American Recovery & Reinvestment Act (ARRA)

FEMP Technical Assistance

Preliminary Feasibility Assessment for the US Forest Service for a Proposed Biomass Facility in Yreka, California

Klamath Site

Final Report
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Acronyms

ARRA	American Recovery and Reinvestment Act
ASME	American Society of Mechanical Engineers
BAMF	Biomass and Alternative Methane Fuels
BDT	Bone Dry Ton (2000 pounds, with no water content)
BDU	Bone Dry Unit, used in pulp/paper industry (2400 pounds with no water)
BLM	Bureau of Land Management
BTU	British Thermal Unit
CCF	Cubic Feet
CE	Categorical Exclusion (document created to comply with NEPA)
CHP	Combined Heat and Power
CO2e	Carbon Dioxide equivalent (greenhouse gas measure)
CROP	Coordinated Resource Offering Protocol
DBH	Diameter at Breast Height (4.5')
DOD	Department of Defense
DOI	Department of Interior
DOE	Department of Energy
TO RFP	Task Order Request for Proposal
EA	Environmental Assessment (document created to meet NEPA)
ECM	Energy Conservation Measure
EERE	Energy Efficiency and Renewable Energy (sub agency of DOE)
EIA	Energy Information Agency
EIS	Environmental Impact Statement (document created to meet NEPA)
EPA	Environmental Protection Agency
ESCO	Energy Service Company
ESP	Electrostatic Precipitator
ESPC	Energy Savings Performance Contract
FAR	Federal Acquisition Regulation
FEMP	Federal Energy Management Program (EERE program)
FFS	Federal Financing Specialist
FS	Forest Service
GT	Green Ton (2000 pounds of wood with varying moisture content)
HAP	Hazardous Air Pollutants
HFR	Hazardous Fuel Reduction (fire mitigation treatments)
IAA	Interagency Agreement
IGA	Investment Grade Audit
IDIQ	Indefinite Delivery Indefinite Quantity
IOU	Investor Owned Utility
kW	kilowatt of electricity (unit of electrical capacity)
kWh	kilowatts of electricity per hour (unit of consumption)
MBF	Thousand Board Feet of lumber
MMBF	Million Board Feet of lumber
MBH	Thousand BTUs per hour

MBTU	1 thousand BTUs
MMBTU	1 million BTUs
MOU	Memo of Understanding
M&V	Measurement and Verification
MSW	Municipal Solid Waste
$MTCO_2$	Metric Tons of CO_2 Equivalents
MWe	megawatts of installed electrical capacity
MWh	megawatts of electricity, one thousand kWh (unit of consumption)
NASS	National Agricultural Statistics Service
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
NOIA	Notice of Intent to Award
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
ODF	Oregon Department of Forestry
POC	Point of Contact
psia	Pounds per square inch – absolute pressure
psig	Pounds per square inch – gauge pressure
RFP	Request for Proposal
RFO	Request for Offers
RPS	Renewable Portfolio Standard
scf (m,d,yr)	standard cubic feet (minute, day, year)
TSI	Timber Stand Improvement
Therm	A unit of heating value equal to 100,000 BTU's
UESC	Utility Energy Savings Contract
USFS	United States Forest Service
USDA	United States Department of Agriculture
WBUG	Woody Biomass Utilization Group

I. Executive Summary

A preliminary feasibility analysis was conducted for a proposed renewable energy project on property adjacent to the Timber Products Company veneer facility in Yreka, California. US Forest Service personnel from the Klamath National Forest Headquarters submitted the project for consideration. The proposed project was analyzed to determine the feasibility of the engineering design as well as potential availability of wood fuel within 50 miles of the project site.

The proposed construction of a combined heat and power (CHP) facility would generate an output of 15.7 megawatts (MW) and a steam output of approximately 150,000 pounds per hour of saturated steam at 150 psig. The project would supply a thermal feed to the Timber Products Company veneer mill and provide residual thermal to surrounding areas and electricity to the grid. Estimated capital costs for this project total approximately $60.1 million. Costs include the new boiler, fuel processing systems, storage area, and related equipment. Projected woody biomass fuel costs for a project of this size are estimated to be $46 per Bone Dry Ton (BDT). During the course of the 20-year project horizon the facility generates in excess of $177 million in revenue, approximately 70% of which is derived from electricity sales. During this same period project costs are approximately $159 million. The project generates a net present value of approximately $17.9 million with a corresponding simple payback period of approximately 8 years and discounted payback period of approximately 14 years.

Based on the preliminary information and analysis conducted in this assessment it is recommended that this project be considered for more detailed analysis.

The following table outlines the major potential accomplishments of this project:

Table 1: Outline of Potential Project Accomplishments.

AMERICAN RECOVERY & REINVESTMENT ACT ACCOMPLISHMENTS		
Klamath National Forest ARRA Project		
Job Created during Construction	30 Jobs (6 month duration)	New building, piping & boiler install
Jobs Created for Long-Term	16+ Jobs	Transportation of fuel
Potential Green House Gas Reductions	50,929 MTCO2e	Generation of Green Electricity to Grid
Total energy savings (MMBtu/yr)	422,333	Generation of Green Electricity to Grid
Total cost savings ($/yr)	$17.9 Million	In Form of Value Generated by Project

FEMP ARRA Technical Assistance from National Laboratories to Federal Agencies

The Federal Energy Management Program (FEMP) facilitates the Federal Government's implementation of sound, cost-effective energy management and investment practices to enhance the nation's energy security and environmental stewardship. To advance that goal and help accelerate agencies' progress, FEMP works to foster collaboration between its federal agency customers and the U.S. Department of Energy (DOE) national laboratories.

In 2009 and 2010, FEMP has utilized funding from the American Recovery and Reinvestment Act of 2009 (ARRA) to facilitate federal agency access to the broad range of capabilities and expertise in the National Laboratories. Funds were directed to labs to assist agencies in making their internal management decisions for investments in energy efficiency and deployment of renewables, with particular emphasis on assisting with the mandates of the Energy Independence and Security Act of 2007 related to federal facilities and fleets. FEMP provided major DOE labs with funding that will allow them to respond quickly to provide technical advice and assistance. FEMP applied a simple vetting and approval system to quickly allocate work to each of the labs in accordance with FEMP-provided funding. All assistance provided by the labs was in accordance with the requirements of Federal Acquisition Regulation (FAR) Subpart 35.017 and the labs' designation as "Federal Funded Research and Development Center" (FFRDC) facilities.

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Introduction

The US Department of Energy's Federal Energy Management Program (DOE-FEMP) team conducted a preliminary engineering feasibility and biomass fuel resource availability review and assessment for an American Recovery and Reinvestment Act (ARRA) project submitted by the US Forest Service (USFS) for the siting of a small-scale, combined heat and power (CHP) plant on vacant industrial property in Yreka, California. Among the many objectives of the ARRA, those associated with this project are to achieve economic stimulus by optimizing economic activity and the number of jobs created or saved; to achieve long-term public benefits by investing in technological advances to increase economic efficiency and improve quality of life and community engagement; investing in infrastructure that will provide long-term economic benefits; and fostering energy independence.

Background

The implementation of a new, 15.7 megawatt (MW) CHP plant on vacant industrial zoned land could provide renewable energy to reduce the amount of manufacturing fueled by fossil-based sources in the Yreka, California area, as well as potentially provide renewable energy to numerous federal facilities in the region.

Throughout much of the region around the proposed site, concentrations of hazardous forest fuels are placing rural communities, sensitive habitat and entire watersheds at significant risk due to catastrophic wildfire, and/or contributing to the decline in vigor and distribution of native flora and fauna. There may be an opportunity to use the wood residues from timber harvesting operations, fuel load reduction treatments, biomass from dedicated thinning, manufacturing residues from Timber Products, a local veneer plant, and urban and orchard wood waste to produce woody biomass[1] power generation[2] at the proposed CHP plant location.

[1]The trees and woody plants, including limbs, tops, needles, leaves, and other woody parts, grown in a forest, woodland, or rangeland environment, that are the by-products of management, restoration and hazardous fuel reduction treatments, or residues from manufacturing, urban wood and green waste.

[2]The process of producing thermal and/or electrical energy using woody biomass at an appropriate scale.

In particular, using woody residues for woody biomass power generation can reduce the costs of and losses from wildfires and improve forest health and productivity. There are a number of additional benefits such as new jobs and businesses in rural communities, citizen engagement via provision of local energy, new property, income and sales tax revenues for local and state agencies to provide more public services, and potential air quality improvements from significantly reducing air pollution caused by wildfires or the open burning of woody biomass. Studies indicate that approximately 4.9 new jobs[3] are generated for every newly-developed megawatt (MW) of biomass power and included are significant environmental benefits.

[3]Morris, Gregory. 1999. The Value of the Benefits of U.S. Biomass Power, NREL/SR-570-27541. National Renewable Energy Laboratory, Golden, CO.

Primary Objectives

The primary objectives for the feasibility assessment were to:

- Assess opportunities for the Klamath National Forest, other Federal lands, and surrounding private industrial and non-industrial forests
- Develop a recommendation for a 15.7 MW CHP system associated with the Forest Products Company's Yreka sawmill
- Consider possibilities for supplying thermal to Timber Products sawmill and/or thermal and electric to the town of Yreka, which considers using woody biomass residuals from private lands, BLM forests, and the Klamath National Forest and others as sources for fuel
- Eliminate waste by utilizing thermal energy for manufacturing that is derived from biomass supplied by scheduled forest operations for thermal and electricity generation
- Create a cost-effective and market-driven solution to support forest fuels reduction and forest restoration/remediation activities in the Klamath District and northern California and southwestern Oregon more generally
- Support renewable energy development, thus diversifying local power generation and providing opportunities to efficiently utilize waste wood material for co-generation
- Assist with decisions about the installation of renewable based technologies on-site to help meet federal requirements
- Assist with decisions about the installation of newer, more efficient heat and power equipment for communities interested in renewable solutions

To achieve these objectives, specific tasks were associated with the engineering technology and biomass resource phases of the feasibility analysis.

Engineering: The overall goal was to determine the structure and feasibility of installing a CHP system on a vacant industrial property in Yreka.

The engineering team evaluated:

1. existing infrastructure (site location, property condition, distance to Timber Products mill and other potential federal consumers)
2. estimated utility demands (cost of fuel)
3. proposed site operations and maintenance practices
4. cost of installing the CHP system
5. use of biomass to fuel energy production

Biomass Resource: The overall goal was to determine if there is enough raw material, community support, and ready markets to site an appropriately-scaled CHP system on the vacant industrial zoned Yreka property.

The resource team evaluated:

1. Woody biomass volume by fuel type potentially available for a biomass power project. Fuel types considered include:
    - manufacturing residues
    - forest-based biomass
    - urban wood waste
    - agricultural biomass
2. Current costs associated with procuring different types of available biomass
3. Alternative markets and competition for woody biomass, including where and how much material is available
4. Current woody biomass markets and potential opportunities for securing a long-term power sales agreement

II. Site Information

Klamath Project Site Description

The Klamath project site is located in the town of Yreka, California, about 4 hours north of Sacramento and 200 miles by road from the Pacific Ocean. The Klamath National Forest is comprised of 2 million acres and managed by the USFS for water quality, wildlife, grazing, recreation and timber. The Yreka area is surrounded by both public and private lands in addition to the Klamath National Forest. These forests include California State lands, BLM property, Timber Products Company lands, and other private industrial and non-industrial ownerships in Siskiyou County.

The site is comprised of a large vacant industrial zoned lot located just outside of Yreka in proximity to the Klamath National Forest. The proposed site is near Timber Products' Yreka sawmill facility and when operational will provide thermal sourcing to the mill for drying and other manufacturing needs. The sawmill consists of a softwood veneer production facility that uses Douglas fir, white fir, spruce, and hemlock stems.

The Klamath National Forest Headquarters office, as well as other federal agency buildings are located in and around Yreka and could be a user of excess renewable energy and beneficiary of renewable energy credits. Electricity generated in the CHP system could additionally provide renewable energy to the town of Yreka, which has an interest in reducing its carbon footprint via federal energy tax credits to support the local production and consumption of renewable energy. Also of interest to Yreka are the jobs the proposed plant would create and sustain.

For the purpose of conducting an engineering assessment, the structure and efficiencies associated with the proposed CHP system were assessed. To conduct the biomass resource assessment, a 50-mile radius woodshed encompassing nearly 800,000 square miles in Josephine, Jackson and Klamath Counties in Oregon and Siskiyou, Trinity, and Shasta County in California were used. Siskiyou County accounts for roughly 70% of the woodshed, while Klamath, Josephine and Jackson and constitute about 25% collectively, and Trinity and Shasta 5%. Forested regions represented by these counties could provide various amounts and types of woody residues from different management treatments. Typical combined levels will supply significant quantities of biomass that could be utilized as value-added products. Biomass generated during land management activities includes but is not limited to:

- Forest products manufacturing residues
- Timber harvest operations
- Hazardous fuel reduction treatments both on public and private lands
- Biomass thinning operations
- Forest remediation/restoration following a catastrophic event (wildfire, insect attack)
- Agricultural by-products

In addition, the 50-mile radius woodshed was also used to estimate potential for purchase of wood pellets, supply of wood from urban zones, and biomass more generally from agricultural sectors. However, because of the scope of the project and characteristics of land use in the study area, agricultural biomass and wood pellets were not proposed for use in this project.

III. Engineering Analysis & Cost Figures

Overview

The proposed project is for the construction of a new CHP generation facility on vacant industrially zoned land adjacent to the Timber Products Veneer Mill located in Yreka, CA. In 2009, the City of Yreka and the Siskiyou County Economic Development Council contracted with Carlson Small Power Consultants to complete a project analysis for this cogeneration facility. The key findings from this 2009 analysis are summarized in Appendix E. Information obtained during a 2010 site visit was used to conduct an initial assessment for a combined heat and power project at the same Yreka location but at a larger scale. The findings from this initial assessment are included below.

2010 Assessment

The proposed project is for the construction of a new combined heat and power generation facility on vacant industrially zoned land in Yreka, CA. This analysis incorporates information received from the agency personnel with the Klamath National Forest, City of Yreka and the Siskiyou County Economic Development Council, and Siskiyou Biomass Utilization Group, during a site visit conducted in May 2010.

Proposed New Cogeneration Facility

The proposed facility would generate a net output of 15.7 megawatts (MW). This base loaded generation facility would have a plant capacity factor of 90% and operate approximately 7,884 hours annually, consuming approximately 900 green tons per day of woody biomass feedstock. This fuel would be sourced primarily from forest thinnings, salvaged material from forest fuel management programs, along with other material identified in the Resource Assessment.

Major System Components

A detailed list of the equipment is provided further below. However, the major system components include the following: fuel reception and prep yard, steam boiler system, steam turbine generator with extraction ports, and a building to house the power generating equipment and control room. The generation facility will have a steam output of approximately 150,000 pounds per hour of saturated steam at 150 psig. If this system were configured to fully optimize for electrical output the total generation would be approximately 24.6 MW.

Export Steam and Condensate Return

The proposed location is situated in the heart of a large industrial zone. Local officials are interested in revitalizing this industrial area and are hopeful that access to process steam will help to incentivize redevelopment of the industrial park. Currently, the primary potential thermal customers include the adjacent Timber Products veneer mill and an asphalt plant. As indicated in the 2009 assessment work, the veneer mill has a current thermal load of 125 psig at approximately 14,000 lbs/hour. As configured, the cogeneration facility will produce approximately 150,000 pounds of steam per hour at 150 psig. Future analysis can refine steam output for the current thermal customers, and for the possible expansion and increased steam requirements at Timber Products veneer mill (i.e., possible addition of jet veneer dryers, etc.). Furthermore, future work should explore strategies for accommodating and attracting potential new industrial thermal users to the industrial park. Depending on the scope of the sites redevelopment and planning horizons thermal feeds could be routed along the axis of the park. However, this preliminary analysis does not include the costs of any land purchases, or leases, associated with easements for the thermal feeds.

Biomass Fuel Feedstock Handling Area

The fuel storage is sized for 18,000 tons of woody biomass, this is sufficient storage for approximately 20 day supply. The bulk storage area is an open structure with a crushed rock floor. This estimation assumes that the fuel has an average 50% moisture content (wet basis) and a density of 40 pounds per cubic foot. Trailers delivering woody biomass will pass through a scale house, back onto a tipping platform, and offload their biomass into a fuel delivery pit. This fuel will then be conveyed to the large storage area. From the storage area a belt storage conveyor will transfer the material from the ambient bulk storage to a live storage silo. The silo is of sufficient capacity to store 24-hours worth of fuel, approximately 900 tons. Fuel from the storage silo will be transferred to the fluidized bed boiler via a drag link conveyor.

Proposed Facility Layout Plan

Appendix A provides a conceptual site plan of the new facility and its associated inner connections.

Grid Interconnection

The 2009 assessment work identified that the industrial park receives its power via Pacific Power's Yreka Substation which is located approximately two miles west of the site. Prior to the interconnect work Pacific Power will require that a robust electrical interconnection analysis be conducted with the expenses paid by the project developer. For this analysis, the grid interconnection costs have been estimated at $500,000 per mile. The actual costs will be determined by the interconnect analysis and determination of grid capacity.

Required Manpower

This analysis assumes that the operation of the plant will require sixteen full time staff, including: one plant manager, three maintenance workers, eight shift workers, and four prep yard workers.

Proposed Facility Layout Plan
Appendix A provides a conceptual site plan of the new facility and its associated inner connections.

Easements
It is anticipated that land will need to be acquired to facilitate right of ways for thermal and electrical runs. The purchase, or lease costs, associated with these easements are beyond the scope of this initial analysis.

Utility Interruptions
The logistics of the interconnection will be coordinated with Pacific Power. The connection of the thermal feeds to various end users of steam would be coordinated to appropriately stage the work to minimize interruptions to normal work operations at these facilities.

Environmental Impacts
This facility will have a positive net environmental impact. The new cogeneration facility will displace approximately 50,929 MTCO2e of greenhouse gases. Siskiyou County is not listed as a non-attainment area. However, the cogeneration facility will use an electrostatic precipitator to further reduce the emission of particulate matter. Future analysis will need to explore any other costs associated with air permitting and potential emission controls.

Projected Biomass Demand
The generation facility will consume approximately 900 tons per day, or 295,650 tons per year, of green woody biomass.

Estimated Implementation Costs
The estimated implementation price of this project is approximately $ 60.1 million. Project costs were estimated primarily by using factors obtained from the installed capital costs of projects of a similar scale, vendor quotes, and other sources, including information found in research literature and released by federal agencies. Table 2 below provides a more detailed description of the estimated cost assumed for each system component.

Table 2: Estimated Project Implementation Costs

Component	Estimated Cost ($1,000)
Fuel Storage Area	$134.01
Fuel Processing and Prep Yard	$8,067.93
Fluidized Bed Boiler	$42,876.38
Steam Turbine Generator	$8,056.77
Interconnection with Pacific Power	$1,000.00
Total Estimated Costs	$60,135.09

Preliminary Financial Analysis
A simplified cash flow was constructed to analyze the project cash flows during the first twenty year period of the project. The cash flow included estimations for the following items:

- Expenses - construction and commissioning, interconnection, annual fuel purchases, and annual operating and maintenance costs associated with manpower and non-fuel consumables.
- Revenue - annual electricity and steam sales

The following table summarizes the key assumptions used in this initial analysis.

Table 3: Preliminary Financial Analysis

Summary Findings & Key Assumptions	
Project Implementation Costs	$60.1 million
Estimated O & M Costs (Year 1)	$1,856,886
Discount Rate	10%
Assumed Fuel Price (BDT)[4]	$46
Assumed Electricity Price ($/kWh)[5]	$0.095
Assumed Steam Price ($/'000 lbs steam)	$4.00
Project Horizon	20 years
Indicators of Financial Efficiency	
Net Present Value	$17.9 Million
Benefit Cost Ratio	1.11
Discounted Pay Back Period	Approximately 14 years

4Value derived from estimates calculated within the Resource Assessment, assuming an annual fuel demand of 147,825 BDT and discounting the potential contribution from mill waste.
5 Rate estimation obtained from 2009 Assessment report conducted by Carlson Small Power Consultants, which based this assumption on the California Public Utilities Commission Annual Market Price Referent report.

The results of this simplified cash flow analysis indicate that the project has positive indicators of financial efficiency, with a positive net present value and benefit cost ratio greater than one. Estimated capital costs for this project total approximately $60.1 million. Costs include the new boiler, fuel processing systems, storage area, and related equipment. Projected woody biomass fuel costs for a project of this size are estimated to be $46 per Bone Dry Ton (BDT). During the course of the 20-year project horizon the facility generates in excess of $177 million in revenue, approximately 70% of which is derived from electricity sales. During this same period project costs are approximately $159 million. The project generates a net present value of approximately $17.9 million with a corresponding simple payback period of approximately 8 years and discounted payback period of approximately 14 years.

Future analysis will require a comprehensive pro forma incorporating depreciation schedules, production incentives, subsidized project financing, project developer's alternative rates of return, insurance costs, steam production cost estimates of potential thermal users, recent power purchase agreement market history, and other detailed estimates to refine the estimated project cash flows. Furthermore, the unique public-private structure creates additional opportunities for structuring the project, each with different potential funding mechanisms specific to the ownership designation of the facility. These initial findings do not incorporate various production incentives for renewable energy, such as the Federal Renewable Electricity Production Tax Credit. This level of detail is beyond the scope of this initial analysis. Detailed descriptions of these and other available financial incentives are included later in this report.

Scope of Project

The scope of the estimate includes the following cost elements:

1. Power Island: Provide and install one fluidized bed boiler and steam turbine generator
2. Fuel Handling and Storage: Provide and install truck dump, conveyor to wood pile, radial stacker, front end loader, reclaim feeder, conveyor, metal separator, screener, grinder, one live storage silo, fuel metering bin, and related control equipment.
3. Provide engineering and design and installation labor.
4. Provide project management and construction management.
5. Conduct system startup, testing and commissioning.

Key Assumptions
(to be confirmed during more detailed study):

1. Total annual wood waste/chip consumption will be approximately 295,650 tons/year
2. The cost of fuel is estimated at $46 per dry ton.
3. Fuel, steam, electricity and operating and maintenance costs will each escalate at the rate of 3% per year.

IV. Resource Analysis & Cost Figures

Overview

An analysis was conducted on the potential supply of woody feedstock to support the development of a potential CHP project for the site. The analysis considers various sources and scales of available woody biomass for power generation within a 50 mile radius woodshed for the project area.

Study Area

California

Forests in northern California have the potential to provide biomass to renewable projects through treatments to mitigate threats to forest health or improve forest productivity. Most of these forests are densely stocked and federally owned and managed, but notable portions are also owned by industry and other family and investment owners. Sources of woody biomass include wood waste generated at manufacturing plants as well as fuel load reduction treatments in various forest types, logging slash, and discarded wood and yard debris in urban settings that may be deposited in landfills. Agricultural crop residues and landfill gas could provide the state with additional feedstock for power generation.

Oregon

A large portion of Oregon's forestland, like California, has the potential to provide useful woody biomass through treatments to address forest health concerns or improve forest production through treatments to mitigate threats to forest health or improve forest productivity. Many of these forests are similarly federally owned and managed, but akin to northern California, a notable portion is also owned by industry and other private family and institutional investment owners. As it is, Oregon already generates nearly 150 MW of electricity from biomass, the third largest in the region behind California and Washington. Also similar to California, other sources of woody biomass include wood waste generated at wood products plants as well as treatments on juniper woodlands, logging slash, and discarded wood and yard debris from urban areas that may be deposited in landfills.

Project Area

The potential availability of woody biomass fuel material within 50 miles of the project area (Siskiyou, Trinity, and Shasta Counties in California and Josephine, Jackson and Klamath Counties in Oregon were included) is estimated to be between 376,053 and 541,732 bone dry tons per year (BDT[6]/yr) and represents an estimated energy potential of 4.74 and 6.83 million MMBtu. This volume of biomass fuel would be sufficient to support between 46 and 66 Megawatts (MW[7]) of power generation[8].

The following table reports high and low estimates of potential annual woody biomass availability by fuel type within the project area. Chart1 depicts data averages in pie-chart form.

[6]One bone dry ton (BDT) is 2,000 pounds of biomass (usually in chip form) at zero percent moisture. At typical wood harvest moisture rates of 50%, two green tons would equal one BDT.

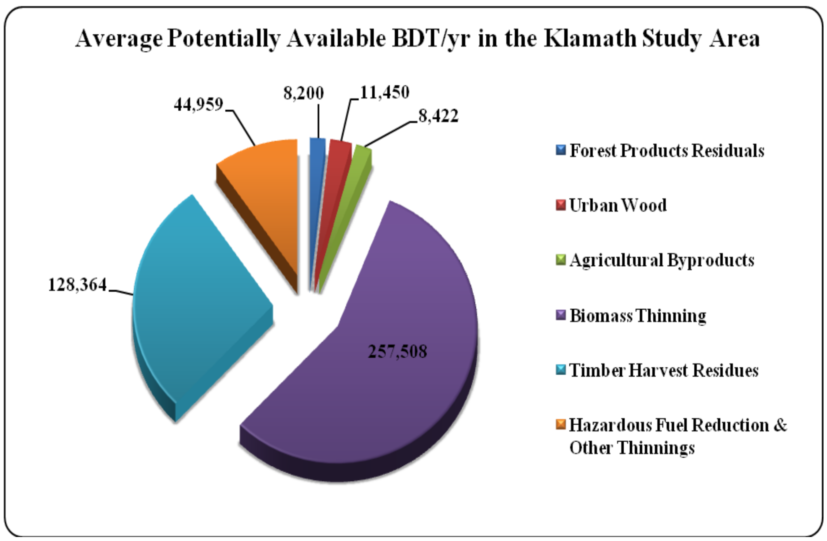
[7]Assumes a consumption rate of 8,000 – 8,500 BDT/year per MW.

[8]One megawatt (MW) is a measure of electrical output and equals 1,000 kilowatts.

Table 4: Summary of Woody Biomass Fuel Potentially Available on an Annual Basis in BDT within Josephine, Jackson, and Klamath Counties in Oregon and Siskiyou, Trinity, and Shasta Counties in California.

Source	Low Estimate	High Estimate
Biomass Thinning Residuals	231,757	283,259
Timber Harvest Residuals	96,274	160,456
Fuels Treatment & Timber Thinning - Public	2,549	7,937
Fuels Treatment & Timber Thinnings - Private	28,293	51,115
Urban Wood	5,415	17,485
Forest Products Residuals	6,150	10,250
Woody Agricultural Byproducts	5,615	11,230
Total (BDT/yr)	**376,053**	**541,732**

Chart 1. Pie-chart Summary of the Average Estim ation of Woody Biomass Fuel Potentially Available on an Annual Basis in BDT within Siskiyou, Trinity, and Shasta Counties in California and Josephine, Jackson, and Klamath Counties in Oregon.



Current Woody Biomass Utilization Markets

A variety of markets for woody biomass exist in the project area. Some of the alternative-use markets for woody biomass in the Klamath study area are summarized in Table 5. The value of these products is usually a function of distance from manufacturing facilities or end markets.

Table 5: Current Markets for Woody Biomass Material Generated within the Klamath Study Area.

Value-markets
Landscape cover, Compost, and Soil amendments
Animal Bedding: Shavings, Sawdust
Firewood, Cull Logs
Biomass Fuel
Hogged Fuel

Biomass Fuel Availability

Biomass Fuel Characteristics

The size, moisture content, and non-wood component (primarily soil for forest-generated woody biomass) will vary from feedstock to feedstock and biomass contractor and equipment used for processing (type of chipper, harvesting and transportation method, etc). It is difficult to draw assumptions until the biomass demand is established and supply contracts are negotiated. At that time it may be possible to set specific requirements for these factors.

For example, moisture content is a major factor when analyzing power conversion and can vary greatly due to the source: mill residues can be very wet or very dry depending on where chips were generated in the sawmill (sawhead vs. dry kiln); urban wood is usually fairly dry (15-25% moisture content) but can include yard waste with over 50% moisture; hazardous fuel reduction, especially on private lands, may be left on site to dry before being chipped and removed. The largest and most consistent fuel source is derived from in-woods chipping (biomass thinning, fuel reduction, and timber harvest residues), which can vary in moisture rates between 45 to 55%.

Timber Harvest Residues

Typically available as limbs, tops, foliage, and unmerchantable logs, timber harvest residues are generated as by-products of timber harvesting and vegetation management and can thus be a relatively economical raw material. Once collected and processed using portable grinders or chippers, the biomass can be transported in a more economical fashion. However, most biomass is currently left in the woods. Exceptions include residues that have been harvested for existing mulch and landscape cover markets.

Woody biomass availability assessments traditionally rely on information regarding historic timber harvest levels. This information can help determine trends and predict forest harvest activities over time. The best historic data available for the Klamath woodshed is California's Timber Tax Section and Oregon Department of Forestry's (ODF) Annual Timber Harvest Report.

Based on experience working with logging and chipping contractors in other regions, the recovery factor for biomass fuel processed from timber harvest residues in the Klamath woodshed is assumed to be approximately 0.9 BDT of woody biomass (tops and limbs) per each thousand boardfoot (MBF)[9] of harvested timber. The table below summarizes the high, low, and average estimated annual biomass fuel potentially available from timber harvest residues using the 0.9 BDT/MBF biomass fuel recovery factor. It also provides an estimate of harvest residues based on planned and historic treatment activities from 2008 through 2009 in Siskiyou, Trinity, and Shasta Counties in California and Josephine, Jackson, and Klamath Counties in Oregon.

[9]MBF represents 1,000 board foot measure. One board foot is a solid wood board measured 12 inches square by 1 inch thick.

Not all timber harvest operations lend themselves to ready recovery of harvest residues. Steep slopes, remote locations, and road systems that will not accommodate chip trucks or roll-off bins (for transport of biomass fuel) will limit the volume of biomass fuel recovered from timber harvest activities. For this reason, low estimates assume approximately 60% of land will accommodate woody biomass recovery. Using the last two years of reported timber harvest levels as a benchmark, an average of 128,365 BDT/yr of biomass fuel could be available from timber harvest treatments in the Klamath study area. As depicted in the table below, the low estimate assumes only 96,274 BDT/yr will actually be recovered and the high 160,456.

Table 6: Annual Potential Woody Timber Harvest Residues Expressed in BDT/yr from Timber Sale Contracts from Public (USFS, BLM, and ODF) and Private Industrial and Non-industrial Forests. Low estimates assume 60% recovery and high estimates 100%.

Fuel Type	Low Estimate	High Estimate	Average
Public Timber Harvest Residues	13,019	21,698	17,358
Private[10] Timber Harvest Residues	83,255	138,758	111,006
Total (BDT/yr)	**96,274**	**160,456**	**128,365**

This data is presented courtesy of the California Tax Center and the Oregon Department of Forestry (ODF).
NOTE[10]: Tribal harvest is not included in harvest figures.

Fuel Treatments – Public Lands

The National Fire Plan was launched after the devastating fire season of 2000 to address the problem posed by unnaturally high fuel accumulation in the inland West region. The National Fire Plan is the foundation for a long-term program to reduce fire risk and restore healthy, fire-adapted ecosystems, primarily on public lands.

In recent years public land managers have started to rethink the use of prescribed fire as the fuels management tool of choice. Public stakeholders have voiced concerns regarding the predominant use of prescribed fire due to the following issues:

- Air quality impacts (haze, human health issues associated with particulate matter, smoke-caused accidents, etc), and concerns about greenhouse gas release
- Potential for escape of controlled fire and loss of infrastructure
- Visual and lost recreational impacts of burned and blackened forests
- Biomass utilization for value-added products and rural employment

In light of the National Fire Plan and stakeholder concerns, public land managers have started to use the "treat and remove" fuels treatment method. In addition, and as a result of the Consolidated Appropriations Resolution of 2003, public forest managers have new contracting tools such as stewardship contracts that can facilitate the treatment of thousands of acres over a maximum contractual term of 10 years. These low, fuel-reduction thinnings accomplish several forest management objectives. They improve fiber production for future commercial harvests, reduce the threat of insect and disease attacks by reducing competition for limited water and nutrients, reduce wildfire threats to communities, watersheds and residual forest structures, and, if properly designed, can improve fish and wildlife habitat. Some treatment residues are presently being diverted to bioenergy production. When recycled as bioenergy, they have the added benefits of reducing smoke and particulates, contributing to domestic energy independence, and reducing greenhouse gas emissions.

According to conversations with federal land managers, the Rogue River National Forest plans to thin 8,820 acres of overstocked forest in 2010, 7,000 acres in 2011, and 6,000 acres in subsequent years. Similarly, the Klamath National Forest is removing 35,000 cubic feet (approximately 49,000 BDT and 2,300 acres) of biomass this year, 24,000 cubic feet in 2011 (about 1,600 acres), and 20,000 cubic feet (around 1,300 acres) per year every year thereafter. The study area could also benefit from fire-reduction and timber stand improvement. Federally owned land in the project area plans to conduct at least 78,000 acres of thinning over the next 10 years. According to Oregon's Coordinated Resource Offering Protocol (CROP), these treatments could provide an average of 440 green tons (GT) per year for the next 5 years. Volume estimates are calculated by assuming an average of 12 BDT of biomass per acre. For this analysis, there has been a more detailed breakdown of information for each area and is shown in the following tables.

Oregon's CROP also notes that the ODF Klamath Lakes plans to harvest considerable amounts of biomass in the coming years. They are offering 4,088 GT in 2010, 1,787 GT in 2011, 1,000 GT in 2012, 2,000 GT in 2013, and 3,000 GT in 2014. All told, this comes to an average of 1,190 BDT/yr for the next 5 years.

The following table denotes low, high, and average estimates of the BDT/yr available from fuel treatments on portions of federal and state forestlands falling within the study area. Following physical constraint examples from the USFS, high estimates assume that 50% of the thinned acreage is conducive to biomass recovery operations, while low estimates assume only 20% of thinned acreage can supply biomass. The average is created using the two assumptions. Low estimates come from the year with lowest projected biomass removals within the next five years (2010-2014), high estimates come from the year with the highest projected removals (2010-2014) and averages are the average offering over the next five years (2010-2014).

Table 7: Potential woody residues expressed in BDT/yr derived from fuel treatments and non-commercial thinnings on public lands (USFS, BLM, and ODF).

Fuel Type	Low Estimate	High Estimate	Average
Fuel Treatments – Federal Lands	2,481	7,542	5,012
Fuel Treatments – State Lands	68	395	232
Total (BDT/yr)	**2,549**	**7,937**	**5,244**

Fuel Treatments – Private Lands

There are no known available records summarizing the number of acres treated or volume of biomass removed from privately-managed forests within the study area. However, from interviews with private forest managers and biomass stakeholders, it is clear that fuel load reduction treatments are occurring on private industrial forests. It is also obvious that substantial local interest in conducting fuel treatment activities to protect green and built infrastructure exists.

Unlike public forest managers, private managers are generally not required to prepare environmental documents prior to startup of harvesting or fuels treatment operations. However, both California and Oregon have published guidance and regulations which landowners are required to follow. The States passed these laws and regulations to prevent overharvesting and reduce the impacts on soil, water, and wildlife resources.

In addition, private managers also face challenges in the implementation of fuel reduction projects, to include:

- Lack of markets and a dearth of chipping contractors available to conduct fuel treatments. There are limited markets for biomass harvesting and in-woods chipping industry for woody biomass in the Klamath area. Several of the local contractors possess portable chipping/grinding machinery, but these systems are mostly underutilized. Until larger biomass markets develop, there may be an opportunity to encourage contractors to concentrate efforts on the implementation of fuel treatment service contracts or stewardship contracts offered by the BLM, USFS, and California and Oregon.
- Limited access to hauling contractors and equipment (typically chip vans or roll-off bins) available to transport biomass fuel to market, especially on roads with tight turn radii.
- Increased diesel fuel costs that are not adequately covered by the value of biomass fuel delivered to biomass plants.
- Uncertainty regarding future biomass fuel markets or prices.

Conversations with existing biomass facilities in Southwestern Oregon indicate that private non-industrial forestland owners supply minimal amounts of biomass. Private industrial land, on the other hand, often contributes the largest percent of biomass supply. For example, Biomass 1 in White City obtains less than 5% of its forest-based supply from private non-industrial lands and about 90% from private industrial lands.

Low, high, and average estimates of the BDT/yr available from fuel treatments on private non-industrial and industrial forestlands are listed in the following table. Following examples from the USFS, high estimates assume that 50% of the thinned land is biophysically conducive to biomass recovery operations, while low estimates assume only 20% of harvest area will supply biomass. The average is created using the two assumptions. An estimated 86% of fuel treatments and thinnings occur on private land, in congruence with the percent of timber harvests occurring on private land. Of the private harvests, we assume that 90% occur on private industrial lands.

Table 8: The Table below displays private land assumptions for fuel treatments and thinnings.

Fuel Type	Low Estimate	High Estimate	Average
Estimated Fuel Treatment Activities – Private Industrial Lands	25,464	46,003	35,744
Estimated Fuel Treatment Activities – Private Non-Industrial Lands	2,829	5,112	3,971
Total	**28,293**	**51,115**	**39,715**

Biomass Thinning

Forest land managers in the study area expressed a desire to implement forest health treatments (e.g., biomass thinning, timber stand improvement) in small diameter stands, but currently feel constrained by limited and non-existent markets for low-grade, woody biomass material. If demand and capacity emerge for marketable biomass thinnings, the woodshed around the Klamath study area could potentially produce substantially more biomass than what is potentially available from current and planned management activities.

According to the United States Department of Agriculture (USDA) Evalidator, there are almost 3,961,000 acres of forested acreage in the Klamath study area that is potentially available to supply forest-based biomass. Public ownership accounts for just over 2,574,000 acres with private ownership covering the remainder.

Total standing biomass is approximately 232,972,000 BDT. However, a notable portion of this biomass is associated with higher-value sawtimber forest products, meaning that most biomass will be obtained from branches, tops, trees under 9" DBH, and any larger cull trees that are of poor form, vigor, or are damaged or diseased. After subtracting standing high-value sawtimber, the net standing above ground biomass is 171,170,000 BDT. Assuming an average 120-year rotation, that half of the volume is accessible, and after accounting for timber harvesting and fuel load reduction treatment projections the annual available biomass from dedicated biomass thinning could total 257,508 BDT/yr. This would increase the availability of BDT/yr on top of what is currently available from thinning, fuel treatments, and timber harvests.

The following table estimates biomass thinning opportunities in the 50-mile woodshed surrounding the Klamath study area. Estimates are based on 3.9 million acres of forestlands, projected sawtimber harvests, and fuel treatments with a presumed 120-year rotation and 50% accessibility. Upper and lower limits are based on 10%variability.

Table 9: Sustainably Available Biomass (BDT/ac) Potentially Available from Biomass Thinnings.

(Assumes 50% of land base managed on a 120-year rotation, not including already-available biomass from timber harvest residues and other thinnings).

Source	Lower Limit	Upper Limit	Average
Public	187,723	229,439	208,581
Private	44,034	53,820	48,927
Total	**231,757**	**283,259**	**257,508**

Urban Wood Waste

There may be opportunities to divert woody debris from the municipal solid waste stream in or near the Klamath study area and increase the amount of wood waste available for power generation instead of being openly burned or deposited in landfills. Tree hauling companies, for instance, may pay close to $20/GT ($40/BDT) to dispose of urban tree wastes. Nationwide, the average American produces 0.1 BDT of wood waste annually. Estimated available urban yard waste was calculated using populations within the woodshed and a national yard waste generation average of 0.1 BDT/capita/year.

Competition for wood waste, however, presently exists in the study area due to alternative markets for woody biomass, such as compost, decorative bark, and existing biomass facilities. Siskiyou County currently sells their wood wastes to Biomass 1 in White City, OR. Jackson County currently recycles its yard wastes into Oakleaf Compost. The study area that encompasses Klamath County does not contain transfer stations.

Nationwide, the average American produces 0.1 BDT of wood waste annually. Using this estimate, the Klamath study area could produce roughly 11,450 BDT/yr of urban wood waste available for biomass energy production or other productive uses.

The following table provides a range of wood waste sorting and recovering opportunities in or near the study area. Low estimates come from the waste volumes in relevant counties known to currently landfill their woody debris, and high estimates assume 100% of per capita urban wood could potentially be diverted to biomass.

Table 10: Estimated Urban Wood Available (BDT/yr).

	Low estimate	High estimate	Average
Estimated available urban waste	5,415	17,485	11,450

Forest Products Manufacturing Residuals

Conversations with land managers in the study area indicate that the pulp industries have been in serious decline in both California and Oregon over the last decade, but lumber industries remain. Among manufacturers, less than 3% of mill residues in California presently go unutilized. Most residues in Oregon are also presently utilized. Many of these byproducts are used for energy production at the facility or sold to nearby facilities in Weed, California or White City, Oregon, for example, as a fuel source or commercialized for other uses such as high-end animal bedding.

The TPO database (USFS FIA data) indicates that there are 1,627,000 BDT/yr of mill manufacturing by-products in the five counties comprising the study area. At the right price it is reasonable to assume that a small portion of these residues may be available. It is estimated that 3-5% of the “Unused, Miscellaneous, and Fuel by-product” mill residues in the TPO (an additional 8,200 BDT/yr on average after weighting for proportional representation of mill residues in each county) could be diverted for use by a bioenergy facility. The table below provides a summary of the estimated residuals.

Table 11: Estimated Forest Products Manufacturing Residuals Available (BDT/yr).

	Low Estimate	High Estimate	Average
Estimated available manufacturing residuals	6,150	10,250	8,200

Agricultural Byproducts

Agricultural byproducts have potential to provide a stable, long-term, and cost effective biomass fuel source and could, as wood or fiber, be coupled with other woody feedstocks in certain circumstances with the right technologies to substantively increase biomass energy production in the Klamath study area. The table below summarizes the amount of potential residual biomass from surrounding agricultural production systems expressed as BDT per year. The estimates are proportional by county using Klamath woodshed boundaries and residue figures derived using the USDA’s 2007 Census of Agriculture database and regional bioresidue estimation coefficients.

Table 12: Agricultural Residue Biomass Projections within 50-mile Radius of the Klamath Study Area.

Biomass Source	Low Estimate	High Estimate	Average
Agricultural Residue Total (BDT/yr)	5,615	11,230	8,422

V. Collection, Processing & Transportation Costs

The full costs of collection, processing and transport must be assessed to better understand the economics of biomass fuel delivered to a power generation facility. Interviews were conducted with forest fuels treatment operation managers, foresters, wood waste processors, and other stakeholders regarding the costs of collection, processing, and transport of biomass fuels. The findings are presented in a low and high range due to the number of variables that can impact costs of operation. These include:

- Haul distance to facility
- Vegetation type and density
- Cost of fuel and labor
- Road improvement and maintenance
- Time of year delivery

Table 13 outlines the range of estimated costs by cost center as determined using the location of the administrative site in Yreka, California. Figures include profit and risk, but there is some uncertainty associated with the estimates due to inconsistent biomass operations. Trucking costs assume an average haul distance from as little as 2 miles to as much as 50 miles. Where a specific biomass operation could not be identified, we have assumed an average haul distance of 25 miles to generate transport costs of biomass fuel to a biomass power plant.

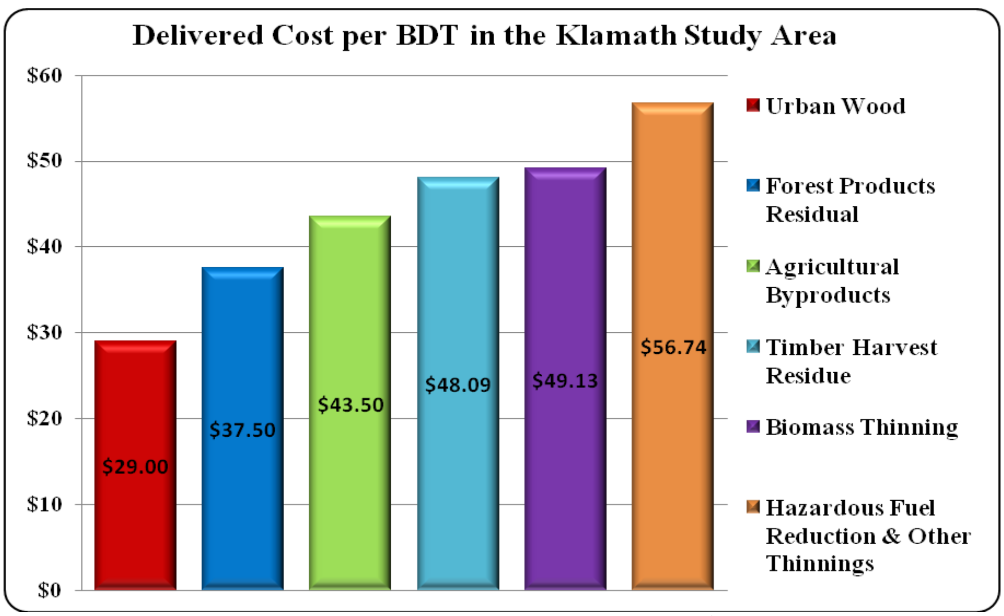
Table 13: Average Stumpage, Collection, Processing, and Transport Costs (all fuel types).

Cost Center	Low Estimate	High Estimate	Average
Stumpage Public Lands	$0.00/BDT	$0.20/BDT	$0.10/BDT[11]
Stumpage Private Lands	$0.02/BDT	$5.00/BDT	$2.50/BDT[12]
Timber Harvest Public (fell, skid/sort, chip)	$24.73/BDT	$79.93/BDT	$44.16/BDT
Timber Harvest Private (fell, skid/sort, chip)	$27.28/BDT	$88.17/BDT	$48.71/BDT
Biomass Thinning Public (fell, skid/sort, chip)	$27.00/BDT	$87.28/BDT	$48.22/BDT
Biomass Thinning Private (fell, skid/sort, chip)	$29.69/BDT	$95.97/BDT	$53.02/BDT
Fuel Reduction Public (fell, skid/sort, chip)	$29.28/BDT	$94.63/BDT	$52.28/BDT
Fuel Reduction Private (fell, skid/sort, chip)	$32.10/BDT	$103.77/BDT	$57.33/BDT
Trucking (per mile)	$0.13/BDT	$0.46/BDT	$0.30/BDT

[11]Based on information from the USFS
[12]Based on information from the BLM

Each fuel type has different harvesting, processing, and trucking costs. The delivered cost for woody biomass depends on the harvest, transportation costs, and stumpage (cost of the raw material “on the stump” or price paid to the landowner). Chart 2 demonstrates that delivered prices for biomass sources range from $29.00 for urban woody biomass to $56.74 for biomass recovered from hazardous fuel reductions.

Chart 2. Delivered Cost per Bone Dry Ton by Source. Data Points Were Determined Using the Average Estimate of Potential Woody Biomass Available and Operational Costs in the Klamath Study Area.



Blended fuel prices for the Klamath study area are estimated to be up to $53.61; for the specific project (147,825 BDT/yr) the blended costs is $46/BDT. The project developer can determine the marginal cost to increase the fuel demand for any given energy load from the table above, but to figure the actual cost of biomass, the project manager should look at the “blended” fuel price. In order to achieve a balanced and adequate fuel supply, a variety of fuel sources are “blended” to make a reliable fuel stream. Blended costs are always lower than the marginal delivered cost due to the accumulation of fuels at lower costs (this assumes you purchase the lowest cost fuel for any desired supply level). The blended delivered price ranges from as little as $33/BDT (Urban Wood and Forest Product Residuals) to as high as $54/BDT (averaged for all fuel types). Table 14 displays the difference between the delivered costs for a given fuel and the "blended" costs.

Table 14: Blended Average Fuel Costs (all fuel types)

Fuel Type (Average Cost)	Available Tons	Cumulative Tons	Delivered Cost	Blended Average
Urban Wood	11,450	11,450	$29.00	$29.00
Forest Products Residuals	8,200	19,650	$37.50	$32.55
Agricultural Byproducts	8,422	28,072	$43.50	$35.83
Timber Harvest Residue	128,364	156,436	$48.09	$45.89
Biomass Thinning	257,508	413,944	$49.13	$47.91
Hazardous Fuel Reduction & Other Thinnings	44,959	458,903	$56.74	$53.61

The delivered cost of urban wood and forest product residuals (mill residues) is expected to be the lowest, as the cost of production is borne by the landowner, there should be no or low stumpage fees as this is waste residue, and transportation distances are expected to be minimal. Wood pellets, on the other hand, have the highest production costs, but are the most easily available biomass source. However, they were not included because they are part of a different product and cost structure. Competition from alternative markets drives up the price for mill residues, which are largely utilized. However, we included mill residues (Forest Products Residuals) in our analysis with the assumption that 3-5% of available residues could be acquired at a competitive price.

Alternative Market Review

The focus of this section is to describe what could be potentially available for use as renewable biomass fuel. However, in order to understand what volume of material may be available over time for use as fuel, a review of alternative markets for this material is necessary. Table 15 provides an overview of alternative value-added markets for woody material currently generated within the Klamath study area. Note that there are numerous higher value options for woody biomass material and that biomass fuel should not be considered necessarily the highest and best use. In the study area the bedding and firewood markets are fully mature and will compete for all clean chips and sawdust. Dirty chips (hog fuel) can be used by the compost and landscape markets, but these markets are less mature and have a restricted capacity and may not present a significant barrier to woody biomass fuel supplies. Also note that if composite or pulp/paper manufacturers reemerge in the study area, the relative value of those products and large feedstock demand could make access to clean chips uneconomical for biomass power.

Table 15: Alternative Markets by Value and Raw Material – Klamath

Alternative Markets (Descending Value – Higher to Lower)	Raw Material Feedstock
Landscape cover, Compost & Soil Amendments (Multiple Markets)	Yard trimmings, green waste, land clearing material, log yard waste
Firewood (Multiple Markets)	Cull logs, tops, limbs, cants, slabs
Biomass fuel (Multiple Markets)	Urban wood, land clearing material, cull logs, tops, limbs, log yard waste, green waste, mill residues

Verification of Biomass Supply Estimates

To verify the assumptions made in the biomass supply availability, two independent analyses of the potentially available fuel supply using national or regional data sets will be conducted:

- National Energy Technology Laboratory data on forest and mill residues (please see Appendix C – BAMF Resource Assessment). The BAMF data is based on a 50 mile radius; the BAMF estimate is 469,332 BDTs.
- Billion Ton Supply Report data [data will not be available until 8/10] (Maybe deleted)

There was no data to cross-check with the Coordinated Resource Offering Protocol (CROP) Forest Service (available on the internet at: http://www.crop-usa.com/).

The analysis indicates a variability of 114% for all fuel types, or 47% excluding the Biomass Thinning estimate from the BAMF Resource Assessment data. This appears to confirm the minimum availability estimates in this Resource Assessment Report.

VI. Incentives & Financing Mechanisms Overview

Incentives

Project developers should evaluate the range of targeted business, Federal, State, and local renewable energy incentives, net financial impact of incentives on the proposed project, and benchmarks that must be met to qualify for specific incentives. The use of incentives can greatly enhance the financial feasibility of a project.

The most valuable biomass incentives are generally production credits or payments. However, the Departments of Energy and Agriculture have administered loan and loan guarantee programs under which qualified applicants may be eligible for loans or loan guarantees that provided direct financing or guaranteed loans for capital construction.

FEMP has a comprehensive source of information on Federal, State, local, and utility incentives that promote renewable energy and energy efficiency. The URL is:
http://www1.eere.energy.gov/femp/financing/energyincentiveprograms.html. The information on this website provides an overview of incentives, but it should not be the used as the only source of information when making purchasing, investment or tax decisions or entering into binding agreements. Verify that a particular incentive is applicable to your project. Data on the website is updated at least annually.

Another good source is the DSIRE website which includes Federal, State, and local incentives: http://www.dsireusa.org/. Appendix F includes a comprehensive list of federal, state and local incentives that may be applicable and available for project use.

Financing Mechanisms

Federal energy projects require funding to generate results. Carefully matching available financing mechanisms with specific project needs can make the difference between a stalled, unfunded project and a successful project generating energy and cost savings.

The U.S. Department of Energy's (DOE) FEMP facilitates the Federal Government's implementation of sound, cost-effective energy management and investment practices to enhance the nation's energy security and environmental stewardship. Energy efficiency, renewable energy, water efficiency, and greenhouse gas management projects require significant funding. FEMP supports Federal agencies in identifying, obtaining, and implementing alternative financing to fund energy and water management projects.

Financing mechanisms include:

- Energy Savings Performance Contracts
- Utility Energy Services Contracts
- Power Purchase Agreements

Federal agencies can take advantage of these alternative financing mechanisms, choosing the best fit for their project needs. That often means a combination of financing mechanisms and agency appropriations. The FEMP Alternative Financing Quick Guide (PDF 697 KB) provides an overview of alternative financing options and strategies available to Federal agencies.

VII. Recommendations

Future Considerations

The proposed facility can serve as an initial base for the expansion and revitalization of the industrial park. Project developers may wish to consider oversizing certain components of the facility's infrastructure to accommodate future expansion. Project developers, in collaboration with the City of Yreka and the Siskiyou County Economic Development Council, may be able to expand generation capacity at the site as new thermal users are attracted to the industrial park. This approach affords Timber Products Veneer Mill both the thermal output needed for their operation and an immediate market for the utilization of their residual waste wood. At the same time, the recommended sizing of the generation facility in this first phase serves to minimize risks to project developers concerning fuel supply and thermal customers. Furthermore, by locating the facility in the vacant industrial lot adjacent to the veneer mill, project developers are well positioned to expand the size of the operation (e.g. sorting yard, ambient storage, tipping station, increased electrical and thermal output, etc.) based on future thermal demands in the industrial park and the grid transmission capacity for additional renewable energy generation. For example, project developers may wish to contact the nearby asphalt plant to discuss their thermal demands and the potential for constructing thermal runs through the heart of the industrial park. The asphalt plant is approximately 1,700 feet north of the proposed generation facility.

Engineering

Based on the preliminary information and analysis conducted in this assessment it is recommended that this project be considered for more detailed analysis.

Siting of Biomass Power Facilities

As noted in the Findings section of this review, the potential availability of biomass fuel for use in the generation of renewable energy is significant. Between 376,053 and 541,732 BDT of biomass fuel is potentially available on an annual basis from sources within the study area. If all of this biomass fuel were converted to electrical energy, between 46 and 66 MW of power could be generated. While this is substantial, it should be noted that 56% of the potential supply is estimated to be from biomass thinings, which have not historically been conducted on a large scale in the study area. If these treatments do not increase dramatically, the potential available biomass could be much lower.

It is clear that support and supply exist within the study area for the siting of one or more biomass power generating facilities. Potential environmental impacts and the scale of a potential facility are of primary concern to many stakeholders.

For these reasons it is suggested a power plant in the study area include the following:

- Small scale (1-3 MW or less) biomass power generation technologies should be considered at selected sites that have the ability to utilize on site or sell to a willing, financially stable buyer both heat and power that would be produced at such a facility.
- Large scale (5MW or larger) biomass generation facilities should be considered for sites that currently support industrial or commercial operations that can utilize the produced heat and power.

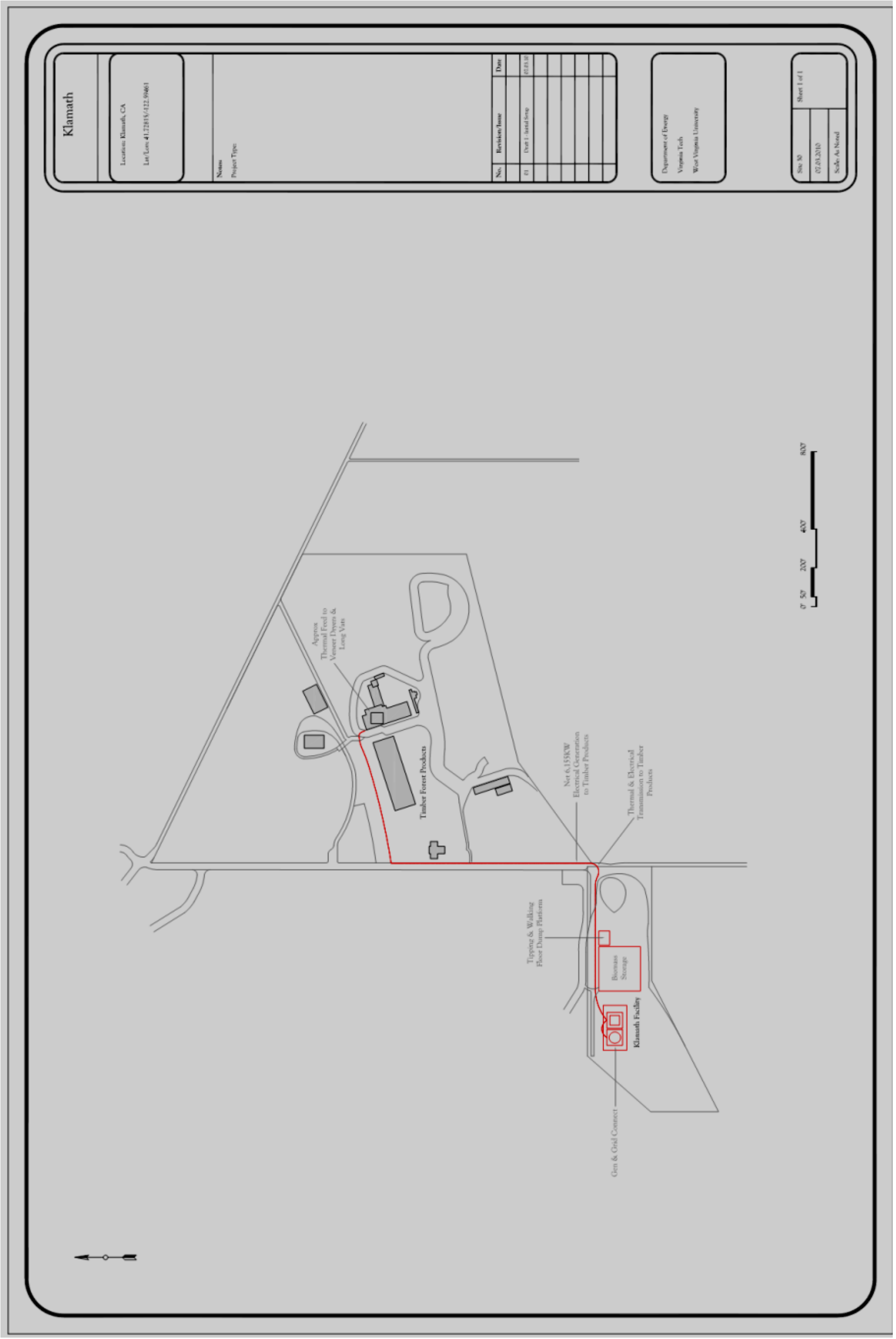
Community Interest in Biomass Utilization

Interviews with stakeholders in the Klamath study are, conducted as part of this review, indicated that community support exists for the establishment of economical, value-added markets in support of woody biomass utilization. Many of those interviewed expressed a concern that any such new or expanded markets should seek to meet the following attributes:

- Environmentally benign – no negative impacts to the environment (air, water, forest resources, wildlife/fisheries, recreation) and the project should be scaled to local conditions
- Provide societal benefits – generate products that are environmentally sustainable and provide multiple benefits to society
- Employ local residents – provide sustainable, family wage jobs

Appendix A: Site Diagrams & Photos

Site Diagram



Photos

Potential Site for CHP

Raw Material and Local Transport Company

Loading Chip Van with Raw Material

On-site Assessment Meeting

Potential Raw Material

Local Harvesting Operation

Appendix B: BAMF Resource Assessment

Note:
This appendix contains a report with its own page numbering and appendices.

Biomass and Alternative Methane Fuels Resource Assessment Report for a Selected Federal Facility

Department of Agriculture
Klamath (1)
Yreka, CA

June 2010

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FEDERAL ENERGY MANAGEMENT PROGRAM

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Table of Contents

Executive Summary

This report has identified a set of potential opportunities for BAMF projects for the Department of Agriculture Klamath (1). By querying national databases of BAMF sources developed by NETL for FEMP, specific matches have been identified. The following table summarizes the estimated quantity of BAMF Resources near Klamath (1).

BAMF Resources				
Resource	**Radius Queried (Miles)**	**Number of Sources Identified**	**Estimated Potential (MMBTU)**	**Estimated Potential (MWe)** [4]
Landfills	15	2	8,339	0.28
Wastewater Treatment Plants	15	0	n/a	n/a
Industrial Wood Residue[1]	50	30	190,944	6.39
Western Forest Fire Mitigation Residue[2]	50	2	943,113	31.55
Coal Bed Methane[3]	n/a	0	n/a	n/a

[1] Industrial Wood Residue resources are industrial sector generators and do not include federal, state, or local forest landlord agencies.
[2] Western Forest Fire Mitigation Residue represents the majority of fire mitigation thinnings on US public forest land. This is due to forest type and low relative humidity.
[3] A Federal facility is evaluated for coal bed methane potential based on whether the facility is located within or outside a coal basin. The fact that a Federal facility is located within a coal basin does not ensure coal bed methane exists under the facility.
[4] MWe values assume a 30% generator efficiency for Industrial Wood Residue and Western Forest Fire Mitigation Residue and a 25% microturbine efficiency for Landfills and Wastewater Treatment Plants.

Information on incentives for renewable energy and energy efficiency is available on the FEMP Website under Financing Mechanisms / Energy Incentive Programs: http://www1.eere.energy.gov/femp/financing/energyincentiveprograms.html. Further information on the FEMP website may be found in Appendix H.

Matching BAMF Sources and Nearby Federal Facilities

Introduction

This report presents an assessment of available biomass and alternate methane fuel (BAMF) sources that are in proximity to Klamath (1) at Yreka Renewable Energy Park in Yreka, CA. This study was performed as part of an effort to identify sources of biomass and alternate methane fuels that could be effectively and economically utilized in Federal buildings. A detailed description of the background for the project and the methodology used to assemble the datasets, determine latitude and longitude values, and establish filtering thresholds for the size and proximity of the resources are provided in Appendix A. Appendix F contains a glossary of acronyms. Weather statistics for the area are provided in Appendix G.

Results for Landfills

A proximity analysis was performed for the landfills in the BAMF database for which latitude/longitude values were available. A proximity cutoff of 15 miles was selected. The assessment determined that there are 2 nearby landfills within 15 miles of Klamath (1). A map and detailed information on the landfills are shown in Appendix B. Included is an estimate of the potential electric power output achievable should a power application be chosen as the end-use (see methodology in Appendix A).

Results for Wastewater Treatment Plants

A proximity analysis was performed for the candidate wastewater treatment plants in the BAMF database for which latitude/longitude values were available. There are no nearby wastewater treatment plants within 15 miles of Klamath (1) having a flow greater than or equal 5 MMGD.

Results for Wood Residue

A proximity analysis was performed for the high volume industrial wood residue generators in the BAMF database for which latitude/longitude values were available. A proximity cutoff of 50 miles was selected. The proximity analysis identified a total of 30 industrial wood residue producers within 50 miles of Klamath (1). The proximity analysis for Western forest fire mitigation residue identified 2 counties with residue where the county centroid is within 50 miles of Klamath (1).

A map and detailed information on the industrial wood residue generators are shown in Appendix C, ordered by greatest estimated capacity of wood residue. A map and detailed information on the counties with Western public land forest fire mitigation sources are shown in Appendix D, also ordered by greatest estimated capacity of wood residue. Also shown is an estimate of the potential heat content (see methodology in Appendix A.)

For reference, Appendix E includes a list of all National Forests where any part of the National Forest is within 50 miles of Klamath (1). Contact information for each of these forests is included in the report.

Results for Coal Bed Methane

This Federal site is not located within a coal basin and therefore does not have the potential for producing coal bed methane. Purchasing coal bed methane from another Federal site and transporting it through existing commercial pipelines, laying a pipeline to the coal bed methane source, or buying electricity off the grid produced from Federal-resourced coal bed methane may meet BAMF project criteria.

APPENDIX A

Resource Assessment Background & Methodology

Resource Assessment Background

To assess the market potential of BAMF resources, the National Energy Technology Laboratory (NETL) developed databases of large Federal facilities, landfills, wastewater treatment plants, sources of wood residues, and areas of coal bed methane potential. The databases contain basic information about the facilities, sites, and coal basins, including latitude/longitude location data.

The databases were developed for the Federal Energy Management Program (FEMP) by NETL, in collaboration with the Pacific Northwest National Laboratory (PNNL), the General Services Administration (GSA) and the U.S. Environmental Protection Agency (EPA). The assessment has focused on four resources that are expected to be major contributors to federal BAMF projects—landfills, wastewater treatment plants, wood residue, and coal bed methane.

An effort has been made to prioritize the BAMF sources with respect to their attractiveness for a BAMF project. However, the data sets used to generate this assessment are not complete and the data have not undergone independent verification and validation. Consequently, before planning a project, identified resources should be verified. In particular, due to the recession, changes are occurring rapidly in the wood industry. Moreover, projects need not be restricted to landfills, wastewater treatment plants, wood residue, or coal bed methane; a project that utilizes any biomass or alternate methane source is encouraged.

This assessment has focused on two key factors: quantity and proximity. For quantity, both the size of the BAMF resource (source) and the size of the Federal facility (demand) are important in determining whether sufficient energy cost savings could be realized to make the cost of the facility enhancement economically attractive. The closer the BAMF resource is to the Federal facility; the lower the cost of delivering the resource. Obviously many other factors are important in determining the economic attractiveness and feasibility of a BAMF project, but quantity and proximity are the two crucial elements.

Resource Assessment Methodology

Data Sources

The key step in the assessment was to develop resource databases that contain quantity and/or capacity data and location information for the eligible BAMF resources.

The landfill database used in the resource assessment was based on information provided by the U.S. Environmental Protection Agency's (EPA) Landfill Methane Outreach Program (LMOP). A snapshot of the LMOP database was provided and contained basic facility information (name, address, owner, and operator contact data).

Latitude/longitude coordinates were included in the LMOP dataset for some landfills and geocoded for much of the remainder. The geocoding algorithm used the centroid of the area based on a prioritized set of decreasing accuracy address information: (1) 9-digit ZIP code, (2) 5-digit ZIP code, (3) city name, or (4) county name.

A measured or EPA-estimated landfill gas (LFG) flow rate was used where available. Municipal solid waste in place (MSW in place) capacity data were available for 1,672 of these landfills. For those landfills without a measured LFG flow, an estimate was made based on the available waste in place (WIP) value.

The wastewater treatment plant database used in the resource assessment was based on information obtained from EPA's Water Discharge Permit (PCS) database. This database was queried for all facilities with a SIC code of 4952 (Sewerage systems). The flow rate was used, when available. Latitude/longitude coordinates were used where possible and geocoded for much of the remainder using the same staged prioritized geocoding algorithm as used for the landfills.

The industrial wood residue data are based on the North American Industrial Classification System (NAICS) for selected categories of wood industries that generate a significant amount of wood residue from their production operations. The number of employees, location, and contact information was obtained from a database of these operations. The quantity of wood residue was calculated from an estimate of the amount of wood generated per employee. This was determined by taking a small sample of individual wood manufacturing locations, determining the quantity of residue, and dividing by total on-site employees at that location to obtain the average.

There is a significant quantity of wood residue generated in the United States from thinning to mitigate fire danger. This is an activity of the state and public landlord agencies, mainly in the Western US, because of the type of forests and low relative humidity found there. Additional wood residue data were therefore obtained from a Western Governor's Association (WGA) Resource Assessment prepared by the USDA Forest Service for the expected accumulation of Western forest fire mitigation residue. Data extracted from this source covers public land in general and includes wood residue from thinning of forests with high fire hazard, treatment of pinyon juniper woodland, precommercial thinning on National Forest land in Washington, western Oregon, and some general thinning of private woodland. These data are only available for the western states and were prepared on a per county basis. Data from the WGA report was excluded on logging and mill residue to avoid duplication with information already included in the industrial wood residue data. This data represents the amount of wood estimated for fire mitigation thinning on an annual basis.

Coal bed methane data are based on regional maps in ARCGIS shape file format showing the areal extent of North American coal basins. The maps, created by the United States Geological Survey (USGS) and the Department of Energy's Energy Information Administration (DOE-EIA), indicate regions where coals are known to exist. Many areas have not been completely assessed for the number of coal seams or for favorable geological conditions conducive to the presence of methane in the coals.

In developing the resource databases, it became apparent that it was not feasible to generate a truly comprehensive set of matches between selected Federal facilities and nearby BAMF sources, primarily because of limitations in the quality of the available data. However, the purpose of the assessment was to identify a number of the most promising matches, rather than a complete list. To do this, reasonable, but somewhat arbitrary cutoffs were established for capacity and proximity factors.

Resource Capacity Screening Criteria

An initial screening was performed to filter out BAMF resources that were too small for a BAMF project. In the case of landfills, sites without a reported LFG flow or WIP value were excluded.

Wastewater treatment facilities having flow rates less than 5 MMGD (million gallons per day) were deemed too small for a BAMF project and were excluded. This initial screening was considered a conservative minimum and used to reduce the size of the dataset used in the proximity analysis. In most cases, an economically viable BAMF project will require a BAMF source having a substantially greater capacity.

The industrial wood residue data were screened by selecting only the producers having at least 3 employees.

For Western forest fire mitigation residue, the estimates of biomass supply were developed after first identifying sustainability principles to guide their use. In general terms sustainability is defined as today's management actions that will not degrade the ecological functioning of a natural system.

With respect to coal bed methane data, Federal sites were divided into two categories: (1) sites located outside the coal basin perimeter that were not considered coal bed methane candidates and (2) sites located within coal basins that were considered potential coal bed methane candidates.

Proximity Analysis Matching Criteria

Because of the great variability in the pipeline or transportation cost with respect to geographic and geologic conditions, the specific cutoffs for an economically viable BAMF project must be determined on a case by case basis. Generally, a larger search radius than the economical cutoff value was used because of the degree of uncertainty in the latitude/longitude data in the database. For this study, the distance criteria selected were 15 miles for landfills, 15 miles for wastewater treatment plants, and 50 miles for Western forest fire mitigation residue. For these three resources, the distances were calculated on a straight-line basis. For industrial wood residues we also used 50 miles, however, we calculated the distance in driving miles as this is the method of transport that would be used for the resource. Since the Western forest fire mitigation data is based on the county level, we used the county centroid for the selection criteria. Depending upon the location of the residue in the county, some or all of the residue may be outside the 50 mile radius. For coal bed methane to be a viable BAMF Energy Conservation Measure (ECM), the coal bed methane must be produced from and utilized on Federal property, although the producing and using Federal properties can be mutually exclusive. For this study, Federal facilities acquiring coal bed methane production from other federal properties must be connected to a commercial natural gas supply or within 15 miles of an existing natural gas transportation pipeline that can be used to transport the coal bed methane from the source to the facility.

Estimates for Bio-gas Flow, Heating Value and Electrical Power Output

For landfills, when the LFG is not reported, it is estimated as 0.6 standard cubic feet per day per ton (scfd/ton) of waste in place. It is further assumed that 50% of this gas can be collected and utilized in a BAMF project. The bio-gas production from wastewater treatment plants is estimated as 0.017 standard cubic feet per gallon (scf/gal) treated water.

The heating value for the bio-gas from landfills and wastewater treatment plants was estimated using a typical composition for the gas (50% methane for landfills, 65% methane for wastewater treatment plants) using the Aspen Plus software package. The potential power estimate was calculated using an assumed microturbine efficiency value of 25%.

For industrial wood residue, the heating value was calculated by taking 1000 lbs of residue generated per employee per day times an estimated 260 working days per year times 4500 BTUs per lb of waste wood converted to units expressed in million BTUs. The power estimate was calculated using a generator efficiency value of 30%.

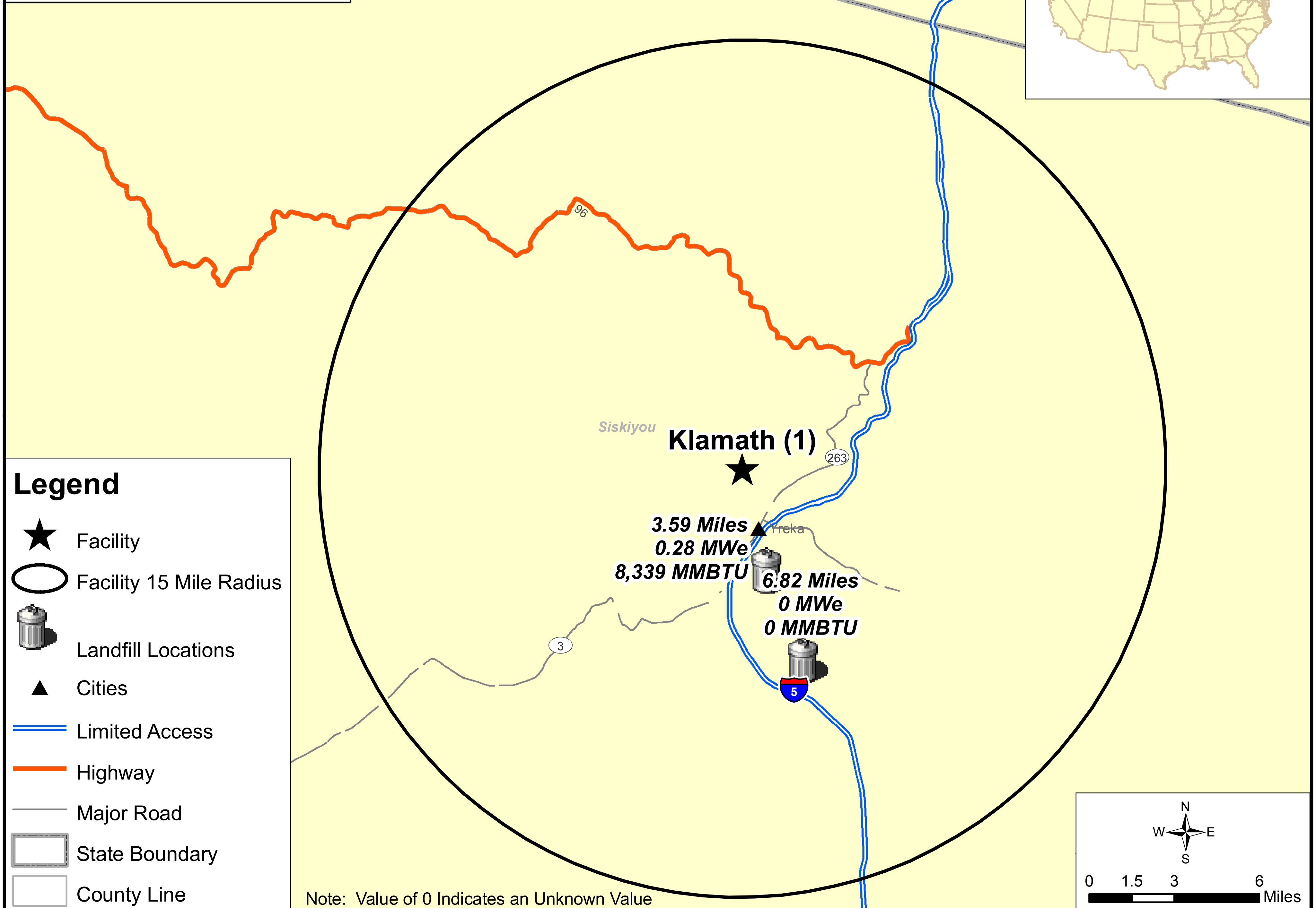
For Western forest fire mitigation residue, we took the tons per year times 4500 British Thermal Units (BTUs) per lb of waste wood converted to units expressed in million BTUs. The power estimate was calculated using a generator efficiency value of 30%.

Energy estimates were not calculated for coal bed methane potential in this assessment, but rather a judgment was made on overall availability. The heating value however of coal bed methane is similar to that of natural gas at 1000 BTUs per scf. Commercially viable production will not only depend on BTU values, but on favorable site geologic and hydrologic conditions in addition to regional environmental considerations such as water quality.

APPENDIX B

Landfill Proximity Analysis

Klamath (1) Landfill Locations



Custom BAMF Market Assessment Report

Landfill Proximity Analysis for Selected Facilities

(Distance <= 15 miles)

Landfill	Owner	Operator	Est. Total Energy (Million BTUs/Year)	Est. Total Power (MWe)	Distance (miles)
Custom Assessment for Klamath (1)					
Yreka Solid Waste Landfill 2420 Oberlin Rd. Yreka, CA	City of Yreka 701 4th Street Yreka, CA 96097 (916) 842-4386	City of Yreka 701 4th Street Yreka, CA 96097 (916) 842-4386	**8,339**	**0.28**	3.59

Comments:

Current Utilization Status:	Potential	Current Status:	Open	Opened:	1979	Close Date:	2026
LFG Collection System in Place:	0	Project Type:	Unknown	LFG Collected:		LFG Flow:	
Waste in Place (est tons):	0	Waste In Place Year:		Design Area (acres):		Current Landfill Area (acres):	161

Landfill	Owner	Operator	Est. Total Energy (Million BTUs/Year)	Est. Total Power (MWe)	Distance (miles)
Tennant Solid Waste Disposal Site Tennant, CA	United States Department of Agriculture 1312 Fairlane Road Yreka, CA 96097 (916) 842-6131	Siskiyou County 305 Butte Street Yreka, CA 96097 (916) 842-8250	**0**	**0.00**	6.82

Comments:

Current Utilization Status:	Potential	Current Status:		Opened:		Close Date:	
LFG Collection System in Place:	0	Project Type:	Unknown	LFG Collected:		LFG Flow:	
Waste in Place (est tons):	0	Waste In Place Year:		Design Area (acres):		Current Landfill Area (acres):	0

2 Landfills — **8,339** MMBTU — **0.28** MWe

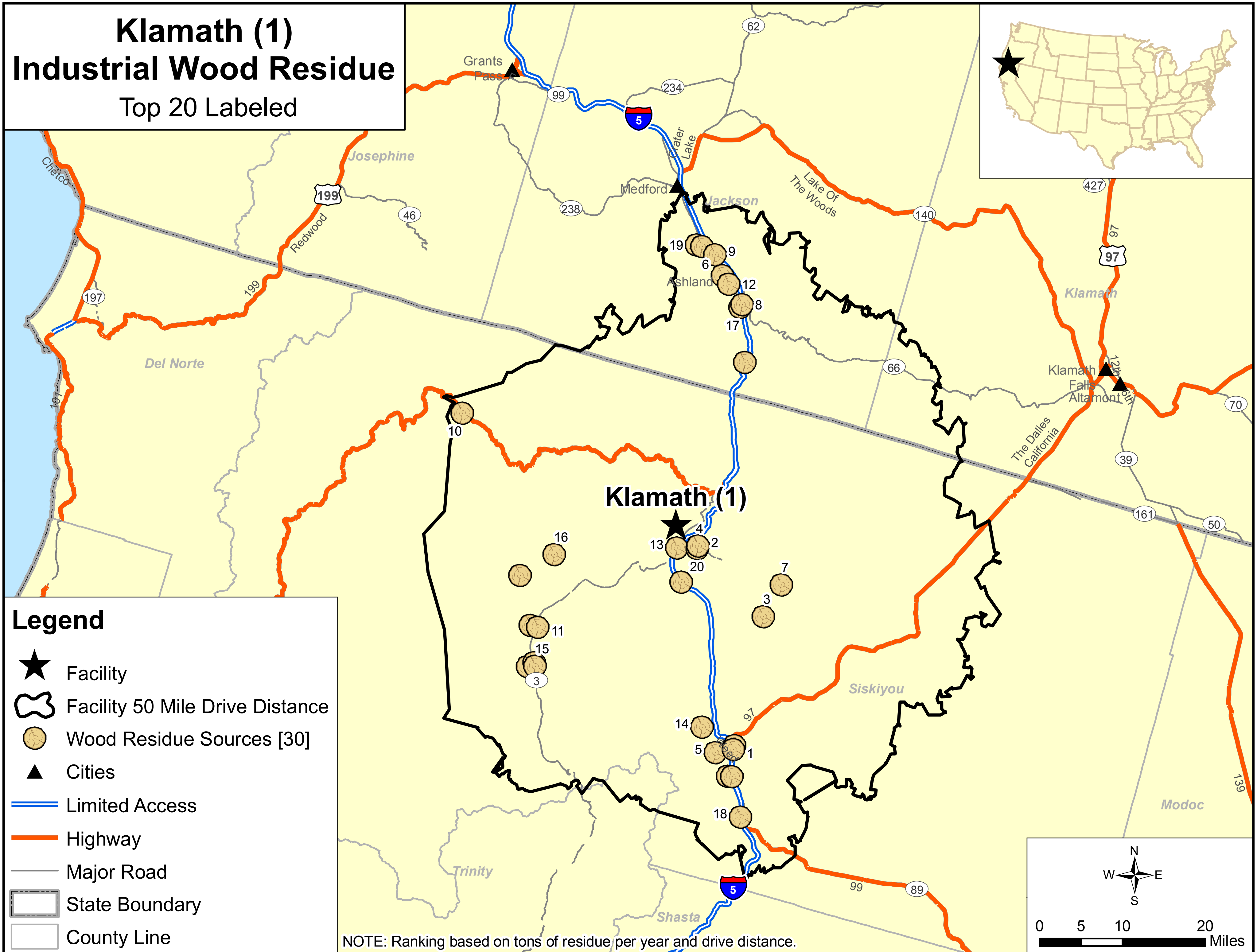
Note: Landfill Data Left Blank or Containing 0 is not available for the report.

APPENDIX C

Industrial Wood Residue Proximity Analysis

Klamath (1)
Industrial Wood Residue

Top 20 Labeled



Legend

- Facility
- Facility 50 Mile Drive Distance
- Wood Residue Sources [30]
- Cities
- Limited Access
- Highway
- Major Road
- State Boundary
- County Line

NOTE: Ranking based on tons of residue per year and drive distance.

Custom BAMF Market Assessment Report

Industrial Wood Residue Proximity Analysis

Distance <= 50 Miles

Potential Source / Contact Info	Est. Total Wood Residue (green tons/year)	Est. Total Energy (Million BTUs/Year)	Est. Total Power (MWe)	Distance (miles)	Rank
Custom Assessment for Klamath (1)					
Roseburg Forest Products Co P O Box 680 Weed, CA 96094-0680 Phone: 530-938-2721	20,930	56,511	1.89	32.39	1
Timber Products Co L P P O Box 766 Yreka, CA 96097-0766 Phone: 530-842-2310	15,080	40,716	1.36	5.47	2
Chuck L Logging Inc 6527 Big Springs Rd Montague, CA 96064-9105 Phone: 530-459-1138	5,850	15,795	0.53	19.77	3
Shasta Forest Products Inc P O Box 777 Yreka, CA 96097-0777 Phone: 530-842-2787	3,900	10,530	0.35	5.42	4
Sanders Prcsion Timber Falling 9509 N Old Stage Rd Weed, CA 96094-9516 Phone: 530-938-4120	3,900	10,530	0.35	31.75	5
Sawyer Wood Products Inc 299 Rogue River Pkwy Talent, OR 97540-8621 Phone: 541-535-3606	2,600	7,020	0.23	43.45	6
Dave Richardson Trucking 8817 Lwer Lttle Shasta Rd Montague, CA 96064-9699 Phone: 530-459-5088	2,340	6,318	0.21	17.36	7
Naturalyards LLC P O Box 3180 Ashland, OR 97520-0306 Phone: 541-488-0838	1,430	3,861	0.13	34.48	8
Vanderlip Logging Company Inc 150 Lowe Rd Ashland, OR 97520-9618 Phone: 541-488-1758	1,300	3,510	0.12	41.54	9
Mark Crawford Logging Inc P O Box 720 Seiad Valley, CA 96086-0720 Phone: 530-496-3272	1,300	3,510	0.12	46.11	10
Jim Johnson Logging 4500 Scott Valley Rd Etna, CA 96027-9537 Phone: 530-467-3956	1,040	2,808	0.09	28.12	11
Morlog Corp 1257 Siskiyou Blvd 1149 Ashland, OR 97520-2241 Phone: 541-840-6490	1,040	2,808	0.09	37.45	12

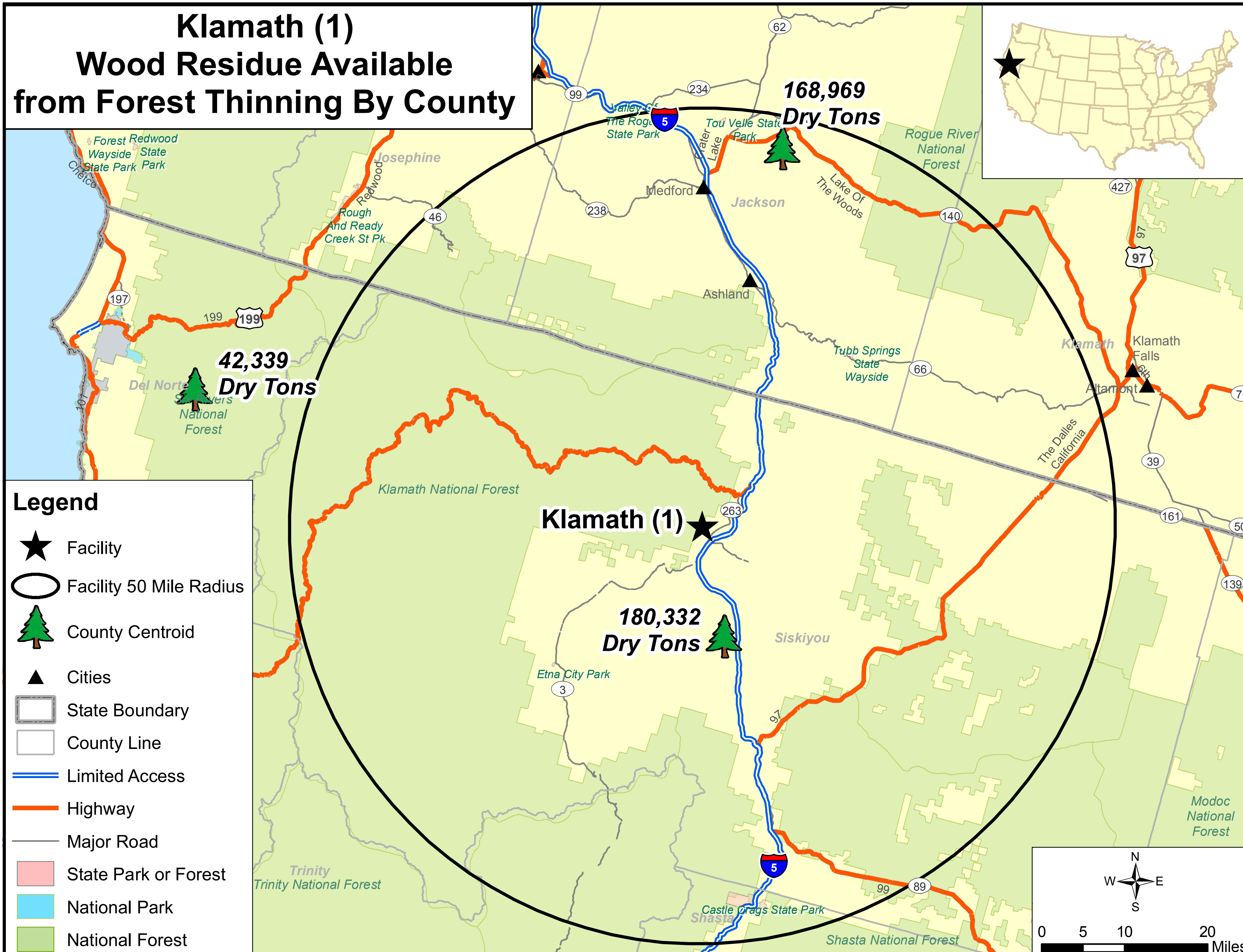
Potential Source / Contact Info	Est. Total Wood Residue (green tons/year)	Est. Total Energy (Million BTUs/Year)	Est. Total Power (MWe)	Distance (miles)	Rank
Buk-N-Run Timber Falling LLC P O Box 1001 Fort Jones, CA 96032-1001 Phone: 530-468-5803	910	2,457	0.08	4.42	13
Edgewood Logging 2134 Stewart Springs Rd Weed, CA 96094-9537 Phone: 530-938-2692	910	2,457	0.08	30.43	14
Robert Gilmore Shop 267 Callahan Etna, CA 96027 Phone: 530-467-5651	780	2,106	0.07	32.30	15
Ken Dysert Logging P O Box 493 Fort Jones, CA 96032-0493 Phone: 530-468-2999	650	1,755	0.06	26.78	16
Fallon Logging LLC 255 Timberlake Dr Ashland, OR 97520-9085 Phone: 541-482-1470	650	1,755	0.06	34.69	17
Shasta Brown Inc 511 S Old Stage Rd Mount Shasta, CA 96067-9743 Phone: 530-926-4010	650	1,755	0.06	41.44	18
Farmer Logging P O Box 368 Talent, OR 97540-0368 Phone: 541-535-6026	650	1,755	0.06	44.24	19
Shasta Forest Products Inc P O Box 777 Yreka, CA 96097-0777 Phone: 530-842-2785	520	1,404	0.05	5.65	20
Jim Eiler Trucking 5505 Shamrock Rd Yreka, CA 96097-9719 Phone: 530-842-5894	520	1,404	0.05	9.22	21
Quartz Valley Cutterz 13605 Quartz Valley Rd Fort Jones, CA 96032-9714 Phone: 530-468-5632	520	1,404	0.05	31.15	22
Hanscom & King Logging Inc 147 N Pioneer St Ashland, OR 97520-1823 Phone: 541-482-3221	520	1,404	0.05	38.80	23
Smiley Brothers Logging LLC 600 Balsam Ln Etna, CA 96027-9514 Phone: 530-467-3144	390	1,053	0.04	28.41	24
Frenzel Company 9344 Mt Ashland Ski Rd Ashland, OR 97520-9793 Phone: 541-482-3522	390	1,053	0.04	28.73	25
McEwen Logging P O Box 248 Etna, CA 96027-0248 Phone: 530-598-1453	390	1,053	0.04	31.83	26

Potential Source / Contact Info	Est. Total Wood Residue (green tons/year)	Est. Total Energy (Million BTUs/Year)	Est. Total Power (MWe)	Distance (miles)	Rank
Siskiyou Forest Products 190 Boles St Weed, CA 96094-2518 Phone: 530-938-2771	390	1,053	0.04	32.08	27
Double Bit Logging 910 Sawyers Bar Rd Etna, CA 96027-9410 Phone: 530-467-5341	390	1,053	0.04	32.87	28
Spencer Logging Co LLC 5401 N Old Stage Rd Mount Shasta, CA 96067-9137 Phone: 530-926-2164	390	1,053	0.04	35.87	29
Darrah Logging Inc P O Box 236 Mount Shasta, CA 96067-0236 Phone: 530-926-1706	390	1,053	0.04	35.93	30
30 Sources	**70,720** tons	**190,944** MMBTU	**6.39** MWe		

APPENDIX D

Western Forest Fire Mitigation Residue Proximity Analysis

Klamath (1)
Wood Residue Available from Forest Thinning By County



Custom BAMF Market Assessment Report

Western Forest Fire Mitigation Residue Detail

Distance <= 50 Miles to County Centroid

County	State	Est. Total Residue (Tons)	Est. Total Energy (Million BTUs)	Est. Total Power (MWe)
Custom Assessment for Klamath (1)				
Siskiyou	California	180,332	486,897	16.29
Jackson	Oregon	168,969	456,216	15.26
2 County(ies)		**349,301** Tons	**943,113** MMBTU	**31.55** MWe

APPENDIX E

National Forest Contact Information

Custom BAMF Market Assessment Report

National Forest Contact Information

Any Portion of Forest Within 50 Miles of Facility

Forest / Forest Supervisor Contact Info

Custom Assessment For: Klamath (1)

Klamath National Forest

PEG BOLAND
1312 Fairlane Road
Yreka, CA 96097-9549
Phone: 530-841-4501

Rogue River National Forest

SCOTT CONROY
333 West 8th St. P.O. Box 520
Medford, OR 97501-0209
Phone: 541-858-2200

Shasta National Forest

J. SHARON HEYWOOD
3644 Avtech Parkway
Redding, CA 96002-9241
Phone: 530-226-2520

Siskiyou National Forest

SCOTT CONROY
333 West 8th St, P.O. Box 520
Medford, OR 97501-0209
Phone: 541-858-2200

Winema National Forest

KAREN SHIMAMOTO
1301 South G Street
Lakeview, OR 97630-1800
Phone: 541-947-6200

APPENDIX F

Glossary of Acronyms and Terms

Glossary of Acronyms and Terms

Term	Definition
BAMF	Biomass and Alternate Methane Fuels
Biomass	An organic nonfossil material -can be used as a renewable fuel
Bio-gas	A gas produced by the digestion of organic materials. In this case, at waste disposal sites and water treatment plants. Contains 50% or more methane.
DOE	Department of Energy
DOI	Department of Interior
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESCO	Energy Service Company
ESPC	Energy Savings Performance Contract
FEMP	Federal Energy Management Program
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information Systems
GSA	General Services Administration
LMOP	Landfill Methane Outreach Program
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
MMGD	Million Gallons per Day
MMSCFD	Million Standard Cubic Feet per Day, measure of gas flow rate
MSW	Municipal Solid Waste
Municipal Solid Waste	Waste generally delivered to a landfill
MWe	Megawatt Equivalence
NETL	National Energy Technology Laboratory
NPDES	National Pollutant Discharge Elimination System
NREL	National Renewable Energy Laboratory Golden, Colorado
PCS	Permit Compliance System
SIC	Standard Industrial Classification
WIP	Waste in Place, capacity factor for landfill
WWTP	Wastewater Treatment Plant

APPENDIX G

Weather Statistics

Yreka, CA
Weather Averages*

Latitude: **41°43'N**, Longitude: **122°38'W**, Elevation: **2630.0 ft**, Distance: **4.60 mi**

	Unit	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average temperature over 51 years	°F	51	34	39	43	48	55	62	71	69	62	51	41	34
Average high temperature over 51 years	°F	66	44	50	55	63	72	80	90	89	82	69	53	44
Average low temperature over 51 years	°F	37	24	27	30	34	40	47	52	51	44	36	29	25
Average precipitation over 51 years	in	19.6	3.5	2.1	1.8	1.0	1.0	1.0	0.4	0.6	0.7	1.3	2.5	3.8
Average snowfall over 51 years	in	19.2	7.6	2.2	1.9	0.4	-	-	-	-	-	-	2.1	5.0
Average snow cover over 51 years	in	-	1.0	-	-	-	-	-	-	-	-	-	-	-
Heating degree days over 30 years	days	5386	958	720	676	486	273	94	13	19	122	375	708	942
Cooling degree days over 30 years	days	572	-	-	-	-	9	85	214	196	68	-	-	-

*Source: www.weatherreports.com

APPENDIX H

Energy Incentive Programs on FEMP Website

FEMP Energy Incentive Programs Website Information

FEMP has a comprehensive source of information on state, local, and utility incentives that promote renewable energy technologies and energy efficiency. The URL is: http://www1.eere.energy.gov/femp/financing/energyincentiveprograms.html . The information on the FEMP web site provides an overview of incentives, but it should not be used as the only source of information when making purchasing decisions, investment decisions, tax decisions or other binding agreements. Verify that a specific incentive is applicable to your project. Data on this website is updated at least annually.

End of BAMF Resource Assessment report.

Page numbering and appendices within the body of the feasibility study resume on the following page.

Appendix C: Financial Incentives

for Biomass and/or Combined Heat/Power (CHP)

Corporate Tax Credit Business Energy Investment Tax Credit (ITC)

Last DSIRE Review: 06/10/2009

State:	Federal
Incentive Type:	Corporate Tax Credit
Applicable Sectors:	Commercial, Industrial, Utility
Amount:	10%** for CHP
Maximum Incentive:	No limit
Eligible System Size:	CHP: 50 MW or less**
Equipment Requirements:	CHP systems must meet specific energy-efficiency criteria
Program Administrator:	U.S. Internal Revenue Service

Note: The American Recovery and Reinvestment Act of 2009 (H.R. 1) allows taxpayers eligible for the federal renewable electricity production tax credit (PTC)** to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The new law also allows taxpayers eligible for the business ITC to receive a grant from the U.S. Treasury Department instead of taking the business ITC for new installations. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business energy investment tax credit instead of the federal renewable electricity production tax credit. The Treasury Department will issue more extensive guidance at a later time.

The federal business energy investment tax credit established new credits for combined heat and power (CHP) systems; extended eligibility for the credits to utilities; and allowed taxpayers to take the credit against the alternative minimum tax (AMT), subject to certain limitations. The credit was further expanded by *The American Recovery and Reinvestment Act of 2009*, enacted in February 2009.

In general, credits are available for eligible systems placed in service on or before December 31, 2016.

Combined Heat and Power (CHP).* The credit is equal to 10% of expenditures, with no maximum limit stated. Eligible CHP property generally includes systems up to 50 MW in capacity that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the credit may be reduced for less-efficient systems. This credit applies to eligible property placed in service after October 3, 2008.
In general, the original use of the equipment must begin with the taxpayer, or the system must be constructed by the taxpayer. The equipment must also meet any performance and quality standards in effect at the time the equipment is acquired. The energy property must be operational in the year in which the credit is first taken.

*** The February 2009 legislation (H.R. 1) that allows PTC-eligible facilities to use the 30% ITC has implications for some technologies that were already potentially eligible for either incentive in some form. Certain geothermal and open- or closed- loop biomass systems (including biomass CHP projects) now qualify for a 30% tax credit through through December 31, 2013, the in-service deadline for these technologies under the PTC. Wind-energy systems of all sizes -- not only systems of 100 kW or less -- also now qualify for the 30% ITC through the wind-energy PTC in-service deadline of December 31, 2012. Applicants should refer to the eligibility definition contained in the PTC to determine if and how their project might qualify for this treatment.*

Contact:

Public Information - IRS
U.S. Internal Revenue Service
1111 Constitution Avenue, N.W.
Washington, DC 20224
Phone: (800) 829-1040
Web Site: http://www.irs.gov

Business Energy Tax Credit
(Biomass, CHP/Cogeneration)

Last DSIRE Review: 05/28/2010

State:	Oregon
Incentive Type:	Corporate Tax Credit
Applicable Sectors:	Commercial, Industrial, Construction, Multi-Family Residential, Agricultural, Equipment manufacturers
Amount:	Renewable energy generation, renewable energy equipment manufacturing, high efficiency combined heat and power: 50% of certified project costs, distributed over five years (10% per year) 35% of certified project costs, distributed over five years (10% in the first and second years, 5% each year thereafter)
Maximum Incentive:	$10 million for other renewable energy generation projects.
Eligible System Size:	Not specified
Equipment Requirements:	System must be new and in compliance with all applicable performance and safety standards; must pass preliminary and final certification of the ODOE review process. "Sustainable Buildings" must achieve LEED Silver Certification in addition to other ODOE requirements.
Carryover Provisions:	Excess credit may be carried forward eight years; those with eligible project costs of $20,000 or less may take credit in one year.
Program Administrator:	Oregon Department of Energy
Start Date:	11/3/2009
Expiration Date:	5/1/2010
Web Site:	http://egov.oregon.gov/ENERGY/CONS/BUS/BETC.shtml

Oregon's Business Energy Tax Credit (BETC) is for investments in energy conservation, recycling, renewable energy resources, sustainable buildings, and less-polluting transportation fuels. Any Oregon business may qualify, including, but not limited to, manufacturing plants, stores, offices, apartment buildings, farms, and transportation. The tax credit can cover costs directly related to the project, including equipment cost, engineering and design fees, materials, supplies and installation costs. Loan fees and permit costs also may be claimed. However, replacing equipment at the end of its useful life or equipment required to meet codes or other government regulations are not eligible. Maintenance costs are also not eligible. All projects must meet the BETC technical requirements to qualify.

Projects that use biomass to produce energy, displace energy, or reclaim energy from waste may qualify for a tax credit. Renewable resource projects must replace at least 10% of the electricity, gas or oil used. The energy can be used on site or sold. The tax credit for facilities using or producing renewable energy resources is capped at $300 million for systems pre-certified from July 1, 2009 to June 30, 2011 and $150 million for systems pre-certified between July 1, 2011 and June 30, 2012. Projects must receive final certification before July 1, 2012 to use the tax credit. Renewable energy equipment manufacturing facilities must receive preliminary certification before January 1, 2014 in order to use the tax credit.

Cogeneration projects may also be eligible. Projects that develop new markets for recycled materials or recycle materials not required by law may be eligible for the tax credit. Projects that reduce employee commuting (or work-related travel) and investments in cleaner-burning fuels may qualify.

Different cost caps and percentage caps apply to different technologies. Generally, the maximum allowable credits are as follows:

- Renewable energy generation, high efficiency combined heat and power: 50% of certified project costs, distributed over five years (10% per year), up to $10 million;
- All other projects: 35% of certified project costs, distributed over five years (10% in the first and second years, 5% each year thereafter), up to $3.5 million; and

Under the pass-through option, a project owner may transfer a tax credit to a pass-through partner in return for a lump-sum cash payment (the net present value of the tax credit) upon completion of the project. The pass-through option allows non-profit organizations, schools, governmental agencies, tribes, and other public entities and businesses without tax liability to use the Business Energy Tax Credit by transferring their tax credit for an eligible project to a partner with a tax liability. As of January 1, 2010, the pass-through rate "is determined by taking the total tax credit amount divided by the sum of one plus three times the five year United States Treasury Note minus the average of the net change for the three previous calendar years of the urban Consumer Price Index (CPI) for the west region based on the index published on the first day of the calendar quarter and the first day of the same calendar quarter for the previous three calendar years exponentially raised by 5."

Applications and instructions are available on the program web site. The ODOE has published a brochure to explain how the tax credit works.

Contact:

Public Information
Oregon Department of Revenue
955 Center St NE
Salem, OR 97301-2555
Phone: (503) 378-4988
Phone 2: (800) 356-4222
Fax: (503) 945-8738
Web Site: http://www.oregon.gov/DOR/

Matt Hale
Oregon Department of Energy
625 Marion Street, N.E.
Salem, OR 97301-3737
Phone: (503) 378-4040
Fax: (503) 373-7806
E-Mail: Matt.Hale@state.or.us
Web Site:
http://www.oregon.gov/energ

Renewable Electricity Production Tax Credit (PTC) (Biomass)

Last DSIRE Review: 05/04/2010

State:	Federal
Incentive Type:	Corporate Tax Credit
Eligible Renewable Technologies:	Biomass
Applicable Sectors:	Commercial, Industrial
Amount:	2.1¢/kWh for closed-loop biomass. Generally applies to first 10 years of operation.
Carryover Provisions:	Unused credits may be carried forward for up to 20 years following the year they were generated or carried back 1 year if the taxpayer files an amended return.
Program Administrator:	U.S. Internal Revenue Service
Expiration Date:	Varies by technology
Web Site:	http://www.irs.gov/pub/irs-pdf/f8835.pdf

Summary:
Note: The American Recovery and Reinvestment Act of 2009 (H.R. 1) allows taxpayers eligible for the federal renewable electricity production tax credit (PTC) to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. The new law also allows taxpayers eligible for the business ITC to receive a grant from the U.S. Treasury Department instead of taking the business ITC for new installations. The Treasury Department issued Notice 2009-52 in June 2009, giving limited guidance on how to take the federal business energy investment tax credit instead of the federal renewable electricity production tax credit. The Treasury Department will issue more extensive guidance at a later time.

The federal renewable electricity production tax credit (PTC) is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by H.R. 1424 (Div. B, Sec. 101 & 102) in October 2008 and again by H.R. 1 (Div. B, Section 1101 & 1102) in February 2009.

The following table below outlines two of the most important characteristics of the tax credit -- in-service deadline and credit amount. The inflation-adjusted credit amounts are current for the 2010 calendar year.

Resource Type	In-Service Deadline	Credit Amount
Closed-Loop Biomass	December 31, 2013	2.2¢/kWh
Open-Loop Biomass	December 31, 2013	1.1¢/kWh

The duration of the credit is generally 10 years after the date the facility is placed in service, but there are two exceptions:

- Open-loop biomass, geothermal, small irrigation hydro, landfill gas and municipal solid waste combustion facilities placed into service after October 22, 2004, and before enactment of the *Energy Policy Act of 2005*, on August 8, 2005, are only eligible for the credit for a five-year period.
- Open-loop biomass facilities placed in service before October 22, 2004, are eligible for a five-year period beginning January 1, 2005.

In addition, the tax credit is reduced for projects that receive other federal tax credits, grants, tax-exempt financing, or subsidized energy financing. The credit is claimed by completing Form 8835, "Renewable Electricity Production Credit," and Form 3800, "General Business Credit." For more information, contact IRS Telephone Assistance for Businesses at 1-800-829-4933.

Contact:
Public Information - IRS
U.S. Internal Revenue Service
1111 Constitution Avenue, N.W.
Washington, DC 20224
Phone: (800) 829-1040
Web Site: http://www.irs.gov
Federal Grant Programs

USDA Rural Energy for America Program (REAP) Grants

U.S. Department of Treasury - Renewable Energy Grants

Last DSIRE Review: 03/31/2010

State:	Federal
Incentive Type:	Federal Grant Program
Applicable Sectors:	Commercial, Industrial, Agricultural
Amount:	10% of property
Maximum Incentive:	50 MW for CHP property, with limitations for large systems
Program Administrator:	U.S. Department of Treasury
Funding Source:	The American Recovery and Reinvestment Act (ARRA)
Start Date:	1/1/2009
Expiration Date:	12/31/2010 (construction must begin by this date)
Web Site:	http://www.treas.gov/recovery/1603.shtml

Note: The American Recovery and Reinvestment Act of 2009 (H.R. 1) allows taxpayers eligible for the federal business energy investment tax credit (ITC) to take this credit or to receive a grant from the U.S. Treasury Department instead of taking the business ITC for new installations. The new law also allows taxpayers eligible for the renewable electricity production tax credit (PTC) to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations. (It does not allow taxpayers eligible for the residential renewable energy tax credit to receive a grant instead of taking this credit.) Taxpayers may not use more than one of these incentives. Tax credits allowed under the ITC with respect to progress expenditures on eligible energy property will be recaptured if the project receives a grant. The grant is not included in the gross income of the taxpayer.

The *American Recovery and Reinvestment Act of 2009* (H.R. 1), enacted in February 2009, created a renewable energy grant program that will be administered by the U.S. Department of Treasury. This cash grant may be taken in lieu of the federal business energy investment tax credit (ITC). In July 2009 the Department of Treasury issued documents detailing guidelines for the grants, terms and conditions and a sample application. There is an online application process, and applications are currently being accepted. See the US Department of Treasury program web site for more information, including answers to frequently asked questions.

Grants are available to eligible property* placed in service in 2009 or 2010, or placed in service by the specified credit termination date,** if construction began in 2009 or 2010. The guidelines include a "safe harbor" provision that sets the beginning of construction at the point where the applicant has incurred or paid at least 5% of the total cost of the property, excluding land and certain preliminary planning activities. Generally, construction begins when "physical work of a significant nature" begins. **Combined Heat and Power (CHP).** The grant is equal to 10% of the basis of the property for CHP. Eligible CHP property generally includes systems up to 50 MW in capacity that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the grant may be reduced for less-efficient systems.

It is important to note that only tax-paying entities are eligible for this grant. Federal, state and local government bodies, non-profits, qualified energy tax credit bond lenders, and cooperative electric companies are not eligible to receive this grant. Partnerships or pass-thru entities for the organizations described above are also not eligible to receive this grant, except in cases where the ineligible party only owns an indirect interest in the applicant through a taxable C corporation. Grant applications must be submitted by October 1, 2011. The U.S. Treasury Department will make payment of the grant within 60 days of the grant application date or the date the property is placed in service, whichever is later.

Credit *termination date of January 1, 2014, for closed-loop biomass, open-loop biomass, January 1, 2017, for CHP.*

Contact:
Grant Information
U.S. Department of Treasury
1500 Pennsylvania Avenue, NW
Washington, DC 20220
Phone: (202) 622-2000
Fax: (202) 622-6415
E-Mail: 1603Questions@do.treas.gov
Web Site: http://www.treasury.gov

Federal Loan Programs

Clean Renewable Energy Bonds (CREBs)

Last DSIRE Review: 05/07/2010

State:	Federal
Incentive Type:	Federal Loan Program
Eligible Renewable Technologies:	Biomass
Applicable Sectors:	Local Government, State Government, Tribal Government, Municipal Utility, Rural Electric Cooperative
Amount:	Varies
Terms:	Certain terms for "new" CREBs differ from those for prior allocations. See IRS Notice 2009-33 for details.
Program Administrator:	U.S. Internal Revenue Service
Start Date:	04/07/2009 (New CREBS solicitation)
Expiration Date:	08/04/2009 (New CREBs application deadline)
Web Site:	http://www.irs.gov/irb/2007-14_IRB/ar17.html

Note: The IRS is not currently accepting applications for CREB allocations. Readers should also note that the terms "new" and "old" CREBs are used in the following summary to distinguish between prior CREB allocations and the new CREB authorizations made by the U.S. Congress in 2008 and 2009. The use of the term "new CREBs" has legal significance in that new CREBs authorized under 26 USC § 54A and 54C have substantially different rules than prior CREB allocations authorized under 26 USC § 54.

Clean renewable energy bonds (CREBs) may be used by certain entities -- primarily in the public sector -- to finance renewable energy projects. The list of qualifying technologies is generally the same as that used for the federal renewable energy production tax credit (PTC). CREBs may be issued by electric cooperatives, government entities (states, cities, counties, territories, Indian tribal governments or any political subdivision thereof), and by certain lenders. CREBs are issued -- theoretically -- with a 0% interest rate.* The borrower pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest.**

The Energy Improvement and Extension Act of 2008 (Div. A, Sec. 107) allocated $800 million for new Clean Renewable Energy Bonds (CREBs). In February 2009, the American Recovery and Reinvestment Act of 2009 (Div. B, Sec. 1111) allocated an additional $1.6 billion for new CREBs, for a total new CREB allocation of $2.4 billion. The Energy Improvement and Extension Act of 2008 also extended the deadline for previously reserved allocations ("old CREBs") until December 31, 2009, and addressed several provisions in the existing law that previously limited the usefulness of the program for some projects. A separate section of the law extended CREBs eligibility to marine energy and hydrokinetic power projects.

Participation in the program is limited by the volume of bonds allocated by Congress for the program. Participants must first apply to the Internal Revenue Service (IRS) for a CREBs allocation, and then issue the bonds within a specified time period. The new CREBs allocation totaling $2.4 billion does not have a defined expiration date under the law; however, the recent IRS solicitation for new applications requires the bonds to be issued within 3 years after the applicant receives notification of an approved allocation (see History section below for information on previous allocations). Public power providers, governmental bodies, and electric cooperatives are each reserved an equal share (33.3%) of the new CREBs allocation. The tax credit rate is set daily by the U.S. Treasury Department. Under past allocations, the credit could be taken quarterly on a dollar-for-dollar basis to offset the tax liability of the bondholder. However, under the new CREBs allocation, the credit has been reduced to 70% of what it would have been otherwise. Other important changes are described in IRS Notice 2009-33.

CREBs differ from traditional tax-exempt bonds in that the tax credits issued through CREBs are treated as taxable income for the bondholder. The tax credit may be taken each year the bondholder has a tax liability as long as the credit amount does not exceed the limits established by the federal *Energy Policy Act of 2005*. Treasury rates for prior CREB allocations, or "old" CREBs are available here, while rates for new CREBs and other qualified tax credit bonds are available here.

In April 2009, the IRS issued Notice 2009-33, which solicited applications for the new CREB allocation and provided interim guidance on certain program rules and changes from prior CREB allocations. The expiration date for new CREB applications under this solicitation was August 4, 2009. Further guidance on CREBs is available in IRS Notices 2006-7 and 2007-26 to the extent that the program rules were not modified by 2008 and 2009 legislation. In October 2009, the Department of Treasury announced the allocation of $2.2 billion in new CREBs for 805 projects across the country. It remains to be seen if the IRS will issue new funding announcements for the remaining $200 million in new CREBs, or for old CREB allocations which are not issued by the December 31, 2009 deadline.

For further information on CREBs, contact Zoran Stojanovic or Timothy Jones of the IRS Office of Associate Chief Counsel at (202) 622-3980. Questions on recent IRS Notice 2009-33 can be directed to Janae Lemley at (636) 255-1202. Public Information – IRS, (800) 829-1040, http://www.irs.gov.

**In practice, for a variety of reasons, bond issuers have sometimes had to issue the bonds at a discount or make supplemental interest payments in order to find a buyer.*

**In March 2010 Congress enacted H.R. 2847 (Sec. 301) permitting New CREB issuers may make an irrevocable election to receive a direct payment -- a refundable tax credit -- from the Department of Treasury equivalent to and in lieu of the amount of the non-refundable tax credit which would otherwise be provided to the bondholder. This option only applies to New CREBs issued after the March 18, 2010 enactment of the law. In April 2010 the IRS issued Notice 2010-35 providing guidance on the direct payment option.

Qualified Energy Conservation Bonds (QECBs) (Biomass)

Last DSIRE Review: 05/07/2010

State:	Federal
Incentive Type:	Federal Loan Program
Applicable Sectors:	Local Government, State Government, Tribal Government
Amount:	Varies
Program Administrator:	U.S. Internal Revenue Service

The *Energy Improvement and Extension Act of 2008*, enacted in October 2008, authorized the issuance of Qualified Energy Conservation Bonds (QECBs) that may be used by state, local and tribal governments to finance certain types of energy projects. QECBs are qualified tax credit bonds, and in this respect are similar to new Clean Renewable Energy Bonds or CREBs. The October 2008 enabling legislation set a limit of $800 million on the volume of energy conservation tax credit bonds that may be issued by state and local governments. *The American Recovery and Reinvestment Act of 2009*, enacted in February 2009, expanded the allowable bond volume to $3.2 billion. In April 2009, the IRS issued Notice 2009-29 providing interim guidance on how the program will operate and how the bond volume will be allocated. Subsequently, H.R. 2847 enacted in March 2010 introduced an option allowing issuers of QECBs and New CREBs to recoup part of the interest they pay on a qualified bond through a direct subsidy from the Department of Treasury. Guidance from the IRS on this option was issued in April 2010 under Notice 2010-35.

With tax credit bonds, generally the borrower who issues the bond pays back only the principal of the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest. The tax credit may be taken quarterly to offset the tax liability of the bondholder. The tax credit rate is set daily by the U.S. Treasury Department; however, energy conservation bondholders will receive only 70% of the full rate set by the Treasury Department under 26 USC § 54A. QECB rates are available here. Credits exceeding a bondholder's tax liability may be carried forward to the succeeding tax year, but cannot be refunded. Energy conservation bonds differ from traditional tax-exempt bonds in that the tax credits issued through the program are treated as taxable income for the bondholder.

For QECBs issued after March 18, 2010, the bond issuer may make an irrevocable election to receive a direct payment from the Department of Treasury equivalent to the amount of the non-refundable tax credit described above, which would otherwise accrue to the bondholder. The direct payment comes in the form of a refundable tax credit to the issuer in lieu of a tax credit to the bondholder. This option was formerly limited to Build America Bonds (see 26 USC § 6431, H.R. 2847 and IRS Notice 2010-35 for details). The advantage of either option is that it creates a lower effective interest rate for the issuer because the federal government subsidizes a portion of the interest costs.

In contrast to CREBs, QECBs are not subject to a U.S. Department of Treasury application and approval process. Bond volume is instead allocated to each state based on the state's percentage of the U.S. population as of July 1, 2008. Each state is then required to allocate a portion of its allocation to "large local governments" within the state based on the local government's percentage of the state's population. Large local governments are defined as municipalities and counties with populations of 100,000 or more. Large local governments may reallocate their designated portion back to the state if they choose to do so. IRS Notice 2009-29 contains a list of the QECB allocations for each state and U.S. territory. Interested individuals should contact their State Energy Office for information on how the program will be administered in their state.

The definition of "qualified energy conservation projects" is fairly broad and contains elements relating to energy efficiency capital expenditures in public buildings; renewable energy production; various research and development applications; mass commuting facilities that reduce energy consumption; several types of energy related demonstration projects; and public energy efficiency education campaigns (see 26 USC § 54D for additional details). Renewable energy facilities that are eligible for CREBs are also eligible for QECBs.

For more information on QECBs, contact Timothy Jones or David White of the IRS Office of Associate Chief Counsel at (202) 622-3980. Public Information – IRS; (800) 829-1040, http://www.irs.gov,

USDA - Rural Energy for America Program (REAP) Loan Guarantees
(Biomass, CHP/Cogeneration)

Last DSIRE Review: 05/17/2010

State:	Federal
Incentive Type:	Federal Loan Program
Applicable Sectors:	Commercial, Agricultural
Amount:	Varies
Maximum Incentive:	$25 million per loan guarantee
Program Administrator:	U.S. Department of Agriculture
Start Date:	FY 2003
Web Site:	http://www.rurdev.usda.gov/rbs/busp/bprogs.htm

Note: The U.S. Department of Agriculture's Rural Development issues periodic Notices of Solicitation of Applications for the Rural Energy for America Program (REAP). The deadline to apply for grants and loan guarantees under the most recent solicitation is June 30, 2010. Grants and loan guarantees will be awarded for investments in renewable energy systems, energy efficiency improvements and renewable energy feasibility studies.

The Food, Conservation, and Energy Act of 2008 (H.R. 2419), enacted by Congress in May 2008, converted the federal Renewable Energy Systems and Energy Efficiency Improvements Program,* into the Rural Energy for America Program (REAP). Similar to its predecessor, the REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. Congress has allocated funding for the new program in the following amounts: $55 million for FY 2009, $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012. REAP is administered by the U.S. Department of Agriculture (USDA). In addition to these mandatory funding levels, there may also be discretionary funding issued each year.

Of the total REAP funding available, approximately 88% is dedicated to competitive grants and loan guarantees for energy efficiency improvements and renewable energy systems. These incentives are available to agricultural producers and rural small businesses to purchase renewable energy systems (including systems that may be used to produce and sell electricity) and to make energy efficiency improvements. Funding is also available to conduct relevant feasibility studies, with approximately 2% of total funding being available for feasibility studies. Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. These grants are limited to 25% of a proposed project's cost, and a loan guarantee may not exceed $25 million. The combined amount of a grant and loan guarantee may not exceed 75% of the project’s cost. In general, a minimum of 20% of the funds available for these incentives will be dedicated to grants of $20,000 or less. The USDA likely will announce the availability of funding for this component of REAP through a Notice of Funds Availability (NOFA).

The USDA will also make competitive grants to eligible entities to provide assistance to agricultural producers and rural small businesses “to become more energy efficient” and “to use renewable energy technologies and resources.” These grants are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities, rural electric cooperatives and public power entities, and other entities, as determined by the USDA. These grants may be used for conducting and promoting energy audits; and for providing recommendations and information related to energy efficiency and renewable energy. Of the total REAP funding available, approximately 9% is dedicated to competitive grants for energy technical assistance.

** The Renewable Energy Systems and Energy Efficiency Improvements Program was created by the USDA pursuant to Section 9006 of the 2002 federal Farm Security and Rural Investment Act of 2002. Funding in the amount of $23 million per year was appropriated for each fiscal year from FY 2003-2007. In March 2008, the USDA announced that it would accept $220.9 million in* *applications for grants, loan guarantees, and loan/grant combination packages under the Renewable Energy Systems and Energy Efficiency Improvements Program. The application deadline was June 16, 2008.*

Contact:

Public Information - RBS
U.S. Department of Agriculture
Rural Business - Cooperative Service
USDA/RBS, Room 5045-S, Mail Stop 3201
1400 Independence Avenue SW
Washington, DC 20250-3201
Phone: (202) 690-4730
Fax: (202) 690-4737
E-Mail: webmaster@rurdev.usda.gov
Web Site: http://www.rurdev.usda.gov/rbs

Production Incentives

Renewable Energy Production Incentive (REPI) (Biomass)

Last DSIRE Review: 01/21/2010

State:	Federal
Incentive Type:	Production Incentive
Applicable Sectors:	Local Government, State Government, Tribal Government, Municipal Utility, Rural Electric Cooperative, Native Corporations
Amount:	2.1¢/kWh (subject to availability of annual appropriations in each federal fiscal year of operation)
Terms:	10 years
Program Administrator:	U.S. Department of Energy
Web Site:	http://apps1.eere.energy.gov/repi

Note: Contact the program administrator for the current funding status of this program.
The federal Renewable Energy Production Incentive (REPI) provides incentive payments for electricity generated and sold by new qualifying renewable energy facilities. Qualifying systems are eligible for annual incentive payments of 1.5¢ per kilowatt-hour in 1993 dollars (indexed for inflation) for the first 10-year period of their operation, *subject to the availability of annual appropriations in each federal fiscal year of operation.* REPI was designed to complement the federal renewable energy production tax credit (PTC), which is available only to businesses that pay federal corporate taxes.

The production payment applies only to the electricity sold to another entity. Eligible electric production facilities include not-for-profit electrical cooperatives, public utilities, state governments and political subdivisions thereof, commonwealths, territories and possessions of the United States, the District of Columbia, Indian tribal governments or political subdivisions thereof, and Native Corporations.

If there are insufficient appropriations to make full payments for electricity production from all qualified systems for a federal fiscal year, 60% of the appropriated funds for the fiscal year will be assigned to facilities that use solar, wind, ocean, geothermal or closed-loop biomass technologies; and 40% of the appropriated funds for the fiscal year will be assigned to other eligible projects. Funds will be awarded on a pro rata basis, if necessary.

Contact:

Program Coordinator - REPI
U.S. Department of Energy
Golden Field Office
1617 Cole Blvd.
Golden, CO 80401-3393
E-Mail: gorepi@go.doe.gov
Web Site: http://apps1.eere.energy.gov/repi

Appendix D: Financing Mechanisms

Financing Mechanisms

Federal energy projects require funding to generate results. Carefully matching available financing mechanisms with specific project needs can make the difference between a stalled, unfunded project and a successful project generating energy and cost savings.

The U.S. Department of Energy's (DOE) Federal Energy Management Program (FEMP) facilitates the Federal Government's implementation of sound, cost-effective energy management and investment practices to enhance the nation's energy security and environmental stewardship. Energy efficiency, renewable energy, water efficiency, and greenhouse gas management projects require significant funding. FEMP supports Federal agencies in identifying, obtaining, and implementing alternative financing to fund energy and water management projects.

These financing mechanisms include:

- Energy Savings Performance Contracts
- Utility Energy Services Contracts
- Power Purchase Agreements

Federal agencies can take advantage of these alternative financing mechanisms, choosing the best fit for their project needs. That often means a combination of financing mechanisms and agency appropriations.

The FEMP Alternative Financing Quick Guide provides an overview of alternative financing options and strategies available to Federal agencies.

Energy Savings Performance Contracts

Energy savings performance contracts (ESPCs) allow Federal agencies to conduct energy projects with no upfront capital costs, minimizing the need for Congressional appropriations.

An ESPC is a partnership between a Federal agency and an energy service company (ESCO). The ESCO conducts a comprehensive energy audit for the Federal facility and identifies improvements to save energy. In consultation with the Federal agency, the ESCO designs and constructs a project that meets the agency's needs and arranges the necessary financing. The ESCO guarantees the improvements will generate energy cost savings sufficient to pay for the project over the term of the contract. After the contract ends, all additional cost savings accrue to the agency. Contract terms up to 25 years are allowed.

DOE indefinite-delivery, indefinite-quantity (IDIQ) ESPCs were awarded to 16 ESCOs. Each contract has a $5 billion ceiling, resulting in up to $80 billion in energy efficiency, renewable energy, water efficiency, and greenhouse gas projects at Federally-owned buildings and facilities. DOE awarded these umbrella contracts to ESCOs based on their ability to serve Federal agencies under terms and conditions outlined in the IDIQ solicitation. These contracts allow agencies to use ESPCs in Federal facilities, both domestic and international.

Contact William Raup at 202-586-2214 or *william.raup@ee.doe.gov* for additional information, or visit: *www.femp.energy.gov/financing/espcs.html*.

Energy Service Companies

Energy service companies (ESCOs) develop, install, and finance projects designed to improve energy efficiency and reduce operation and maintenance (O&M) costs for their customers' facilities. ESCOs generally act as project developers for a wide range of tasks and assume the technical and performance risk associated with the project.

ESCOs are set apart from other firms that offer energy efficiency improvements by performance-based contracting. When an ESCO undertakes a project, the company's compensation is directly linked to the cost savings from energy actually saved.
The comprehensive energy efficiency retrofits inherent in energy service company projects typically require a large initial capital investment and may have a relatively long payback period. Debt payments are tied to the energy savings guaranteed for the

project so that the Federal facility pays for the capital improvement with the money saved by the project—the difference between pre-installation and post-installation energy use and other related costs.

There are two types of energy service companies that Federal agencies may use:

- Department of Energy (DOE) ESCOs: Have competed and been awarded a master DOE ESPC contract.
- Qualified ESCOs: Have been screened by a Qualifications Review Board composed of representatives of the Federal Interagency Energy Management Task Force and DOE.

The U.S. Department of Energy (DOE) holds quarterly ESCO Public Forums to discuss energy savings performance contract (ESPC) projects and processes. The forums are open to ESCOs, Federal agencies, and the general public.

Utility Energy Service Contracts

Utility energy service contracts (UESCs) allow Federal agencies to enter into contract with serving utilities to implement energy and water related improvements at their facilities. Agencies may fund the project with appropriations, or the utility may arrange for financing to cover the capital cost of the project, which is repaid over the contract term from cost savings generated by the energy and water efficiency measures. The end benefit of UESCs to Federal agencies is the ability to implement energy projects with no initial capital investments, minimal net costs, and savings of time and resources.

The Federal Utility Partnership Working Group (FUPWG) assists with UESC and other utility partnerships. The group gathers Federal agencies with utilities and ESCOs to discuss all possibilities and processes in utility partnerships.

Contact David McAndrew at 202-586-7722 or *david.mcandrew@ee.doe.gov* for additional information, or visit: *www.femp.energy.gov/financing/uescs.html*.

Power Purchase Agreements

Power purchase agreements (PPAs) are an emerging model for financing Federal on-site renewable energy projects. Already common in the private sector, the PPA model is gaining momentum in the Federal sector.

Power purchase agreements (PPAs) allow Federal agencies to finance on-site renewable energy projects with no up-front capital costs incurred. With a PPA, a developer installs a renewable energy system on agency property under an agreement that the agency will purchase the power generated by the system. The agency pays for the system through these power payments over the life of the contract. After installation, the developer owns, operates, and maintains the system for the life of the contract. Contract terms determine energy prices and buyback options for the system.

Additional information visit: www.femp.energy.gov//financing/power_purchase_agreements.html.

Power purchase agreements feature a variety of benefits and considerations for Federal agencies, including:
Benefits:

- No up-front capital costs
- Ability to monetize tax incentives
- Typically a known, long-term energy price
- No operations and maintenance responsibilities
- Minimal risk to the agency

Considerations:

- Federal sector experience with PPAs is still growing
- Contract term limitations
- Inherent transaction costs
- Challenges with site access contracts and concerns

Power purchase agreements (PPAs) allow Federal agencies to finance on-site renewable energy projects with no up-front capital costs incurred.

With a PPA, a developer installs a renewable energy system on agency property under an agreement that the agency will purchase the power generated by the system. The agency pays for the system through these power payments over the life of the contract. After installation, the developer owns, operates, and maintains the system for the life of the contract

Project Information

FEMP outlines the power purchase agreement process in its Alternative Finance Options (AFO) webinar. Dates and times are posted to the FEMP events calendar.

The PPA portion of this presentation is available, featuring typical PPA processes, benefits, challenges, and several case studies (PDF 2 MB).

Several PPA sample documents are available. Available resources include sample requests for proposal, contracts, land use agreements, case studies, and more.

Project Assistance

FEMP offers technical assistance to Federal agencies interested in implementing PPA projects through renewable energy experts at the National Renewable Energy Laboratory (NREL) and other U.S. Department of Energy (DOE) national laboratories.

These experts often facilitate cooperation between a Federal agency and the Western Area Power Administration (Western) or the Defense Energy Support Center (DESC). DESC features a Renewable Energy Initiatives team, while Western has authority to sign longer-term contracts for Federal agencies in its service territory.

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Biomass Power Sales Market Review

A key component of a biomass power generation preliminary assessment includes a study of power sales marketing opportunities. This includes identifying potential markets for the long-term sale of base-load renewable power from a biomass power project located within the study area. Most of the study area is located within Pacificorp's service territory. Since a new biomass power plant would be built within or close to Pacific Power's service territory, there are major advantages with the sale of power generation to this regulated utility, primarily associated with reduced costs to connect with the transmission/distribution system and the ability to distribute the power generation locally.

Pacific Power is a wholly owned subsidiary of MidAmerican Energy Holdings Company and required to meet certain legislated mandates including the Renewable Portfolio Standard (RPS). California's RPS was originally established by the legislature in 2002. Subsequent amendments to the law resulted in a requirement for California's investor-owned electric utilities to increase their sales of eligible renewable-energy resources by at least 1 percent of retail sales per year, so that 20% of their retail sales are derived from eligible renewable energy resources by December 31, 2010. The RPS also currently requires an increase to 33% by 2020. Biomass qualifies as a renewable resource under the RPS. Because of these and other logistic advantages, Pacificorp is a logical customer for base-load generation from a biomass power project in study area.

Appendix E: Previous Assessment Work

In 2009, the City of Yreka and the Siskiyou County Economic Development Council contracted with Carlson Small Power Consultants to complete a project analysis for this cogeneration facility. The key findings from this 2009 analysis are summarized here.

The proposed facility would generate an output of 6.2 MW and a net output of 5.9 MW. This base loaded generation facility will be optimized to meet the thermal demands of the veneer mill at the sacrifice of additional electrical output, which could otherwise be approximately 13 MW. The facility will have a plant capacity factor of 95% and operate approximately 8,400 hours annually. The facility will consume approximately 225 tons per day, which is approximately 82,132 BDT annually, of woody biomass feedstock. This fuel would be sourced primarily from mill waste from the Timber Products Veneer Mill, along with material from forest fuel management programs and waste wood diverted from the adjacent landfill.

Major System Components

A detailed list of the equipment is provided further below. The major system components include the following: a 100,000 lb/hr wood fired boiler, 6.2 MW steam turbine generator, economizer, superheater and necessary control equipment, a condensing steam turbine with two extraction ports, condenser, cooling tower, deaerator, pumps, control system, water treatment equipment, and structure to house generation equipment. The generation facility will have a steam output of approximately 80,000 pounds per hour of saturated steam at 275 psig.

Emission Controls

Siskiyou County is classified as an attainment area with no exceedances for air pollutants. Regardless, the cogeneration facility will use a sophisticated emission control system primarily consisting of a thermal denitrification (de-NOx) system, electrostatic precipitator (ESP), and a continuous emission monitoring system to manage and reduce the emission of particulate matter and nitrogen oxides.

Export Steam and Condensate Return

A preliminary analysis of the adjacent facilities to the proposed site has been conducted to evaluate their potential as end users of the process steam generated from the facility. Due to distances and specific manufacturing processes, the steam will be exported to the adjacent Timber Products Veneer Mill for use in their log vats and possibly in two new steam jet veneer dryers. The log vats operate at 125 psig and loads vary from 10,000 to 18,000 lb/hour, averaging approximately 14,000 lb/hour. The new steam jet veneer dryers would each require 40,000 lb/hour of 275 psig saturated steam. With the installation of the new steam jet veneer dryers the mill will be plumbed so that the exhaust steam from these units is reflashed to 30 psig and used in log vat heating. This configuration will likely require modifications to the existing log vat units. The veneer mill operates three shifts a day year round. A return from the mill is assumed to return a product devoid of contaminates with a return temperature of 234°F.

Grid Interconnection

Prior to interconnection with the power grid, Pacific Power requires that a robust electrical interconnection analysis be conducted with the expenses paid by the project developer. The 2009 assessment determined that it is probable that the facility's 12.47kV distribution line has sufficient capacity to transmit the project output to the Yreka substation approximately two miles to the west. The interconnection study will likely identify needs for additional relaying and communication equipment from the generation station to Pacific Power's dispatch center in Portland, OR.

Easements

It is anticipated that land will need to be acquired to facilitate right of ways for thermal and electrical runs. The findings of the interconnection study will assist in determining the significance of these costs to the overall project concept.

Utility Interruptions

The logistics of the interconnection will be coordinated with Pacific Power. The connection of the thermal feeds to the steam jet veneer dryers and log vats at the Timber Products Veneer Mill will also be coordinated to appropriately stage the work to minimize normal work operations at this facility.

Environmental Impacts

This facility will have a positive net environmental impact. The new cogeneration facility will displace approximately 21,273 MTCO2e of greenhouse gases. In reality, the net greenhouse gas reductions are even greater given the fact that the veneer mill will now be able to increase the amount of veneer shipped per truck load for final processing at the Timber Products facility in White City, OR approximately 60 miles away. Currently, these shipments max out on weight significantly reducing the amount of veneer shipped per load due to the high moisture content.

Projected Biomass Demand

The generation facility will consume approximately 225 tons per day, or 82,132 tons per year of woody biomass.

Assumed Sources of Revenue

The cash flow analysis assumed revenue generation from the following sources: steam sales, renewable energy production incentive, and power sales.

Estimated Implementation Costs

The estimated implementation price of this project is approximately $38.6 million. The project generates an estimated net present value of $29.9 million at a 5% discount rate over a project timeline of 20 years, and an internal rate of return of 16.9%. These values are estimated using the detailed information provided in the report commissioned by the City of Yreka, the Siskiyou County Economic Development Council, and executed by Carlson Small Power Consultants with vendor quotes from Wellons, Inc.

The scope of the estimate includes the following cost elements:

1. Power Island: Provide and install one 100,000 PPH boiler and one steam turbine generator with accessories, including: condenser, two steam jet air ejectors, gland steam condenser, cooling tower, deaerator, and sample panel.
2. Fuel Handling and Storage: Live bottom pit, feed and stackout conveyors (50 tons/hour), live storage silos, and feed system to boiler metering bin.
3. Pumps: Provide and install boiler feedwater pumps, condensate pumps, three circulating water pumps, auxiliary cooling water pumps, and demineralized water transfer pumps.
4. Tanks: Provide and install one demineralized water storage tank, one steam turbine generator drain tank, one boiler blowdown tank, and one oil water separator tank.
5. Compressed Air System: Provide and install air compressors, one air dryer and one air receiver.
6. Water Treatment: Provide and install one demineralized water system, one boiler chemical feed system, and one cooling tower chemical feed system.
7. Emission Control: Provide and install one electrostatic precipitator, multiple cone collectors, induced draft fan, thermal denitrification system, and related equipment.
8. Interconnect: Fund required interconnection study (executed by Pacific Power) for connection to 12.47kV distribution line with output routed to Yreka substation.
9. Permitting: Secure all required plant licenses and environmental permits.
10. Provide engineering and design and installation labor.
11. Provide project management and construction management.
12. Conduct system startup, testing, and commissioning.