Phase II Biopower Market Assessment

Sizing and Characterizing the Market for Oregon Biopower Projects

Prepared for

Energy Trust of Oregon, Inc.

April 2005

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PDX/051050029_USR.DOC

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Executive Summary

This study assesses the near- and mid-term potential of five biomass market segments:

- Sewage treatment plant-based digesters
- Dairy-based anaerobic digesters
- Landfill gas-to-energy
- Woody mill waste
- Forest waste (including timber residue and forest thinnings)

Objective

The overall objective of this report, for each segment listed above, is to provide data and discussion in the following three areas:

- Cost: Ranges for capital cost and all-in cost of electricity
- Potential: Realistic, medium-term in-state development potential (in megawatts and number of projects)
- Reliability: Reliability of these data as program planning tools, including a discussion of market, technological, or other factors which affect the certainty of the data

Approach

In light of these project objectives, the market segments identified above were assessed in terms of their potential to be developed in a manner that would benefit the Oregon ratepayers of Portland General Electric (PGE) and PacifiCorp in the near-term (less than 2 years) and mid-term (2 to 7 years). The assessments were conducted in accordance with the Biopower Program currently being implemented by the Energy Trust of Oregon. The resources evaluated can be found throughout the Oregon service areas of PGE and PacifiCorp. **Figure ES-1** shows the locations of the sewage treatment plants, dairies, landfills and wood waste boiler facilities described in this report. Overlaid on this location map are both PGE and PacifiCorp service territories, to illustrate the relationships between potential project locations and the service areas of interest to Energy Trust.

Key Findings

Each market segment was assessed in terms of the following key market parameters: fuel availability and cost; fuel collection activities and costs; fuel processing costs; energy conversion technologies and costs; power sales opportunities and revenues; cost and financial evaluation; development potential; and key market segment issues. A summary of key findings in each of the resource areas is presented below **and in Table ES-1**.

Sewage Treatment Plant-Based Digesters

Market potential of 5 to 7 megawatts (MW) at approximately 25 sites. Nine of these sites already have generation for a total of 3 MW. New generation potential is 2 to 4 MW. Estimated cost of these projects would be approximately $0.03 to $0.05 per kWh at the larger sites (approximately 1 MW and larger), and $0.09 to $0.14 per kWh at the smaller sites (roughly 70 kilowatts (kW) to 1 MW). Most of these projects would offset purchased retail power at rates of approximately $0.06 to $0.07 per kWh, improving the economics of projects in this segment as compared to other projects which sell into the wholesale market.

Dairy-Based Anaerobic Digesters

In theory, 20 to 30 MW of power could be generated at farms with 500 or more dairy cows. However, the actual potential for near-term economic projects is much less—in the range of 10 to 12 MW - due to the variation in farm practices. Costs for these projects would be in the $0.04 to $0.07 per kWh for largest (2-6 MW) projects that could be developed and in the $0.8 to $0.11 per kWh range for smaller projects. These projects could potentially be feasible in the long term, but face significant economic, technological and regulatory challenges in the near- to mid- term.

Landfill Gas-to-Energy

Market potential of 40 to 45 MW across approximately 13 landfills, with the largest potential existing at the Columbia Ridge facility in Arlington where a 25- to 30-MW potential project exists. Near-term also includes other sites ranging in size down to approximately 1 MW. There are 5-10 sites with potential for 1MW and above. Project costs are estimated to be in the $0.025 to $0.045 per kWh for the larger (greater than 2 MW)projects, although they could be higher depending on project-specific requirements related to transmission and interconnection costs and other issues. In the smaller size range, for those projects ranging in size down to 70kW, the costs would be in the $0.09 to $0.15 per kWh range.

Woody Mill Waste

There is approximately 50 MW of potential, but the availability of this resource is highly dependent on market conditions affecting both the amount of biomass produced and consumed. Using data on the amount of woody mill waste landfilled in 2000, the last year for which data are available, there appears to be approximately 10 MW of power generation potential. However, given current market conditions and recognizing that not all woody mill waste produced is accounted for, the near-term potential is probably greater than 10 MW. This resource can be developed in two ways: through the installation of topping cycle turbines (typically during a boiler upgrade), or as new projects. When the only cost considered is the incremental cost of the topping unit, the cost is in the $0.02 to $0.04 per kWh range. For new condensing turbine projects the estimated cost would be in the $0.05 to $0.07 per kWh range.

Forest Waste (Including Timber Residue and Forest Thinnings)

This segment has a very large potential (up to 500 MW), but the vast majority of that potential is unobtainable in the near or mid term. The primary obstacle is uncertainty regarding fuel-supply: the lack of a dependable contractual mechanism to assure that forest waste resources will be available throughout the life of a project with enough certainty to justify a major investment in a power generation project. If such a project were to be developed, the fuel collection costs alone are estimated in the $0.04 to $0.05 per kWh range. This does not include the cost of thinning operations which would be attributed to forest management activities. Total project costs could be in the range of $0.09—0.13 per kWh, too high to justify through power sales alone, but other forms of revenue streams could offset the higher costs.

Market Segment Groups

The market segments are categorized into the following groups in terms of their ability to increase the near- or mid-term supply of biomass energy for the benefit of PGE and PacifiCorp ratepayers and Energy Trust:

- Group 1: Near- to Mid-Term Interest
  - Woody mill waste
  - Landfill gas-to-energy
  - Sewage treatment plant-based digesters
- Group 2: Mid-Term Interest Only
  - Dairy-based anaerobic digesters
- Group 3: Long-Term Interest—Not Accessible at this Time
  - Forest waste (including timber residue and forest thinnings

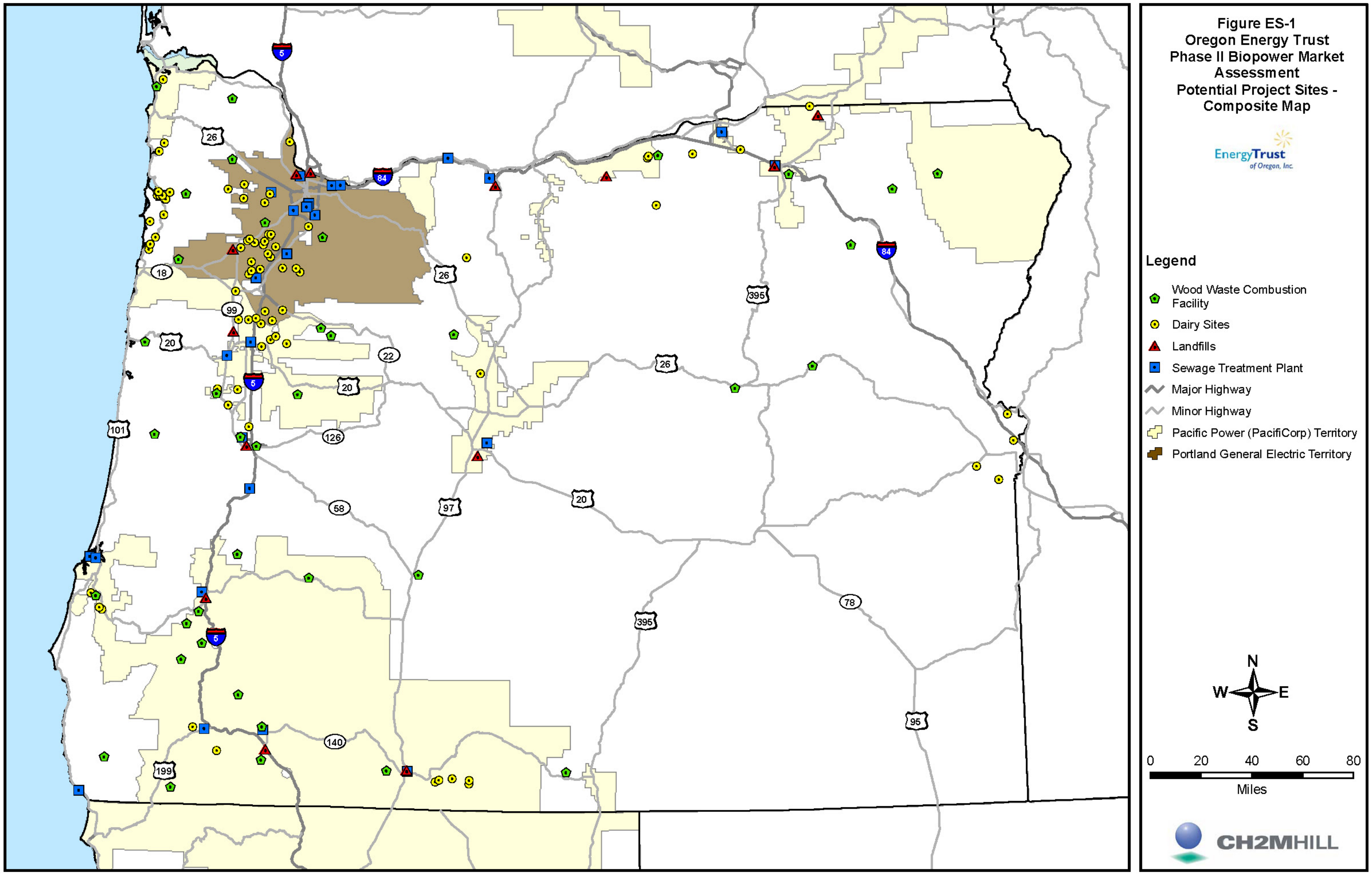
TABLE ES-1
Biopower Market Assessment—Findings Summary Table

	Sewage Treatment Plant-Based Digesters	Dairy-Based Anaerobic Digesters	Landfill Gas to Energy	Woody Mill Waste	Forest Waste (Timber Residue and Thinnings)
Number of Potential Project Sites	28 facilities with anaerobic digesters currently installed.	32 facilities with over 1,000 cows. Several (5-10) sites where dairy clusters could enable centralized digesters, and 52 secondary sites with 500-1,000 cows.	13 landfills and over 100,000 tons of waste in place with gas collection systems.	12 sites (mills) with boilers at potential for 50 MW of new power capacity.	Unknown. Biomass 1 is a current site.
Fuel Availability and Cost (Quantity and $/Btu)	1,270 million cubic feet per year or 3.48 million scfd, equivalent to 7-10 MW of power potential if all the gas were used, at heating value of 600-650 Btu/scf.	113,808 animals on the 32 facilities with over 1,000 head, with potential to generate up to 10.2 million cfd of gas with heating value of 600–650 Btu/scf. Equivalent to 18–24 MW total for those farms. Another 52 farms with 500 to 1,000 animals could add another 5-7 MW.	10,600 Mscf per year, or about 29 million scfd potential gas generation at the 13 landfills. Average heating value of 450 Btu/scf. Equivalent to 61 MW if all gas was collected and used in reciprocating engines.	Quantity of waste in 2000 was 62,000 tons, equal to 608,000 MMbtu. Market price plus haul rate of $20/ton, or $2 per MMbtu.	1.8 million tons/year from logging waste and 2.5 million tons/year from forest thinning. 4.3 million tons total. Equates to 43 trillion Btu/yr or 300–500 MW.
Power Sales Opportunities and Revenues	Offset retail (standard tariffs)–$0.06-0.07 per kWh. This does not include demand charges.	Offset retail (standard tariffs, $0.06-0.07 per kWh) for 50-75 percent of power produced. Rest must be sold through power purchase or net metering at $0.03-0.05/kWh.	No captive use for energy onsite, so little opportunity to offset retail. Use of biogas for heating can be more economical. Must sell power through power purchase agreement ($0.03-0.04).	Cogeneration opportunity. Offsets retail and sells into wholesale market ($.05-.06 per kWh).	Little opportunity to offset retail and typically requires sale into wholesale market at $0.03-0.04 per kWh.

TABLE ES-1
Biopower Market Assessment—Findings Summary Table

	Sewage Treatment Plant-Based Digesters	Dairy-Based Anaerobic Digesters	Landfill Gas to Energy	Woody Mill Waste	Forest Waste (Timber Residue and Thinnings)
Market Segment Issues	Facility operations focus on treating wastewater, not energy. Gas is wet and requires treatment.	Dairy operators generally not motivated to manage a digester. However, increasing environmental restrictions (CAFO rule will drive interest in better manure management).	Operators are not on site for landfills; must be brought in. Location relative to grid tie-in point is important. After landfill closes, gas production briefly rises, then slowly decays over about 30 years. Largest projects (two in Oregon) may consider combined-cycle power plant.	Waste is already being used and long-term supply to support additional plants is uncertain.	Need for long-term supply commitment and from Forest Service; currently not possible. Water needed, and water rights may be difficult to obtain at eastern Oregon sites. Air permitting is a potentially market-limiting factor.
Market Segment Summary	Market potential of 5-7 MW over 28 sites. Nine sites already have generation for a total of 3 MW. New generation potential is 2-4 MW. Project costs $0.04-$0.06 per kWh at large sizes (1 MW), and $0.09-$0.14 at small end of range (70 kW). Offsets retail prices.	Based on theoretical potential of 20 to 30 MW total for farms 500 animals and up. Actual potential for near- or mid-term may be 10-12 MW because of variation in farm practices. Project costs $0.04-$0.07 per kWh at large sizes (2 MW), and $0.08-$0.11 at small end of range (70 kW). About 50 to 75 percent of energy offsets retail prices.	Market potential of 40-45 MW across the 13 landfills. Largest potential is Columbia Ridge in Arlington, Oregon, with 25- to 30-MW potential. Near-term includes projects down to 1 MW in size (five sites), and mid-term includes projects from 500 kW to 1MW (two sites). Two sites already have generation. Project costs $0.03-$0.04 per kWh at large sizes (2 MW), and $0.10-$0.15 at small end of range (70 kW).	About 50 MW of potential facilities. However, market output will depend on actual wood waste generated. In 2000, this was about 10 MW worth. Project costs of $0.03-0.04 for 4.8-MW size facility, based on feasibility studies and vendor discussions.	Very large MW potential (up to 500 MW), but unattainable in near- or mid-term. Amount of potential sites unknown. Project costs of $0.10-0.13 for 13-MW facility, based on feasibility studies and vendor discussions.

FIGURE ES-1
Map of Potential Project Locations with Service Territories



SECTION 1

Introduction

Biomass resources offer the state of Oregon an opportunity to expand its renewable energy base. The recently completed *Biomass Market Assessment (Phase 1)* (Itron, 2004) provides a general description of this market and its potential. This report and other information prepared by the Energy Trust of Oregon (Energy Trust) are available at http://www.energytrust.org/RR/bio/index.html.

In addition, the Oregon Department of Energy (ODOE) has compiled extensive information on Oregon's biomass energy resources. That information is available on ODOE's website at http://egov.oregon.gov/ENERGY/RENEW/Biomass/BiomassHome.shtml.

The ODOE site contains general information on biomass, including technology and project development. The ODOE and the earlier work of the Energy Trust provided the foundation for the analysis undertaken in this *Phase 2 Biomass Market Assessment*.

The Energy Trust, whose mission includes the support of renewable energy projects to the extent their cost is above market, is focusing on biomass because:

- It is anticipated that wind projects, which have comprised the greatest share of renewable energy projects supported by the Energy Trust to date, may in the future no longer be "above market," and may therefore offer only a limited ability to help the Energy Trust achieve its renewable energy goals. Biomass is generally considered to be an economical renewable resource, and therefore will receive more attention from the Energy Trust as wind resources become economical and no longer need incentives from the Energy Trust to be developed.

- The Energy Trust has an explicit commitment for increasing biomass utilization.

- There are extensive biomass resources available in the state.

In order for the Energy Trust to develop an effective biopower program, however, a more detailed analysis, focusing on the relative cost-effectiveness of the following market segments, is needed:

- Sewage treatment plant-based digesters
- Dairy-based anaerobic digesters
- Landfill gas-to-energy
- Woody mill waste
- Forest waste (including timber residue and forest thinnings)

The analyses included in this assessment focus on the costs and risks associated with developing each of these markets. This assessment is based on actual experience and real-world cost information. Issues affecting the potential size of these market segments have been identified and the results are presented in ranges for each potential market segment depending on the costs associated with their potential development. The cost information has been grouped into discrete categories so that it can be analyzed and presented in as systematic a manner as possible.

Wherever possible, the results have been assembled into a tabular format, by market segment, so that comparisons across the different market segments can be made and so the results can be used in a spreadsheet model. This model is supported by data from real projects and other appropriate sources so that the Energy Trust staff and interested stakeholders are able to understand the reasons for the findings presented in the report and validate them through the use of the model and other project experience as appropriate.

The overall objective of the report, for each segment listed above, is to provide data and discussion on cost ranges, realistic development potential, and the reliability of those estimates for the following three areas:

- Cost: Ranges for capital cost and all-in cost of electricity
- Potential: Realistic, medium-term in-state development potential (in megawatts and number of projects)
- Reliability: Reliability of these data as program planning tools, including a discussion of market, technological or other factors which affect the certainty of the data.

SECTION 2

Approach

The approach used in this report to achieve the project objectives listed above is a consistent analytical framework across all the market segments. This discussion of the approach focuses on:

- The analytical framework employed
- Description of resource and characterization of key parameters
- Cost and financial evaluation
- Near- and mid-term development potential
- Factors that reflect each market segment's potential reliability
- Presentation of summary information in a clearly presented tabular format suitable for market segment comparison

2.1 Analytical Framework

A key feature of the analytical framework used in this assessment is that it applies to all of the market segments, and within the framework all segments are treated consistently. For example, similar costs occur for each energy conversion technology, regardless of the market segment involved. Therefore, those are defined and treated uniformly across all market segments. Also, clear differences in costs associated with different market segments are identified and described, within the overall framework.

To illustrate, the dairy waste to energy projects presented here includes the cost of the digester, while the sewage treatment plant projects assume that the digester already exists, and that only power generation and associated equipment are needed. In the framework used, these different cost components are shown, and the costs common to both markets are treated similarly, while the added costs for the digester are noted and treated consistently in the dairy waste market analysis.

This approach allows for careful analysis of both the common and distinct costs for each of the market segments.

2.1.1 Description of Resource and Characterization of Key Parameters

For each market segment analyzed, the initial activity was to identify and define the parameters used to characterize the key resource issues. For example, on projects involving forest residue, costs associated with collecting and transporting the waste were identified and calculated. This information was used in the subsequent analysis but it was also presented in such a manner that this cost is readily identified. Thus, the reviewers of our work are able to see which costs are associated with which aspects of each individual market segment. The key parameters addressed for each of the market segments include:

- Fuel Availability and Cost
- Fuel Collection Activities and Costs
- Fuel Processing Costs
- Energy Conversion Technologies and Cost
- Power Sales Opportunities and Revenues
- Market Segment Issues

2.1.2 Cost and Financial Evaluation

Existing cost information is used as the basis for the cost estimates in this study. The cost information used ranges from rough cost estimates typically used for planning purposes (within a factor of 2 or 3), to some detailed cost estimates associated with construction activities, where those were available. Data used in this effort across all market segments has been developed to achieve a common level of accuracy so that comparisons of different market segments will be on a comparable basis. In general, order of magnitude estimates were used in the analysis as it is more appropriate for planning purposes with the more-detailed cost estimates used to validate the results and conclusions.

Costs are broken down into standard elements, including those related to fuel supply and energy conversion. Within these two broad areas, individual cost elements are presented in a standard format, such as dollar per installed kilowatt, for different size ranges of generation equipment. To ensure consistency in the analysis of fuel costs, all fuel-related costs are presented on a dollars-per-million-British-thermal-unit (MMBtu) basis. Life-cycle cost elements are identified so that the full project life-cycle costs are calculated considering all future costs and are discounted and presented in a net present value format. By adopting this approach, report reviewers will be able to determine what a range of expected costs would be for each of the market segments. This includes average installed cost per kilowatt, average operating cost in terms of cents per kilowatt hour, and the life-cycle costs for a standard 15-year project. A 15-year project life was chosen for the analyses in this report as that is a standard which applies to a wide range of renewable energy projects, and reflects the approximate useful life of most generation equipment. In practice, project-planning horizons are likely to vary between specific projects; for instance, microturbine projects may be analyzed using a shorter life due to the equipment, unless significant rebuilds are planned.

2.1.3 Near- and Mid-Term Development Potential

In order to evaluate and prioritize various market segments, both the near-term (less than 2 years) and mid-term (between 2 and 7 years) potential of each of the market segments are described. The findings of the *Phase 1 Biomass Market Assessment* and the work of the ODOE are used along with the cost information described above to describe the near- and mid-term potential for each of the market segments. Expected technological improvements and anticipated changes in market conditions are also considered for the latter portion of the mid-term planning horizon, but these are given only moderate weight given the uncertainty associated with them. For each market segment, a summary table reflecting near- and mid-term development potential is presented.

2.1.4 Reliability

The reliability considerations for each of the market segments are described. Factors affecting reliability include: accuracy of available data, market risk, technological risk, environmental considerations, long-term resource supply uncertainties, and other risks. For each of the reliability categories described, a description of the risks is provided.

2.1.5 Summary of Findings

The findings for each market segment are presented in narrative format using a summary spreadsheet/table across all segments. This will be presented in Section 3, Market Assessments. Cost information is presented so that it is apparent to the reader which cost elements are common to multiple market segments and which ones are unique to a particular market segment. By presenting data using this approach, it is apparent which factors are important in prioritizing each market segment. It also facilitates the use of sensitivity analysis to determine how changes in such factors affect the overall standing of a particular market segment. The net result is a stand-alone description of each market segment presented in Section 3. This is followed by a summary presentation in Section 4. The summary included in Section 4 will be easy to use and well-suited for the Energy Trust's prioritization activities. It will include a brief

- Narrative Summary of the Framework Categories and Market Segment Issues
- Summary of Costs by Category for Each Market Segment
- Summary Table Presenting Key Findings

2.2 General Approach to Market Segments

The following general assumptions are used for cost analysis and estimation of market potential across the different segments:

- Project life is 15 years. Salvage value is not included. Reciprocating engines may have some salvage value at the end of 15 years, but technologies such as microturbines or fuel cells would not.

- Engine generators run at 90 percent availability (7,884 hours per year) unless otherwise specified.

- Microturbines also run at 90 percent availability. In addition, their gas treatment systems exert a parasitic load that reduces total power generation by 10 percent. This is reflected in increased heat rates for that equipment, and de-rating nominal power rating by 10 percent.

- Steam systems run at 75 percent load factor.

- Depreciation of capital equipment is on a 5-year modified acceleration recovery schedule (MACRS) unless otherwise specified, which is typical for this type of equipment. The MACRS depreciation schedule for large plants to take forest residue is 15 years. Only capital equipment is depreciated, not other project costs such as design and construction management.

- Combined state and federal corporate taxes are assumed to be 40 percent, so the deprecation benefit is 40 percent of value of capital equipment, spread in accordance with the depreciation schedule.
- The pass-through option for the Business Energy Tax Credit is assumed, representing 25.5 percent of total up-front costs (including design, construction management, etc.), taken up-front. In practice a taxpaying project host or developer could take this up-front or spread the credit at 35 percent of project costs over 5 years.
- When retail power is offset, that power is valued at average retail price of $0.07 per kWh. Specific project analyses will include a rate study according to rate schedules available from power providers to specific facilities. For this report, $0.07 per kWh is considered a reasonable average across most rate schedules in place in early 2005. Larger consumers may have lower rates, which, if offset by onsite power, will tend to increase, making projects less attractive and increasing above-market costs. Also, demand charges are not included in offsetting retail rates because they cannot be eliminated by reducing the power load.
- The price for power exported to the grid will depend on size of the facility and service area. It is based on the power company's "avoided cost," which includes cost to generate plus a portion of transmission and distribution cost. For facilities 1 MW and less, both Portland General Electric (PGE) and PacifiCorp have small power production price schedules in place which are based on avoided cost. For facilities greater than 1 MW, the price is negotiated directly with the company, and will fall between $0.03 and $0.04 per kWh. Data found for 1 MW and smaller installations are summarized in Table 2-1:

TABLE 2-1
Small Power Producer Rates: PacifiCorp and PGE
From rate schedules as specified, based on avoided costs

	PGE	PacifiCorp
1 MW or less	$0.0447-$0.0508 (Sched. 201)	$0.032-$0.048 (Sched. 5)

Note:
Valid for qualifying facilities 1 MW or less.

- Renewable energy credits (green tags) may be generated by any of these projects, and could be tradable in a market that is dictated by renewable portfolio standards. At this writing, Oregon itself does not have a renewable portfolio standard. They are not included in the total per-kWh project costs shown in this report. If they are applicable to a specific project their impact could be to reduce total project costs from $0.002 to $0.005 per kWh.
- The desired rate of return for the overall project net present value (NPV) calculations is 9 percent in the examples, based on 12 percent return on equity (ROE) for the equity developer and debt at 6 percent interest, with a 50-50 debt/equity capital structure. Both interest on debt and cost of equity capital are reflected in total project costs on a per-kWh basis.

- The sum of the discounted cash flows over 15 years, less the total up-front costs, is defined as the NPV of the project. The project is economical at NPV= $0 and above.
- Total project costs per kWh include the desired returns on the project. Ranges for comparative value of power generated are included as appropriate to each project environment.

2.3 Accuracy of Data

Information on the size, location and operating characteristics of facilities assessed in this report is appropriate for use in a planning level assessment. This data was collected for facilities that either produce biomass resources, or would potentially host a biomass energy project. Data used was generally obtained from publicly available sources such as from the Oregon Department of Environmental Quality (DEQ) or ODOE. This information proved very useful for this assessment, particularly in assessing the biomass power potential in different regions in the state and in determining the availability of biomass resources within the service areas of PGE and PacifiCorp.

It is recognized, however, that this dataset is not complete, nor is it appropriate for use at a level of detail needed to assess the feasibility of individual projects. For example, ODOE's data on facilities that use woody biomass does not include some mills that are actively using such resources. These facilities may not be included because certain data were not reported or collected by ODOE. It is also possible that an individual mill was not operating or that for other reasons information was not available at the time the data were collected. Further, the forest products sector is dynamic and highly influenced by market forces and changes in supply conditions. Therefore, individual facilities expand or contract at different times and the inclusion or exclusion of individual facilities in this analysis is not anticipated to significantly affect conclusion in the overall market assessment. Because of these considerations, the data included in this report is appropriate for assessing the biomass energy market in Oregon, but its use for other purposes is limited.

2.4 Wheeling Charge and Service Area Boundary Considerations

An important consideration in the development of this report is the assessment of the potential of biomass resources outside the service areas of PGE and PacifiCorp to be of benefit to ratepayers of those entities. For projects outside the PacifiCorp and PGE service areas, a charge to transmit over other networks, known as a "wheeling charge," will be incurred in addition to other project costs. At a minimum, this charge will be paid to Bonneville Power Administration (BPA) for transmission on their lines, and it may also need to be paid to local utility districts where a facility is located. The BPA charge starts at around $0.011 per kWh.[1]

[1] Compiled from Bonneville Power Administration 2004 Transmission and Ancillary Service Rate, available at http://www.transmission.bpa.gov/Business/Rates_and_Tariff/

In general, for projects less than 5 MW in size, it is impractical to transmit power for long distances because the costs associated with the required transaction costs, wheeling charges, and line losses are not offset by the value received for the power. In the case of some larger projects, the economies of scale of developing a larger project can offset the cost of wheeling power from outside the service areas to customers within it. These larger projects, however, are limited in number. A review of the potential for these types of projects in the various resource areas is discussed below.

- In the case of wastewater treatment plants, the projects at these facilities will almost always serve onsite loads, because wastewater treatment plants typically draw more power than the digester gas would produce. Furthermore, these potential projects are well below the 5-MW size limit, which means that wheeling the power would not be economical.
- In the case of dairies, the potential project size is typically less than 5 MW, and for those few potential projects that are larger, they are not likely to be economical in the near term.
- For landfill gas to energy projects, the only landfill of sufficient size to potentially justify wheeling to another load center is in the vicinity of Arlington, Oregon— within PacifiCorp's service area. Thus, wheeling is not a major consideration in this market segment either.
- For woody mill waste projects, there are projects potentially over 5 MW that could be developed outside the service areas to serve loads within the service areas. Upon closer analysis, however, most of the available woody mill waste resource available is in or adjacent to the service areas of PGE and PacifiCorp (in particular, Douglas County has the largest quantities of this resource available). Given the fact that there is a relatively mature infrastructure in place for transporting and distributing this resource, it is expected that the woody mill waste would naturally flow to the projects within the PGE and PacifiCorp service areas if the Energy Trust were to institute a program to encourage projects in those locations. As the data show, there are many potential hosts for such projects within the service areas. Stated another way, if the Energy Trust were to develop a program to encourage the use of woody mill waste in biomass energy projects in the PGE and PacifiCorp service areas, the market would adjust moving the waste to the projects, thereby supporting projects that were in the service areas.
- In the case of potential forest-thinning projects, the analysis indicates that there are many institutional, market, and other forces that will keep these projects from being practical in the near term. Therefore, considerations related to the merit of wheeling power from outside the service areas to within them do not affect the findings of this study.

SECTION 3

Market Assessments

This section discusses each of the five biomass market segments.

3.1 Sewage Treatment Plant-Based Digesters

3.1.1 Description of Resource and Characterization of Key Parameters

Municipal Sewage Treatment Plants (STPs) collect and treat domestic waste water from residential and commercial customers before discharging the treated waste to a receiving body of water (a river, stream, lake or ocean). One of the critical steps in this treatment process is the clarifying process, in which solids in the raw sewage settle and collect to form as sludge. The sludge contains high amounts of volatile organics, and must be treated before disposal or reuse of the material. Anaerobic digestion (at temperatures between 95 and 98 degrees F) is one common treatment method.

In the anaerobic digester, bacteria break down the volatile organics in the sludge to form biogas (a mixture of carbon dioxide, methane and a few trace gases) and a treated solids stream that can be land-applied or reused in other ways. The energy resource in this case is the biogas, which can be used to fuel a reciprocating engine, turbine, or fuel cell; as well as heating of the anaerobic digesters themselves. Because of the carbon dioxide content, the biogas will have a typical heating value of approximately 600-650 Btu/standard cubic foot (scf). As a comparison, commercially available natural gas, as supplied to homes and industry, will have typical heating values around 1,000 Btu/scf. The heating value of 600-650 Btu/scf is consistent between anaerobic digester facilities at different STPs.

Key parameters for this market segment are:

- Population served by the STP (and therefore, the solids loading to the treatment plant)
- Total permitted and average actual daily wastewater flow through the plant, in million gallons per day (mgd)
- Gas production from the digester, in standard cubic feet per day (scfd)
- Heating value of the biogas (typically 600 Btu/scf)
- Heat rate of power generation equipment, which measures fuel into the unit versus power out, in Btu/kWh. This is a measure of energy conversion efficiency.
- Amount and type of contaminants in the biogas, such as sulfur compounds, moisture, and siloxane, measured in parts per million by volume (ppmv)

3.1.2 Fuel Availability and Cost

Municipal sewage treatment plants in Oregon have wastewater discharge permits on file with the DEQ. As of March 2005, DEQ listed 222 permitted sewage treatment plants, ranging in size from less than 1 mgd to 50 mgd of flow (permitted). Note that not all permits are current, and therefore, some of the STPs actually have flows higher than indicated in the DEQ listing.

Most, but not all, STPs with flows higher than 5 mgd and some in the 1-5 mgd range have anaerobic digesters as part of their sludge treatment system. Other sludge treatment options include aerobic digestion and treatment lagoons, neither of which produces significant biogas. For purposes of this report, having an anaerobic digester is considered a prerequisite condition for inclusion of a facility in near-term or mid-term biogas market potential. This is because installing a new anaerobic digester at an existing facility of 1 mgd or greater size will cost $500,000 or more. This cost cannot be justified using revenue or savings from power production at current electrical rates. Therefore, only plants that have already installed anaerobic digesters are part of near- or mid-term market potential. Those plants installed anaerobic digesters as part of their sludge handling method, and not as part of an energy project. According to ODOE information collected for this project, 28 of the 222 permitted STPs mentioned above have anaerobic digesters. There may be more facilities within the 222 that have anaerobic digesters that were not known to ODOE at the time their list was compiled; this could be corroborated by contacting specific facilities, which was not done in the scope of this report. The 28 facilities known to have digesters are listed in Table 3-1 with key information.

TABLE 3-1
Sewage Treatment Plants with Anaerobic Digesters

Plant Name	City	County	Service Area	Avg Flow (ODOE), mgd	Gas (ODOE), Mcf/year	Energy MMBtu/yr	Power potential @ 9,000 Btu/kWh heat rate, kW	Power potential @ 12,000 Btu/kWh heat rate, kW	Has Anaerobic Digester	Has Electricity Generation
Columbia Boulevard STP	Portland	Multnomah	PGE	65	379.3	227,580	2,887	1,998	Yes	Yes
Rock Creek STP	Hillsboro	Washington	PGE	33.7	153	91,800	1,164	806	Yes	Yes
MWMC—Eugene/Springfield STP	Eugene	Lane	neither	39.2	119.4	71,640	909	629	Yes	Yes
Salem Willow Lake STP	Keizer	Marion	PGE	40.5	118.6	71,160	903	625	Yes	Yes
Durham STP	Tigard	Washington	PGE	22.3	117	70,200	890	616	Yes	Yes
Gresham STP	Portland	Multnomah	neither	13.2	77	46,200	586	406	Yes	Yes
Medford STP	Central Point	Jackson	Pacific Power	18.8	75.5	45,300	575	398	Yes	Yes
Kellogg Creek STP	Milwaukie	Clackamas	PGE	7.9	36	21,600	274	190	Yes	Yes
Tri-City WPCP	Oregon City	Clackamas	PGE	8.2	23.1	13,860	176	122	Yes	Yes
Corvallis STP	Corvallis	Benton	neither	10.8	21	12,600	160	111	Yes	
Grants Pass STP	Grants Pass	Josephine	Pacific Power	5.7	19.9	11,940	151	105	Yes	
Albany STP	Albany	Linn	Pacific Power	8.2	18.9	11,340	144	100	Yes	
Bend Wastewater Control Plant	Bend	Deschutes	neither	4.5	18	10,800	137	95	Yes	
Oak Lodge STP	Milwaukie	Clackamas	PGE	3.7	17.9	10,740	136	94	Yes	
R.U.S.A. Roseburg STP	Roseburg	Douglas	Pacific Power	4.6	14	8,400	107	74	Yes	
Pendleton STP	Pendleton	Umatilla	Pacific Power	2.5	13.7	8,220	104	72	Yes	
Wastewater Treatment And Reclamation Facility (@ Spring Street)	Klamath Falls	Klamath	Pacific Power	3.7	10.7	6,420	81	56	Yes	
Brookings WWTP	Brookings	Curry	neither	1.6	6.5	3,900	49	34	Yes	
Coos Bay STP No. 2—Empire	Coos Bay	Coos	Pacific Power	1.1	6.3	3,780	48	33	Yes	
The Dalles STP	The Dalles	Wasco	neither	2.1	4.8	2,880	37	25	Yes	
Woodburn POTW	Woodburn	Marion	PGE	2.8	4.7	2,820	36	25	Yes	
Cottage Grove STP	Cottage Grove	Lane	Pacific Power	2	3.7	2,220	28	19	Yes	

TABLE 3-1
Sewage Treatment Plants with Anaerobic Digesters

Plant Name	City	County	Service Area	Avg Flow (ODOE), mgd	Gas (ODOE), Mcf/year	Energy MMBtu/yr	Power potential @ 9,000 Btu/kWh heat rate, kW	Power potential @ 12,000 Btu/kWh heat rate, kW	Has Anaerobic Digester	Has Electricity Generation
Hermiston STP	Hermiston	Umatilla	Pacific Power	1.4	3.1	1,860	24	16	Yes	
Hood River STP	Hood River	Hood River	Pacific Power	1.1	2.3	1,380	18	12	Yes	
Tillamook STP	Tillamook	Tillamook	neither	1.7	2.2	1,320	17	12	Yes	
Coos Bay STP No. 1	Coos Bay	Coos	Pacific Power	1.8	1.8	1,080	14	9	Yes	
Tryon Creek WWTP	Lake Oswego	Clackamas	PGE	8.4	0.5	300	4	3	Yes	
Water Pollution Control Facility	Troutdale	Multnomah	neither	1.4	0.4	240	3	2	Yes	
Totals				**317.9**	**1269.3**	**761,580**	**9,660**	**6,688**	**28**	**9**

The total population served by these 28 plants is approximately 1.5 million, and the total average daily flow is approximately 318 mgd. This represents approximately 1,270 million cubic feet per year (Mcf/yr) of potential biogas generation.

3.1.3 Fuel Collection Activities and Costs

Because the plants considered for this market already have anaerobic digesters, they currently collect the biogas. Most plants use the biogas for heating the digester, and flare any excess gas. As shown above, nine plants currently use some biogas to make power. Because all of these plants collect the gas already, fuel collection activities are minimal, and considered to be zero for this study. For actual projects, a nominal amount would be spent to tap into existing biogas piping to bring the gas to a separate location for processing and conversion to energy.

3.1.4 Fuel Processing Costs

Biogas produced at STPs contains several impurities that must be addressed. Chief among these are moisture, hydrogen sulfide, and siloxane. Each of these has a detrimental effect on emissions or equipment life. Removal requires several steps— cooling and drying, absorption, and filtration are some of the processes used to remove these impurities.

Fuel processing technology has evolved over the past five years, driven by project experience both good and bad. As of 2005, vendors are starting to offer pre-packaged gas treatment skids that group several treatment steps together as part of the power conversion package. Prices vary by vendor, project size and technology used. The cost range for fuel processing is $200 to $1,000 per installed kW. The low end of this range would be for large-scale projects 1 MW and above, or for reciprocating engines requiring a modest level of treatment, not necessarily including siloxane removal. The high end would be for small projects where the fixed costs to build the gas treatment system are spread over a small amount of kW, or for projects requiring a high level of treatment, such as deep drying and/or full siloxane removal. Fuel cells, which have a very low tolerance for fuel contaminants, tend to incur higher gas treatment costs than other technologies.

3.1.5 Energy Conversion Technologies and Cost

Experience exists with reciprocating engines, microturbines and fuel cells at STPs. Some pilot projects have been done using Stirling engines, but field experience on those is lacking.

Reciprocating engines are available in the 250 kW to 1.5 MW size range, at an installed cost of $900–$1,200 per kW. Microturbines are available to cover the size range of 30–250 kW, at an installed cost of $2,000–$3,500 per kW. Fuel cells are available from 250 kW to 2 MW, at an installed cost of $6,000–$10,000 per kW. These figures do not include engineering and project administration costs, which are noted below in Section 3.1.6.

Reciprocating engines have the longest track record and offer good thermal efficiency and low installed cost. However, they have the highest emissions. In recent years lean-burn engines have become available that have lower emissions; however, these emissions are still higher than for other options. This is not currently a factor except for areas that are designated non-attainment zones for air quality according to the U.S. Environmental Protection Agency (EPA). Few areas in Oregon are non-attainment zones; however, such a zone does exist around the Medford-White City area, where it may be difficult to permit installation of reciprocating engines.

Microturbines are a good alternative for the smaller size ranges, and have low emissions. However, their power conversion efficiency is lower and they produce more low-grade waste heat than reciprocating engines. Some of the efficiency loss can be recuperated if the exhaust gases are used to heat the digester. In addition, microturbines typically have a shorter operating life than reciprocating engines. Microturbines are sensitive to fuel quality and demand higher levels of gas treatment than reciprocating engines.

Fuel cells offer the highest power conversion efficiency with the lowest emissions. However, they are currently by far the most expensive power conversion technology on the market and are very sensitive to any fuel contaminants, so their gas treatment tends to cost more than for other technologies. The high cost of fuel cells makes it difficult to obtain any rate of return from a project, and most projects completed to date seem to be demonstration or show projects, with significant grant funding. Also, fuel cells do have some emissions, including carbon monoxide. These emissions are not from the fuel cell itself, but from the fuel reformer, which is needed to break down methane and other carbon-based fuels into pure hydrogen for the fuel cell.

The Oregon Business Energy Tax Credit (BETC) is applicable to most or all of these projects, and would reduce capital costs by 35 percent if taken over 5 years, or 25.5 percent if taken as a pass-through in the first year. It is included in the analyses shown in this report.

3.1.6 Engineering, Administration, and Project Management Costs

These project costs include feasibility studies, preliminary and final design of the system, permitting, interconnect studies, and project management. They will typically total from 25 to 40 percent of project costs. Typical ranges for these costs are listed in the cost evaluation below. Costs on specific projects may vary widely by project location.

3.1.7 Power Sales Opportunities and Revenues

Sewage treatment plants have the advantage of a captive market for power produced from a biogas project. STPs use enough power that even if all of the available biogas is converted to power, that produced power will typically cover only about 40–60 percent of the plant’s total power use. Large energy uses at a typical STP include aeration treatment basins and pump stations. Because these processes operate 24 hours per day, there is a constant load to take the power produced by a biogas energy project.

This means that the plant can use the power generated by its own biogas energy project in place of power that would be bought from the power company at retail rates. The value of the power should be evaluated at retail which for purposes of this report is taken from PGE and PacifiCorp power retail schedules, at an average of $0.07 per kWh.

In the case of offsetting retail power, “revenues” are actually savings on the plant’s electric bill. The number of kWh generated by the biogas project per year, multiplied by the retail cost of power from the power company (that is, $0.07/kWh) equals the dollar savings per year experienced by the plant.

Tax credits could also add to the annual financial benefit from the project. Since municipal entities do not pay taxes, they cannot directly benefit from this, but they could indirectly benefit by allowing a tax-paying entity such as an independent developer, or the power company itself, to sponsor and develop the project, and then pass through the tax benefit as a direct translation or via other savings to the municipality.

In addition, as public agencies, owners and operators of treatment plants are typically interested in promoting a sustainable and energy efficient image to their customers. This provides some incentive for agencies to advocate for higher utilization of their digester gas, in a way that captures the most value from this resource.

3.1.8 Cost and Financial Evaluation

Table 3-2 shows typical costs for the following sample projects: 70-kW size (lower end of size range) for microturbines, 250-kW size (mid-range) for microturbines and fuel cells, and 1.0-MW size (upper end of size range) with a reciprocating engine.

TABLE 3-2
Comparative Costs for Biogas Energy Systems at Sewage Treatment Plants

Size	**70 kW**	**250 kW**	**250 kW**	**1 MW**
Technology	**Microturbine**	**Fuel Cell**	**Microturbine**	**Reciprocating Engine**
Project Costs (one-time)				
Installed cost —gas treatment, per kW	$600 - $1,000	$1,000 - $1,500	$500 - $1,000	$200 - $500
Installed cost—power generation, per kW	$2,500 - $3,500	$5,000 - $9,000	$2,000 - $ 3,000	$900 - $1,200
Feasibility Study	$ 5,000 - $ 15,000	$25,000 - $40,000	$5,000 - $15,000	$10,000 - $20,000
Preliminary and Final Design	$ 20,000 - $ 30,000	$80,000 - $100,000	$30,000 - $50,000	$50,000 - $80,000
Permitting	$5,000 - $ 15,000	$5,000 - $10,000	$7,000 - $15,000	$15,000 - $25,000
Interconnect to grid	$5,000 - $ 10,000	$5,000 - $10,000	$5,000 - $10,000	$20,000 - $40,000
Project/Construction Management	$ 25,000 - $ 35,000	$30,000 - $50,000	$80,000 - $150,000	$110,000 - $180,000
Gas treatment equipment (installed)	$ 42,000 - $ 70,000	$250,000 - $375,000	$150,000 - $250,000	$200,000 - $500,000
Power generation equipment (installed)	$ 175,000 - $ 245,000	$1,500,000 - $2,250,000	$500,000 - $750,000	$900,000 - $1,200,000
Less BETC refund (25.5 percent, up-front)	$ (71,000) - $ (107,000)	$(483,000) - $(723,000)	$(198,000) - $(316,000)	$(333,000) - $(521,000)
Total Up-front costs	**$206,000 - $313,000**	**$1,412,000 - $2,112,000**	**$579,000 - $924,000**	**$972,000 - $1,524,000**
Annual Costs				
Operations/Maintenance	$7,000 - $10,000	$ 30,000 - $50,000	$20,000 - $30,000	$150,000 - $ 200,000
Supplies	$5,000 - $ 9,000	$ 20,000 - $ 30,000	$10,000 - $15,000	$ 25,000 - $35,000
Major Overhauls	$50,000 -$70,000, years 6 and 11	$200,000 -$500,000, years 6 and 11	$200,000 -$300,000, years 6 and 11	$70,000 -$100,000, years 6 and 11
Less tax benefits of depreciation	40 percent of equipment costs accelerated over 5 years (MACRS schedule)			
Annual energy generation (kWh)	497,000	1,774,000	1,774,000	7,884,000
Total project costs (over 15 years) per kWh	**$0.094 - $0.144**	**$ 0.142 - $0.229**	**$0.074 - $0.117**	**$0.040 - $0.057**
- includes returns to equity at 12%, interest on debt at 6%, 50/50 debt/equity structure				
Estimated value of power, per kWh	**$0.065 - $ 0.070**	**$0.065 - $0.070**	**$0.065 - $0.070**	**$0.065 - $0.070**

The general assumptions listed in section 3.1 apply to this table. The analyses suggest the following conclusions:

- Projects in the 70-kW size range (2–5 mgd plant) have total costs significantly above market value for power, depending on the power generation technology chosen. For microturbines, the project cost is in the range of $0.094 to $0.144 per kWh over a 15-year project life.
- Projects in the 250-kW size range (7–10 mgd plant) have above-market costs that may be offset with a subsidy. Because fuel cells carry a significant cost premium for the equipment, a 250-kW fuel cell project would have much higher costs, in the range of $0.14 to $0.23 per kWh over the project life.
- Projects at the upper end of the range tend to be more economical due to economies of scale and the lower costs incurred by going to a reciprocating engine. For instance, a 1-MW project (about 33 mgd), which can use a reciprocating engine, may already be economical.

3.1.9 Development Potential

Theoretical Potential

Translating the 1,270 Mcf/yr of biogas production into electricity depends on the conversion efficiency of the power generation technology chosen. At 600 Btu/scf, this amount of biogas represents approximately 762,000 MMBtu per year. Power conversion efficiency can be represented by “heat rate,” which measures amount of heat in (Btu) per amount of electricity out (kWh). At 9,000 Btu/kWh, typical for reciprocating engines, if *all* of the biogas were used to make power, the result would be approximately 9.7 MW of renewable power. At 13,000 Btu/kWh, typical for microturbines, the power output would be about 6.6 MW. This potential includes some plants that are already generating power

It should be noted that if the biogas itself were not free, but carried a per-cubic-foot cost, the higher efficiency (lower heat rate) for fuel cells would give them a cost advantage, because more power (revenue) could be made for a given amount of fuel (cost). However, fuel is free in this analysis, so there is no cost advantage for the higher efficiency of fuel cells. This does mean, however, that more total power could be gotten from each project by using fuel cells than from the other technologies.

Practical Potential

In practice, it is important to consider that some biogas is typically used to provide heat for the digester itself. Thus, the total amount of biogas available is not 1,270 Mcf, but something less than that. On the other hand, all of the power conversion technologies discussed in the report produce waste heat, which could be fed from the power unit to heat the digester. For reciprocating engines, heat is shed in the exhaust gases and the cooling water, both of which can be used to a heat exchanger to capture waste heat. Microturbines create high amounts of waste heat in the exhaust gases. Fuel cells, due to their efficiency, create less waste heat, which exits the unit in the form of hot water. Thus, even in situations where all of the biogas is used for heat, some power generation may be able to be installed, if the waste heat is fed back to the digester.

These conditions will be site-specific, and will vary with each plant. Therefore, it is difficult to predict exactly what a practical power generation potential will be, however the 9.7 MW quoted above for engines should be considered an upper limit, and is likely not realistic. It is reasonable to conclude that a mix of power generation technologies will be used; that a portion, not all, of the available biogas will be used to make power; and that waste heat will be fed back to digesters in successful projects. In this case, the practical potential is probably close to or slightly less than the lower end of the theoretical range, somewhere between 5 and 7 MW total. Of this, nine sites listed above already have some form of power production, for a total of approximately 3 MW. Some of these sites may be candidates for replacement or upgrades to existing systems. The remaining sites add up to 2–4 MW of new potential that could be accessed in the near term. Included in this new potential is Columbia Boulevard, which has potential to generate 2.0–2.8 MW and which only currently generates about 120 kW from microturbines, plus a fuel cell which was reported to be non-operational.

Project Locations

Potential project locations for biopower at STPs are mapped with an overlay of PGE and PacifiCorp service areas in Figure A-1 of Appendix A.

3.1.10 Market Segment Issues

The following issues affect this market segment:

- Operator availability and cost. While it is true that trained operators are already on site, the operators are typically trained to run sewage treatment systems, not power generation systems. Therefore, some training costs will be incurred to provide skilled operators.
- There may be facilities that have existing plans to add anaerobic digestion, and energy incentives may help them make that decision. In these cases, anaerobic digestion would be added to replace other sludge handling equipment, such as aerobic processes.
- Power generation is not the core business or core responsibility of a sewage treatment plant. They will always defer attention from a power project toward their main responsibilities, such as meeting permit levels and assuring good treatment process.
- Sometimes “good neighbor” issues can also affect the ability or the cost of producing power at a STP. Some plants are located in residential areas and an installation would need to be placed inside, or additional noise containment may be necessary, raising the costs.
- Stability of energy prices—there is a strategic incentive for public agencies to make an investment in energy production, behind the meter, to stabilize their energy costs, or at least a high portion of their energy costs.

3.1.11 Market Segment Summary

In summary, this market segment could potentially produce about 5–7 MW of new renewable power if developed fully across the 28 plants listed as having anaerobic digesters. Some of these projects at larger plants are already economical, independent of any subsidies, as indicated by the existence of several reciprocating engine generators at STPs around the state.

At the small end of the size range, projects are not yet economical and have significant above-market costs. In the 7–15 mgd average flow size range, reasonable subsidies from the Energy Trust may help drive projects to implementation in the near term.

Those plants in the 1–2 mgd size range may be able to do projects up to 30-kW maximum. These projects are less economical, but may become more so as equipment evolves and becomes more standardized. These projects are mid-term potential.

Selection of power conversion technology plays a big role in whether a project can be made economical. Fuel cells incur a significant cost premium, and the total costs for those projects are much higher than for the other technologies. On the other hand, reciprocating engines, though they have higher emissions, probably offer the least-cost alternative for power generation at the upper end of the size range for this market segment.

3.1.12 Data Reliability

The following factors could change the energy potential and number of economical projects:

- As vendor packages for equipment, including gas treatment, become more standardized and project experience increases, both installed equipment costs and other project costs such as feasibility studies and design work should decrease. This will reduce above-market costs, especially at the lower end of the size range, and make more of these projects economical.
- Fuel cells should decrease in price as number produced increases. This would reduce above-market costs for that technology, and fuel cell projects would become more cost-competitive.
- Other plants in Oregon may choose to build anaerobic digesters. This would increase the total potential market. In these cases, it would be good to identify the project in early stages, and design the biogas power project into the overall plant strategy.
- Plants may change operations. For example, conversations with Coos Bay sewage treatment personnel indicated that some operational changes were to be made that would put all of the biosludge into the hands of *one* of the plants (Coos Bay #1). This may enable a biogas power project, due to anticipated higher gas production at Coos Bay #1.

3.2 Dairy Waste to Energy Projects

3.2.1 Description of Resource and Characterization of Key Parameters

Cow manure is a natural by-product of dairy operations. Large dairies and other cattle facilities that concentrate animals into a small area for feeding are classified by EPA as Concentrated Animal Feeding Operations (CAFOs). EPA promulgated a revised CAFO rule at the end of 2002 which requires all operations classified as large CAFOs to apply for a discharge permit under the National Pollutant Discharge Elimination System (NPDES) permit system to discharge wastewater from dairy operations. For purposes of dairies, operations with 700 cows and over are classified as large CAFOs. These operations will also be required to submit an annual report, and develop and follow a plan for handling manure and wastewater. More information on the CAFO including text of the rule itself is available on the EPA website at http://cfpub.epa.gov/npdes/afo/cafofinalrule.cfm.

Manure management practices at dairies have varied in the past. Most involve an anaerobic lagoon, in which waste is allowed to settle and decompose over time. It is then applied to fields as compost. Drainage and runoff from both the lagoons and the fields can be an environmental and regulatory problem. Also, odors from the lagoons can become a nuisance problem for neighboring properties.

Anaerobic digestion is one method of handling manure that EPA considers as a "Best Management Practice." Similar to the process at sewage treatment plants, the waste is fed into a tank or trough in which methanogenic bacteria breakdown volatile solids in the material into methane and carbon dioxide under anaerobic conditions. The digested solids can be used for compost or cattle bedding. The gas contains approximately 55 to 65 percent methane, and is the biomass resource for this market segment.

Key parameters for this market segment are:

- Size of the dairy, in terms of number of cows. Reports from existing dairy digester operations indicate gas generation potential of up to 90 scf per day per animal, and energy generation of 3–5 kWh per day per animal. This is for dairies that have manure collection operations conducive to capturing waste and feeding it to the digester.

- Amount of waste generated and type of manure management practiced at the dairy. Depending on dairy setup, waste will collect in feed lanes, milking centers and open corrals. Waste that collects in corrals tends to dry and is not recoverable for digestion. How manure is managed at a specific dairy is an important factor in determining whether that dairy can recover enough waste to make a viable project. If most of the waste is allowed to sit in corrals, the site will not be attractive for an energy project.

- Heating value of the biogas produced from the digester. Similar to sewage treatment plant facilities, dairy digesters produce biogas with an average heating value of approximately600 Btu/scf.

- Type and amount of contaminants in the biogas. Dairy digester gas typically contains moisture and hydrogen sulfide, but not siloxane. This affects gas treatment used, and ultimately, project economics.

- Heat rate of power generation equipment, which measures fuel into the unit versus power out, in Btu/kWh. This is a measure of energy conversion efficiency.

3.2.2 Fuel Availability and Cost

The Oregon Department of Agriculture maintains a list of all permitted CAFOs in Oregon, including name, location, and number of animals on the farm. This list shows 32 dairy farms in Oregon, with more than 1,000 animals as of March 2005. Those farms are listed in Table 3-3 in order of size, with potential gas and power generation indicated. The optimistic power generation estimate considers more usage of the gas generated, while the realistic estimate is more in line with breakpoints in engine sizes and real project experience. These 32 farms total over 113,000 animals, and could potentially generate over 10 million scfd of biogas, corresponding to 14–24 MW of power, if successful digester projects are implemented at each site.

Another 52 farms (not shown in Table 3-3) have between 500 and 1,000 animals, and together these farms could potentially produce another 3 million scfd of biogas and 4–7 MW more power.

TABLE 3-3
Oregon Concentrated Animal Feeding Operations with More Than 1,000 Animals
(Source: Department of Agriculture, March 2005)

Farm Name	City	County	Service Area	Number of Animals	Gas Potential (90 scfd/cow)	Power Potential, kW (optimistic, 5 kWh per day per cow)	Power Potential, kW (realistic, 3 kWh per day per cow)
TMCF (Six Mile Dairy)	Boardman	Morrow	Pacific Power	21,819	1,963,710	4,546	2,727
TMCF Colombia River	Boardman	Morrow	Pacific Power	17,499	1,574,910	3,646	2,187
H4 Farms, Inc. (Stage Gulch Dairies)	Umatilla	Umatilla	Neither	12,900	1,161,000	2,688	1,613
Williams Dairy Heifer Raising	Milton-Freewater	Umatilla	Pacific Power	6,250	562,500	1,302	781
Platt’s Turner Operation	Turner	Marion	PGE	5,000	450,000	1,042	625
Farley’s Feedlot	Ontario	Malheur	Neither	4,230	380,700	881	529
Hazenberg Dairy	Saint Paul	Marion	PGE	3,400	306,000	708	425
Rickreall Dairy LLC	Rickreall	Polk	Pacific Power	3,221	289,890	671	403
JVB Dairy	Ione	Morrow	Neither	3,210	288,900	669	401
Pete & Tressa Meendernick	Jerome	Umatilla	Neither	3,000	270,000	625	375
Platt’s Oak Hill Dairy	Independence	Polk	Pacific Power	2,888	259,920	602	361
Veeman Dairy	Saint Paul	Marion	PGE	2,000	180,000	417	250
Bonanza View Dairy	Bonanza	Klamath	Pacific Power	1,900	171,000	396	238
Mallorie’s Dairy Inc.	Silverton	Marion	PGE	1,850	166,500	385	231
AJ Dairy	Mount Angel	Marion	PGE	1,700	153,000	354	213
Peter Dehaan Holstein LLC	Salem	Polk	PGE	1,700	153,000	354	213
Misty Meadow Dairy	Tillamook	Tillamook	Neither	1,699	152,910	354	212
Holland’s Dairy Inc.	Klamath Falls	Klamath	Pacific Power	1,660	149,400	346	208
Mallorie’s Dairy Inc.	Silverton	Jefferson	Pacific Power	1,600	144,000	333	200
Dejong, Tom or Nellie	Klamath Falls	Klamath	Pacific Power	1,560	140,400	325	195
Volbeda Dairy Inc.	Albany	Linn	Pacific Power	1,531	137,790	319	191

TABLE 3-3
Oregon Concentrated Animal Feeding Operations with More Than 1,000 Animals
(Source: Department of Agriculture, March 2005)

Farm Name	City	County	Service Area	Number of Animals	Gas Potential (90 scfd/cow)	Power Potential, kW (optimistic, 5 kWh per day per cow)	Power Potential, kW (realistic, 3 kWh per day per cow)
Forest Glen Oaks Inc.	Dayton	Yamhill	Neither	1,495	134,550	311	187
Moisan Dairy	Salem	Marion	PGE	1,430	128,700	298	179
Van Beek Dairy Farms	Monroe	Benton	Neither	1,300	117,000	271	163
Danish Dairy LLC	Coquille	Coos	Pacific Power	1,208	108,720	252	151
Langell Valley Dairy	Bonanza	Klamath	Pacific Power	1,193	107,370	249	149
Konyn Dairy LLC	Eugene	Lane	Pacific Power	1,190	107,100	248	149
Peter Dehaan Holstein LLC	Salem	Yamhill	PGE	1,150	103,500	240	144
Lochmead Farms Inc	Junction City	Lane	Pacific Power	1,109	99,810	231	139
Dejager Dairy LLC	Jefferson	Marion	Pacific Power	1,050	94,500	219	131
Coleman Ranch Inc - Dairy HQ	Woodburn	Marion	PGE	1,050	94,500	219	131
Noble Dairy	Grants Pass	Josephine	Pacific Power	1,016	91,440	212	127
TOTALS				**113,808**	**10,242,720**	**23,710**	**14,226**

3.2.3 Overall Project Costs

Most published cost estimates for animal waste to energy systems include the digesters as well as the gas utilization equipment. A review of EPA data for dairy gas to energy systems constructed since 1997 indicates an installed cost range of between $250 and $900 per cow.[2] This is a wide range, and shows the variability of costs that has been experienced in real projects. Average costs for these 12 systems were $562 per cow. Another data set of seven digesters from an internal CH2M HILL analysis shows a range of $450 to $750 per cow, with an average of $620 per cow. This is total cost, which includes engineering and installation of the digester, the power generation equipment, and ancillary manure handling equipment. These are on-farm systems, with herd sizes ranging from 200 to 2,000 animals. It was also noted that costs on a per-cow basis tended to be lower for the larger farms.

The EPA costs reported above are for on-farm digester projects where much of the design, engineering and project administration were not reported, but absorbed by the farm owner. In general, these owners were motivated to install these projects by more than just financial returns, and were willing to invest time and effort to do much of the design and project management themselves. That is not anticipated to be the case going forward. Standard projects will incur design and project management costs, which will include engineering design, siting, permitting, administration and construction management, at anywhere from 25 to 40 percent of total project costs. Thus, for this study, a range of $750 to $900 per cow is used for considering on-farm systems up to 2,000 animals. Systems at large farms above 2,000 animals use a range of $600 to $700 per cow as an estimate in this analysis.

A large percentage of this cost is for the digester. Available data suggest digester costs have ranged between 30 and 50 percent of total costs in the past. When miscellaneous manure management costs are included, digesters and related systems can be more than 60 percent of total system costs.

Costs at a centralized facility are different than for on-farm digesters. Two data points are used to estimate a reasonable breakdown of costs: one for on-farm digesters and one for centralized facilities.

On-Farm Digester

Table 3-4 shows the cost breakdown for Haubenschild Farms, a 750- to 1,000-cow dairy farm in Minnesota:[3]

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[2] EPA AgSTAR website

[3] "Final Report: Haubenschild Farms Anaerobic Digester, Updated," Carl Nelson and John Lamb, The Minnesota Project, August 2002

TABLE 3-4
Haubenschild Farms Cost Breakdown

Herd Size, animals		750
Biogas Production, scfd		70,000
Engine Size:		135 kW
Cost Breakdown		
Engineering	$ 40,000	11 percent
Collection	$ 32,400	9 percent
Digester	$ 125,000	35 percent
Generator	$ 157,500	44 percent
TOTAL	**$ 354,900**	**100 percent**

The total cost for this installation comes out close to $500 per cow, though it should be noted that the design is for 1,000 cows, so that the ultimate cost could be around $350 per cow, if the farm expands to the full complement of animals. Note also that gas output is close to 90 scfd per cow per day, and may be more; the 70,000 scfd is what is metered at Haubenschild and additional gas that is not metered goes to a flare. This farm provides a successful data point to validate generation potential. Not all farm-based digesters show these results—many are less successful due to a number of factors, including variations in manure management and equipment operations, undersized power generation units, and reduced digester efficiency over time.

This digester project included some engineering design as shown, though much of the project administration was still handled by the owners themselves.

Centralized Digester

Internal information at CH2M HILL for a centralized digester—i.e., an offsite facility receiving waste from several or many dairies--shows the following:

1. It incurred more expenses that many on-farm digesters due to extra ancillary equipment needed to take delivery of manure from surrounding dairies. Its all-in cost was approximately $925 per cow. This was a first-time project, and follow-up discussions indicate that costs closer to the $600 to $700 range per cow for centralized dairies might be expected in the future.
2. Total project costs broke down approximately as follows:
   - Digester and handling equipment: 52 percent
   - Power generation (reciprocating engine): 25 percent ($1,500 per kW installed)
   - Site preparation 8 percent

- Engineering, contractors and administration: 16 percent

The project produces approximately 500 kW of power, taking in manure from six local dairies equivalent to 3,000 to 3,300 cows.

These costs are higher than for on-farm digesters, and reflect a fuller accounting of certain project management and engineering design costs. This project went through siting and permitting. Centralized digesters offer the advantage of allowing several farms located in close proximity that would not individually be big enough to fund economical on-farm projects to contribute waste to a larger digester that would enjoy economies of scale. This has been practiced for over 20 years in Denmark. Inland Empire Utilities Agency in southern California is also implementing this strategy to serve clusters of dairies in the Chino Valley. However, centralized digesters do incur higher construction and operating costs than on-farm units have in the past.

3.2.4 Fuel Collection Activities and Costs

For dairies, fuel collection includes collecting the manure and building the digester. Only a few farms already have anaerobic digesters, and those that do installed them as part of the waste-to-energy system. EPA rules for CAFOs can be expected to drive more farms to install manure management systems, but not all of these will be anaerobic digesters. Those farms that do install digesters will do so as part of a manure management and energy system. For that reason, the project economics for dairies will include the costs for the digester.

Changes to other aspects of dairy operations may also be required. Dairies that have gone to anaerobic digestion of manure typically use a scrape method for cleaning feed lanes and emptying the manure into a holding tank, and also send milking center washdown water into the same holding tank. The resulting solids level in the holding tank is typically between 8 and 12 percent. Dairies that intend to install anaerobic digesters need to consider whether changes are needed in current operations to accommodate manure management in this way. Those changes will vary widely from farm to farm and some farms will already have many of the accommodations in place, so these accommodations are not considered in the sample analyses presented in this section. They do need to be considered for specific project analysis.

Data from previous studies indicates that manure collection and handling equipment, including a holding tank, comprises about 10 to 15 percent of total up-front costs, or about $30 to $40 per cow. These costs may be as much as twice as high for centralized digesters.

For the digesters themselves, data indicate this is about 30 to 50 percent of project costs, or about $90 to $130 per cow. This is another cost that could be higher for large or centralized digesters.

3.2.5 Fuel Processing Costs

Biogas from dairy manure will have moisture and hydrogen sulfide, but not siloxane. Therefore, gas treatment tends to be simpler for dairy waste than for other types of biogas. Often only a small dryer is needed, followed by an iron sponge unit to remove hydrogen sulfide. These systems range from $100 to $500 per installed kW, or about $20 to $90 per cow. Gas treatment for reciprocating engines will tend to be lower than for other technologies. For this study, the top end of the range, $50–90 is used.

3.2.6 Energy Conversion Technologies and Cost

Installed costs for power conversion technologies are expected to be similar to those in the other biomass markets:

- Reciprocating Engines (50 kW–3 MW): $900–$1,200 per kW, or $160–$240 per cow
- Microturbines (30–250 kW): $2,000–$3,000 per kW, or $360–$540 per cow
- Fuel Cells (250 kW–2 MW): $6,000–$9,000 per kW, or $1,080–$1,620 per cow
- Stirling Engines (25 kW): $2,500–$3,000 per kW, or $450–$540 per cow

The BETC should be applicable to most projects, and would reduce capital costs by 35 percent if taken over 5 years, or 25.5 percent if taken as a pass-through in the first year.

3.2.7 Engineering, Administration, and Project Management Costs

The data points discussed in the sections above show engineering costs of about 11 percent for the on-farm system and about 16 percent for the centralized digester. Both percentages are low; the on-farm system does not include time and expenses absorbed by the farm owner, and the centralized system may not include some project administration costs that were spread across other projects done by that agency. All-inclusive engineering, administration, and project management costs will include feasibility studies, preliminary and final design of the system, permitting, and interconnect studies. These costs typically will comprise 15 to 25 percent of total project costs. Some on-farm systems could be lower, if the owner donates time to the project. Costs for specific projects will vary widely by project location.

3.2.8 Power Sales Opportunities and Revenues

Most dairies have a captive use for some, but not all, of the power produced. Conditions will vary between farms, but a reasonable range is that the farm will use 50 to 75 percent of power produced by a digester. The rest must be sold back to the power company. At small scales, this might be done through net metering. At larger scales, the farm may work as a small power producer. The reality is that many farmers who have on-farm dairies find it too difficult to manage the power sales process with the power company, and so they simply use their own energy and do not export. For purposes of this report, 75 percent of the power is considered used on the farm, with the rest going into the power grid.

3.2.9 Cost and Financial Evaluation

Table 3-5 summarizes project investment, annual costs, and total generation costs per kWh for typical projects in several size ranges. The 500-kW case is a centralized facility scenario, put in as comparison with the others. Whether costs for centralized digesters can be reduced in the future remains to be seen; currently only a handful of examples exist in the U.S. One of these is the Tillamook, where a centralized digester project was considered for several years, and started up in 2003.

TABLE 3-5
Comparative Cost Ranges for Dairy Waste-to-Energy Systems

Size	**70 kW On-Farm**	**180 kW on-Farm**	**500 kW Centralized**	**2 MW on-Farm**
Technology	**Reciprocating Engine**	**Reciprocating Engine**	**Reciprocating Engine**	**Reciprocating Engine**
Herd Size	**450 Cows**	**1,000 Cows**	**3,000 Cows**	**11,000 Cows**
Project Costs (one-time)				
Engineering/Administration, per cow	$ 160 - $220	$ 150 - $220	$ 210 - $320	$150 - $220
Manure handling collection, per cow	$ 50 - $60	$ 40 - $50	$ 90 - $120	$40 - $50
Installed cost - digester, per cow	$130 - $160	$110 - $ 150	$200 - $ 300	$ 100 - $150
Installed cost - gas treatment, per cow	$50 - $90	$50 - $90	$50 - $90	$50 - $90
Installed cost - power generation, per cow	$160 - $240	$160 - $ 240	$ 160 - $240	$160 - $240
Engineering/Administration,	$72,000 - $ 99,000	$150,000 - $ 220,000	$ 630,000 - $960,000	$ 1,650,000 - $2,420,000
Manure handling collection,	$22,500 - $ 27,000	$40,000 - $ 50,000	$ 270,000 - $360,000	$ 440,000 - $550,000
Installed cost - digester	$58,500 - $ 72,000	$ 110,000 - $150,000	$600,000 - $900,000	$1,100,000 - $1,650,000
Installed cost - gas treatment,	$22,500 - $40,500	$50,000 - $ 90,000	$150,000 - $ 270,000	$ 550,000 - $990,000
Installed cost - power generation,	$72,000 - $108,000	$ 160,000 - $ 240,000	$480,000 - $720,000	$1,760,000 - $2,640,000
Subtotal	$ 247,500 $346,500	$510,000 $750,000	$ 2,130,000 $3,210,000	$ 5,500,000 $8,250,000
Less BETC refund (25.5 percent, up-front)	$(63,000) - $(88,000)	$(130,000) - $(191,000)	$(543,000) - $(819,000)	$(1,403,000) - $(2,104,000)
Total Up-front costs	**$185,000 - $ 259,000**	**$ 380,000 - $559,000**	**$ 1,587,000 - $ 2,391,000**	**$ 4,097,000 - $ 6,146,000**
Annual Costs				
Operations/Maintenance	$ 7,000 - $10,000	$10,000 - $ 15,000	$50,000 - $ 60,000	$70,000 - $100,000
Supplies	$ 5,000 - $9,000	$ 5,000 - $9,000	$ 7,000 - $12,000	$ 10,000 - $15,000
Major overhauls	$30,000 -$50,000, years 6 and 11	$50,000 -$80,000, years 6 and 11	$80000 -$100,000 years 6 and 11	$100,000 - 130,000, years 6 and 11
Less tax benefits of depreciation	40 percent of equipment costs accelerated over 5 years (MACRS schedule)			
Annual energy generation (kWh)	497,000	1,419,120	3,942,000	15,768,000
Total project costs (over 15 years) per kWh	**$0.077 - $ 0.113**	**$0.054 - $0.081**	**$0.075 - $ 0.109**	**$0.044 - $ 0.065**
- includes returns to equity at 12%, interest on debt at 6%, 50/50 debt/equity structure				
Estimated value of power, per kWh				
- Retail rates if offset	$ 0.065 - $0.070	$ 0.065 - $0.070	$ 0.065 - $0.070	$0.065 - $0.070
- Export Power	$ 0.032 - $0.051	$ 0.032 - $0.051	$ 0.032 - $ 0.051	$0.030 - $0.040

In addition to the general assumptions listed in section 3.1, the following also applies to the above table:

- Various values of power are shown: the farm may offset retail for about half to 75 percent of power use, then sell the rest at wholesale or avoided cost rates. Also, after using biogas to make power, the remaining gas may be used internally for heating the digester or for facility heating. For export power, the 70-, 180-, and 500-kW systems use a range derived from the small power producers schedule discussed in Section 2.2 and shown in Table 2-1. For the 2-MW system, export prices for power are at typical wholesale rates, as would be negotiated through a power purchase agreement.

The above analyses suggest the following conclusions:

- Most farms with fewer than 1,000 animals would require a subsidy for the system to be economical. For farms under 500 animals, the subsidy would be significant - the 450-animal example has total project costs of $0.077 to $0.113 per kWh.
- On-farm systems at farms above 1,000 animals begin to be economical, or might be made economical with a modest subsidy. The total per kWh cost shown might work if offsetting retail, but would not be economical for exporting power.
- Centralized systems may be an economical way to bring manure from a cluster of farms to one location for processing. Their costs are higher due to transportation and extra handling and design considerations, but they may be good alternatives for small farms where on-farm systems are uneconomical. A centralized digester also needs an outlet for power. One way to do this is to locate the centralized digester close to a high power user, such as a sewage treatment plant. Opportunities exist in Tillamook, and possibly Coos and Marion counties.
- Large on-farm systems (5,000 animals or more), will tend to benefit from economies of scale. Therefore, they may be able to run economically while exporting a significant portion of the power. There may be five or six such opportunities in Oregon. Subsidizing these locations would require large amounts of money; however, some opportunities may be close to being economical.

3.2.10 Development Potential

The 3–5 kWh per day per cow estimate represents what has been seen in successful installations. It should be noted that:

- Although most of the operations listed above are specified as dairies, some of them may include beef cattle or other similar operations wherein cattle spend most of the time in large pastures. Manure from these operations is generally not considered to be collectible for digestion.
- Not all dairy operations are set up to easily collect the waste. Major changes in these operations to accommodate a digester are considered to be uneconomical from an energy production standpoint.
- In most cases, farms will use biogas for heating purposes. Often, once the power needs for the farm are covered, it may be easier and more economical to use any remaining

biogas for facility and process heat than to make more power and export it to the power company. Thus, on-farm power systems may be sized more for what the farm is expected to use than for maximum power generation.

As a result, the 18 MW for operations over 1,000 animals and 5 MW for those 500- to 1,000–animal operations are high to expect for even mid-term development. A figure of 10 to 12 MW total may be a more realistic mid- to long-term potential. If the TMCF farms in Boardman were to install a project, those two farms alone could account for about 8 MW potential.

Potential project locations for biopower at dairies are mapped with an overlay of PGE and PacifiCorp service areas in Figure A-2 of Appendix A.

3.2.11 Market Segment Issues

The following issues affect this market segment:

- For on-farm dairies, most dairy operators are not trained in running a digester, and do not have the time or personnel to do so. Those on-farm digesters that have been successful in the past were run by operators who had a significant interest in the digester process and were willing to expend extra effort to make it work. This is not typical of most dairy operators.
- Many on-farm dairies do not have the incremental capital available needed to install a digester project. In these cases, even if it is economical, the farm will not do so because the capital is not available.
- Some vendors are improving and reducing costs of the packages available to smaller (fewer than 1,000 head) dairies so that projects in that size range may start to become economical.
- Several clusters of dairies exist in Oregon where a centralized facility may be successful. The most obvious of these is Tillamook, which is home to many dairies in the size range of 100–500 animals, but about 30,000 animals overall. A centralized digester is already being installed, with plans for more around the area. Clusters with centralized digesters could be good mid-term projects for the Energy Trust to consider. It appears that other dairy clusters may exist in Coos, Umatilla, and Marion counties.

3.2.12 Market Segment Summary

In summary, dairies offer the Energy Trust several opportunities. One is to subsidize centralized dairy digesters in areas where there are clusters of dairies located close to each other, to minimize transport costs. Tillamook, Oregon, has a centralized digester project that has already gone through the process of changing the project to optimize haul lengths from farms to the digester. This could be applied elsewhere over the mid-term. Tillamook itself is not in PGE or PacifiCorp service areas.

Another opportunity may lie in the very large farms in Boardman and Umatilla. Projects at these farms would generate large amounts of electricity. What subsidies they might require to get a project going is unclear, and it may be that projects would already be economical. This is likely to be a mid-term opportunity.

Another opportunity for mid-term is to work projects at dairies between 1,000 and 5,000 animals. These projects might be made economical with modest subsidies.

It should be noted as well that as CAFO regulations are enforced, more farms will be examining new alternatives to manure management, so that the market can be expected to increase for processes such as anaerobic digestion.

This study found about 18 MW total potential at farms above 1,000 animals in Oregon. About 10 to 12 MW of this potential may be realistic to develop in the mid-term. Due to the variability of existing data and varying success with on-farm systems, this potential is considered to be mid-term, not near-term. While the MW potential is significant, specific projects for dairies are expected to be harder to develop and incur higher risk than those in the sewage treatment plant, landfill or wood waste market segments.

3.2.13 Data Reliability

The following factors could change the energy potential and number of economical projects:

- Farm economics vary over time, so that even if projects are economical, the investment capital needed for projects may not always be available in this industry. Subsidies for projects could help alleviate this situation.
- Vendors are improving and standardizing equipment so that, especially at the small end of the range (200–1,000 animals), digester costs may decrease in the near- to mid-term. This will cause more small projects to be economical.
- Increasing regulations are expected to drive the market so that farmers may look increasingly to digesters as the method of choice for manure management, with the energy being a secondary benefit.
- If project costs for centralized digester facilities can be reduced through experience and standardization of approach, these may make dairy waste to energy more economical for clusters of smaller farms (in the range of 500 animals) where those clusters exist.

3.3 Landfill Gas to Energy Projects

3.3.1 Description of Resource and Characterization of Key Parameters

Biodegradable waste in a landfill produces combustible biogas in amounts that are predictable within a range. The gas is about half methane and half carbon dioxide with trace constituents that cause odor. Other trace constituents may cause equipment corrosion if the gas is to be used as fuel, but these can be removed by available treatment systems. The gas is often used as fuel for heating or in engine-generator sets.

Solid waste landfills in Oregon above a certain size (2.5 million metric tons permitted capacity) are required to install a gas monitoring and collection system to control and dispose of the gas, usually by flaring it. However, the collected landfill gas also represents a potential energy resource, either to produce heat or power. The collected gas at landfills that have gas collection systems is the energy resource for this market segment.

Key parameters for this market segment are:

- Size of the landfill (amount of waste), expressed in two ways: (a) waste in place (tons) and (b) total permitted waste (tons)
- Opening date and closure date for the landfill (year)
- Heating value of the landfill gas—this is dependent on contents of the landfill, and can vary significantly over time. Heating values for landfill gas tend to be lower than those for other types of biogas, and a typical range is 400–550 Btu/scf. It is possible to have heating values as low as 250 Btu/scf, at which level many power generation technologies will cease to function.
- Amount of contaminants in the biogas, which can include hydrogen sulfide and siloxane, plus trace amounts of chlorinated/halogenated hydrocarbons, non-methane organic compounds (NMOCs), volatile organic compounds (VOCs) and other organics, all measured in parts per million by volume (ppmv)
- Heat rate of power generation equipment, which measures fuel into the unit versus power out, in Btu/kWh. This is a measure of energy conversion efficiency.
- Annual landfill gas generation, in scf/year. This number can be estimated for a given year, but it is not constant. Rather, it follows a decay pattern. After the landfill is closed, gas production typically reaches a peak within 1 to 3 years, then declines as the decay process winds down over a period of 30 to 40 years.

The EPA has developed several approaches of estimating landfill gas production. To estimate for a single year, given the amount of waste in place, a general rule is that gas generation ranges from 0.05 to 0.2 cubic feet of gas per pound of refuse per year, with an average of 0.10 cubic feet per pound per year. Thus (annual landfill gas generation (scf)) = 0.10 scf/lb x 2000 lb/ton x waste-in-place (tons)

However, gas production from a landfill decreases over time after closure in accordance with a first order decay function.[4]

For purposes of this study, total MW potential from landfills in the state of Oregon in the near- and mid-term is estimated using the single-year equation, so that it is an instantaneous estimate of MW potential across a number of landfills. However, for individual sample

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[4] The basic first order decay model is:

$$LFG = 2L_0R\left(e^{-kc} - e^{-kt}\right)$$

Where: LFG = landfill gas generation in current year (cubic feet)
Lo = Total methane generation potential of waste (cubic feet per pound)
R = Average annual waste acceptance rate during active life of landfill (pounds per year)
k = Rate of methane generation per year
t = time since landfill opened (years)
c = Time since landfill closed (years)
The values for Lo and k depend on many factors. EPA regulations for control of landfill gas at new and existing landfills with design capacities equal to or greater than 2.5 million metric tons use the following default values:
Lo = 2.72 cf/lb.
k = 0.05/year

projects to estimate a range of above-market costs, the decay equation shown above should be taken into consideration to project total gas production over the project life.

3.3.2 Fuel Availability and Cost

DEQ lists permits for a total of 129 landfills that handle municipal solid waste in Oregon, of which 37 are active and 92 are closed. These sites range in size from small community landfills that receive 20 to 30 tons per year up to the largest, Columbia Ridge Landfill in Arlington, which received over 1.8 million tons of waste in 2000.

For the landfill gas to be available as a fuel, the landfill must have a gas collection system. The large cost of installing a gas collection system generally cannot be justified by revenue from a power project. However, EPA requires that landfill gas be collected and controlled at all landfills with design capacities over 2.5 million metric tons (2.76 million U.S. tons), so the largest landfills will have gas collection systems. Somewhat smaller landfills often build landfill gas collection systems to prevent odors and subsurface gas migration. For purposes of this study, having a gas collection system is required for a site to have near-term energy potential. Those landfills that are large enough to fall under the EPA requirement that do not yet have a gas collection system fall into mid-term potential. As those landfills build gas collection to meet regulations, they may become near-term potential sites for landfill gas energy projects.

EPA’s Landfill Methane Outreach Program (LMOP) maintains databases of landfills in each state that have energy recovery systems or have potential for installing systems. Data for Oregon include 13 of the 129 total permitted landfills. These landfills are listed in Table 3-6, and comprise the near- to mid-term potential for landfill gas energy generation in Oregon.

TABLE 3-6
Oregon Landfills with Landfill Gas-to-Energy Project Potential

Facility	Service Area	Total Tons Received (annual, 2000)	Waste in Place (tons)	Gas Generation Potential (Mcf/yr)	Energy Potential, MMBtu/yr at 450 Btu/Scf	Power Potential, MW, at 9,000 Btu/kWh heat rate	Open Date	Operational Status	Close Date	County	Known Gas Collection System	Has Energy Generation
Columbia Ridge Landfill	Pacific Power	1,887,066	20,000,000	4,000	1,800,000	22.83	01/02/1990	Active	2060	Gilliam	Yes	
St. Johns Landfill	PGE		12,000,000	2,400	1,080,000	13.70	07/01/1972	Closed	1991	Multnomah	Yes	Yes, Direct Thermal
Coffin Butte Landfill	Neither	413,530	4,500,000	900	405,000	5.14	03/16/1978	Active	2042	Benton	Yes	Yes, Engine, 2.4 MW
Finley Buttes Landfill	Neither	390,412	4,000,000	800	360,000	4.57	02/28/1989	Active	2060	Morrow		
Short Mountain Landfill	Neither	266,240	3,410,000	682	306,900	3.89	12/20/1976	Active	2050	Lane	Yes	Yes, Engine, 3.2 MW
Riverbend Landfill	PGE	409,987	2,500,000	500	225,000	2.85	11/25/1981	Active	2016	Yamhill	Yes	Yes, Leachate Evap.
Dry Creek Landfill	Pacific Power	279,404	1,650,000	330	148,500	1.88	07/01/1974	Active	2048	Jackson		
Wasco Landfill	Neither	137,674	1,600,000	320	144,000	1.83	07/01/1972	Active	2075	Wasco	Yes	
Roseburg Landfill	Pacific Power	90,010	1,200,000	240	108,000	1.37	11/21/1975	Active	2021	Douglas		
Klamath Falls Landfill	Pacific Power	64,277	1,000,000	200	90,000	1.14	10/31/1977	Closed	2001	Klamath	Yes	
Knott Landfill	Pacific Power	117,755	700,000	140	63,000	0.80	07/01/1971	Active	2008	Deschutes	Yes	
Pendleton Regional Landfill	Pacific Power		500,000	100	45,000	0.57	07/01/1972	Closed	1994	Umatilla		
Milton-Freewater Landfill	Pacific Power	5,075	125,000	25	11,250	0.14	07/01/1972	Active	2030	Umatilla		
TOTALS			**53,185,000**	**10,637**	**4,786,650**	**60.7**						

As shown in Table 3-6, the total gas generation potential from these 13 landfills is estimated at about 10,600 Mcf/year using 0.1 scf/lb of waste in place. At a typical heating value of 450 Btu/scf, the potential gas generation above represents approximately 4.8 trillion Btu per year. If all of this gas could be collected and converted to electric power at a rate of 9,000 Btu/kWh (typical for reciprocating engines), the total power would be approximately 60 MW. Two sites already have generation producing 5.6 MW of power, and two others use the gas to generate beneficial thermal energy. The raw gas itself is considered to be free in the economics of the energy conversion and use system once the collection system is in place, since the collection system is required for environmental control. In isolated cases there may be a market for the raw gas if there is a potential customer for it located close to the landfill; however, these instances are expected to be rare.

3.3.3 Fuel Collection Activities and Costs

The landfills considered to have near- or mid-term potential for energy production already have gas collection systems. Further collection costs would be minimal and are considered to be zero for this study. For actual projects, a nominal amount would be spent to tap into existing biogas piping to bring the gas to a separate location for processing and conversion to energy.

Most landfills that collect gas currently flare the gas, with the exception of the four landfills shown in Table 3-6 that have energy recovery systems: Coffin Butte and Short Mountain, both of which generate electricity using reciprocating engines; St. John's, which sends the gas to a neighboring industrial facility to provide heat; and Riverbend, which produces heat for a leachate evaporation process.

3.3.4 Fuel Processing Costs

Landfill gas in the United States contains hydrogen sulfide and often contains siloxane, plus other organic hydrocarbons and halides. Treatment options include iron sponge for hydrogen sulfide removal, and deep-drying refrigeration or carbon treatments for siloxane removal. Treatments selected will be site-specific, as landfill gas varies more than other types of biogas due to variations in waste types across landfills. For specific projects, testing of gas quality is required to determine the appropriate treatment.

Due to biogas impurities, gas treatment is a necessary part of any landfill gas project. Most landfill energy generation projects use reciprocating engines, which are least sensitive to gas impurities, though some gas treatment (often only chilling to wash out contaminants that dissolve in condensate and particulate filtering) is still required for those to be reliable. Gas turbines and microturbines are another power conversion alternative that requires treatment for siloxane as well as hydrogen sulfide. Fuel cells have very little track record on landfill gas, though one demonstration project in Groton, CT is mentioned by LMOP.[5] Treatment costs can be expected to vary from $200 to $1,000 per installed kW, with the lower end being larger reciprocating engines and the high end being smaller systems with microturbines, or possibly fuel cells.

[5] Article on LMOP's website; http://www.epa.gov/landfill/res/fuelcell.htm

Another issue for landfill gas is low Btu content. Landfill gas heating value can vary over time and can sometimes fall below 400 Btu/scf. This reduces speed and power output from the power generation equipment. Around 300 to 350 Btu/scf, most reciprocating engines will tend to stall and not operate again until heating value recovers to above 400 Btu/scf. Microturbines are reported to be less sensitive to this problem, though they also can cease to function at about 250 Btu/scf or lower. One way to overcome this problem is to have a supply of natural gas that can be blended with the landfill gas to bring the average heating value up. This adds to both the up-front project costs (to provide blending capability) and annual costs (of natural gas used). These costs are not factored into the sample analyses below, but may need to be considered on a case-by-case basis for specific projects. Whether a project relying in part on a non-renewable fuel would be eligible for Energy Trust funding is a policy question beyond the scope of this report.

3.3.5 Energy Conversion Technologies and Cost

The LMOP database lists approximately 300 landfill power generation installations around the United States that use some type of generating equipment—a heat engine or fuel cell. Only one is a fuel cell, indicating that fuel cells have not yet gone past the demonstration stage. Over 220 of the installations are reciprocating engines—which have the largest installed base and longest track record in the field. Two sites have Stirling engines. A number of sites are large enough to have gas turbines in the 1-5 MW size range installed, and several installations 6 MW and larger have a steam turbine, or a combined cycle power system, in which waste heat from a large gas turbine is fed to a boiler to make steam and run a steam turbine to create more power. As shown above, only two of the sites in Oregon are above 6 MW potential at this time; however, several more may be expected to get that large over time. Gas turbines may be considered between about 2 and 10 MW, and may be suitable for some of the other large landfills on the list.

Installed costs for power conversion technologies are expected to be similar to those in the other biomass markets:

- Gas Turbines (2–10 MW): $700–$1,200 per kW
- Reciprocating Engines (0.5–3 MW): $900–$1,500 per kW
- Microturbines (30–250 kW): $2,000–$3,000 per kW
- Fuel Cells (250 kW–2 MW): $6,000–$9,000 per kW
- Stirling Engines (25 kW): $2,500–$3,000 per kW

These figures do not include engineering and project administration costs, which are noted below in Section 3.3.6.

The BETC should be applicable to most projects, and would reduce capital costs by 35 percent if taken over 5 years, or 25.5 percent if taken as a pass-through in the first year.

3.3.6 Engineering, Administration, and Project Management Costs

These project costs include feasibility studies, preliminary and final design of the system, permitting, interconnect studies, and project management. They will typically total from 25 to 40 percent of project costs. Typical ranges for these costs are listed in the cost evaluation below. Costs on specific projects may vary widely by project location.

3.3.7 Power Sales Opportunities and Revenues

Landfills, with very few exceptions, do not have a captive onsite use for the amounts of electricity generated by a landfill gas power project. Therefore, they must sell that power to a power company at a price that will closely follow the wholesale market. Project considerations include generating and managing a power purchase agreement, and building transmission facilities to export the power offsite to the closest tie-in point in the local power grid at the small power producers schedule of $0.032-$0.051 per kWh for facilities 1 MW and under, or wholesale prices negotiated directly at $0.03-$0.04 per kWh for facilities over 1 MW.

Tax credits could also add to the annual financial benefit from the project. Since municipal entities do not pay taxes, they cannot directly benefit from this, but they could indirectly benefit by allowing a tax-paying entity such as an independent developer, or the power company itself, to sponsor and develop the project, and then pass through the tax benefit as a direct translation or via other savings to the municipality. This arrangement is, in fact, often used in landfill gas-to-energy projects.

3.3.8 Cost and Financial Evaluation

Table 3-7 summarizes project investment, annual costs, and total generation costs per kWh for typical projects in several size ranges.

TABLE 3-7
Comparative Cost Ranges for Landfill Gas-to-Energy Systems

Size	**70 kW**			**250 kW**			**1MW**			**6 MW**		
Technology	**Microturbine**			**Microturbine**			**Reciprocating Engine**			**Gas Turbine**		
Project Costs (one-time)												
Installed cost - gas treatment, per kW	$ 600	-	$1,000	$500	-	$1,000	$ 200	-	$500	$ 200	-	$ 700
Installed cost - power generation, per kW	$ 2,500	-	$ 3,500	$2,000	-	$3,000	$ 900	-	$1,200	$ 800	-	$ 1,000
Feasibility Study	$ 10,000	-	$15,000	$10,000	-	$15,000	$ 30,000	-	$50,000	$180,000	-	$ 306,000
Preliminary and Final Design	$20,000	-	$30,000	$20,000	-	$30,000	$50,000	-	$80,000	$ 480,000	-	$816,000
Permitting	$ 5,000	-	$15,000	$10,000	-	$ 20,000	$15,000	-	$30,000	$ 30,000	-	$ 70,000
Interconnect to grid	$ 25,000	-	$ 30,000	$ 30,000	-	$50,000	$ 50,000	-	$80,000	$ 100,000	-	$ 600,000
Project/Construction Management	$ 25,000	-	$35,000	$30,000	-	$50,000	$50,000	-	$80,000	$ 400,000	-	$600,000
Gas treatment equipment (installed)	$ 42,000	-	$70,000	$125,000	-	$ 250,000	$200,000	-	$500,000	$1,200,000	-	$ 4,200,000
Power generation equipment (installed)	$175,000	-	$245,000	$500,000	-	$750,000	$900,000	-	$1,200,000	$ 4,800,000	-	$ 6,000,000
Less BETC refund (25.5 percent, up-front)	$ (77,000)	-	$(112,000)	$(185,000)	-	$(297,000)	$ (330,000)	-	$ (515,000)	$(1,833,000)	-	$(3,211,000)
Total Up-front costs	**$ 225,000**	**-**	**$ 328,000**	**$ 540,000**	**-**	**$ 868,000**	**$ 965,000**	**-**	**$ 1,505,000**	**$ 5,357,000**	**-**	**$ 9,381,000**
Annual Costs												
Operations/Maintenance	$7,000	-	$ 10,000	$20,000	-	$ 30,000	$100,000	-	$150,000	$400,000	-	$500,000
Supplies	$5,000	-	$9,000	$7,000	-	$12,000	$ 10,000	-	$15,000	$30,000	-	$50,000
Major overhauls	$50,000 -$70,000, years 6 and 11			$70,000 -$100,000,years 6 and 11			$70000 -$100,000, years 6 and 11			$300,000 -$500,000, years 6 and 11		
Less tax benefits of depreciation	40 percent of equipment costs accelerated over 5 years (MACRS schedule)											
Annual energy generation (kWh)	497,000			1,774,000			7,884,000			44,939,000		
Total project costs (over 15 years) per kWh	**$0.101**	**-**	**$0.150**	**$0.060**	**-**	**$ 0.095**	**$ 0.031**	**-**	**$0.048**	**$0.026**	**-**	**$0.042**
- Includes returns to equity at 12%, interest on debt at 6%, 50/50 debt/equity structure												
Estimated value of power, per kWh	**$0.035**	**-**	**$ 0.051**	**$0.035**	**-**	**$0.051**	**$0.035**	**-**	**$ 0.051**	**$0.030**	**-**	**$0.040**

In addition to the general assumptions listed in section 3.1, the following also applies to the table above:

- Value of power is based on exporting to the power grid, through a power purchase agreement with PGE or PacifiCorp

The above analyses suggest the following conclusions:

- Projects in the 70 kW size range have a significant above-market cost, due to the fact that fixed project costs are spread across a small amount of power generation revenue. In almost all cases these projects would require subsidies. This size of project with a microturbine equates to approximately 80,000 tons of waste in place. Stirling engines would have costs similar to the microturbines shown. Fuel cells would have higher costs. The range of values per kWh for power is based on PGE's schedule 201 or PacifiCorp's schedule 5 for small power producers (up to 1MW).

- Projects in the 250 kW size range, using microturbines, have above-market costs, but could be made economic with a subsidy. This size project with a microturbine equates to approximately 290,000 tons of waste in place. The range of values per kWh for power is based on PGE's schedule 201 or PacifiCorp's schedule 5 for small power producers (up to 1MW).

- Projects in the 1-3 MW size range will tend to use reciprocating engines, and may be economical with small subsidies. Some of these projects are already economical, thus it is not surprising to see projects up and running at Coffin Butte and Short Mountain. These projects benefit from economies of scale and lower installed costs of engines on a per-kW basis. A 2 MW project with a reciprocating engine equates to approximately 1.7 million tons of waste in place. Above 1 MW, the range of value for power changes because at the current time, those projects drop off from the small power producer rate schedules for PGE and PacifiCorp, and the facility must negotiate a special contract with the power company tied to wholesale rates, which range from $0.03 to $0.04 per kWh.

- Projects around 6 MW tend to use gas turbines, again due to economies of scale for the technology at this size and above. The total project costs per kWh overlap the range of estimated value per kWh, so that some of these projects are already economical, or may be made economical with a subsidy. At this level, the subsidy may be a small percentage of total up-front costs (less than 10 percent), but due to the size of the project, may still be over $500,000. This size project with a gas turbine system equates to about 5.5 to 6 million tons of waste in place.

3.3.9 Development Potential

Theoretical Potential

Translating the 10,600 Mcf/year of landfill gas production into electricity depends on the conversion efficiency of the power generation technology chosen. At 450 Btu/scf, this amount of biogas represents approximately 4.8 trillion Btu per year. Power conversion efficiency can be represented by "heat rate," which measures amount of heat in (Btu) per amount of electricity out (kWh). At 9,000 Btu/kWh, typical for reciprocating engines, the power output from all of the landfills would be approximately 60 MW. At 13,000 Btu/kWh, typical for microturbines, the power output would be about 41 MW.

Practical Potential

In practice, it is important to consider the following issues:

- Landfill gas quality is site-specific, and some landfills may not generate gas with consistently high enough heating values to make a power project economical.
- Landfill gas quantity is also site-specific. Rainfall and humidity conditions can significantly affect the rate of matter decomposition and methane production, because the active bacteria need water to function. Landfills in dry or arid areas may experience lower methane production than those in wetter climates.
- Some landfills already use some of the gas for heating. In some cases, this is more economical than generating power. In other cases, a power project may turn out to be a more effective use for the gas.
- Only those landfills and landfill cells that have gas collection installed and have started to collect gas are candidates for a power generation system.
- For some of these landfills, such as Klamath Falls, which recently closed, gas production will start to decrease after a few years, so that a specific project evaluation must take this into account. For other landfills, total gas production will increase as more material is deposited.
- These conditions will be site-specific. Therefore, it is difficult to predict exactly what a practical power generation potential will be, however 60 MW represents an upper limit, and is likely not realistic in the near term. It is reasonable to conclude that a mix of power generation technologies will be used, and that a portion, not all, of the available biogas will be used to make power. In this case, the practical potential is probably between 45 and 60 MW for the 13 landfills listed above.
- However, it should be noted that many of these landfills will increase in gas production over the next decade as more waste is deposited in them. Only one of the active landfills listed is scheduled to close before 2010. The closed ones can be expected to start to drop off in production, however that will be more than offset by the increase in those that remain open. By 2010, the total practical potential of these landfills may be more like 60 to 70 MW.

Potential project locations for biopower at landfills are mapped with an overlay of PGE and PacifiCorp service areas in Figure A-3 of Appendix A.

3.3.10 Market Segment Issues

The following issues affect this market segment:

- Operator availability and cost: A landfill does not have operators for power generation facilities. All such personnel would need to be brought onsite as part of the project. Therefore, operator costs for landfills are higher than for other biomass markets.

- Location: Economics and feasibility of specific projects will be highly affected by proximity to tie-in points for the power grid to export power.
- Electrical interconnect: an interconnect study will be required for each landfill power project, at the preliminary design stage. Grid interconnect equipment is required to export power, as specified by the power company. For the large plants, this cost will be significant.
- Gas production: While gas production rates can be estimated within a range, there is considerable uncertainty in future production. Conservative estimates based on proven estimation models and reliable site data are essential.
- Gas quality: As noted above, gas treatment of some kind is typically needed for energy recovery. The specific treatment method and its cost depend on the types and amounts of contaminants in the gas. This varies considerably from site to site.
- Most landfill gas-to-energy projects currently in operation (several hundred in the US) have excellent reliability records. The gas is produced at a nearly constant rate regardless of season or weather, so these projects are available for peaking or base load applications.

3.3.11 Market Segment Summary

In summary, this market segment could potentially produce about 40-45 MW of new renewable power if developed across the 13 landfills listed above. Some potential projects may already be economical, as indicated by the existence of reciprocating engine generators at two of the locations, which together generate approximately 5-6 MW of power already.

At the small end of the size range, 70 to 140 kW, projects are not economical and will have significant above-market costs. This represents about 125,000 tons of waste in place and below.

Projects up to 1 MW (about 900,000 tons of waste in place) represent an opportunity for groups of one or more 250-kW microturbines. Most of these projects will have an above-market cost that could be offset with a modest subsidy, and could be of interest to the Energy Trust.

Projects between 1 and 2 MW (1.0 to 1.8 million tons of waste in place) may see less revenue per kWh, due to being off the pricing schedules for small power producers. This condition may change. This range is good for reciprocating engines, and many of these projects could already be economical, or be easily made economical with modest subsidies. This could be an area of interest to the Energy Trust.

Projects in the 2-6 MW range are applicable for gas turbines, and will see higher economies of scale. These projects could already be economical, however they can also face extra costs for interconnecting to the grid, permitting, and building ancillary facilities.

Projects above 6 MW (5.8 million tons of waste in place) are applicable for gas turbines and could be applicable for combined-cycle power plants, which use a gas turbine and then a steam cycle that takes waste heat from the gas turbine to produce more power. The Columbia Ridge landfill in Arlington may be a candidate for such a project. This could produce over 30 MW of power from this one project as a combined-cycle plant, based on tons of waste currently in place. This is subject to local conditions with regards to both gas quality and quantity, and specific project analysis would be needed to proceed. This type of project would have significant economies of scale, and may be economical now; however, significant planning and other costs would go into the project, and it would likely have $25 million to $35 million in up-front costs.

3.3.12 Data Reliability

The following factors could change the energy potential and number of economical projects:

- As mentioned above, as waste is added, total tons in place, and therefore power potential, for most of these landfills is expected to increase.
- As vendor packages for equipment, including gas treatment, become more standardized and project experience increases, both installed equipment costs and other project costs such as feasibility studies and design work should decrease. This will reduce above-market costs, especially at the lower end of the size range, and make more projects economical.
- Smaller projects are estimated with fixed costs for feasibility, design, permitting, and construction. As more of these projects are done, a learning curve effect can be expected so that these fixed costs decrease, making more of these projects economical.

3.4 Woody Mill Waste

All wood processing produces waste - material that is less valuable than the original raw material. Wood waste includes bark, sawdust and planer shavings. Wood chips are made from the round and irregular portions of the wood and are no longer considered waste because they have value at pulp mills. Sawdust and planer shavings can be used in pulp mills but their value as pulp material is comparable to their value as fuel. Woody wastes are produced by sawmills, planer mills, and veneer mills. Woody mill waste is almost entirely consumed by sawmills and pulp or paper mills to produce steam for mill processes. At sawmills the steam is used for kiln-drying of lumber. Pulp or paper mills use the steam to dry sheets of pulp or paper. (Pulp and paper are both composed of cellulose fibers. The difference is that pulp has not yet been processed to develop its strength as paper.)

In general, the market for woody mill waste as a fuel is a mature commodity market. When there is an excess fuel relative to the capacity of boilers to use it, the market price drops until an additional boiler is constructed to use up the excess. When there is a shortage, the price rises until oil or natural gas is substituted. Because woody mill waste is expensive to transport over long distances, there can be persistent local shortages or surpluses. When assessing this resource for electric power production we should look only at the portion of it that is now being disposed of in landfills. The state of Oregon keeps landfill records that allow this to be determined.

3.4.1 Description of Resource and Characterization of Key Parameters

The value of woody mill waste for energy production depends chiefly on its moisture content. The lower heating value of dry woody wastes is about 8,000 Btu/dry lb and varies little whether the source is hardwood, soft wood or bark. At 50 percent moisture content, the heating value is reduced to 4,900 Btu/dry lb, but the weight to transport is doubled. The heat content per wet pound at 50 percent moisture is only 2,450 Btu/wet lb. Green wood is typically about 50 percent moisture.

Wood gathered in winter east of the cascades or in Southern Oregon has about 45 percent moisture content. Wood left in the rain on the coast has closer to 60 percent moisture content and has a much lower value as a fuel. In contrast, woody wastes allowed to dry in the summer can get down to 25 percent moisture and are much more valuable as fuel. In general, coastal wood waste has a low value as a fuel and is too heavy and too far from a dry climate to make it worthwhile to transport. There are processes for drying wet wood, but in this application they are considered noneconomic.

3.4.2 Fuel Availability and Costs

The total quantity of woody waste landfilled in the year 2000 was 62,000 tons, which equates to 608,000 MMBtu/yr. If converted by steam topping cycles into electricity, an average of 10 MW or 87,600 MWh/yr would result. There is currently a glut of woody waste caused by the most recent housing boom, which increased demand for plywood, and a diminished demand for particle board. Also, once topping cycles are installed, they are so economically attractive to run that materials other than the traditional woody wastes would be used.

The current market price for wood waste is $10 to $15 per dry ton plus freight. Freight is about $10 per dry ton per 100-mile haul. Much of the waste produced is already used for fuel or other purposes. In some locations there is more wood waste produced than can be economically used, typically because the transport costs are not offset by the revenue received for the material. In such situations, the material is typically landfilled. This landfilled material has the best potential for being used to produce electricity. One needs to look at the woody waste being put in landfill in light of the fact that the owner of the waste must pay disposal fees. One can also assume that if it is being landfilled it is because it is uneconomic to ship elsewhere. Therefore, if the wastes are not trucked more than 100 miles, a reasonable maximum haul distance, it can be assumed that the fuel would have a delivered value of $20/ton, which is $2 per million Btu (MMBtu). In practice, as this resource is used, it will be allocated by market forces and distributed economically to minimize transportation costs and maximize the return for a given project. For planning purposes, however, it is reasonable to use these typical costs.

3.4.3 Fuel Collection Activities and Costs

Woody waste is collected at mills as standard practice. No additional fuel collection costs are incurred other than possible transportation costs to offsite locations.

3.4.4 Fuel Processing Costs

Fuel can be dried by installing drying equipment or aging it in large piles during dry weather. These measures would enhance the material’s fuel value and may not significantly increase project costs, if it is simply allowed to age in piles. As more wood waste is used for electricity generation , more drying operations may come into existence. Incentives for drying may be logical to consider in the mid and long term, but in the short term the economics of individual projects will determine if such facilities make economic sense.

3.4.5 Energy Conversion Technologies and Costs

There are two technologies for converting the woody waste to electricity worthy of consideration in the near and mid term. Both use steam as the working fluid. The first is called a topping cycle. In this cycle, steam is generated at a higher pressure than needed by the mill’s processing equipment (e.g., kilns and other drying equipment). The high-pressure steam is run through a back-pressure turbine to generate electricity. After passing through the turbine, it is at the lower pressure needed by the mill's process. The second technology uses a condensing turbine. In this technology, the steam is passed through a turbine and all the useful energy is used for electricity production. No useful thermal energy is available for process use. All of the equipment is the same for both technologies except that a water-cooled condenser and cooling tower are needed for the condensing turbine. In both cases the steam needs to be made at a higher pressure than the 15 to 100 psig needed for drying paper or wood.

The back-pressure turbine produces very little power relative to the amount of heat input, but is nearly 100 percent efficient. That is to say, every Btu of additional fuel becomes an additional Btu of electricity. The condensing turbine, however, operates at lower efficiency. For instance, the unit at Biomass 1 in Medford is 19 percent efficient, averaging 2,100 dry lbs. of fuel per MWh.

In considering alternative uses of the woody waste, it is important to note that there are natural gas-fired dryers in Oregon. It is generally more economic to use woody waste to generate heat for this process, offsetting the purchase of oil or gas. There would also be more efficient use of the woody waste if boilers also had a topping turbine because it is the most efficient way possible to convert fuel to electricity. Even if there is not enough surplus woody mill waste for the extra fuel needed to make electricity, topping turbines would still be advantageous to install. [6] The topping turbine is so efficient that it could pay to use natural gas or potentially forest thinnings to keep it fed. If the price of electricity were low the topping turbine would not need to be used. Condensing turbines have a lower overall efficiency, but could be economic in an area where there is abundant woody waste and little demand for process steam.

To make best use of topping turbines, drying kilns should operate at as low a pressure as possible—about 15 psig. High-temperature kilns process the wood faster but degrade the quality of the wood. Most Douglas fir mills and many hemlock mills do not kiln dry. Increasing concern about molds is causing some reconsideration of this practice. There may therefore be some new boilers to be built. These should be encouraged to have topping turbines.

3.4.6 Engineering, Administration, and Project Management Costs

These project costs include feasibility studies, preliminary and final design of the system, permitting, interconnect studies, and project management. They will typically total from 25 percent to 40 percent of project costs. Typical ranges for these costs are listed in the cost evaluation below. Costs on specific projects may vary widely by project location.

3.4.7 Power Sales Opportunities and Revenues

Generally, power from woody waste can be used internally at the mills that burn it. However, it is often advantageous for mills to enter into an agreement to sell the power generated to the local utility or third party rather then reduce the power they purchase from the local utility. Such an arrangement benefits the mill because even if the mill were to reduce the amount of

[6] Note that the Energy Trust's renewable energy programs are permitted to offer incentives only for the production electricity from eligible renewable resources. Although the Trust does offer incentives for the efficient use of natural gas to commercial and residential customers of NW Natural, these incentives are not available to industrial gas users, since those firms do not currently contribute to the Trust.

energy it purchased, it would still have to pay a significant demand charge, thereby reducing the savings that would be realized. Therefore, it could be expected that mills would receive revenues at a price equivalent to utility's avoided costs that are applicable to qualifying facilities. If a suitable arrangement could not be worked out with the local utility or third party, it may be logical to ship the woody waste to another location that can use the energy more cost-effectively or command a higher price for the electricity. The cost to ship the fuel 100 miles, ($1.10/MWh), is comparable to the transmission cost for the power.

With 50 percent moisture woody waste delivered at $20/dry ton to a topping turbine the fuel component of electricity is only $7.20 per MWh ($0.0072 per kWh). Once the topping turbines are installed they can burn fuels other than woody mill wastes such as sawdust and planer shavings that ordinarily are used in particle board, or wood from timber landings normally not considered worth gathering, or even fossil fuel (although fossil generation would not be eligible for Energy Trust support).

3.4.8 Cost and Financial Evaluation

Table 3-8 provides a cost evaluation conducted as part of a feasibility study for power projects using wood waste at a mill in Oregon. The estimated costs for equipment and other project components are augmented by information from equipment vendors, other project locations, and CH2M HILL internal experience with typical projects.

TABLE 3-8
Cost Evaluation for Woody Mill Waste Power Projects

Size (typical)		**4.8 MW**	
Technology (Topping Cycle)		**Steam Turbine**	
Project Costs (one-time)			
Installed cost—high-pressure boiler (incremental cost above low-pressure boiler), per kW	$600	-	$1,000
Installed cost—steam turbine, per kW	$350	-	$600
Feasibility Study	$ 80,000	-	$150,000
Preliminary and Final Design	$ 510,000	-	$ 800,000
Permitting	$ 50,000	-	$ 80,000
Interconnect to grid	$50,000	-	$100,000
Project/Construction Management & Administration	$900,000	-	$2,000,000
Boiler (installed)	$ 3,100,000	-	$4,800,000
Power generation equipment (installed)	$2,100,000	-	$2,880,000
Less BETC refund (25.5%, up-front)	$(1,697,500)		$(2,702,500)
Total Up-Front Costs	**$5,093,000**	**-**	**$8,108,000**
Annual Costs			
Operations/Maintenance/Supplies	$150,000	**-**	$200,000
Fuel Delivery Cost		$0.007 per kWh	
Major Overhauls		$100,000 -$200,000, years 6 and 11	
Less tax benefits of Depreciation		40% of equipment costs accelerated over 5 years (MACRS schedule)	
Annual energy generation (kWh)		31,720,000	
Total Project Costs (over 15 years) per kWh	**$0.025**	**-**	**$0.040**
Includes returns on investment at 12% ROE, 50% equity project, debt at 6%, 9% project ROI			
Estimated value of power, per kWh		**$0.030 -$0.040**	

The total project cost range shown is the effective cost of power if produced by a topping cycle, assuming an initial replacement of a low-pressure boiler were paid for by other considerations. If the owners were to be sure of receiving this much of more for the power, it is the point at which adding the topping cycle would provide a 9 percent rate of return on the project. At a capital structure of 50/50 debt to equity and 6 percent interest on debt, the return to equity is 12 percent. This indicates that some projects may already be economic, however incentives may be needed to get mill interest in the projects due to market volatility of economic factors.

This range assumes all-new equipment.

The boiler cost reported above is the incremental difference one would pay between buying a new low-pressure boiler to replace an existing one, and buying a new high-pressure boiler that replaces an existing low pressure boiler and provides high-pressure steam for power. It is assumed that for a project to be economic, a boiler replacement is already being done for other reasons such as age of the existing equipment, and the project entails going to a high-pressure boiler instead of a low-pressure one. This is estimated to be about 1/3 additional cost.

It is generally not economic to replace a perfectly good, relatively new low-pressure boiler with one capable of the higher pressure and temperatures needed for power generation. Doing so would result in a total power cost in excess of $0.08 per kWh, which is above current value of power at wholesale or avoided cost rates. It would take a very substantial subsidy to get someone to replace a good existing boiler just for the topping power cycle.

3.4.9 Development Potential

Table 3-9 lists potential project locations where woody mill waste is currently used for plant processes. Included in this table is an indication of whether the location is close to or in PacifiCorp or PGE territory. Those that are inside the territories will not incur a wheeling cost to export power. Many of the mills, however, may be close to or within the territories, but have formed a small utility district around themselves. In these cases, exporting power may incur the cost of running a line for a short distance to take power from the plant boundary to a connection point in the service territory. For those that are not close to the service territory, the mill would incur a wheeling cost to deliver power into the service territory. This would be an extra cost that is not reflected above.

TABLE 3-9
Mills with Boilers for Woody Waste
Data Source: Oregon Biomass Energy Facility Directory: 2004 by Oregon Department of Energy

Facility Name	City	County	Near or In Energy Trust Territory?	Equipment	Fuel Type	Energy Value, Trillion Btu/yr	Btu/hr	lbs. steam/hr	End Use	Current MW	Potential New Project (MW)
Roseburg Forest Products: Coquille	Coquille	Coos	Yes	Kipper & Sons boiler, 8,136 hr/yr, 285 psi	hogged fuel	0.62	73,809,524	70,295	process steam		3.2
Roseburg Forest Products: Riddle	Riddle	Douglas	Yes	Wyatt & Kipper boiler, 110,000 lb/hr, 300 psig; one Kipper & Sons boiler, 50,000 lb/hr, 280 psig	hogged wood	1.56	185,714,286	176,871	steam		8.2
Superior Lumber Company	Glendale	Douglas	Yes	Babcock & Wilcox water tube boiler, 8,640 hr/yr, 75,000 lb/hr, 250 psig	hogged conifer bark	0.47	55,952,381	53,288	process steam		2.5
Boise Cascade Corporation: Medford Operations	Medford	Jackson	Yes	Three spreader stoker hogged fuel boilers (Eric City, 60,000 lb/hr; Eric City, 85,000 lb/hr; Alpha, 120,000 lb/hr)	hogged fuel	1.67	198,809,524	189,342	steam for dry kilns, veneer dryer and plywood process, electricity	3.7	5.0
Warm Springs Forest Products Industries	Warm Springs	Jefferson	Yes	Two dutch oven Babcock & Wilcox power boilers, 4,200 hr/yr, 60,000 lb/hr, 250 psig; one stoker fired Riley process boiler 3,400 hr/yr, 60,000 lb/hr, 175 psig; one Wickes dutch oven, 150 psig	hogged fuel	0.78	92,857,143	88,435	process steam, electricity	1.0	3.1

TABLE 3-9
Mills with Boilers for Woody Waste
Data Source: Oregon Biomass Energy Facility Directory: 2004 by Oregon Department of Energy

Facility Name	City	County	Near or In Energy Trust Territory?	Equipment	Fuel Type	Energy Value, Trillion Btu/yr	Btu/hr	lbs. steam/hr	End Use	Current MW	Potential New Project (MW)
Georgia-Pacific West, Inc.	Toledo	Lincoln	Yes	Combustion Engineering hogged fuel boiler, 8,760 hr/yr, max. 250,000 lb/hr at 420 psig	bark, wood fiber rejects	0.56	66,666,667	63,492	process steam		2.9
Weyerhaeuser Company: Foster	Sweet Home	Linn	Yes	Wellons boiler, 8,100 hr/yr, 50 lb/hr	hogged fuel	0.38	45,238,095	43,084	process steam		2.0
Stimson Lumber Company	Forest Grove	Washington	Yes	Three Babcock & Wilcox boilers, 8,592 hr/yr, 91,607 lb/hr, 250 psi	Douglas fir, hardboard dust, hemlock bark, shavings	1.01	120,238,095	114,512	process steam		5.3
Pacific Wood Laminates, Inc.	Brookings	Curry	No	Riley Bros. boiler, stationary grate stoker with water tube boiler, 8,000 hr/yr, 250 psi	hogged wood fuel	0.6	71,428,571	68,027	process steam		3.1
Crown Pacific Ltd.: Gilchrist	Gilchrist	Klamath	No	Two Stirling-Wickes biomass boilers, 8,760 hr/yr, 100,000 lb/hr combined, 235 psig	pine bark, sawdust	0.63	75,000,000	71,429	process steam, electricity	0.6	2.7
Hampton Lumber Mills: Tillamook Division	Tillamook	Tillamook	No		wood waste	1.06	126,190,476	120,181	process steam		5.5

TABLE 3-9
Mills with Boilers for Woody Waste
Data Source: Oregon Biomass Energy Facility Directory: 2004 by Oregon Department of Energy

Facility Name	City	County	Near or In Energy Trust Territory?	Equipment	Fuel Type	Energy Value, Trillion Btu/yr	Btu/hr	lbs. steam/hr	End Use	Current MW	Potential New Project (MW)
Boise Cascade Corporation: Elgin Plywood and Studmill	Elgin	Union	No	Two Keeler spreader-stoker boilers, 60,000 lb/hr each	hogged fuel	1.19	141,666,667	134,921	process steam		6.2
Totals	**12**									**5.3**	**50**

Of the facilities listed above, it is not known which boilers are ready to be replaced. About 30 percent of the wood kilns are supplied by natural gas. It is uneconomic for those to continue to do so. Mills planning to put in new boilers should be encouraged to using topping cycles. The list above indicates approximately 50 MW of new generation potential. As shown in the cost evaluation above, some projects may already be economic, or require a small percentage subsidy to get interest from the facilities. Those mills with boilers ready to be replaced will be in the near-term potential, while the rest will be mid-term.

Potential project locations for biopower at wood waste boiler facilities are mapped with an overlay of PGE and PacifiCorp service areas in Figure A-4 of Appendix A.

3.4.10 Market Segment Issues

The forest products industry is historically very cyclical. Some mills deal with this highly cyclical market by being willing to make an investment in electric generation, believing that it will pay off over time. Other mills view such investments as speculative and risky given the volatility in both the power and forest products markets. The typical mill looks for investments when it is having a good year or when the price of power is extraordinarily high, as it is projected to be in the third quarter of 2005. Unfortunately, it can take up to one year to decide and about 2 years to engineer, permit and construct a power project. During that time the situation will likely change causing economic projections to be questionable.

A key consideration in this market is whether a subsidy, in the form of a loan with no repayment required until the new equipment were profitable enough to run, would allow the owners to use longer time horizons to justify projects.

At this time there is a surplus of wood waste because the plywood mills are enjoying the housing boom while at the same time particle board use is down. Information from an interview with a boiler manufacturer indicates that several boilers in the 150 million Btu/hr range are on order or are being contemplated.

Outside the Energy Trust service territory, topping turbine projects are possible at Elgin, Tillamook, and Forest Grove with power production potentials of 6.2, 5.5 and 5.3 MW respectively.

3.4.11 Market Segment Summary

In summary, the market for woody mill waste as a fuel is mature and opportunistic, with most of the waste being used up as fuel for mill processes. Overall, surpluses and deficits of fuel are adjusted for by market forces. Locally, some surpluses do exist, which are landfilled. Therefore, there may be local areas where adding projects to make power from the woody waste could be economic to take up the surplus. Some of these surpluses are due to the recent housing boom, which created waste from plywood that was not used in particle board.

Based on a survey of existing facilities, there appears to be potential to build 50 MW of new projects using topping cycles on woody mill waste. However, this total potential is dependent on availability of extra wood waste to burn. As an example, in the year 2000 it is known that only approximately 10 MW worth of waste was landfilled. That number may be higher in the current market, but it is expected to fluctuate with the lumber, pulp and paper markets. The 50 MW should be considered an upper limit to potential.

The most economically attractive projects will be for topping cycles, where an existing system has a high-pressure boiler added to make steam to power a turbine, after which the reduced-pressure steam is used in thermal processes. A project study example shows the total project cost (including returns on investment) to be in a range of $0.025 - $0.040 per kWh, which may make some projects economical if contracts can be written with the local power company to buy at a higher price ($0.03–0.04/kWh).

However, both the energy market and the pulp/paper market are volatile, so that mills have a hard time investing in projects with a 15-year horizon; often their analysis is simply based on 2-3 year payback. Subsidies in this area could be in the form of loans at no interest until the project makes money, or some similar arrangement.

Because this market already uses the biomass to create energy and makes investments as surpluses exist, it may be of less interest to ETO.

3.4.12 Data Reliability

A serious limitation is the fact that landfill data are not available from the state of Oregon for years later than 2000.

Anything that permanently alters the supply of woody waste would change these conclusions. Addition of forest thinnings, urban wood, brush or agricultural waste to the fuel supply at prices similar to woody waste would alter the situation and make several other projects viable. Renewed logging of National Forests would also completely alter everything, by revitalizing the industry and making large amounts of wastes available.

3.5 Forest Waste (Timber Residue and Forest Thinnings)

3.5.1 Description of Resource and Characterization of Key Parameters

Due to decades of fire suppression, there is a significant quantity of fuel in the form of dense undergrowth and residue in the western forests. It is not economic to remove this material for making energy in the current economy. However, the current economy does not take into account the following factors:

1. Cost of fighting forest fires is $1,170/acre
2. Destruction of buildings by forest fires
3. Air pollution from forest fires
4. Potential to offset air emissions from fossil fuels by using biomass
5. Human mortality from forest fires (estimated at $6/acre by the Rural Technology Initiative)
6. Loss of habitat (estimated at $1,600/acre by the Rural Technology Initiative at the University of Washington, http://www.ruraltech.org)

7. Loss of timber value by forest fire
8. Loss of timber value by not thinning small trees

These costs are not all quantified in the analysis below, as changes in the current economic structure will be needed to realize their value. An adequate recognition of these issues would lead to a pricing structure that would make it economical to burn timber residue and thinnings. Nevertheless, we mention them briefly in recognition of the policy drivers that could motivate pursuit of energy projects based on this fuel resource.

3.5.2 Fuel Availability

Oregon produced 6.7 million board feet of softwood lumber in 2004. There are about 2,900 dry lbs. of material in the logs processed to produce 1,000 Board feet. This is about 10,000,000 tons of dry material taken out of the forest per year through logging. However, limbs left in the forest from these operations amount to about another 1,800,000 tons/yr. This equates to about 18 trillion Btu/yr of potential fuel left in the forest in the form of residual from logging. If converted to electrical power with condensing turbines, this residual material would produce **112 MW.**

The amount of thinnings potentially available by thinning overgrown forests is 2,490,000 tons/year. By the same reasoning above this would amount to an additional **183 MW**.

As a point of illustration, if the logging waste and thinnings were put into the Boardman coal-fired plant (which is about twice as efficient as Biomass 1 due to its larger size), the power produced would be 205 and 336 MW respectively. Use of this fuel stream would convert the entire capacity of the Boardman plant, Oregon's only coal-fired facility, from coal to wood.

Other options for using this material may include mixing it with other wood fuel streams at existing sites and using back-pressure turbines, however it should be noted that this amount of material easily represents more fuel than existing boilers can use to make power.

3.5.3 Fuel Collection Activities and Costs

Fuel collection is free at logging landings for limbs and tops. Bringing thinnings to a road costs a variable amount depending on the distance to an existing road.

It costs $12/ oven-dried ton (ODT) to chip materials at logging landings or roadsides.

It costs $21/ODT to truck chipped wood 100 miles.

Therefore, the total cost of wood delivered to a power plant would start at $32/ODT and increase depending on cost to do the thinning. For the proposed Lake County Resources Biomass Power Plant an overall cost of $40 per ODT has been determined, not including the actual cost of thinning. This is equivalent to about $2.35 per MMBtu, or a range of $0.04–0.05 per kWh produced for fuel.

As a comparison, coal is delivered to the Boardman plant for only $10/ton and it has twice the energy per ton as wood.

3.5.4 Energy Conversion Technologies and Costs

The only near-term way to convert these quantities of biomass to energy is with a boiler and condensing turbine. The Biomass 1 system, at about 30 MW, is 19 percent efficient. In the woody mill waste section above, topping cycles for lumber drying are identified as being almost 100 percent efficient, but there is not enough capacity in all of the potential topping cycle facilities in Oregon to take up these quantities of biomass. If topping cycles were to take in forest residue, the project costs would be similar to those shown in Table 3-9 above for wood waste, however the fuel cost, instead of $0.007 per kWh, would by $0.04–0.05 per kWh, and total project costs would rise accordingly.

3.5.5 Engineering, Administration, and Project Management Costs

These project costs include feasibility studies, preliminary and final design of the system, permitting, interconnect studies, and project management. They are specifically listed below as estimates based on the Lake County Feasibility Study.

3.5.6 Power Sales Opportunities and Revenues

Power plants of the size to take the amounts of potentially available fuel noted above would certainly sell power on the wholesale market through a power purchase agreement. Therefore, wholesale prices in the range of $0.03 to $0.04 per kWh are assumed. Also, transmission out of the plant in order to export power to the grid must be considered as a project cost in any specific project evaluation. In the cost evaluation below, based on Lake County Resources Biomass Power Plant project feasibility study, power export includes a 3-mile line out to a grid interconnect point. These costs will vary by location.

Wheeling costs must be considered for locations outside PGE or PacifiCorp service territory. These costs will be site-specific, but will at a minimum include BPA fees for transmission, which start at about $0.011 per kWh[7].

3.5.7 Cost and Financial Evaluation

A feasibility study done for Lake County Resources Biomass Power Plant shows total costs of $25 to $36 million for 12.67 MW. The actual estimate for the project was around $31 million, after incentives. At an 80 percent load factor, this equates to approximately $2,500,000 per MW, or $2,500 per installed kW. Note that the cost components of this evaluation differ from other market segments. This is because the project consists of designing, siting, and constructing an entirely new power plant with all ancillary facilities and grid interconnection, not just installing new equipment at an existing site. Table 3-10 shows cost ranges resulting from a summary evaluation of the project.

[7] Compiled from Bonneville Power Administration 2004 Transmission and Ancillary Service Rate, available at http://www.transmission.bpa.gov/Business/Rates_and_Tariff/

TABLE 3-10
Cost Evaluation—Forest Residue
Based on Lake County Resources Biomass Power Plant

Size	**12.67 MW**		
Technology	**Condensing Turbine**		
Project Costs (one-time)			
Power Generation Equipment - total installed cost, including engineering design, per kW	$2,200	-	$3,200
Power Generation Equipment - total installed cost, including engineering design, total	$28,000,000		$40,000,000
Other Project Costs:			
Siting, Licensing, Permitting	$500,000	-	$800,000
Owner's Engineer costs during construction	$500,000	-	$800,000
Electrical Interconnect Studies	$200,000	-	$240,000
Interconnect to grid - 3 miles, 69 kW transmission line	$800,000	-	$1,000,000
Land Acquisition / Right-of-ways	$300,000	-	$400,000
Installation of wastewater metering	$50,000	-	$70,000
Project/Construction Management & Administration	$1,500,000	-	$1,900,000
Interest during construction and working capital	$3,000,000	-	$4,000,000
Subtotal	**$34,850,000**	**-**	**$49,210,000**
Less BETC refund (25.5%, up-front)	$(8,886,750)	-	$(12,548,550)
Total Up-front costs	**$25,963,250**	**-**	**$36,661,450**
Annual energy generation (kWh) (75% - 80% load factor)	**83,000,000 - 88,000,000**		
Annual Costs			
Operations/Maintenance/Supplies ($0.01 per kWh)	**$830,000**	**-**	**$880,000**
Total fuel costs	**$3,350,000**	**-**	**$4,100,000**
Ash, wastewater disposal	**$100,000**	**-**	**$150,000**
Major Overhauls	**$1,000,000 - $2,000,000 years 6 and 11**		
Less tax benefits of Depreciation	**40% of equipment costs accelerated over 15 years (MACRS schedule)**		
Total project costs (over 15 years) per kWh	**$0.097**	**-**	**$0.134**
- includes returns to equity at 12%, interest on debt at 6%, 50/50 debt/equity structure			
Estimated value of power, $ per kWh	**$0.030**	**-**	**$0.040**
Other Potential Revenue Streams, $ per kWh produced	**$0.00**	**-**	**$0.048**
- Includes potential federal and state annual subsidies, fees from USFS and USBLM, carbon reduction credits, steam export, and renewable production incentives.			

In addition to power revenue, other potential revenue streams were evaluated for the feasibility study. These included government subsidies, fees from the U.S. Forest Service and the Bureau of Land Management, potential carbon reduction credits, export of steam from the site, production tax credits and other production-based incentives. These revenue streams could add up to as much as $0.05 per kWh, in addition to the power revenue.

However, the mechanisms for these revenue streams are not all in place, and will not apply to all sites. Therefore, they are mentioned, but not counted against total project costs.

3.5.8 Development Potential

Until the market segment issues are addressed there will not be economical projects using forest thinnings and residue. The Lake County Resources Biomass Power Plant evaluation represents a first attempt at valuing a project. There the wood supply has been guaranteed, the water rights are established and the region is not in a non-attainment area for air pollution. Non-private subsidies have also been used to create an economically viable project.

3.5.9 Market Segment Issues

The following issues regarding limbs, tops, and forest thinnings can only be addressed by the government:

- Water must be available for condensing turbines to function. Obtaining water rights is difficult, especially in Eastern Oregon. A pound of water used for a condenser produces less power than a pound of water that runs through the turbine of a dam 100 ft high. So, from a policy perspective, it may be difficult to justify diverting water that could be used for hydro power to the condenser of a power plant unless the power plant is near sea level or in parts of the great basin area in Eastern Oregon, where water flow does not have hydro power potential.
- Air pollution concerns limit the ability of power plants to be licensed, even though the alternative to using forest thinnings in a power plant is often a catastrophic forest fire, which is equivalent to open burning. Open burning produces about 17 lbs. of particulates per ODT (Oven Dry Short Ton) whereas the Biomass 1 facility produces 0.07 lbs./ODT. Yet Biomass 1 cannot expand and is under pressure to reduce particulate emissions. The Boardman power plant is reticent to make any operational changes or improvements because it may be required to meet new air pollution standards that are not feasible. Yet emissions from these facilities are small when compared to, for example, the Biscuit fire of 2002.
- Given the current legal environment, the Forest Service is often unable to fulfill any contract that it writes concerning timber harvest. Though they are theoretically able to write such a contract, in practice the contracts are often overturned in the courts. This effectively eliminates any guarantee of long-term fuel supply making it impossible to invest in these projects at the current time.

3.5.10 Market Segment Summary

Forest residue, if collected, represents the largest potential source of biomass energy in Oregon. Depending on the generation facility or facilities, the total power production could be 300 to 500 MW or more, if all of the residue could be collected and used.

None of this potential is available in the near or mid-term. There is no infrastructure set up to gather forest residue, and costs to gather that material alone were estimated at $0.04–0.05 per kWh, which is higher than the current wholesale value of the power produced.

There are also significant administrative and regulatory barriers to gathering and using this material. Current air regulations make it extremely difficult to permit such an operation, and contracts for supply, which must be made with the U.S. Forest Service, are not possible at this time. These issues are beyond Energy Trust's control. Therefore this market segment, while potentially promising in the long term, does not present near- or mid-term opportunities for Energy Trust.

3.5.11 Data Reliability

Estimates of fuel availability are subject to great uncertainty because this material is not now being collected. Regardless of the certainty, the conclusion that the energy potential is high is correct.

The cost of thinning is also a matter of speculation. In this report, the thinning itself is assumed to be supported by entities other than a power plant.

SECTION 4

Conclusions

Conclusions regarding the five market segments studied are as follows:

- Landfills represent the largest near- and mid-term power potential, with up to 45-50 MW estimated. A large project could be subsidized at Columbia Ridge in Arlington that could tap up to 30 MW as a combined-cycle power plant. Or, smaller projects could be subsidized to help drive the market to being economical at landfills with 1–2 millions tons in place that could support 1–2 MW systems.
- Wood waste at mills represents a near-term potential. Within this market the best near-term opportunity would be for the Energy Trust to provide incentives to install topping cycle turbines at existing mills where steam is presently produced for process use. The capacity for power could be up to 50 MW. However, actual fuel availability may limit this potential to something closer to 10 MW.
- Sewage Treatment plants represent a near- and mid-term potential of 2–4 MW. This is the smallest opportunity in terms of power production. However, there is experience in the industry with digesters and the facilities listed as having potential all have digesters currently installed. Several near-term projects may be possible, in the 100-kW to 2-MW range, the largest being at Columbia Boulevard, which is the largest STP but which currently operates only a small fuel cell.
- Dairies are concentrated in the coastal areas of Tillamook, Marion and Coos Counties as well as scattered locations throughout the state. There are also three very large dairies in excess of 10,000 animals each in the areas of Boardman and Umatilla. The potential exists for using manure from these cows to produce electricity. The potential is dependent on the amount of manure that can be readily collected, the BTUs that can be captured during the digestion process, and the nature of the system to convert that biogas to electricity. It is estimated that there is a theoretical potential of 20–30 MW at farms with 500 animals and up. However, due to variations in farm practices, 10–12 MW of power is probably a more realistic estimate from dairy-based anaerobic digesters on farms with over 1,000 animals, with potentially another 5 MW from farms with 500–1,000 animals. Most projects at farms under 1,000 cows will be uneconomical because the project costs include manure collection and the digester, in addition to power production. The Energy Trust may find three areas of interest: (1) working at the 2-3 largest dairies, each of which has over 10,000 cows, (2) working with smaller dairies under 1,000 animals to help drive down the economic size of an on-farm system or (3) subsidizing centralized digester facilities, which could make this process economical for clusters of smaller dairies that would not be able to implement the process on their own. All of these possibilities are mid-term at best.
- Forest residue represents a vast amount of fuel and power potential. However, it is inaccessible in the current market environment, or in the near or mid-term. Up to 300 to 500 MW might be produced given the basic market ingredients, including dependable

supply and contracting mechanisms. Therefore, the Energy Trust might usefully aim its current efforts at researching and, where appropriate, helping the development of the necessary institutional and market infrastructure

Table 4-1 summarizes key findings.

TABLE 4-1
Biopower Market Assessment—Findings Summary Table

	Sewage Treatment Plant-Based Digesters	Dairy-Based Anaerobic Digesters	Landfill Gas to Energy	Woody Mill Waste	Forest Waste (timber residue and thinnings)
Number of Potential Project Sites	28 facilities with anaerobic digesters currently installed.	32 facilities with over 1,000 cows. Several (5-10) sites where dairy clusters could enable centralized digesters, and 52 secondary sites with 500-1,000 cows.	13 landfills and over 100,000 tons of waste in place with gas collection systems.	12 sites (mills) with boilers at potential for 50 MW of new power capacity.	Unknown. Biomass 1 is a current site.
Fuel Availability and Cost (Quantity and $/Btu)	1,270 million cubic feet per year or 3.48 million scfd, equivalent to 7-10 MW of power potential if all the gas were used, at heating value of 600-650 Btu/scf.	113,808 animals on the 32 facilities with over 1,000 head, with potential to generate up to 10.2 million cfd of gas with heating value of 600–650 Btu/scf. Equivalent to 18–24 MW total for those farms. Another 52 farms with 500 to 1,000 animals could add another 5-7 MW.	10,600 Mscf per year, or about 29 million scfd potential gas generation at the 13 landfills. Average heating value of 450 Btu/scf. Equivalent to 61 MW if all gas was collected and used in reciprocating engines.	Quantity of waste in 2000 was 62,000 tons, equal to 608,000 MMbtu. Market price plus haul rate of $20/ton, or $2 per MMbtu.	1.8 million tons/year from logging waste and 2.5 million tons/year from forest thinning. 4.3 million tons total. Equates to 43 trillion Btu/yr or 300–500 MW.
Fuel Collection Activities and Costs	None, as gas is being collected already at plants with anaerobic digesters. Plants without digesters are uneconomical for a power project.	Manure collection points include milking center and feed lanes. Project costs are about $200-$240 per installed kW, or $30-$40 per cow. Digesters cost $90-$130 per cow, or $500-$800 per kW.	Collection systems in place for larger landfills; cost assumed zero. Those without gas collection systems are uneconomical for an energy project.	Limited activities, as fuel is already being collected. Haul cost is only collection cost.	Collection (thinning–often justified for forest health and fire reduction benefits) and transportation–$40 per ton, or $4 per MMBtu.
Fuel Processing Costs	Removal of contaminants needed: moisture, hydrogen sulfide (H_2S) and siloxane. Cost: $200-$1,000 per kW installed, depending on energy conversion technology.	Gas treatment requires moisture and H_2S removal, for about $100-$500 per installed kW, or $20-$90 per cow.	Treatment for H_2S and siloxane required, at $100-$1,000 per installed kW.	Costs are limited; wastes already collected. Fuel dried in piles for no cost except for time spent drying.	$20-$30 per ton, or $2-$3 per MMBtu.

TABLE 4-1
Biopower Market Assessment—Findings Summary Table

	Sewage Treatment Plant-Based Digesters	Dairy-Based Anaerobic Digesters	Landfill Gas to Energy	Woody Mill Waste	Forest Waste (timber residue and thinnings)
Energy Conversion Technologies and Cost	Recip. Engines: $900-$1,200 per kW. Microturbines: $1,200-$3,000 per kW. Fuel Cells: $4,000-$9,000 per kW.	Recip. Engines: $900-$1,200 per kW. Microturbines: $1,200-$3,000 per kW. Fuel Cells: $4,000-$9,000 per kW.	Recip. Engines: $900-$1,200 per kW. Microturbines: $1,200-$3,000 per kW. Fuel Cells: $4,000-$9,000 per kW. Gas Turbines: $700-$1,200 per kW.	One back-pressure topping cycle steam turbine system estimated at $905/kW installed.	$2,000-4,000 per installed kW, based on Lake County project data point at $3,000 per kW.
Power Sales Opportunities and Revenues	Offset retail (standard tariffs)–$0.06-0.07 per kWh. This does not include demand charges.	Offset retail (standard tariffs, $0.06-0.07 per kWh) for 50-75 percent of power produced. Rest must be sold through power purchase or net metering at $0.03-0.05/kWh.	No captive use for energy onsite, so little opportunity to offset retail. Use of biogas for heating can be more economical. Must sell power through power purchase agreement ($0.03-0.04).	Cogeneration opportunity. Offsets retail and sells into wholesale market ($.05-.06 per kWh).	Little opportunity to offset retail and typically requires sale into wholesale market at $0.03-0.04 per kWh.
Market Segment Issues	Facility operations focus on treating wastewater, not energy. Gas is wet and requires treatment.	Dairy operators generally not motivated to manage a digester. However, increasing environmental restrictions (CAFO rule will drive interest in better manure management).	Operators are not on site for landfills; must be brought in. Location relative to grid tie-in point is important. After landfill closes, gas production briefly rises, then slowly decays over about 30 years. Largest projects (two in Oregon) may consider combined-cycle power plant.	Waste is already being used and long-term supply to support additional plants is uncertain.	Need for long-term supply commitment and from Forest Service; currently not possible. Water needed, and water rights may be difficult to obtain at eastern Oregon sites. Air permitting is a potentially market-limiting factor.

TABLE 4-1
Biopower Market Assessment—Findings Summary Table

	Sewage Treatment Plant-Based Digesters	Dairy-Based Anaerobic Digesters	Landfill Gas to Energy	Woody Mill Waste	Forest Waste (timber residue and thinnings)
Market Segment Summary	Market potential of 5-7 MW over 28 sites. Nine sites already have generation for a total of 3 MW. New generation potential is 2-4 MW. Project costs $0.04-$0.06 per kWh at large sizes (1 MW), and $0.09-$0.14 at small end of range (70 kW). Offsets retail prices.	Based on theoretical potential of 20 to 30 MW total for farms 500 animals and up. Actual potential for near- or mid-term may be 10-12 MW because of variation in farm practices. Project costs $0.04-$0.07 per kWh at large sizes (2 MW), and $0.08-$0.11 at small end of range (70 kW). About 50 to 75 percent of energy offsets retail prices.	Market potential of 40-45 MW across the 13 landfills. Largest potential is Columbia Ridge in Arlington, Oregon, with 25- to 30-MW potential. Near-term includes projects down to 1 MW in size (five sites), and mid-term includes projects from 500 kW to 1MW (two sites). Two sites already have generation. Project costs $0.03-$0.04 per kWh at large sizes (2 MW), and $0.10-$0.15 at small end of range (70 kW).	About 50 MW of potential facilities. However, market output will depend on actual wood waste generated. In 2000, this was about 10 MW worth. Project costs of $0.03-0.04 for 4.8-MW size facility, based on feasibility studies and vendor discussions.	Very large MW potential (up to 500 MW), but unattainable in near- or mid-term. Amount of potential sites unknown. Project costs of $0.10-0.13 for 13-MW facility, based on feasibility studies and vendor discussions.

APPENDIX A

Potential Project Location Maps