state, federal, and local officials.

Sections 311 and 312. Community Right-to-Know Requirements: Facilities manufacturing, processing, or storing designated hazardous chemicals must make Material Safety Data Sheets (MSDSs) describing the properties and health effects of these chemicals available to state and local officials and local fire departments. Facilities must also report, to state and local officials and local fire departments, inventories of all on-site chemicals for which MSDSs exist. Information about chemical inventories at facilities and MSDSs must be available to the public.

Section 313. Toxics Release Inventory: Facilities must complete and submit a Toxic Chemical Release Inventory Form annually for each of the more than 600 Toxic Release Inventory (TRI) chemicals that are manufactured or otherwise used above the applicable threshold quantities.

It is not expected that hazardous waste will be produced directly by the process based on the expected composition of material input. Maintenance operations could produce hazardous waste, however, and the following waste streams should be considered as potential sources.

- Wastewater treatment sludges
- Residual fly ash

A Toxicity Characteristic Leaching Procedure (TCLP) test should be conducted on the residual fly ash to characterize the waste as hazardous or non-hazardous. Hazardous and non-hazardous waste should be properly disposed of at approved municipal solid waste landfills or permitted hazardous waste facilities. The Clearwater County Transfer Station is the closet approved solid waste and hazardous waste landfill.

The Resource Conservation and Recovery Act (RCRA) is the federal law regulating the generation, handling, storage, treatment, and disposal of hazardous wastes. All facilities that generate, transport, recycle, treat, store, or dispose of hazardous waste are required to notify EPA Region 10 or their state agency of their hazardous waste activities. In Idaho, DEQ's Waste Management and Remediation Division administers the RCRA regulations. Under these regulations businesses are responsible for tracking the volume of waste generated, determining whether any wastes generated are hazardous and the amount, and ensure all wastes are properly disposed of according to federal, state, and local requirements. The degree to which a generator of hazardous waste is regulated depends on how much waste is produced and/or stored every calendar month. In general, a biomass CHP plant should not be a hazardous waste generator.

A facility that generates a small amount of hazardous waste may fall into the least regulated category of hazardous waste generator called the Conditionally Exempt Small Quantity Generator (CESQG). CESQGs generate less than 100 kg (220 pounds) of hazardous waste per month, or less than 1 kg (2.2 pounds) of acutely hazardous waste, and are subject to a limited, less stringent set of generator waste management standards.

CESQGs are required to keep track of the amount of hazardous waste generated and stored on-site each month, limit on-site storage of hazardous wastes to no more than 2,200 pounds, including no more than 2.2 pounds of acute hazardous waste at any time. The facility must also properly dispose of all hazardous waste to an approved municipal solid waste landfill, a permitted hazardous waste facility, or a facility that beneficially uses or reuses, or legitimately recycles or reclaims waste, and have on-site documentation that the facility is within the limits for this classification and properly dispose of the wastes.

As a CESQG, you are not required, but may wish, to obtain an EPA Identification Number to track quantities, types, and movement of hazardous wastes you generate. A Summary to Idaho Hazardous Waste Generator Requirements can be accessed at the following link:
http://www.deq.idaho.gov/waste/assist_business/haz_waste/generator_requirements_0607.pdf

Solid Waste. The combustion process associated with a wood boiler will have only one significant source of solid waste. The typical or standard design for conversion of woody biomass to steam includes a combustion boiler. The boiler would produce a fly ash waste stream requiring disposal. It may be possible to use the fly ash byproduct as a soil amendment, but its value in this application is uncertain. We have assumed that the fly ash stream is non-hazardous and will be land filled. The resulting environmental impacts should be minimal.

8.0 Federal and State Funding Mechanisms

In this section various funding mechanisms, grants, tax credits and loan opportunities applicable to renewable energy projects in the state of Idaho are presented. These incentives can have a significant impact on the financial viability and operational returns of a biomass power project.

Aside from the funding opportunities presented below, solicitations for renewable energy projects are periodically issued by state, local, and federal departments such as the Ferderal Energy Management Program (FEMP), a division of the DOE EERE Program, USDA, DOE, and EPA. These incentives should be monitored throughout the development process and applicable programs should be pursued throughout. Generally, applicable one-time grants are only available to projects that are at significant stages of development (i.e., project site secured, engineering at 50% completion or better, feedstock supply and product off-take agreements including PPA's secured, etc.). Thus, it is unknown whether such programs can be of assistance to the biomass power plant, but based on the number of grants and grant programs currently available for renewable energy and biomass-based power production, it is likely that at some point during the development process at least one grant program will be available for application. See https://www.fedconnect.net/FedConnect/ for up-to-date information regarding available solicitations.

8.1 FUNDING SOURCES AND GRANTS

Federal Grants, Loans, and Incentives

At the time of preparing this report, the proposed amendments and changes to the new energy bill were still pending. Therefore, some of the programs and incentives presented below are subject to change, extension, or termination. The financial assistance identified in this section is subject to eligibility requirements established by the various agencies/authorities, funding by the agencies and competition for the awards/loans.

USDA Rural Energy for America Program (REAP). REAP provides a suite of incentive and assistance-based support in the form of payments, grants, loans, and loan guarantees, for the development and commercialization of renewable energy sources. To be eligible to apply for REAP funding, a project must be owned by an agricultural producer or rural small business. Tribal enterprises are also eligible.

Programs specific to biomass-based CHP energy generation include:

- Rural Energy for America Program Grants/Energy Audit and Renewable Energy Development Assist (REAP/EA/REDA)(Section 9007)
- Rural Energy For America Program Grants (REAP Feasibility Study Grants)(Section 9007)

- Rural Energy for America Program Guaranteed Loan Program (REAP Loans)(Section 9007)
- Value-Added Producer Grant Program
- Business and Industry Guaranteed Loan Program
- Section 9003 Interim Rule
- Section 9003 Application Guide
- Repowering Assistance Program (Section 9004)

For 2011, the program included both grants and loan guarantees and were available to agricultural producers and rural small businesses. $70M is set aside for REAP funding, required by the 2008 Farm Bill. The maximum grant limit is $500,000 or 25% of the total project cost, and the loan guarantee is available for up to 75% of the project between $5,000 and $25 million. New definitions for eligibility are being determined at the time of report completion. For more information, see http://www.rurdev.usda.gov/Energy.html.

USDA Biomass Crop Assistance Program (BCAP). BCAP provides financial assistance to owners and operators of agricultural and non-industrial private forest land who wish to establish, produce, and deliver biomass feedstocks. BCAP provides two categories of assistance. The first program is more likely to be applicable; matching payments for delivery of eligible materials (biomass feedstocks) to qualified biomass conversion facilities, including facilities that produce heat, power, biobased products, or advanced biofuels from biomass feedstocks. A much-less utilized system format involves contracting with the Commodity Credit Corporation (CCC) to produce eligible biomass crops on contract acres within BCAP project areas. For more information, see http://www.fsa.usda.gov/FSA/webapp?area=home&subject=ener&topic=bcap.

NOTE: Is it unknown at this time whether BCAP and REAP will be continuing programs. On June 16, 2011, the US House of Representatives voted to de-fund BCAP, effective in 2012. The same bill (H.R. 2122) also eliminated funding for REAP, but with its much larger scope the program is more likely to prevail. The bill as written faces a vote in the Senate and must also survive presidential veto before the programs are officially de-funded.

IRS Production Tax Credit (PTC) and Investment Tex Credit (ITC), and 1603 Grant-in-Lieu. The Federal Internal Revenue Service has two renewable energy funding mechanisms available, an investment tax credit and a production tax credit. The American Recovery and Reinvestment Act of 2009 included an additional provision to allow grantees to elect a cash grant in lieu of the PTC. The ITC and Grant-in-Lieu are able to fund up to 10% of CHP, geothermal, and microturbine systems, and 30% for solar, fuel cells and small wind, placed in service on or before December 31, 2016 (ITC) or having construction begun by December 31, 2011 (Grant-in-Lieu). The PTC funds 2.2¢/kWh for the first 10 years of operation of a ‘closed-loop biomass plant placed in operation by December 31, 2012. Applicants must be eligible taxpayers; federal, state and local government bodies, non-profits, qualified energy tax credit bond lenders, and cooperative electric companies are not eligible, nor are partnerships or pass-thru entities for such organizations. See

http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1
for more information.

US DOE Tribal Energy Program Grants. The U.S. Department of Energy's (DOE) Tribal Energy Program promotes tribal energy sufficiency, economic growth and employment on tribal lands through the development of renewable energy and energy efficiency technologies. The program provides financial assistance, technical assistance, education and training to tribes for the evaluation and development of renewable energy resources and energy efficiency measures. Program funding is awarded through a competitive process (from DSIRE USA). See http://apps1.eere.energy.gov/tribalenergy/government_grants.cfm#Tribal
for more information regarding individual grants available.

Natural Resources Conservation Service (NRCS) Conservation Innovation Grant (CIG). NRCS requests applications for Conservation Innovation Grants (CIG) to stimulate the development and adoption of innovative conservation approaches and technologies. Grants are available to non-Federal government organizations, non-governmental organization, tribes, or private individuals. Applicants must be an agricultural producer that is engaged in livestock or agricultural production, or a private, non-industrial forest landowner. Awards vary by year. Two CIG national funding opportunities are available in FY 20011, focusing the Chesapeake Bay Watershed and the Mississippi River Basin.

Environmental Quality Incentive Program (EQIP). EQIP is a voluntary conservation program that helps farmers and agricultural producers, including forest landowners, reduce pollution and improve natural resources. EQIP provides technical and financial assistance to help producers plan, install and implement structural, vegetative and management conservation practices on agricultural land. EQIP in Pennsylvania offers financial assistance to help off-set the costs of eligible conservation practices. Incentive payments may also be made to encourage a farmer to adopt land management practices, such as nutrient management, manure management, integrated pest management, wildlife habitat management, or forest management. EQIP contracts can be as short as one year, with a one year maintenance period. Most contracts are for work that can be completed within four years. Financial assistance is provided through incentive payments that are based on average costs to implement conservation practices. Incentive rates are listed on the annual Practice Payment Rate schedule. Limited resource Farmers, Beginning Farmers and Ranchers, and Socially Disadvantaged Farmers may be eligible for higher incentive payment rates. Total financial assistance payments are limited to $300,000 per an individual over a six-year period.

Value-Added Producer (VAP). The Value-Added Producer Grant (VAPG) Program awards grants to agricultural producers, businesses owned by a majority of agricultural producers, and organizations representing agricultural producers for business planning or working capital expenses associated with marketing a value-added agricultural product. Agricultural producers include farmers, ranchers, loggers, agricultural harvesters and fishermen that engage in the production or harvesting of an agricultural commodity. Value-Added Producer Grants may be used for feasibility studies or business plans, working capital for marketing value-added agricultural products and for farm-based renewable energy projects. Eligible applicants include independent producers, farmer and rancher cooperatives, and agricultural producer groups. Funding is limited to $100,000 for feasibility studies and $300,000 for capital expenditures.

State Grants and Incentive Programs

Renewable Energy Project Bond Program. Idaho House Bill 106 enacted the Idaho Energy Resources Authority (IERA), a state bonding authority created in March 2005 (Idaho Code §67-8901 et seq). Senate Bill 1192 further allowed independent energy developers to request a bond from IERA to finance renewable energy projects. According to the text of the bill, (§67-8902(2)(g), "It is in the best interest of the state of Idaho and its people to encourage and promote the development of renewable energy resources in order to develop sustainable sources of energy supply, reduce inefficiencies in the use of electric energy and enhance the long-term stability of the energy resources and requirements of the state."

§ 67-8925. "Renewable Energy Generation Projects. The authority may undertake any renewable energy generation project for the benefit of one (1) or more independent power producers and may issue its bonds to finance the cost thereof, all to the same extent and subject to the same provisions applicable to the undertaking and financing of other facilities for the benefit of one (1) or more participating utilities. In furtherance of the foregoing, an independent power producer shall be deemed to be a participating utility with respect to a renewable energy generation project for purposes of sections 67-8909, 67-8910 and 67-8911, Idaho Code."

Contact:

Ron Williams
Idaho Energy Resources Authority
1015 West Hays Street
Boise, ID 83702
Phone: (208) 344-6633
Fax: (208) 344-0077
Web Site: http://www.iera.info

Renewable Energy Equipment Sales Tax Refund. Pursuant to Idaho State Code §63-3622QQ, this state incentive is a sales-and-use tax rebate for qualifying equipment and machinery used to generate electricity from fuel cells, low-impact hydro, wind, geothermal resources, biomass, cogeneration, solar and landfill gas. Purchasers qualify for a rebate only if the equipment is used to develop a facility or a project capable of generating at least 25 kilowatts (kW) of electricity. Applicable sectors include commercial, industrial and residential. Eligible technologies include Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, CHP/Cogeneration, Fuel Cells using Renewable Fuels. The rebate is scheduled to sunset July 1, 2011, but may be extended additional years. For more information, see http://legislature.idaho.gov/idstat/Title63/T63CH36SECT63-3622QQ.htm.

Contact:

Public Information
Idaho Tax Commission
800 Park Blvd. #4
Boise, ID 83722
Phone: (208) 334-7660
Phone 2: (800) 972-7660
Fax: (208) 334-7846
E-Mail: taxrep@tax.idaho.gov

Tax Incentives

Various tax incentives are available for installation and operation of renewable energy generation equipment. These incentives are not available to publicly-owned systems, but are important to keep in mind for potential private-sector investment and for PPA negotiations. These incentives include:

- IRS: Renewable Energy Production Incentive
  (Available to the electrical cooperative only)

- Clean Renewable Energy Bonds
  (Available to the electrical cooperative only)

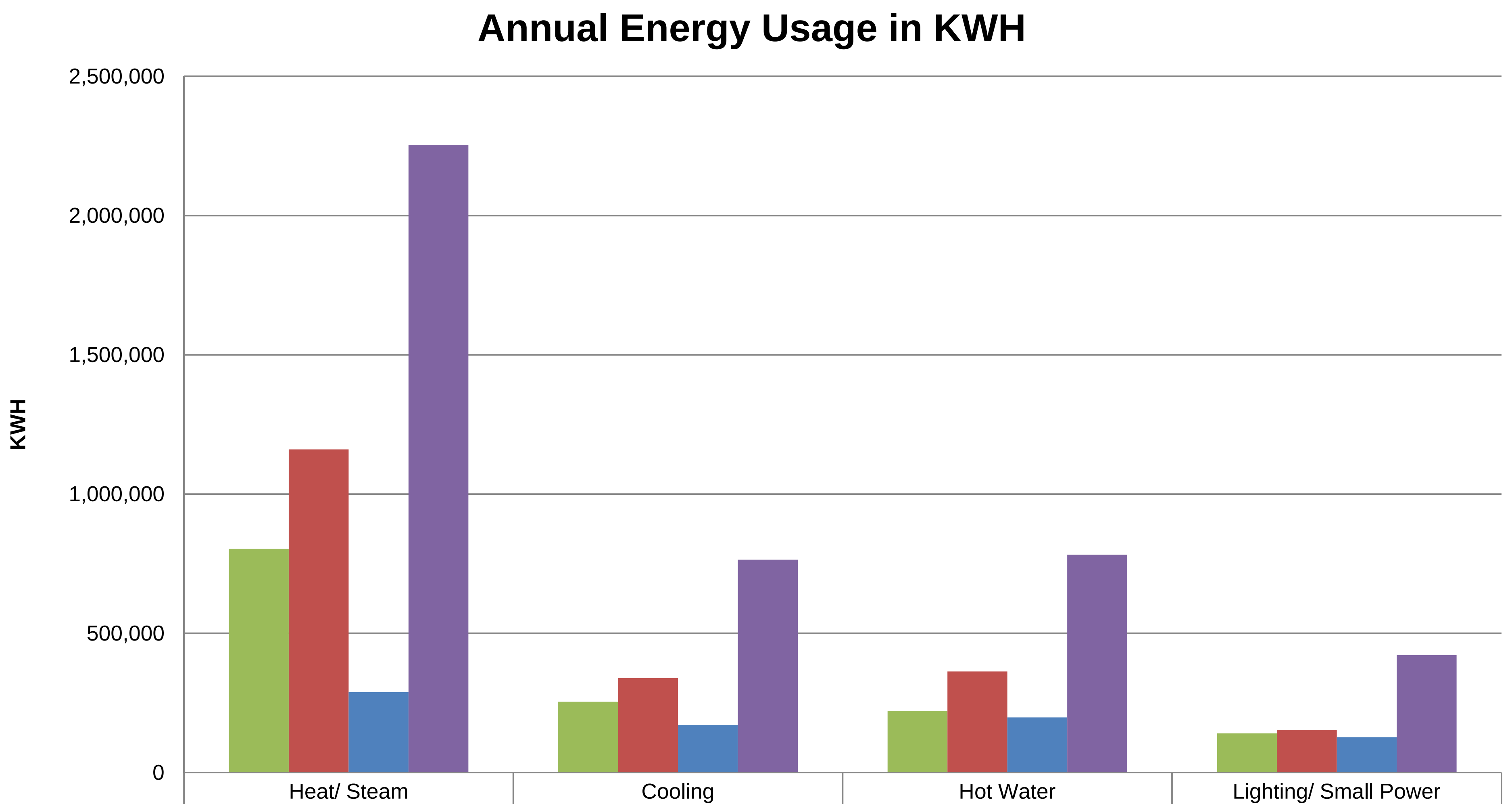
8.2 RENEWABLE ENERGY CREDITS AND CARBON CREDITS

Valuation of renewable energy credits (REC) carbon credits (CC) were not conducted for this study, though it may be possible to monetize the carbon savings of the project. Joining a REC carbon trading system utilizing a brokerage firm is the recommended pathway requiring the least administrative burden to tap into the additional product stream.

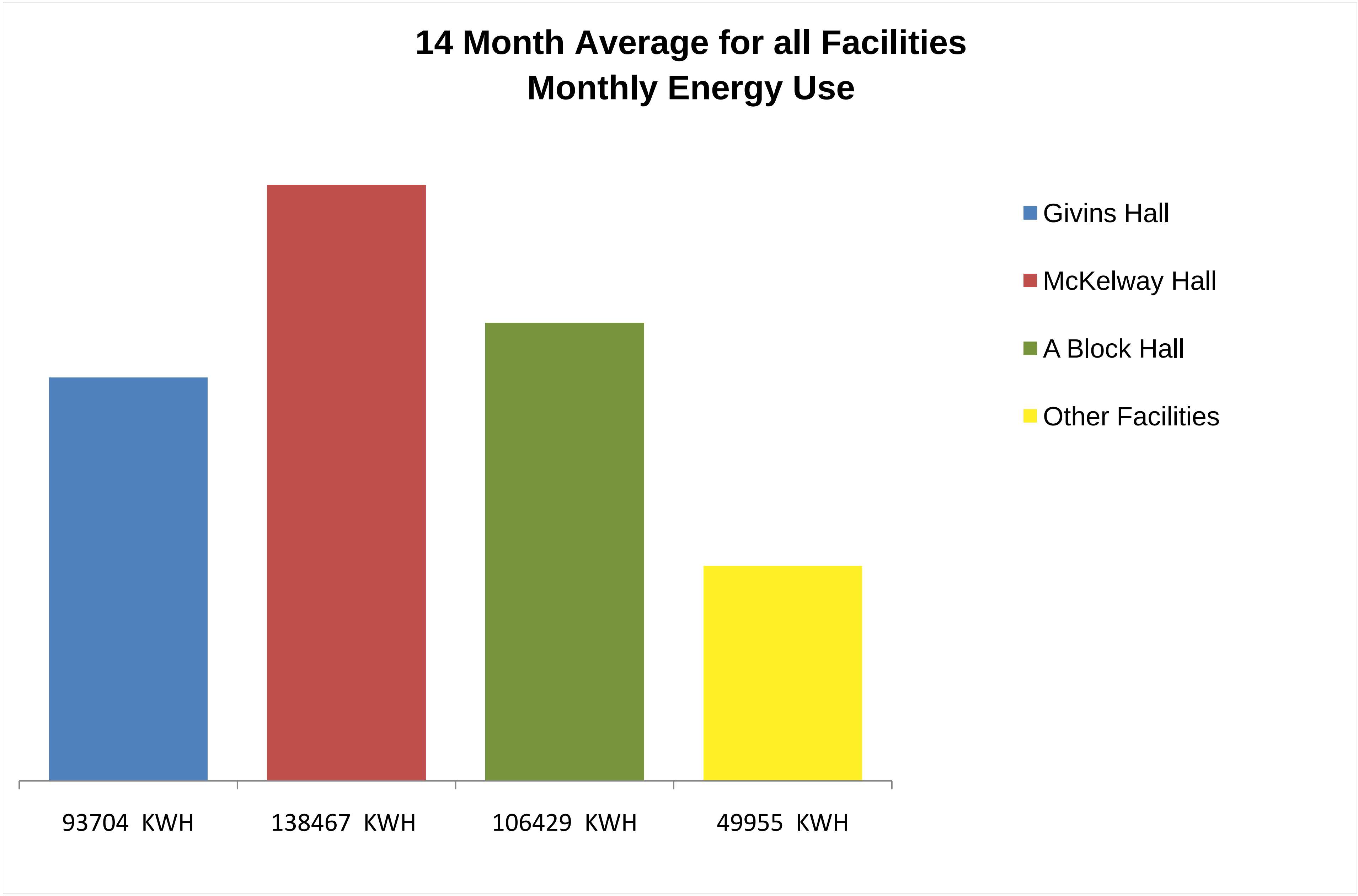
Valuation of carbon credits is contingent on calculating the reduction of carbon emissions the plant will produce. Unfortunately, with the current carbon accounting practices in the U.S., the full carbon footprint benefit of this project is debatable. Some carbon footprint models view thermal energy from a CHP system as 'waste heat' and use of such heat is a pure benefit, while other models calculate the wood input for both electricity and heat production for a CHP system, and thus reduce the carbon benefit of using thermal energy. However calculated, the consensus is that woody biomass CHP systems provide a definite emissions benefit for the local community.

APPENDIX A

ICI-O ENERGY AUDIT

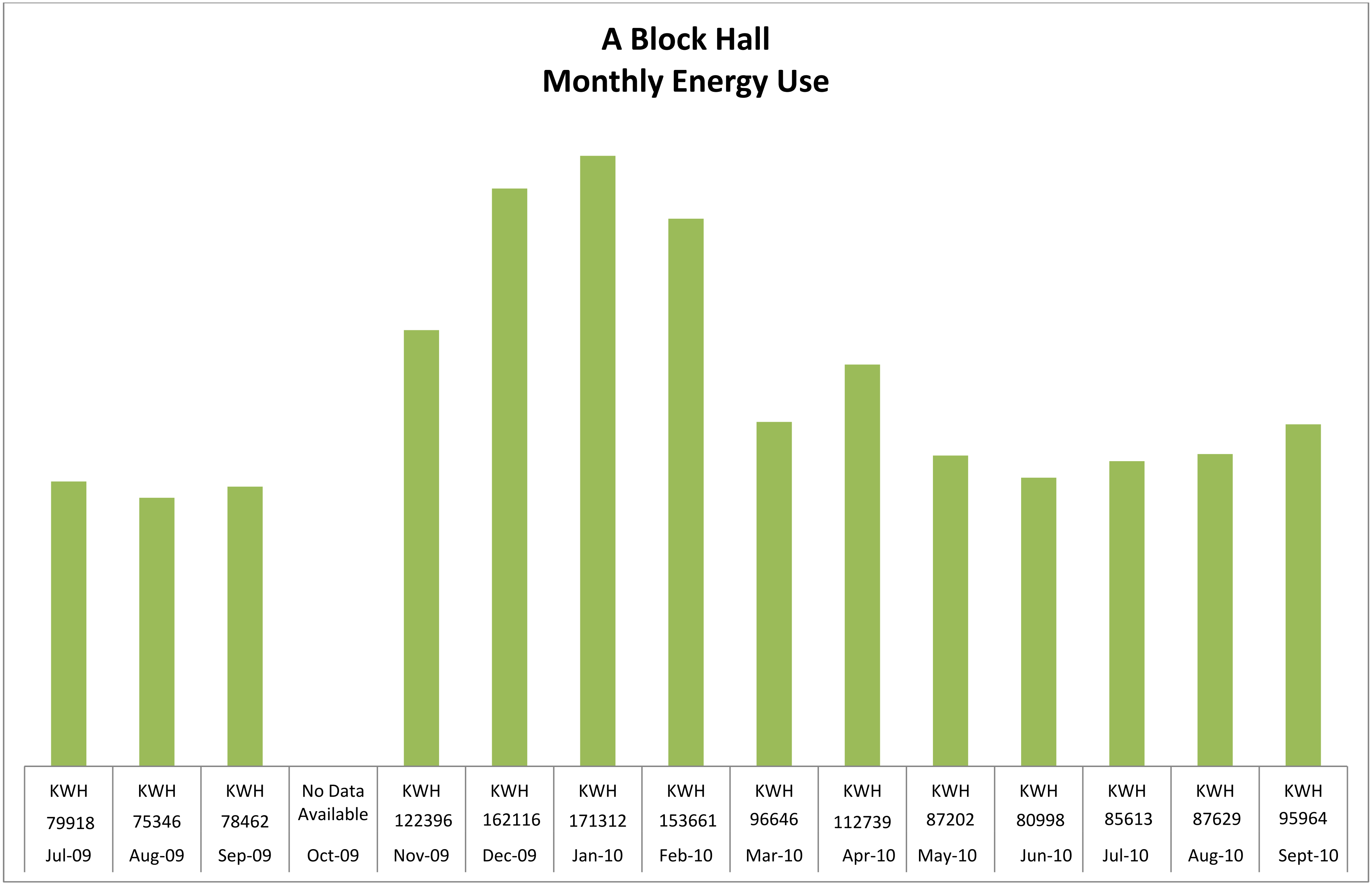


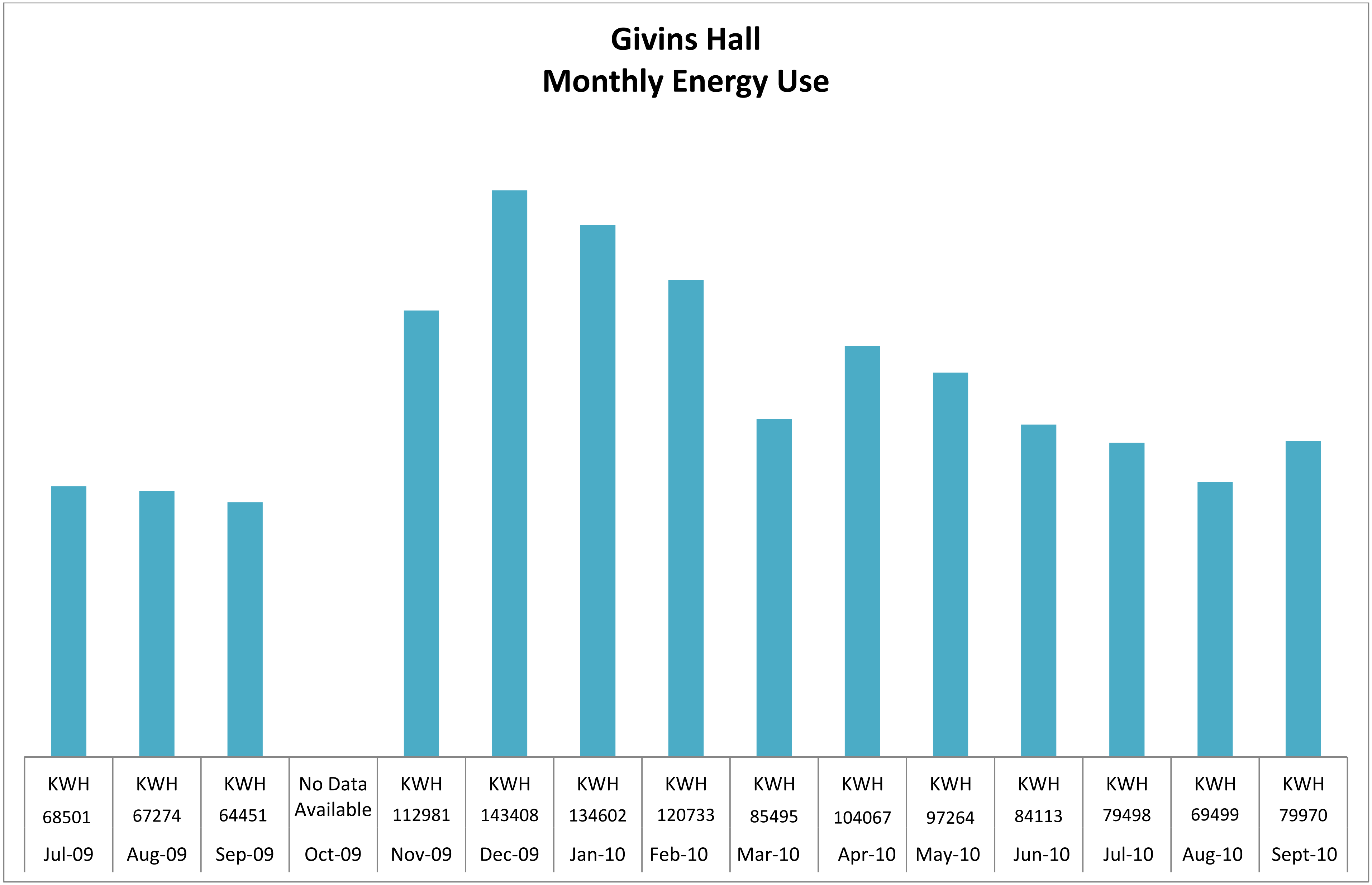
	Heat/ Steam	Cooling	Hot Water	Lighting/ Small Power
A-Block	803,250	254,465	220,320	140,675
McKelway Hall	1,160,250	339,779	363,528	153,848
Givins Hall	289,170	170,000	198,288	127,500
Total	2,252,670	764,244	782,136	422,023



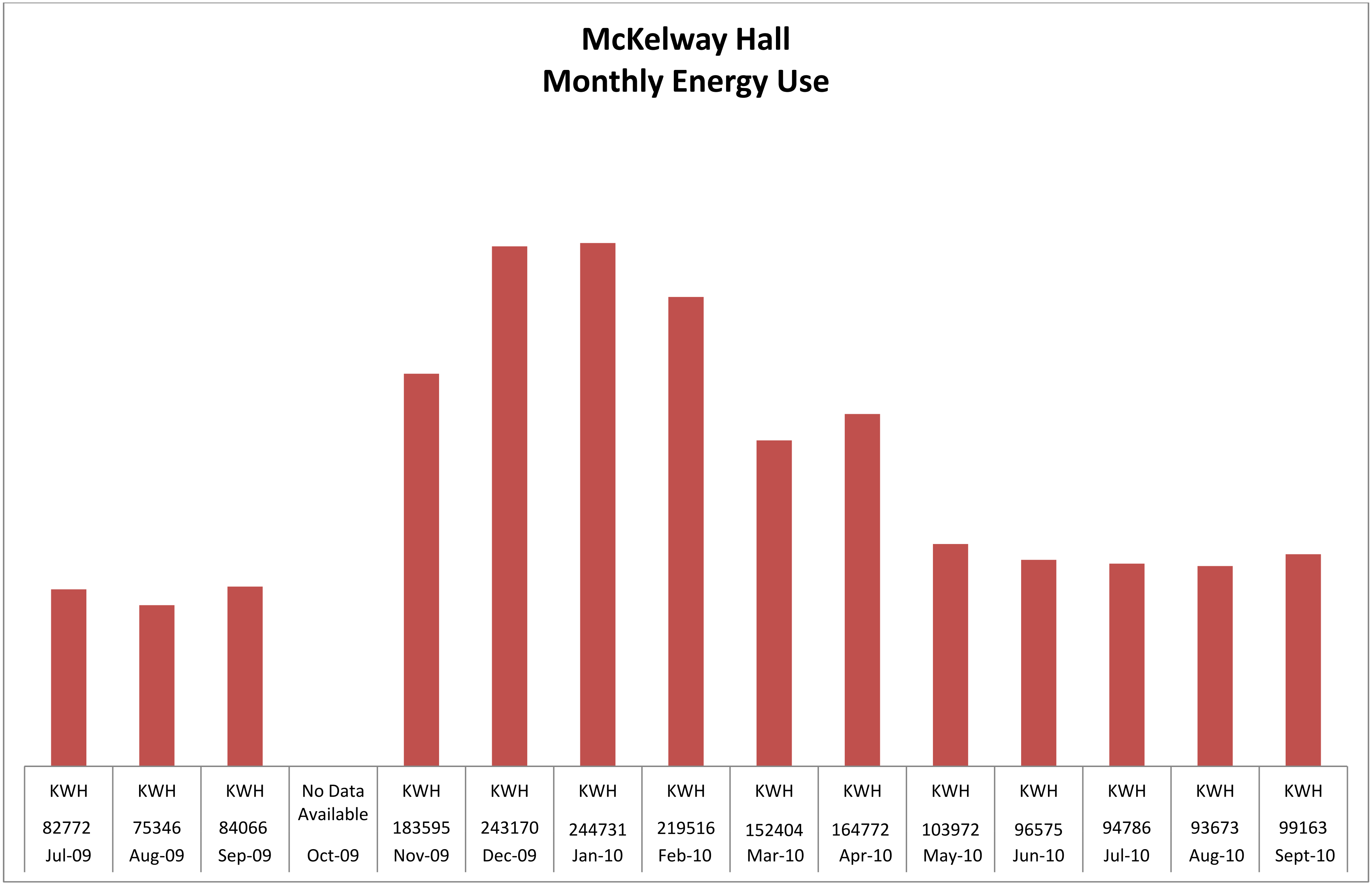
14 Month Average for all Facilities
Monthly Energy Use
Givins Hall
McKelway Hall
A Block Hall
Other Facilities
93704 KWH
138467 KWH
106429 KWH
49955 KWH

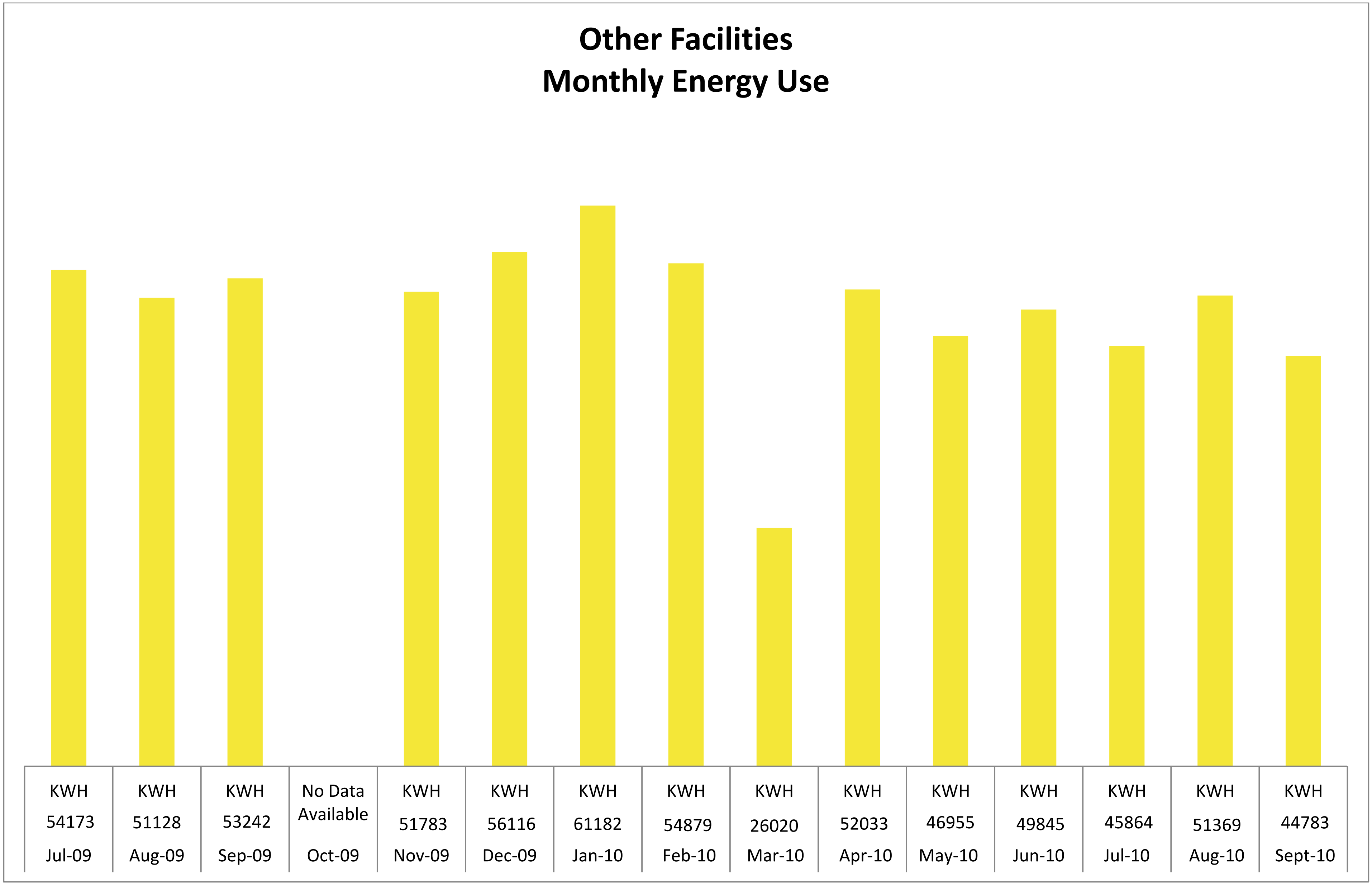
TETRA TECH


A Block Hall
Monthly Energy Use
KWH 79918 Jul-09
KWH 75346 Aug-09
KWH 78462 Sep-09
No Data Available Oct-09
KWH 122396 Nov-09
KWH 162116 Dec-09
KWH 171312 Jan-10
KWH 153661 Feb-10
KWH 96646 Mar-10
KWH 112739 Apr-10
KWH 87202 May-10
KWH 80998 Jun-10
KWH 85613 Jul-10
KWH 87629 Aug-10
KWH 95964 Sept-10


Givins Hall
Monthly Energy Use
KWH 68501 Jul-09
KWH 67274 Aug-09
KWH 64451 Sep-09
No Data Available Oct-09
KWH 112981 Nov-09
KWH 143408 Dec-09
KWH 134602 Jan-10
KWH 120733 Feb-10
KWH 85495 Mar-10
KWH 104067 Apr-10
KWH 97264 May-10
KWH 84113 Jun-10
KWH 79498 Jul-10
KWH 69499 Aug-10
KWH 79970 Sept-10

TETRA TECH

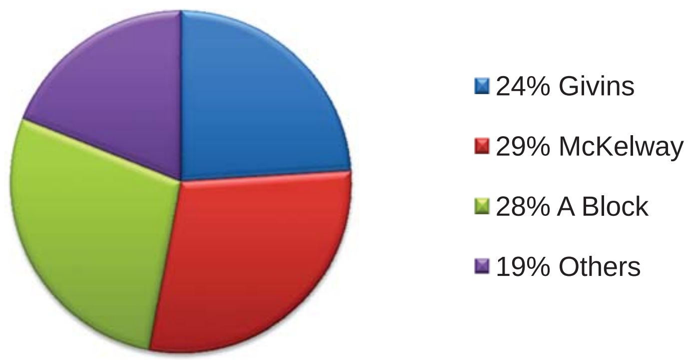

McKelway Hall
Monthly Energy Use
KWH 82772 Jul-09
KWH 75346 Aug-09
KWH 84066 Sep-09
No Data Available Oct-09
KWH 183595 Nov-09
KWH 243170 Dec-09
KWH 244731 Jan-10
KWH 219516 Feb-10
KWH 152404 Mar-10
KWH 164772 Apr-10
KWH 103972 May-10
KWH 96575 Jun-10
KWH 94786 Jul-10
KWH 93673 Aug-10
KWH 99163 Sept-10


Other Facilities
Monthly Energy Use
KWH 54173 Jul-09
KWH 51128 Aug-09
KWH 53242 Sep-09
No Data Available Oct-09
KWH 51783 Nov-09
KWH 56116 Dec-09
KWH 61182 Jan-10
KWH 54879 Feb-10
KWH 26020 Mar-10
KWH 52033 Apr-10
KWH 46955 May-10
KWH 49845 Jun-10
KWH 45864 Jul-10
KWH 51369 Aug-10
KWH 44783 Sept-10

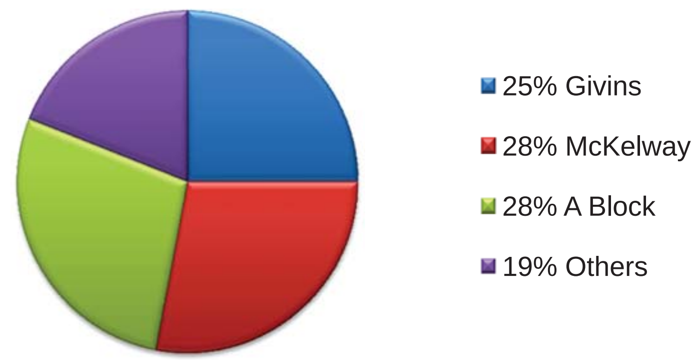
TETRA TECH

Monthly Energy Use

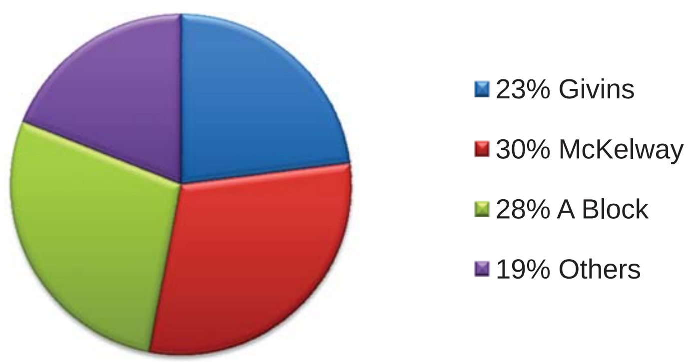
July 2009



August 2009



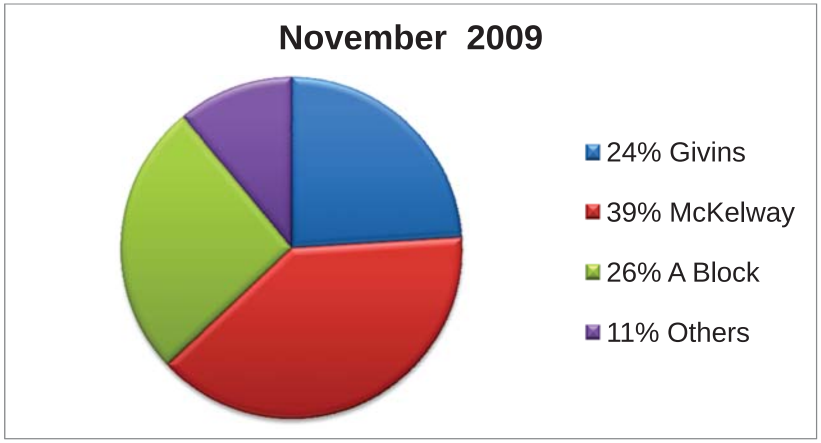
September 2009

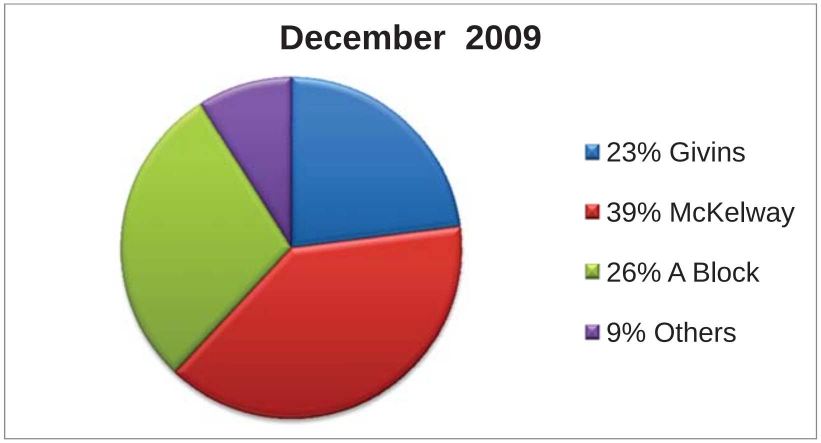


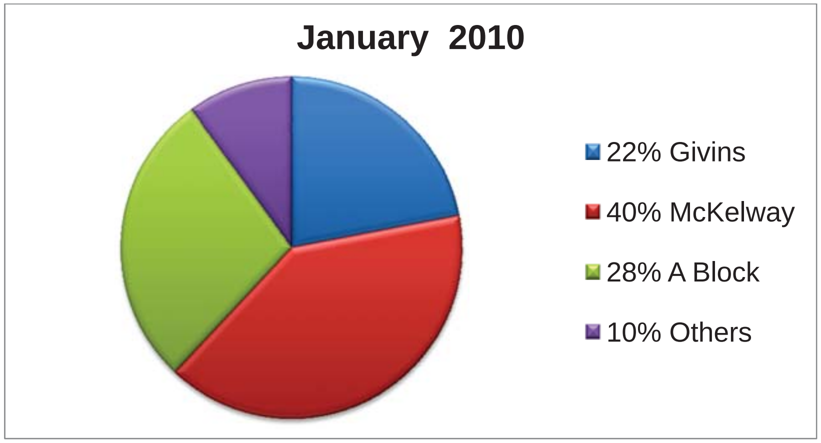
October 2009

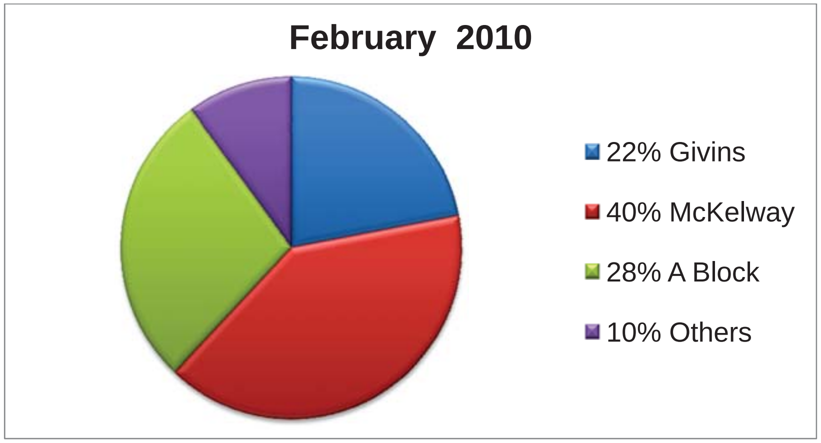
No Data

Monthly Energy Use



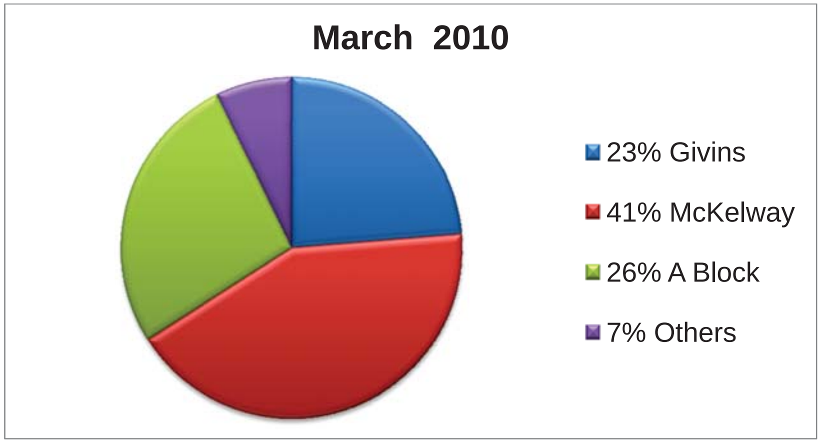


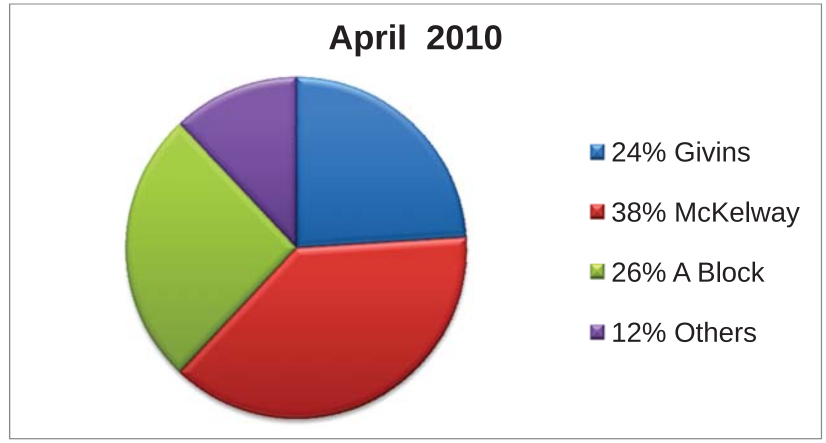


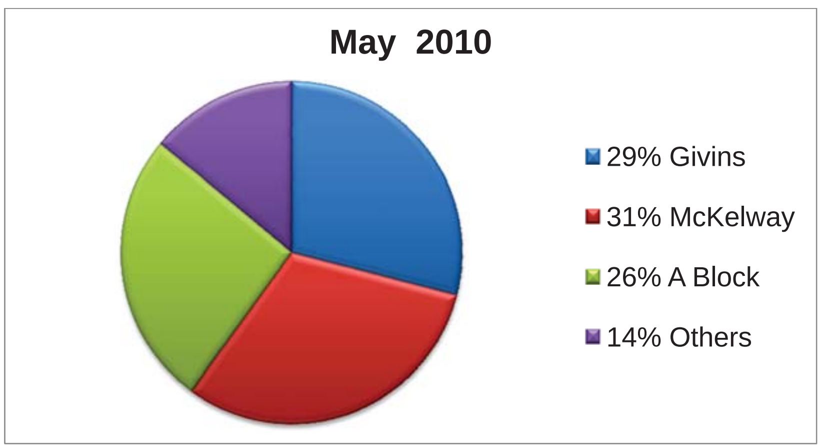


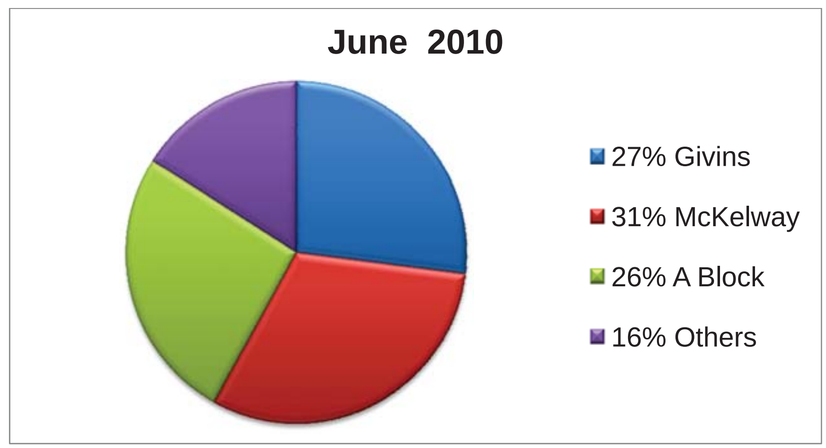
TETRA TECH

Monthly Energy Use

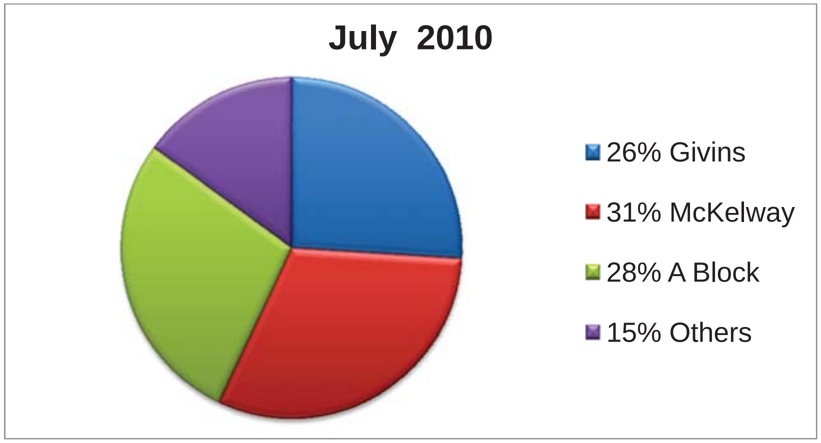


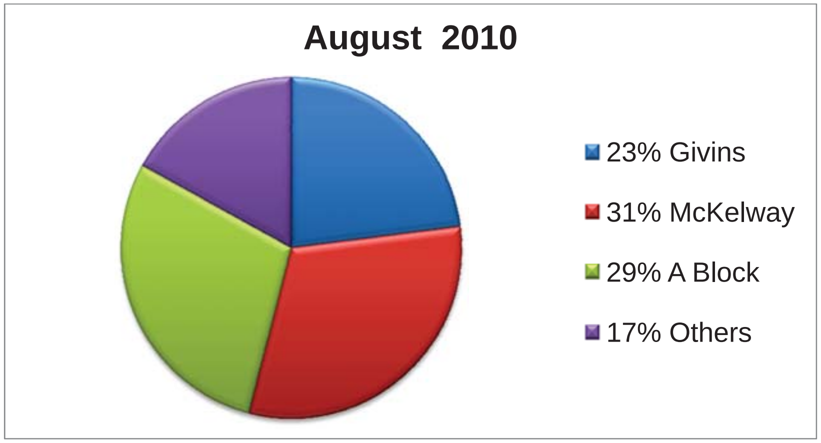


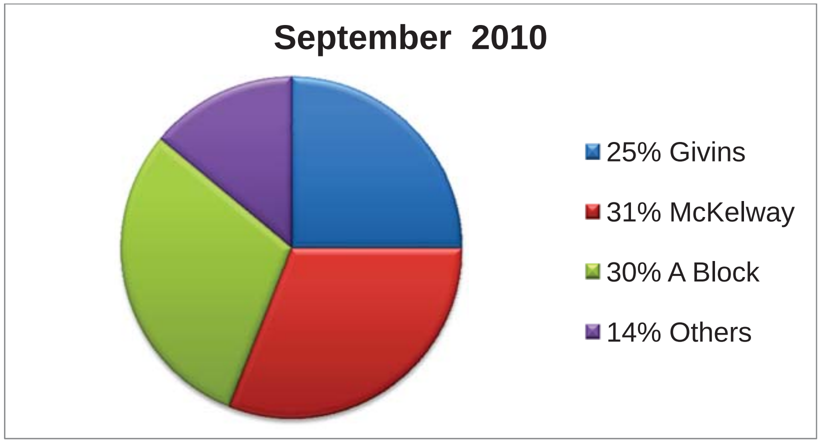




Monthly Energy Use

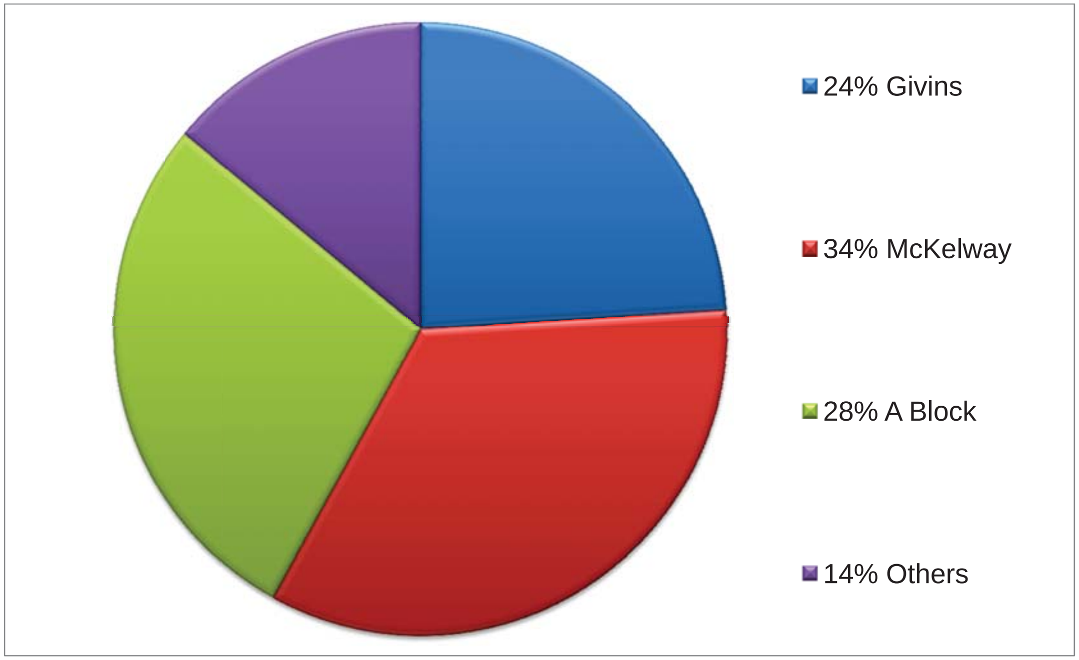






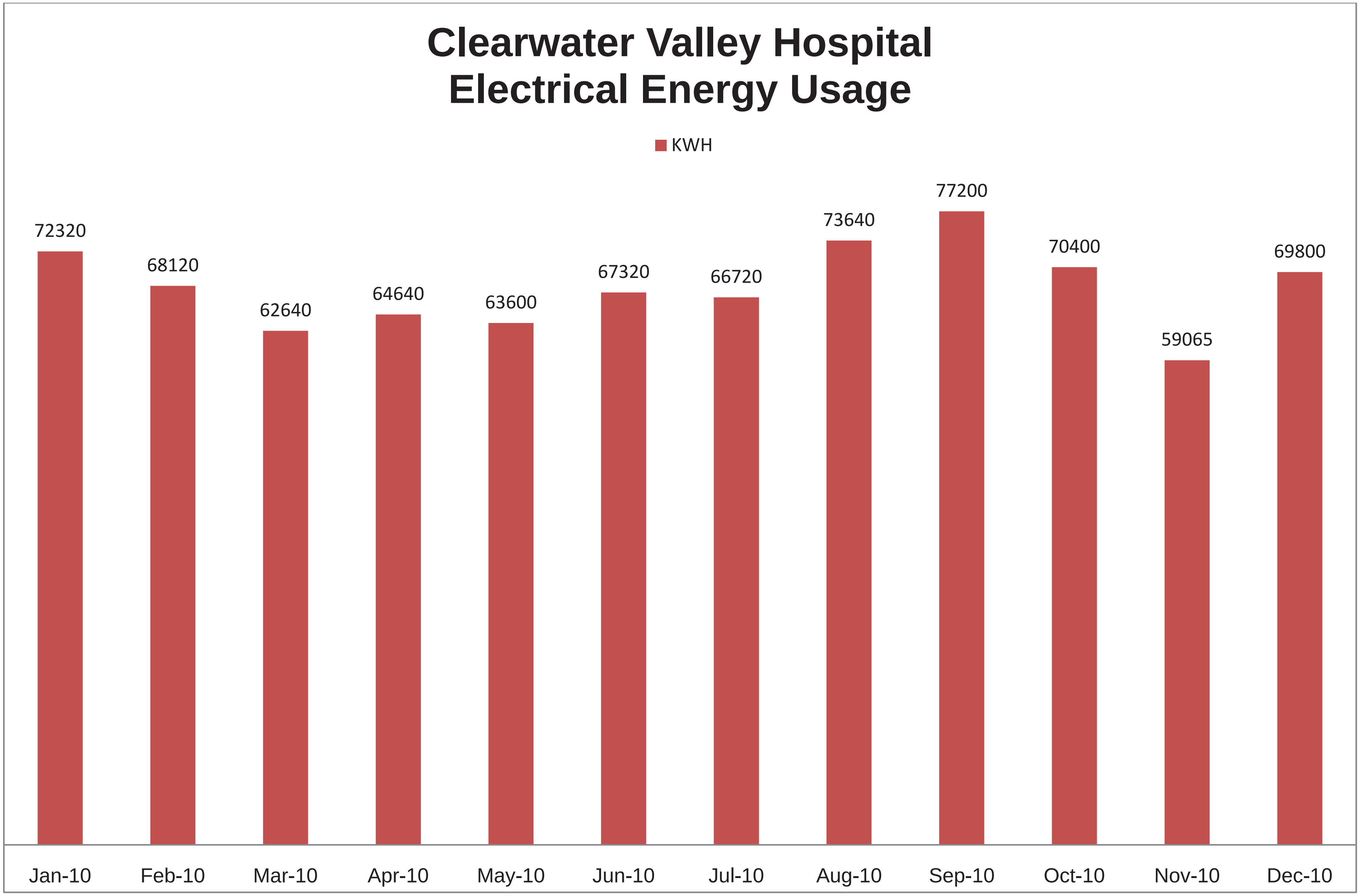
TETRA TECH

14 Month Average



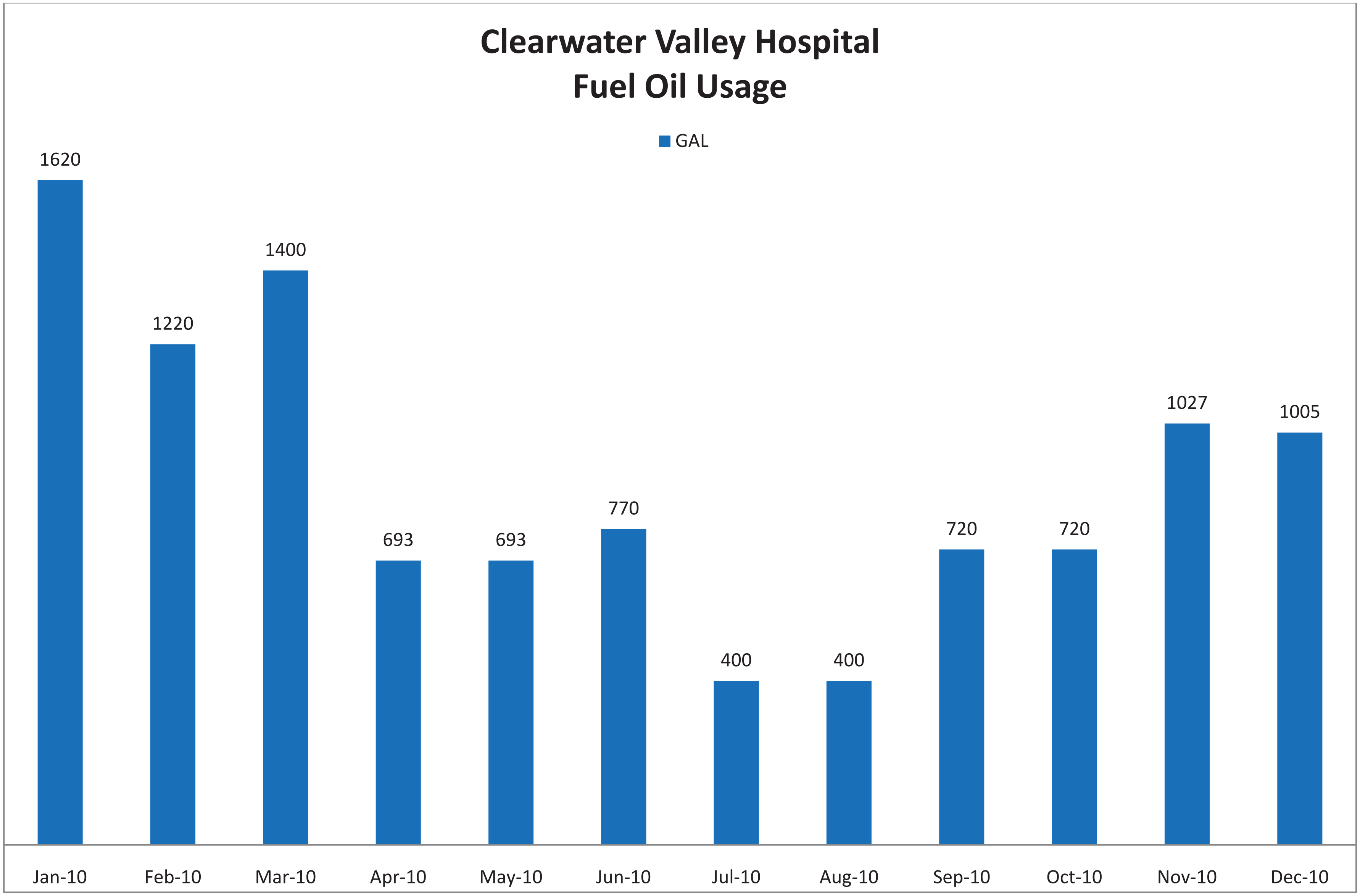
APPENDIX B

CLEARWATER VALLEY HOSPITAL ENERGY AUDIT



Average Monthly Usage = 67955 KWH
January peak could be due to Christmas Lighting and shorter daylight hours.
August, September peak due to Air conditioning?
Average Price per KWH = $0.135
Question: Does this include the hospital and the clinic?

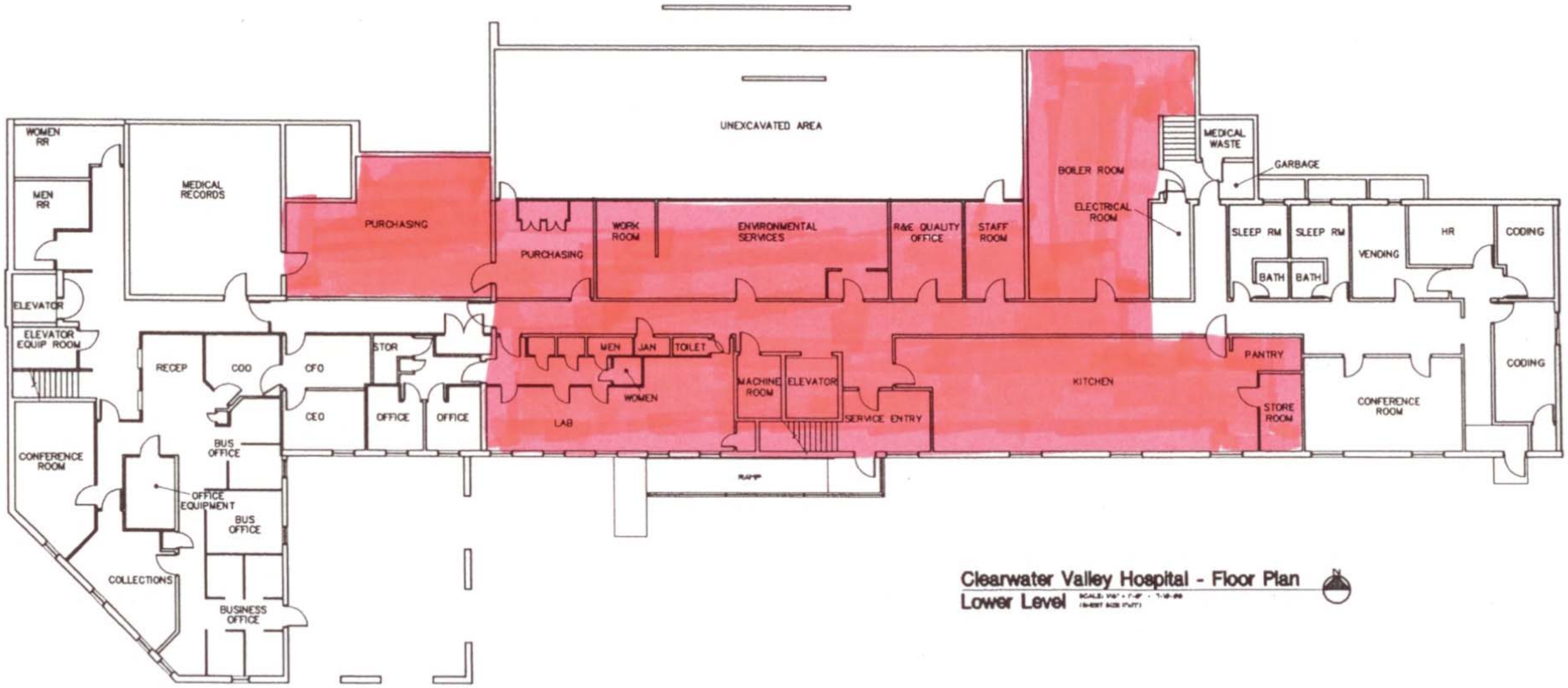
TETRA TECH



Average Monthly Usage = 890 GAL
November, December, January, February, & March = Heating Season.
July & August = Hot water for kitchen, laundry, rest rooms, & showers?
2010 Average price per gallon = $2.615
Fuel oil used in areas of hospital only.
Heating for clinic unknown? Electric?

TETRA TECH

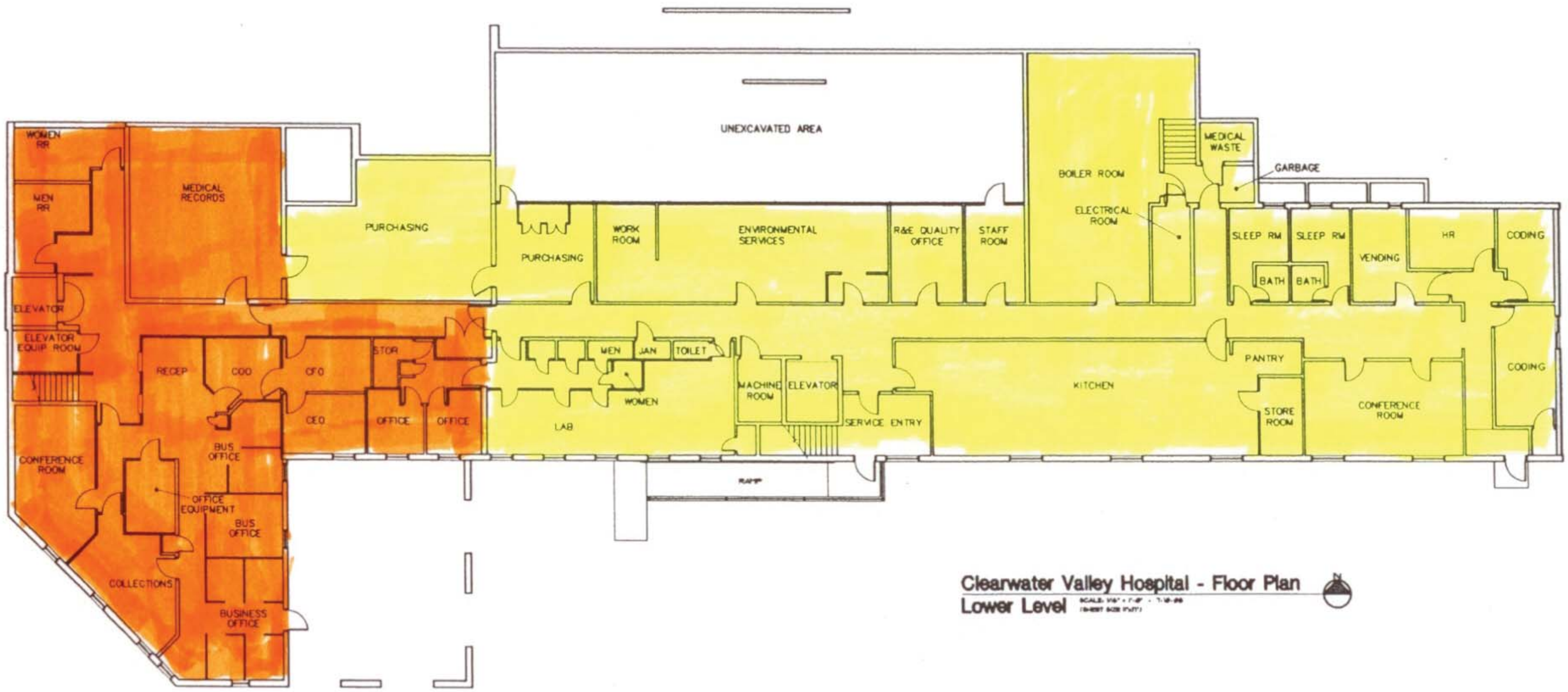
Fuel Oil Heating



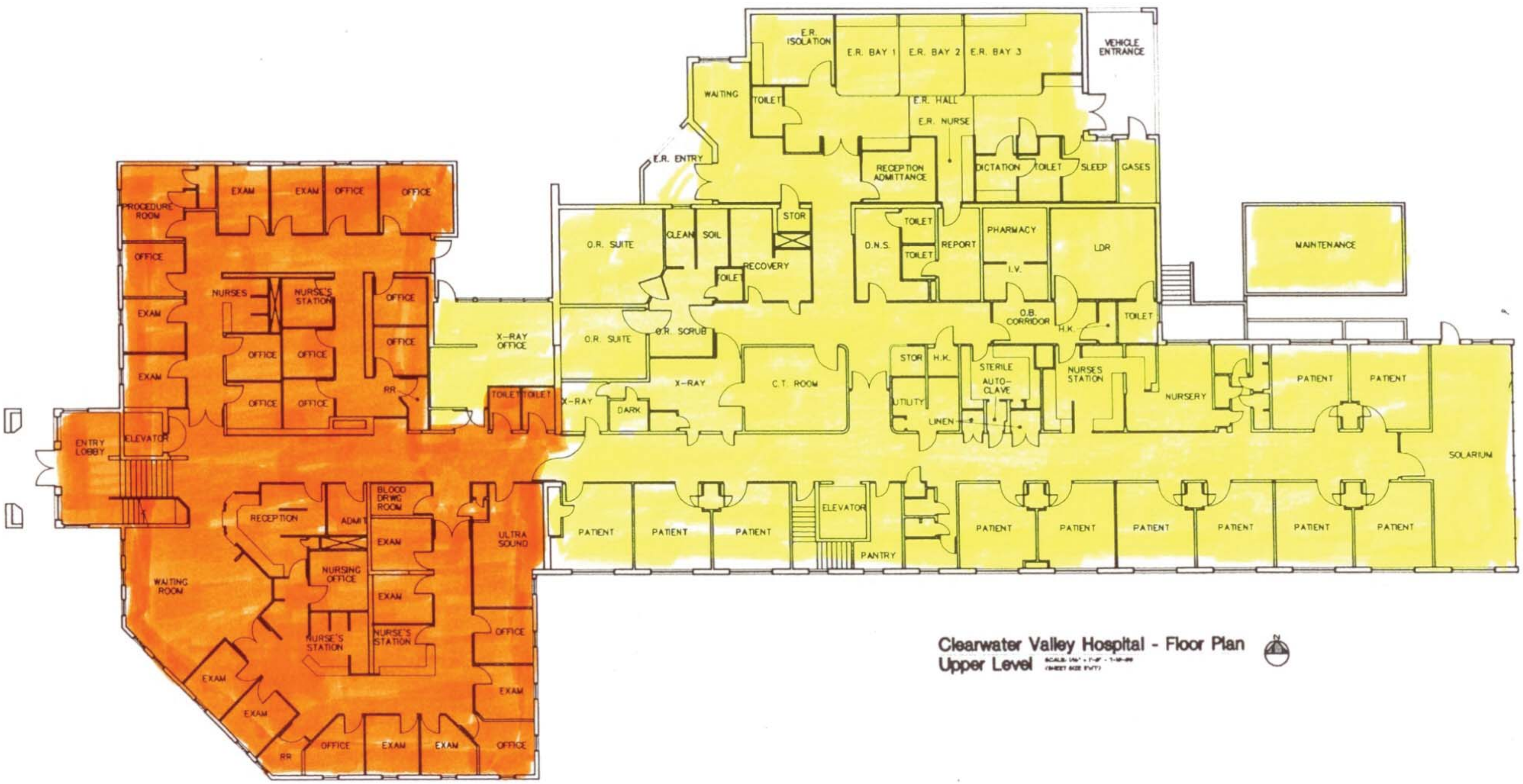
Clearwater Valley Hospital - Floor Plan
Lower Level

TETRA TECH

Clinic Lower Floor - 6797 sq. ft.
Hospital Lower Floor - 6932 sq. ft.



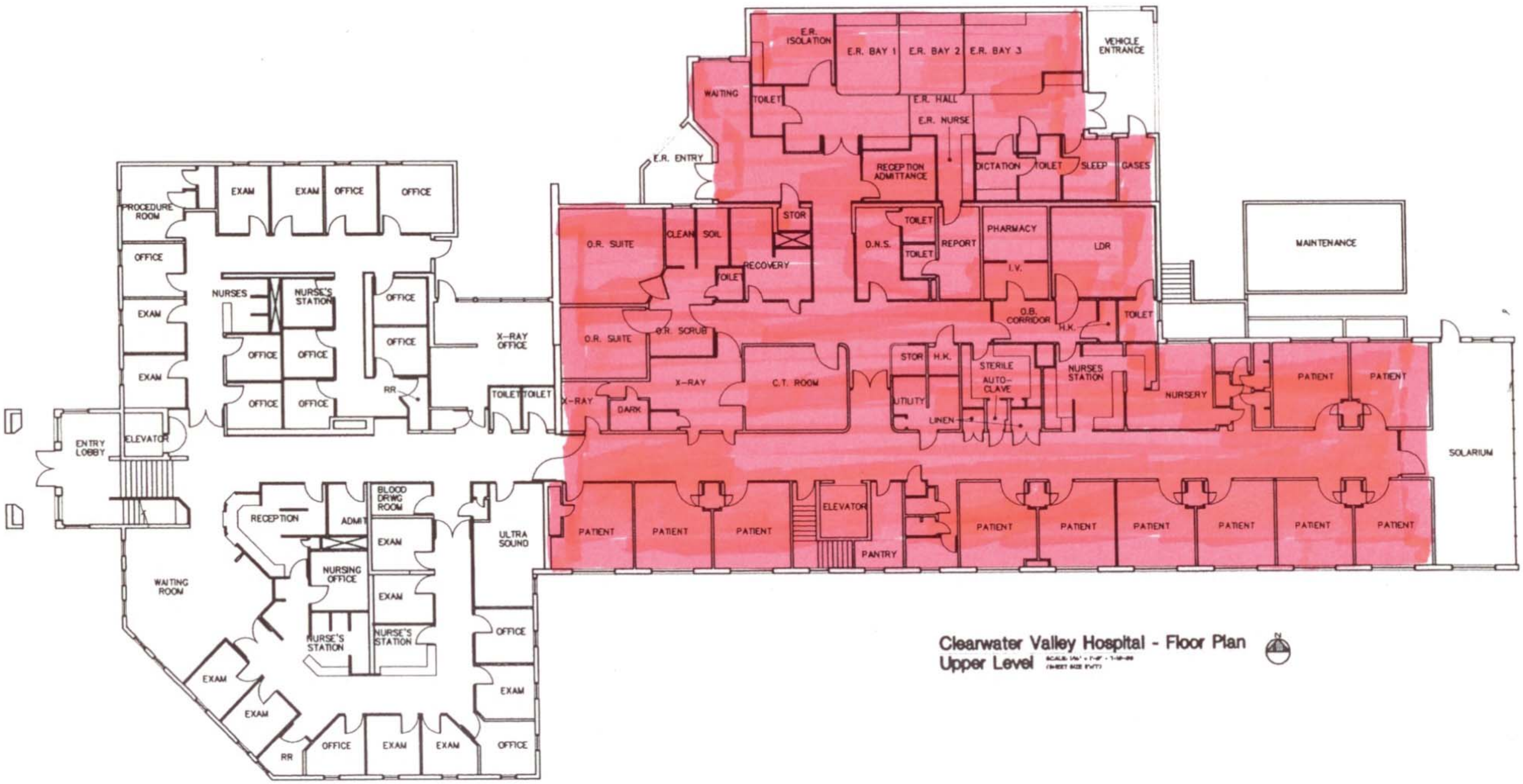
Clinic Main Floor — 7,011 sq ft
Hospital Main Floor — 11,021 sq ft



Clearwater Valley Hospital - Floor Plan
Upper Level

TETRA TECH

Fuel Oil Heating

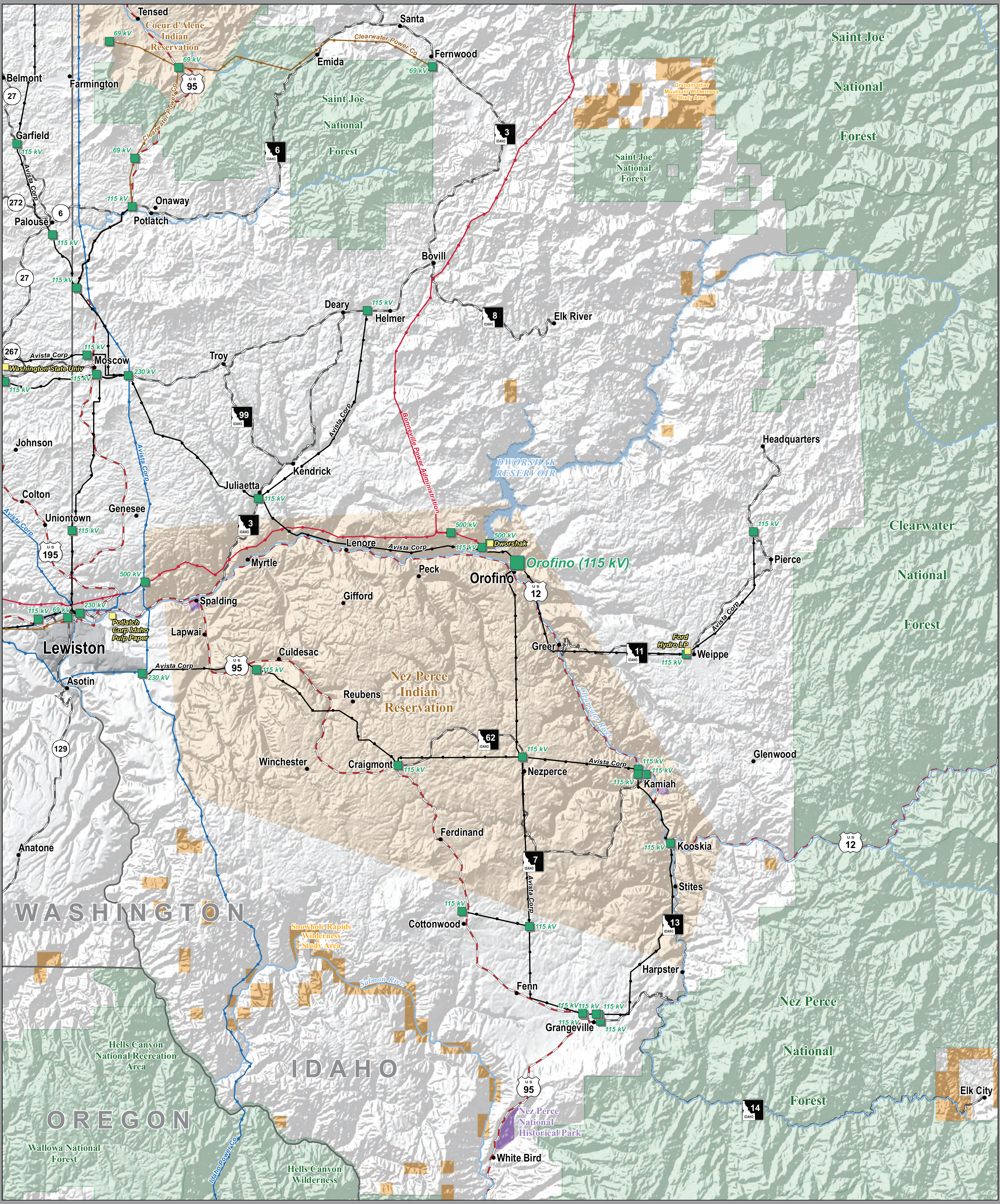


Clearwater Valley Hospital - Floor Plan
Upper Level

APPENDIX C

TRANSMISSION INFRASTRUCTURE

Clearwater Regional Electrical Transmission



Legend

Federal Jurisdiction

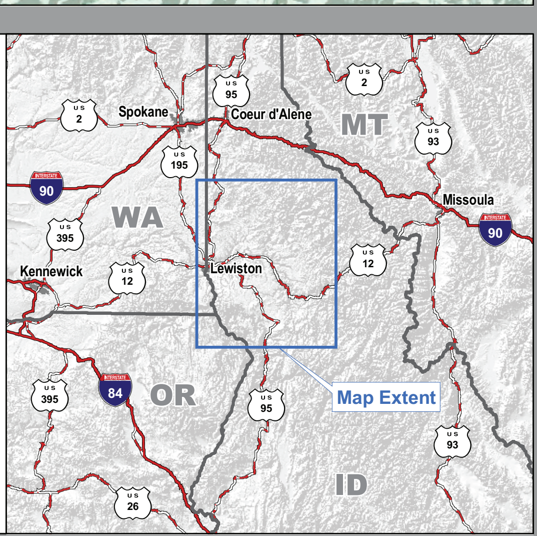
- Bureau of Indian Affairs
- Bureau of Land Management
- U.S. Forest Service
- National Park Service

Transmission

- Power Plant
- Substation
- 69kV Transmission Line
- 115kV Transmission Line
- 230kV Transmission Line
- 500kV Transmission Line

TETRA TECH EC, INC.

0 5 10 Miles
Scale is 1:261,834 when printed at 22x34 inches



Source: BTS, ESRI, and Ventyx Path: G:\GISLibrary\Marketing\Layouts\Orofino_Potlatch\map_1.mxd Last modified: 11-23-2010

Orofino Substation and Local Electrical Distribution

Legend

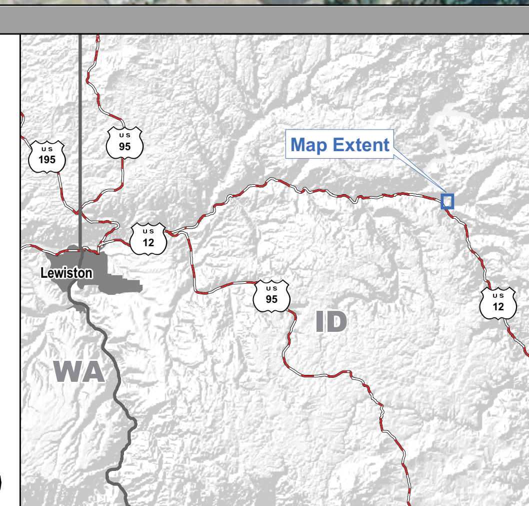
Transmission

- Substation
- 115kV Transmission Line
- Site Delineation
- Local Facility

TETRA TECH EC, INC.

0 300 600 Feet

Scale is 1:3,362 when printed at 22x34 inches



Source: BTS, ESRI, and Ventyx Path: G:\GISLibrary\Marketing\Layouts\Orofino_Potlatch\map_2.mxd Last modified: 11-24-2010

APPENDIX D
1MW CHP PROFORMA

Clearwater County - 1MW CHP
Financial Assumptions

Nameplate Plant Scale (raw tons feedstock/year)	6,672
Operating Days Per Year	330

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$5,596,625
Site Development	$402,771
Rail	$0
Barge Unloading	$0
Additional Feedstock Storage	$0
Contingency	$1,479,000
Total Engineering and Construction Cost	$7,478,396
Development and Start-up Costs	
Inventory - Feedstock	$15,000
Inventory - Chemicals, Yeast, Denaturant	$0
Inventory - Spare Parts	$150,000
Start-up Costs	$7,400
Land	$40,000
Fire Protection & Potable Water	$57,375
Building & Office Equipment	$276,417
Insurance & Performance Bond	$0
Rolling Stock & Shop Equipment	$70,000
Organizational Costs & Permits	$300,000
Capitalized Interest & Financing Costs	$452,080
Working Capital/Risk Management	$27,000
Total Development Costs	$1,395,272
TOTAL USES	**$8,873,668**

SOURCE OF FUNDS:			
Senior Debt			
Principal	$5,324,201	60.00%	
Interest Rate	4.49%	fixed	
Lender and Misc. Fees	$0	0.000%	
Placement Fees	$53,242	1.000%	
Amortization Period	30	years	
Cash Sweep	0.000%		
Subordinate Debt			
Principal	$0	0.00%	
Interest Rate	0.00%	interest only	
Lender Fees	$0	0.646%	
Placement Fees	$0	0.000%	
Amortization Period	10	years	
Equity Investment			
Total Equity Amount	$1,549,467	17.46%	
Placement Fees	$0	0.000%	
Common Equity	$1,549,467	100.000%	
Preferred Equity	$0	0.000%	
Grants			
Amount	$2,000,000	22.54%	
TOTAL SOURCES	**$8,873,668**		

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	0.00%
Operating Line Interest	0.00%
State Producer Payment	
Producer payment, $/gal	$0
Estimated annual payment	$0
Incentive duration, years	0
Other Incentive Payments	
Small Producer Tax Credit	0
ITC / PTC Tax Credit	$0.00

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	50.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Finished Products	14		0
Chemicals		15	0
Feedstock		10	30
Utilities		15	

Clearwater County - 1MW CHP

Production Assumptions

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
Feedstock Inputs											
Total Feedstock Purchase (raw ton/year)	6,444	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	
Feedstock Usage (raw ton/year)	5,838	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	6,672	
Feedstock Moisture Content (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	
Feedstock LHV (btu/lb)	6,268	6,268	6,268	6,268	6,268	6,268	6,268	6,268	6,268	6,268	
Feedstock Usage (dry ton/year)	4,086	4,670	4,670	4,670	4,670	4,670	4,670	4,670	4,670	4,670	
Delivered Feedstock Price ($/raw ton)	$26.78	$27.23	$27.72	$28.17	$28.66	$29.04	$29.41	$29.75	$30.18	$30.52	Index
Delivered Price ($/dry ton)	$38.25	$38.90	$39.60	$40.24	$40.94	$41.48	$42.01	$42.50	$43.11	$43.61	Index
Heat & Power											
Co-generation Efficiency (%)	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	
Heat Recovery (%)	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	
Total Raw Feedstock Energy Content (MMBTU/yr)	73,180	83,634	83,634	83,634	83,634	83,634	83,634	83,634	83,634	83,634	
Electricity Production (kWh/yr)	6,218,022	7,106,311	7,106,311	7,106,311	7,106,311	7,106,311	7,106,311	7,106,311	7,106,311	7,106,311	
Electricity Available for Sale (kWh/yr)	5,285,318	6,040,364	6,040,364	6,040,364	6,040,364	6,040,364	6,040,364	6,040,364	6,040,364	6,040,364	
Electricity Sale Price ($/kWh)	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	0.00%
Thermal Energy Production (MMBTU/yr)	19,354	33,264	33,264	33,264	33,264	33,264	33,264	33,264	33,264	33,264	
Thermal Energy Available for Sale (MMBTU/yr)	19,354	21,113	21,113	21,113	21,113	21,113	21,113	21,113	21,113	21,113	
Thermal Energy Sale Price ($/MMBTU)	$19.0448	$19.3305	$19.6204	$19.9147	$20.2135	$20.5167	$20.8244	$21.1368	$21.4538	$21.7756	1.50%
Utility Usage											
Thermal Energy Required (BTU/raw ton feedstock)	511,200	511,200	511,200	511,200	511,200	511,200	511,200	511,200	511,200	511,200	
Thermal Energy Generated (BTU/raw ton)	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	
Makeup Energy Needed (BTU/raw ton)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Price ($/MMBTU)	6.95	7.02	7.13	7.28	7.47	7.64	7.52	7.32	7.39	7.49	
Annual Thermal Energy Use (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Required (kWh/raw ton feedstock)	159.8	159.8	159.8	159.8	159.8	159.8	159.8	159.8	159.8	159.8	
Electricity Generated (kWh/raw ton)	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	
Makeup Electricity Needed (kWh/raw ton)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Electricity Price ($/kWh)	0.0548	0.0550	0.0552	0.0556	0.0561	0.0568	0.0572	0.0571	0.0573	0.0577	
Annual Electricity Use (kWh/year)	0	0	0	0	0	0	0	0	0	0	
Electricity Demand (MW)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Makeup Water Use (1000 gal/raw ton)	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	
Makeup Water Price ($/1000 gallons)	1.25	1.26	1.28	1.29	1.30	1.31	1.33	1.34	1.35	1.37	1.00%
Makeup Water Flow Rate (gpm)	1	1	1	1	1	1	1	1	1	1	
Daily Makeup Water (gpd)	1,661	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	
Waste Effluent Flow Rate (1000 gal/raw ton)	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	
Waste Effluent Price ($/1000 gallons)	1.50	1.52	1.53	1.55	1.56	1.58	1.59	1.61	1.62	1.64	1.00%
Waste Effluent Flow Rate (gpm)	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	
Daily Waste Effluent (gpd)	166	190	190	190	190	190	190	190	190	190	
Number of Employees	3	3	3	3	3	3	3	3	3	3	
Average Salary Including Benefits	$57,708	$59,151	$60,630	$62,146	$63,699	$65,292	$66,924	$68,597	$70,312	$72,070	2.50%
Maintenance Materials & Services (% of Capital Equip	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Property,	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Clearwater County - 1MW CHP
Proforma Balance Sheet

	Construction (Year 0) 2013	1st Year Operations 2014	2nd Year Operations 2015	3rd Year Operations 2016	4th Year Operations 2017	5th Year Operations 2018	6th Year Operations 2019	7th Year Operations 2020	8th Year Operations 2021	9th Year Operations 2022	10th Year Operations 2023
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	231,729	332,194	430,763	526,185	618,084	707,186	793,477	877,083	957,323	1,034,783
Inventories											
Feedstock	0	14,210	16,513	16,813	17,083	17,380	17,611	17,835	18,043	18,304	18,513
Finished Product Inventory	0	0	0	0	0	0	0	0	0	0	0
Spare Parts	0	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Total Inventories	0	164,210	166,513	166,813	167,083	167,380	167,611	167,835	168,043	168,304	168,513
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	395,940	498,707	597,576	693,268	785,463	874,797	961,312	1,045,126	1,125,627	1,203,296
Land	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	6,990,969	7,992,188	7,992,188	7,992,188	7,992,188	7,992,188	7,992,188	7,992,188	7,992,188	7,992,188	7,992,188
Less Accumulated Depreciation & Amortization	0	75,386	133,971	190,203	244,632	297,612	351,445	401,941	451,603	500,488	548,647
Net Property, Plant & Equipment	6,990,969	7,916,801	7,858,217	7,801,984	7,747,556	7,694,576	7,640,742	7,590,247	7,540,584	7,491,700	7,443,541
Capitalized Fees & Interest	121,445	160,275	144,248	128,220	112,193	96,165	80,138	64,110	48,083	32,055	16,028
Total Assets	7,152,414	8,513,016	8,541,172	8,567,781	8,593,017	8,616,204	8,635,677	8,655,669	8,673,793	8,689,382	8,702,864
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	4,999	5,545	5,645	5,735	5,835	5,912	5,987	6,057	6,145	6,214
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	90,239	94,359	98,668	103,173	107,884	112,810	117,961	123,348	128,980	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	95,237	99,904	104,313	108,908	113,719	118,722	123,949	129,405	135,124	6,214
Senior Debt (excluding current maturities)	3,939,243	5,147,664	5,053,305	4,954,637	4,851,464	4,743,580	4,630,770	4,512,809	4,389,461	4,260,482	4,260,482
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	3,939,243	5,242,901	5,153,209	5,058,950	4,960,373	4,857,299	4,749,493	4,636,758	4,518,866	4,395,606	4,266,696
Capital Units & Equities											
Common Equity	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467	1,549,467
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(336,296)	(279,352)	(161,504)	(40,636)	83,177	209,438	336,717	469,444	605,460	744,309	886,701
Total Capital Shares & Equities	3,213,171	3,270,115	3,387,963	3,508,831	3,632,644	3,758,905	3,886,184	4,018,911	4,154,927	4,293,776	4,436,168
Total Liabilities & Equities	7,152,414	8,513,016	8,541,172	8,567,781	8,593,017	8,616,204	8,635,677	8,655,669	8,673,793	8,689,382	8,702,864

Clearwater County - 1MW CHP
Proforma Income Statement

	Construction (Year 0) 2013	1st Year Operations 2014	2nd Year Operations 2015	3rd Year Operations 2016	4th Year Operations 2017	5th Year Operations 2018	6th Year Operations 2019	7th Year Operations 2020	8th Year Operations 2021	9th Year Operations 2022	10th Year Operations 2023
Revenue											
Heat	0	368,585	408,124	414,246	420,460	426,767	433,168	439,666	446,261	452,955	459,749
Power	0	435,510	497,726	497,726	497,726	497,726	497,726	497,726	497,726	497,726	497,726
Total Revenue	0	804,095	905,850	911,972	918,186	924,493	930,894	937,392	943,987	950,681	957,475
Production & Operating Expenses											
Feedstocks	0	156,314	181,643	184,947	187,916	191,176	193,719	196,185	198,476	201,345	203,639
Chemicals	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0
Electricity	0	0	0	0	0	0	0	0	0	0	0
Makeup Water	0	685	791	799	807	815	823	831	840	848	856
Wastewater Disposal	0	82	95	96	97	98	99	100	101	102	103
Direct Labor & Benefits	28,854	173,125	177,453	181,889	186,437	191,098	195,875	200,772	205,791	210,936	216,209
Total Production Costs	28,854	330,207	359,982	367,731	375,256	383,186	390,515	397,888	405,207	413,231	420,808
Gross Profit	(28,854)	473,889	545,868	544,241	542,930	541,307	540,379	539,504	538,779	537,450	536,667
Administrative & Operating Expenses											
Maintenance Materials & Services	0	97,941	113,611	115,316	117,045	118,801	120,583	122,392	124,228	126,091	127,982
Repairs & Maintenance - Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Consulting, Management and Bank Fees	53,242	0	0	0	0	0	0	0	0	0	0
Property Taxes & Insurance	0	0	0	0	0	0	0	0	0	0	0
Admin. Salaries, Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Engineering and Organizational Costs	250,000	0	0	0	0	0	0	0	0	0	0
Office/Lab Supplies & Expenses	4,200	6,000	6,120	6,242	6,367	6,495	6,624	6,757	6,892	7,030	7,171
Travel, Training & Miscellaneous	0	0	0	0	0	0	0	0	0	0	0
Total Administrative & Operating Expenses	307,442	103,941	119,731	121,558	123,413	125,296	127,208	129,149	131,120	133,121	135,153
EBITDA	(336,296)	369,948	426,137	422,683	419,517	416,011	413,171	410,355	407,659	404,329	401,514
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	237,617	233,677	229,556	225,248	220,742	216,031	211,105	205,954	200,568	194,935
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	75,386	74,612	72,260	70,456	69,008	69,861	66,523	65,690	64,912	64,187
Pre-Tax Income	(336,296)	56,944	117,848	120,867	123,813	126,261	127,279	132,727	136,016	138,849	142,392
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(336,296)	56,944	117,848	120,867	123,813	126,261	127,279	132,727	136,016	138,849	142,392
Pre-Tax Return on Investment	-4.9%	0.8%	1.7%	1.8%	1.8%	1.8%	1.9%	1.9%	2.0%	2.0%	2.1%
11-Year Average Annual Pre-Tax ROI	1.2%										

Clearwater County - 1MW CHP
Proforma Statements of Cash Flows

	Construction (Year 0) 2013	1st Year Operations 2014	2nd Year Operations 2015	3rd Year Operations 2016	4th Year Operations 2017	5th Year Operations 2018	6th Year Operations 2019	7th Year Operations 2020	8th Year Operations 2021	9th Year Operations 2022	10th Year Operations 2023
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(336,296)	56,944	117,848	120,867	123,813	126,261	127,279	132,727	136,016	138,849	142,392
Non cash charges to operations											
Depreciation & Amortization	0	75,386	74,612	72,260	70,456	69,008	69,861	66,523	65,690	64,912	64,187
Total cash provided by (used in)	(336,296)	132,331	192,460	193,127	194,269	195,269	197,140	199,250	201,706	203,761	206,579
Changes in non-cash working capital balances											
Accounts Receivable	0	0	0	0	0	0	0	0	0	0	0
Inventories	0	164,210	2,303	300	270	296	231	224	208	261	209
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(4,999)	(546)	(101)	(90)	(99)	(77)	(75)	(70)	(87)	(70)
Total changes in capital balances	0	159,211	1,757	200	180	197	154	149	138	173	139
Investing Activities											
Land Purchase	40,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	6,990,969	1,001,219	0	0	0	0	0	0	0	0	0
Capitalized Fees & Interest	121,445	38,830	0	0	0	0	0	0	0	0	0
Total Investing activities	7,152,414	1,040,049	0	0	0	0	0	0	0	0	0
Financing Activities											
Senior Debt Advances	3,939,243	1,384,957	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(86,298)	(90,239)	(94,359)	(98,668)	(103,173)	(107,884)	(112,810)	(117,961)	(123,348)	(128,980)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	1,549,467	0	0	0	0	0	0	0	0	0	0
Grants	2,000,000	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	231,729	100,465	98,568	95,422	91,899	89,102	86,291	83,606	80,240	77,460
Cash (Indebtedness), Beginning of Year	0	0	231,729	332,194	430,763	526,185	618,084	707,186	793,477	877,083	957,323
Cash (Bank Indebtedness), End of Year	0	231,729	332,194	430,763	526,185	618,084	707,186	793,477	877,083	957,323	1,034,783
30-Year IRR	-5.4%										

Clearwater County - 1MW CHP

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		369,948	426,137	422,683	419,517	416,011	413,171	410,355	407,659	404,329	401,514
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(159,211)	(1,757)	(200)	(180)	(197)	(154)	(149)	(138)	(173)	(139)
Investing Activities (Capital Expenditures)		(1,040,049)	0	0	0	0	0	0	0	0	0
Senior Debt Advances		1,384,957	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		555,645	424,380	422,483	419,337	415,814	413,018	410,206	407,521	404,155	401,375
Senior Debt P&I Payment		323,915	323,915	323,915	323,915	323,915	323,915	323,915	323,915	323,915	323,915
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		1.72	1.31	1.30	1.29	1.28	1.28	1.27	1.26	1.25	1.24
10-year Average Debt Coverage Ratio	**1.32**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	20 year SLN	253,626	253,626	253,626	253,626	253,626	253,626	253,626	253,626	253,626	253,626
Minor process equipment	20 year SLN	55,947	55,947	55,947	55,947	55,947	55,947	55,947	55,947	55,947	55,947
Process buildings	30 year DDB	88,991	83,059	77,521	72,353	67,530	63,028	58,826	54,904	51,244	47,828
Vehicles	5 year DDB	14,000	16,800	10,080	6,048	3,629	14,000	0	0	0	0
Office building	30 year DDB	18,428	17,199	16,053	14,982	13,984	13,051	12,181	11,369	10,611	9,904
Office equipment	5 year DDB	0	0	0	0	0	0	0	0	0	0
Start-up cost	20 year DDB	740	666	599	539	486	437	393	354	319	287
Annual capital expenditures	10 year SLN	0	0	0	0	0	0	0	0	0	0
Total Depreciation		431,732	427,296	413,826	403,496	395,200	400,089	380,973	376,200	371,746	367,591

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

APPENDIX E

2MW CHP PROFORMA

Clearwater County - 2MW CHP
Financial Assumptions

Nameplate Plant Scale (raw tons feedstock/year)	13,343
Operating Days Per Year	330

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$7,774,200
Site Development	$608,600
Rail	$0
Barge Unloading	$0
Additional Feedstock Storage	$0
Contingency	$2,072,000
Total Engineering and Construction Cost	$10,454,800
Development and Start-up Costs	
Inventory - Feedstock	$30,000
Inventory - Chemicals, Yeast, Denaturant	$0
Inventory - Spare Parts	$150,000
Start-up Costs	$9,600
Land	$60,000
Fire Protection & Potable Water	$93,320
Building & Office Equipment	$439,610
Insurance & Performance Bond	$0
Rolling Stock & Shop Equipment	$70,000
Organizational Costs & Permits	$300,000
Capitalized Interest & Financing Costs	$777,140
Working Capital/Risk Management	$50,000
Total Development Costs	$1,979,670
TOTAL USES	**$12,434,470**

SOURCE OF FUNDS:			
Senior Debt			
Principal	$7,460,682		60.00%
Interest Rate	4.49%	fixed	
Lender and Misc. Fees	$74,607		1.000%
Placement Fees	$74,607		1.000%
Amortization Period	30	years	
Cash Sweep	0.000%		
Subordinate Debt			
Principal	$0		0.00%
Interest Rate	0.00%		interest only
Lender Fees	$0		0.646%
Placement Fees	$0		0.000%
Amortization Period	10	years	
Equity Investment			
Total Equity Amount	$973,788		7.83%
Placement Fees	$0		0.000%
Common Equity	$973,788		100.000%
Preferred Equity	$0		0.000%
Grants			
Amount	$4,000,000		32.17%
TOTAL SOURCES	**$12,434,470**		

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	0.00%
Operating Line Interest	0.00%
State Producer Payment	
Producer payment, $/gal	$0
Estimated annual payment	$0
Incentive duration, years	0
Other Incentive Payments	
Small Producer Tax Credit	0
ITC / PTC Tax Credit	$0.00

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	50.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Finished Products	14		0
Chemicals		15	0
Feedstock		10	30
Utilities		15	

Clearwater County - 2MW CHP
Production Assumptions

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Year:	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
Feedstock Inputs											
Total Feedstock Purchase (raw ton/year)	12,888	13,343	13,343	13,343	13,343	13,343	13,343	13,343	13,343	13,343	
Feedstock Usage (raw ton/year)	11,675	13,343	13,343	13,343	13,343	13,343	13,343	13,343	13,343	13,343	
Feedstock Moisture Content (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	
Feedstock LHV (btu/lb)	6,268	6,268	6,268	6,268	6,268	6,268	6,268	6,268	6,268	6,268	
Feedstock Usage (dry ton/year)	8,173	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	
Delivered Feedstock Price ($/raw ton)	$26.78	$27.23	$27.72	$28.17	$28.66	$29.04	$29.41	$29.75	$30.18	$30.52	Index
Delivered Price ($/dry ton)	$38.25	$38.90	$39.60	$40.24	$40.94	$41.48	$42.01	$42.50	$43.11	$43.61	Index
Heat & Power											
Co-generation Efficiency (%)	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	29.0%	
Heat Recovery (%)	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%	
Total Raw Feedstock Energy Content (MMBTU/yr)	146,359	167,268	167,268	167,268	167,268	167,268	167,268	167,268	167,268	167,268	
Electricity Production (kWh/yr)	12,436,043	14,212,621	14,212,621	14,212,621	14,212,621	14,212,621	14,212,621	14,212,621	14,212,621	14,212,621	
Electricity Available for Sale (kWh/yr)	10,570,637	12,080,728	12,080,728	12,080,728	12,080,728	12,080,728	12,080,728	12,080,728	12,080,728	12,080,728	
Electricity Sale Price ($/kWh)	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	0.00%
Thermal Energy Production (MMBTU/yr)	19,354	66,528	66,528	66,528	66,528	66,528	66,528	66,528	66,528	66,528	
Thermal Energy Available for Sale (MMBTU/yr)	19,354	21,113	21,113	21,113	21,113	21,113	21,113	21,113	21,113	21,113	
Thermal Energy Sale Price ($/MMBTU)	$19.0448	$19.3305	$19.6204	$19.9147	$20.2135	$20.5167	$20.8244	$21.1368	$21.4538	$21.7756	1.50%
Utility Usage											
Thermal Energy Required (BTU/raw ton feedstock)	511,200	511,200	511,200	511,200	511,200	511,200	511,200	511,200	511,200	511,200	
Thermal Energy Generated (BTU/raw ton)	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	12,536,000	
Makeup Energy Needed (BTU/raw ton)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Price ($/MMBTU)	6.95	7.02	7.13	7.28	7.47	7.64	7.52	7.32	7.39	7.49	
Annual Thermal Energy Use (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Required (kWh/raw ton feedstock)	159.8	159.8	159.8	159.8	159.8	159.8	159.8	159.8	159.8	159.8	
Electricity Generated (kWh/raw ton)	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	1065.2	
Makeup Electricity Needed (kWh/raw ton)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Electricity Price ($/kWh)	0.0548	0.0550	0.0552	0.0556	0.0561	0.0568	0.0572	0.0571	0.0573	0.0577	
Annual Electricity Use (kWh/year)	0	0	0	0	0	0	0	0	0	0	
Electricity Demand (MW)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Makeup Water Use (1000 gal/raw ton)	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	
Makeup Water Price ($/1000 gallons)	1.25	1.26	1.28	1.29	1.30	1.31	1.33	1.34	1.35	1.37	1.00%
Makeup Water Flow Rate (gpm)	2	3	3	3	3	3	3	3	3	3	
Daily Makeup Water (gpd)	3,322	3,797	3,797	3,797	3,797	3,797	3,797	3,797	3,797	3,797	
Waste Effluent Flow Rate (1000 gal/raw ton)	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094	
Waste Effluent Price ($/1000 gallons)	1.50	1.52	1.53	1.55	1.56	1.58	1.59	1.61	1.62	1.64	1.00%
Waste Effluent Flow Rate (gpm)	0.23	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	
Daily Waste Effluent (gpd)	332	380	380	380	380	380	380	380	380	380	
Number of Employees	5	5	5	5	5	5	5	5	5	5	
Average Salary Including Benefits	$58,750	$60,219	$61,724	$63,267	$64,849	$66,470	$68,132	$69,835	$71,581	$73,371	2.50%
Maintenance Materials & Services (% of Capital Equip	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Property,	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Clearwater County - 2MW CHP
Proforma Balance Sheet

	Construction (Year 0) 2013	1st Year Operations 2014	2nd Year Operations 2015	3rd Year Operations 2016	4th Year Operations 2017	5th Year Operations 2018	6th Year Operations 2019	7th Year Operations 2020	8th Year Operations 2021	9th Year Operations 2022	10th Year Operations 2023
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	416,969	533,049	641,723	740,452	828,440	907,101	976,363	1,036,440	1,085,928	1,125,957
Inventories											
Feedstock	0	28,421	33,026	33,627	34,167	34,759	35,222	35,670	36,087	36,608	37,025
Finished Product Inventory	0	0	0	0	0	0	0	0	0	0	0
Spare Parts	0	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Total Inventories	0	178,421	183,026	183,627	184,167	184,759	185,222	185,670	186,087	186,608	187,025
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	595,390	716,075	825,350	924,618	1,013,199	1,092,322	1,162,033	1,222,527	1,272,536	1,312,982
Land	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	9,828,957	11,147,730	11,147,730	11,147,730	11,147,730	11,147,730	11,147,730	11,147,730	11,147,730	11,147,730	11,147,730
Less Accumulated Depreciation & Amortization	0	47,382	64,236	79,805	94,348	108,041	121,929	134,145	145,823	157,000	167,710
Net Property, Plant & Equipment	9,828,957	11,100,348	11,083,494	11,067,925	11,053,382	11,039,689	11,025,801	11,013,585	11,001,907	10,990,730	10,980,020
Capitalized Fees & Interest	245,188	299,331	269,398	239,465	209,532	179,599	149,666	119,732	89,799	59,866	29,933
Total Assets	10,134,145	12,055,069	12,128,967	12,192,740	12,247,532	12,292,487	12,327,789	12,355,351	12,374,233	12,383,132	12,382,936
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	9,998	11,089	11,290	11,471	11,669	11,824	11,975	12,114	12,289	12,429
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	126,449	132,223	138,261	144,574	151,175	158,078	165,296	172,844	180,736	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	136,447	143,312	149,551	156,045	162,845	169,903	177,271	184,958	193,026	12,429
Senior Debt (excluding current maturities)	5,538,122	7,213,305	7,081,082	6,942,821	6,798,247	6,647,072	6,488,994	6,323,697	6,150,853	5,970,117	5,970,117
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	5,538,122	7,349,752	7,224,394	7,092,372	6,954,292	6,809,917	6,658,896	6,500,968	6,335,812	6,163,142	5,982,546
Capital Units & Equities											
Common Equity	973,788	973,788	973,788	973,788	973,788	973,788	973,788	973,788	973,788	973,788	973,788
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(377,765)	(268,471)	(69,215)	126,580	319,452	508,782	695,105	880,595	1,064,633	1,246,202	1,426,602
Total Capital Shares & Equities	4,596,023	4,705,317	4,904,573	5,100,368	5,293,240	5,482,570	5,668,893	5,854,383	6,038,421	6,219,990	6,400,390
Total Liabilities & Equities	10,134,145	12,055,069	12,128,967	12,192,740	12,247,532	12,292,487	12,327,789	12,355,351	12,374,233	12,383,132	12,382,936

Clearwater County - 2MW CHP
Proforma Income Statement

	Construction (Year 0) 2013	1st Year Operations 2014	2nd Year Operations 2015	3rd Year Operations 2016	4th Year Operations 2017	5th Year Operations 2018	6th Year Operations 2019	7th Year Operations 2020	8th Year Operations 2021	9th Year Operations 2022	10th Year Operations 2023
Revenue											
Heat	0	368,585	408,124	414,246	420,460	426,767	433,168	439,666	446,261	452,955	459,749
Power	0	871,020	995,452	995,452	995,452	995,452	995,452	995,452	995,452	995,452	995,452
Total Revenue	0	1,239,606	1,403,576	1,409,698	1,415,912	1,422,219	1,428,620	1,435,118	1,441,713	1,448,407	1,455,201
Production & Operating Expenses											
Feedstocks	0	312,629	363,286	369,893	375,832	382,352	387,437	392,370	396,952	402,690	407,279
Chemicals	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0
Electricity	0	0	0	0	0	0	0	0	0	0	0
Makeup Water	0	1,370	1,582	1,598	1,614	1,630	1,646	1,662	1,679	1,696	1,713
Wastewater Disposal	0	164	190	192	194	196	198	199	201	204	206
Direct Labor & Benefits	37,604	225,625	231,266	237,047	242,973	249,048	255,274	261,656	268,197	274,902	281,775
Total Production Costs	37,604	539,788	596,323	608,730	620,613	633,225	644,555	655,888	667,030	679,492	690,972
Gross Profit	(37,604)	699,817	807,253	800,968	795,299	788,994	784,066	779,230	774,683	768,915	764,229
Administrative & Operating Expenses											
Maintenance Materials & Services	0	136,049	157,816	160,184	162,586	165,025	167,500	170,013	172,563	175,152	177,779
Repairs & Maintenance - Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Consulting, Management and Bank Fees	74,607	0	0	0	0	0	0	0	0	0	0
Property Taxes & Insurance	0	0	0	0	0	0	0	0	0	0	0
Admin. Salaries, Wages & Benefits	11,354	68,125	69,828	71,574	73,363	75,197	77,077	79,004	80,979	83,004	85,079
Engineering and Organizational Costs	250,000	0	0	0	0	0	0	0	0	0	0
Office/Lab Supplies & Expenses	4,200	6,000	6,120	6,242	6,367	6,495	6,624	6,757	6,892	7,030	7,171
Travel, Training & Miscellaneous	0	0	0	0	0	0	0	0	0	0	0
Total Administrative & Operating Expenses	340,161	210,174	233,764	238,000	242,317	246,717	251,202	255,774	260,434	265,185	270,028
EBITDA	(377,765)	489,644	573,489	562,968	552,983	542,277	532,863	523,456	514,249	503,730	494,201
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	332,967	327,446	321,672	315,634	309,321	302,720	295,817	288,599	281,051	273,158
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	47,382	46,787	45,501	44,477	43,626	43,821	42,149	41,612	41,110	40,643
Pre-Tax Income	(377,765)	109,294	199,256	195,795	192,872	189,330	186,323	185,490	184,038	181,569	180,400
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(377,765)	109,294	199,256	195,795	192,872	189,330	186,323	185,490	184,038	181,569	180,400
Pre-Tax Return on Investment	-4.5%	1.3%	2.4%	2.3%	2.3%	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%
11-Year Average Annual Pre-Tax ROI	1.5%										

Clearwater County - 2MW CHP
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Operating Activities											
Net Earnings (loss)	(377,765)	109,294	199,256	195,795	192,872	189,330	186,323	185,490	184,038	181,569	180,400
Non cash charges to operations											
Depreciation & Amortization	0	47,382	46,787	45,501	44,477	43,626	43,821	42,149	41,612	41,110	40,643
Total cash provided by (used in)	(377,765)	156,676	246,043	241,297	237,348	232,956	230,144	227,639	225,650	222,679	221,043
Changes in non-cash working capital balances											
Accounts Receivable	0	0	0	0	0	0	0	0	0	0	0
Inventories	0	178,421	4,605	601	540	593	462	448	417	522	417
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(9,998)	(1,091)	(201)	(181)	(198)	(155)	(150)	(140)	(175)	(140)
Total changes in capital balances	0	168,423	3,514	400	359	394	307	298	277	347	277
Investing Activities											
Land Purchase	60,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	9,828,957	1,318,773	0	0	0	0	0	0	0	0	0
Capitalized Fees & Interest	245,188	54,143	0	0	0	0	0	0	0	0	0
Total Investing activities	10,134,145	1,372,916	0	0	0	0	0	0	0	0	0
Financing Activities											
Senior Debt Advances	5,538,122	1,922,560	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(120,928)	(126,449)	(132,223)	(138,261)	(144,574)	(151,175)	(158,078)	(165,296)	(172,844)	(180,736)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	973,788	0	0	0	0	0	0	0	0	0	0
Grants	4,000,000	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	416,969	116,080	108,674	98,729	87,988	78,661	69,262	60,077	49,488	40,029
Cash (Indebtedness), Beginning of Year	0	0	416,969	533,049	641,723	740,452	828,440	907,101	976,363	1,036,440	1,085,928
Cash (Bank Indebtedness), End of Year	0	416,969	533,049	641,723	740,452	828,440	907,101	976,363	1,036,440	1,085,928	1,125,957
30-Year IRR	-6.4%										

Clearwater County - 2MW CHP

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		489,644	573,489	562,968	552,983	542,277	532,863	523,456	514,249	503,730	494,201
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(168,423)	(3,514)	(400)	(359)	(394)	(307)	(298)	(277)	(347)	(277)
Investing Activities (Capital Expenditures)		(1,372,916)	0	0	0	0	0	0	0	0	0
Senior Debt Advances		1,922,560	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		870,864	569,975	562,569	552,624	541,883	532,556	523,157	513,972	503,383	493,924
Senior Debt P&I Payment		453,895	453,895	453,895	453,895	453,895	453,895	453,895	453,895	453,895	453,895
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		1.92	1.26	1.24	1.22	1.19	1.17	1.15	1.13	1.11	1.09
10-year Average Debt Coverage Ratio	**1.25**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	20 year SLN	356,842	356,842	356,842	356,842	356,842	356,842	356,842	356,842	356,842	356,842
Minor process equipment	20 year SLN	78,715	78,715	78,715	78,715	78,715	78,715	78,715	78,715	78,715	78,715
Process buildings	30 year DDB	125,208	116,860	109,070	101,798	95,012	88,678	82,766	77,248	72,098	67,292
Vehicles	5 year DDB	14,000	16,800	10,080	6,048	3,629	14,000	0	0	0	0
Office building	30 year DDB	29,307	27,354	25,530	23,828	22,239	20,757	19,373	18,081	16,876	15,751
Office equipment	5 year DDB	0	0	0	0	0	0	0	0	0	0
Start-up cost	20 year DDB	960	864	778	700	630	567	510	459	413	372
Annual capital expenditures	10 year SLN	0	0	0	0	0	0	0	0	0	0
Total Depreciation		605,032	597,435	581,014	567,931	557,067	559,558	538,206	531,346	524,944	518,971

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)