Oregon Energy Trust

Biomass
Market Assessment

Final Report

Prepared by:

Itron

1104 Main Street, Suite 630
Vancouver, WA 98660

360-906-0616

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Introduction

1.1 Overview

This study was conducted to provide an initial assessment of the potential market for new biomass and biogas facilities in the state of Oregon. The Energy Trust of Oregon commissioned this study in order to review and evaluate current information on the market and consider recommendations for possible program design options that would provide sustainable development support of a growing market for biomass generated energy in Oregon.

It is important to note that biomass differs from other types of renewable energy resources (such as solar, wind, and hydro) in several ways. First, the fuel feedstock must be collected, transported, and treated to some extent before it can be used as a fuel input for an energy conversion device. Second, biomass-generated energy is not generally seasonal, but is capable of providing continuous baseload electricity. Third, the utilization of biomass fuel for electrical generation provides positive externalities, such as reduced emissions of harmful gases[1] and for the forest residue resource reduced risk of wildfire. These differences with other renewable fuel sources also create a number of technical and economic issues that a potential facility developer might face, and these particular issues are discussed in Section 3 of this report.

1.2 Study Objectives

This assessment includes an initial look at the market opportunities; identify primary obstacles to further market penetration, and to provide preliminary recommendations. A second phase of research was expected to examine key market elements more closely. The study was designed around the following three objectives.

- The first objective was to provide information on the potential opportunities for new biomass and biogas facilities using the available known resources within the state.

[1] As compared to other forms of disposing of these fuels; for example, flaring methane gas at landfills and wastewater plants or open burning of forest residue.

- The second objective was to solicit suggestions on program design and lessons learned from the administration of renewable energy/biomass support programs implemented in other states or by regional or federal agencies.
- The third objective was to collect, analyze, and present information relevant to the Energy Trust's decision in determining when and how to intervene in the market to best leverage funds and enhance the market response to program intervention.

1.3 Study Approach

The approach employed for this study consisted of initially conducting a literature review on existing biomass resources and technologies in Oregon, developing a preliminary list of potential technologies and suppliers in the state, conducting in-depth interviews with suppliers, end-users, and administrators of related programs, analyzing the results, and preparing a final report. Each of these tasks performed is briefly described below.

Literature Review

The literature review focused on the following four areas of research:

- Summarizing existing resources for biomass energy production available in Oregon,
- Describing existing commercial energy conversion technologies utilizing biomass fuel in Oregon,
- Identifying existing programs and incentives that support biomass technologies in Oregon, and
- Summarizing barriers to adoption from the literature.

Fuel types examined in this assessment include cow manure, landfill gas, wastewater treatment gas from biosolids, forest residue, and wood waste. The Energy Trust requested that the study omit further research on ethanol production, along with the use of urban wood waste and municipal solid waste as biomass fuels. In addition, it was decided early in the study to omit further research on agricultural residues as a biomass fuel source. The primary reason was that the high cost of collecting the residue from the fields, storing it, and transporting it exceeds its value as a fuel for electric energy production.

Preliminary Technology Assessment

An assessment was performed on available near-term, intermediate-term, and long-term technologies. Near-term conversion technologies identified included anaerobic digesters, reciprocating engines, small gas turbines, and boilers. Intermediate-term technologies identified included microturbines and fuel cells. Long-term technologies identified included gasification and pyrolysis. For each of the near- and intermediate-term technologies, a preliminary list of suppliers was assembled.[2]

In-Depth Interviews

In-depth interviews were conducted in-person and by telephone with equipment and system suppliers, end-users, and administrators of relevant programs. In addition, several interviews with other industry stakeholders were completed. Table 1-1 presents the completed sample.

Table 1-1: Interview Sample

Type	Completed Sample
Program Administrators and industry experts	14
Suppliers	13
End-Users and related stakeholders	18
Total	***45***

As shown, a total of 45 interviews were completed for this study. A list of the organizations participating in the interviews is provided in Appendix A. The interviews were designed to address the following topics:

- Key lessons learned from implementing or participating in other programs,
- Information on technology availability,
- Supplier/provider costs,
- Key market barriers,
- Adequacy of current technical resource base and supply infrastructure,
- Electric utility reception to distributed generation project opportunities,
- Identification of market opportunities in Oregon, and
- Determination of the need for technical assistance and/or project support.

Copies of the interview guides are provided in Appendix B.

Analysis and Reporting

The results of the literature review, preliminary technology assessment, and in-depth interviews were analyzed in order to discern any available market opportunities and develop recommendations for pursuing a biomass incentive program in Oregon. This final report presents the key findings.

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[2] The long-term technologies were not included in this list because they were not part of the scope of this market assessment.

1.4 Report Organization

The remainder of this report is organized as follows.

- Section 2 provides an overview of general market issues for biomass generated electricity in Oregon.
- Section 3 discusses findings by fuel type.
- Section 4 describes lessons learned by administrators of programs in other states.
- Section 5 identifies existing market opportunities.
- Section 6 provides recommendations for a support program to be offered through the Energy Trust.
- Appendix A provides a list of the organizations interviewed for this study.
- Appendix B provides copies of the interview questionnaires.
- Appendix C provides a preliminary listing of suppliers.
- Appendix D provides a list of operational landfills, publicly-owned wastewater treatment plants, large dairies and feedlots, estimated area of forest land, and operating lumber mills and paper producers in Oregon.

2

Market Overview

This section provides overall information on existing technologies, key market barriers, market trends, available equipment and suppliers, and existing incentives for biomass facilities in Oregon.

1.1 Existing Conversion Technologies

Overview

Biomass fuels are converted by a variety of technologies including: thermal and thermo-chemical processes such as combustion, gasification and liquefaction; biochemical processes such as anaerobic digestion; and fermentation to obtain fuel ethanol. In particular, the production of electricity from biomass fuels involves a thermo-chemical or biochemical process that produces an intermediate fuel or other energy form (steam or gas) that then drives a generator to produce electricity. Examples include the following:

- Power plants that burn wood and wood waste to produce steam, which is then passed through a steam turbine to generate electricity;
- Plants that oxidize rice hulls to produce a gas, which then drives a gas turbine to generate electricity;
- Anaerobic digesters that process cow manure to produce digester gas, which then drives a generator to produce electricity.

Methods of converting biomass fuel into hot gas, air, water, or steam include direct combustion, gasification, anaerobic digestion, and pyrolysis. The hot gas, air, water or steam can then be converted into electricity using engines, turbines or fuel cells.

- ***Direct Combustion.*** Most biopower plants use direct-fired systems, which burn feedstocks in a boiler to produce steam. The steam is then captured by a turbine and converted into electricity by a generator. In some cases, the steam is also used in a cogeneration system for space heat or as part of the manufacturing process of a product. For example, wood waste might be burned at a paper mill to produce both electricity and steam.

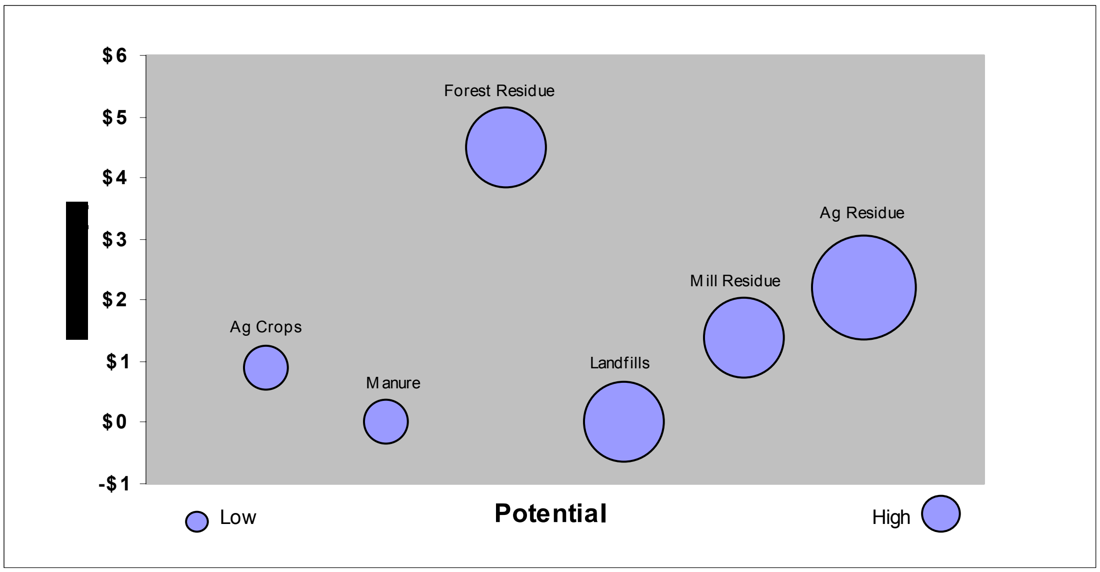
- ***Co-firing.*** Co-firing involves burning biomass with coal in existing coal-fired plants, in order to reduce emissions such as sulfur dioxide and nitrogen oxide. Feedstocks are burned along with coal in high efficiency boilers.
- ***Gasification.*** Biomass is partially oxidized (burned) to produce a gas that is a mixture of hydrogen, carbon monoxide and methane. The biogas is then converted to electricity through the process of combustion in a gas turbine containing a working shaft and electric generator.
- ***Anaerobic Digestion.*** Bacteria are used to decompose organic waste matter in a controlled process and produce a low- to medium-BTU methane-based gas byproduct. The gas is then conditioned and combusted in a reciprocating engine, small gas turbine, or in a boiler to produce steam, which then can be used to generate electricity. Methane can also be collected from landfills and be used as a fuel source for reciprocating engines, gas turbines, microturbines and fuel cells.
- ***Pyrolysis.*** By heating biomass in the absence of oxygen, a liquid is produced called pyrolysis oil. This liquid fuel can be burned like petroleum to generate electricity.

As is the case with most renewable resources, the technologies used to convert the available biomass fuels into electricity exist in various stages of development and availability. The same is true for the biomass fuels available in Oregon today; some have significant potential while others have considerably less potential. For each of these fuels there are multiple technology options that can be used to convert them into electricity. The fuels, technologies and their applications that are used to convert the fuels into electricity can be categorized into near term, intermediate term, and long-term categories. *Near term* is defined as available now and/or within the next three years. *Intermediate term* is defined as being commercially available within four to six years, and *Long-term* technologies are estimated to be available beyond six or more years. A technology may fall into the long-term category because of the time it will take for the technology to reach the commercial development stage, or it may be in the long-term category because the cost is currently high. Due to limited available resources, this assessment addresses only the near-term and intermediate term technologies and applications.

The biomass fuel resources include landfill gas, animal manure, timber residues, mill residues, agricultural residues, and wastewater. Each resource has a different cost and a varying energy generation potential. These general characteristics are shown in Figure 1. In Figure 1, the size of the circle indicates the relative potential, a larger circle means there is greater potential. In addition, resources with greater potential are located further to the right on the chart.

As shown, some resources have low cost, but also low potential (agricultural crops and manure) while others have high potential but also higher cost (agricultural residue). Ideally, high potential and low cost (e.g., lower right quadrant of the graph) provides the ideal fuel resource attributes. Outside of landfill gas, none of the resources currently fit into this category. However, Figure 1 does give an indication for further research and can be considered along with commercial technology availability to help guide the direction of this market assessment.

Figure 1: Field Cost ($/MBTU) vs. Energy Potential



Many of these resources cannot be directly used to generate electricity, but must be converted to a useable fuel using a fuel conversion technology. Primarily, the near term fuel conversion methods include direct combustion, co-firing, and anaerobic digestion, whereas long-term fuel conversion methods include gasification and pyrolysis. The long-term methods are classified as long-term mainly due to technology development and cost issues.

Once the biomass resource is in a fuel form, the fuel must be converted into electricity using a power conversion technology. These technologies overlap to some degree in their commercialization/market entry status in Oregon. The technologies include boilers, combustors, heat recovery steam generators, fuel cells, microturbines, reciprocating engines, and small gas turbines in the short term. The near and intermediate term conversion technologies include fuel cells and microturbines. The fuel cell category also includes several long-term technology applications.

A preliminary list of biomass technology suppliers and service providers is presented in Appendix C.

1.2 Market Barriers

A number of barriers exist to the adoption of distributed generation technologies in general. Chief among these include low power prices in the Northwest, high installation costs, and interconnection complexities and utility surcharges. In addition, there are barriers to adopting biomass technologies specifically. This subsection provides a brief overall description of the key barriers to the biomass applications discussed in this report. Obstacles specific to resource type are presented in Section 3.

Low Power Prices. It was the opinion of most respondents interviewed for this study that currently the electric power market does not support the development of new biomass power plants. In particular, the price of electricity is not sufficient to support the other costs of building and operating a plant. Low retail prices in Oregon limit the value of biofuel self-generation. Low wholesale prices limit the opportunities for selling power. Power purchase agreements are hard to find at prices that cover the high generation costs.

High Installation Costs. The capital cost of developing biomass-based generation systems is high, especially in smaller-scale operations. In some cases, end-users reported that capital was not a problem, but that their inability to meet their company's required internal rate of return prevented them from going forward. In other cases (in particular, wood burning plants) the inability to guarantee a long-term fuel supply kept them from obtaining financing.

Utility Interconnection and Operating Surcharges. Existing operators of biomass facilities in the state, who produced electricity mostly to sell on the grid, reported that the utilities were receptive or very receptive to these systems. However, those who operated net-metered cogeneration systems reported they had run into resistance with utilities. Specifically, they reported that the utilities wanted to charge extra fees and demand charges. In one case, the respondent reported having to hire energy attorneys and consultants to get through a frustrating and expensive interconnection process.

Cost of Fuel Transportation. The cost of collecting and transporting hard biomass fuels is expensive. This is especially true for forest residue. In addition, any regional plant that collects waste from nearby collection sites and delivers it to a central processing facility will face high transportation costs.

Air Permitting Requirements. Obtaining required air quality approvals increases the project development costs and, in some cases, the operating costs of biofuel projects. This barrier is especially difficult for smaller projects run by end-users who are not familiar with these requirements and whose small-scale projects can ill afford the necessary additional expense associated with compliance. In addition to having to maintain emission control devices, end users also experience decreased efficiency of the generating equipment as a result of meeting emission requirements.

Lack of Financial Recognition of Environmental Benefits. Although green energy credits (green tags) account for some of the benefits of biomass energy, there are other benefits that are not accounted for as yet in the market. Biogas applications, which capture and utilize methane gas, have the benefit of reduced greenhouse gas emissions. For the dairy/animal waste applications, an added benefit is reduced groundwater nitrates contamination. For the forest residue resources, an added benefit is reduced emissions from controlled combustion with emissions controls as compared to the open forest slash burn practice.

Public Perception. While not characterized as a barrier, it was also mentioned by a few respondents that the public's perception that biomass technology is not a "green energy" source can limit acceptance of projects in some areas of the state. It was reported that they tend to see burning as producing emissions and view wind and solar as cleaner, more preferred technologies. Additionally, for wood biomass there are concerns among communities in wildlife-urban interfaces that excessive forest thinning might have a negative impact on wildlife habitats and possibly on soil and water quality. Furthermore, the development of power plants in these areas may not be welcomed by the communities due to overall negative public perceptions of power plants in general.

Awareness of biomass as a viable alternative energy solution has been reported in the industry literature as being low.[3] Unfavorable perceptions held by some consumers regarding the harvesting of trees and the environmental effects of biomass power plants also contribute to a lack of understanding of the overall benefits of biomass technologies. In addition, while the fossil fuel industry has an effective lobbying effort to gain political support, the biomass industry is relatively weak in comparison.

1.3 Market Trends

The following are some developing trends in the industry relevant to this study.

Interest in Using Forest Residue. Several recently published reports have indicated that there is a growing interest in using forest thinning residue as biomass fuel. In addition, several respondents interviewed for this study reported developing proposals for new facilities in Eastern Oregon that take advantage of the residue.[4] In fact, there seem to be statewide, regional and national efforts to promote forest biomass, although a major

[3] See, for example, R. L. Bain, et. al. "Highlights of Biopower Technical Assessment," National Renewable Energy Laboratory (NREL/TP-510-33132), January 2003.

[4] The proposed facilities were in the areas of La Grande, Warm Springs, and Wallowa.

stumbling block – the cost of transporting the wood to a plant where it can be burned – remains a barrier. A new tool known as a "slash bundler" was recently demonstrated in Oregon for cutting and bundling small trees in the process of thinning forests and private land. This new technology mechanically collects, compresses and bundles forest residue from logging operations, making it easier to transport, less time consuming, and less costly.

Interest in Fuel Cells and Microturbines. Fuel cells and microturbines are now being considered for biogas projects. The City of Portland's wastewater treatment plant recently installed a fuel cell and four microturbines running on biogas. This is the first installation in the Northwestern U.S. of a fuel cell running on wastewater digester gas and the third such system in the nation. The city representative interviewed for this study described some of the problems they had to overcome in cleaning the gas in order to use these technologies. In particular, he described how the hydrogen sulfide needed to be removed from the gas because it was detrimental to the fuel cell. To do this, they used an activated carbon process that uses oxygen; however, it was important to control the amount of oxygen going to the fuel cell. So they experimented with a flow switch that would control the level of oxygen to provide enough for cleaning the fuel without harming the fuel cell.

Regional Facilities. While many of the existing facilities in Oregon are cogeneration plants, a regional dairy digester recently started operation. The Port of Tillamook Bay recently developed a regional digester servicing ten dairy farms with over 4000 animal units in the area. The digester facility trucks dairy waste to the digester and produces electricity and a compost byproduct material for sale and delivers a liquid fertilizer product back to the dairy farm. The facility reports that costs are high, especially due to the intensive transportation time. They are currently looking into using rail for delivery, which should be less expensive than trucks. In addition, one respondent interviewed for this study discussed plans for a dedicated facility that will produce electricity and ethanol from forest biomass resources in eastern Oregon. The project is currently seeking a funding source to continue.

Green Tags and Carbon Credits. While green tag opportunities are available in Oregon, many respondents interviewed either did not know about them or believed the revenue was so low that it was not worth the trouble. In fact, only two respondents reported having experience selling green tags. One of these respondents operated a dairy digester (and reported selling their green tags for one-half cent per kWh); the other respondent operated a wood cogeneration plant. In addition, some suppliers interviewed suggested that if carbon credits were traded (as they are in Europe) the value of the project would be greatly enhanced.[5]

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[5] It should be noted that each gram of methane not released is equivalent to 21 grams of carbon in terms of its effectiveness as a greenhouse gas. This is recognized where carbon credits or carbon trading is in effect.

1.4 Equipment Suppliers

Technology applications examined in this assessment included anaerobic digesters, reciprocating engines, small gas turbines, steam turbines, boilers, microturbines, and fuel cells. Results of interviews with end-users indicated there were no difficulties obtaining equipment, although some technologies required a one year lead time. Equipment suppliers interviewed for this study reported that equipment appropriate for biomass fuels is available for a wide range of fuel types, technologies, and generation capacities. Suppliers further reported they are able to provide the prime mover and electric generation equipment or, in some cases, fully integrated fuel conditioning, prime mover/generation, heat transfer, emission control equipment, and electrical connection equipment.

The supplier survey respondents were drawn from a fairly limited population of generation equipment manufacturers, total systems providers, and consultants who provide turnkey project development services. The population is limited due to the newness of the biofuel market; however, a fairly large percentage of this total biofuel supplier population was included in the sample for this study.

Equipment for biofuel generation falls into the following categories:

- Gas turbine (used for biofuel from landfills and anaerobic digester gas),
- Steam boilers and steam turbine (used for larger biogas and direct combustion of solid biofuel),
- Reciprocating engines (used for smaller biogas systems using gas from landfills and anaerobic digesters),
- Microturbines (used for small biogas applications), and
- Fuel cells using liquid or biogas fuels.

Some equipment manufacturers and their dealers are involved with several aspects of the project, including specifying design criteria, designing and procuring a balance of system components such as fuel conditioning equipment, electrical interconnection, and system performance measuring and monitoring. Some dealers also provide permitting assistance and financing.

Some consulting engineering companies specialize in providing turnkey services for biogas end-users. Their services include identifying potential biofuel end-users, designing the system, project finance assistance, procurement, construction and/or construction supervision, permitting assistance, and testing and monitoring project performance.

The remainder of this subsection presents a summary of supplier responses to the following topics: product availability, market awareness, market barriers, utility interconnection cooperation, system operation and maintenance, development and operating costs, and need for program support.

Products and Product Availability

Equipment suppliers reported that equipment appropriate for biomass fuels is available for a wide range of fuel types, technologies, and generation capacities. There were no indications of difficulties in obtaining equipment in a timely manner. Suppliers are able to provide their electric generation equipment, or when offered, fully integrated fuel conditioning, generation, heat transfer, emission control equipment and electrical interconnection equipment. Some suppliers also offer financing services and related assistance. Generator gross output ratings as reported by the interviewed suppliers ranged from 70 kW to 300 kW (microturbines, and fuel cells), 100 kW to 3+ MW (reciprocating engines), and from 3 MW to 40 MW (small gas turbines).

Market Awareness and Potential

Market awareness among potential public sector customers such as wastewater treatment plants and landfills was generally reported by suppliers to be medium to high. Whether or not they elected to utilize biomass generation, these public sector customers were aware of the technology options for biogas generation and the energy price risks associated with the value of this generation. Awareness among potential agriculture customers was judged low to medium.

Because the equipment manufacturers sell their products to a national and/or international market, their awareness of the market potential specific to Oregon was limited. Most of the interviewed services providers were more focused on the Northwest region and noted that the biogas opportunity is greatest in the major population centers and in the more intensive agricultural (dairy, beef and poultry) producing areas. Solid-fuel biomass project potential is greatest near the resource itself, i.e., logging/thinning/forestry management operations, and in lumber/wood products/paper milling operations in the northeastern and southwestern areas of the state.

Market Barriers

Respondents reported their views on why biomass-based electric power is not more widespread in Oregon and elsewhere in the Pacific Northwest. The most common response heard from all supply channel stakeholders was that the current economics did not support it. The highest rated deterrent to project development by respondents was that the retail electric energy prices in Oregon limit the competitiveness of biomass fueled self-generation. One very active biogas respondent that develops animal waste self-generation projects worldwide indicated that deferred energy costs of 6.5 cents per kWh is required for dairy digester projects to make economic sense. In addition, historic long-term wholesale energy prices based on hydroelectric power markets, coupled with the application of transmission rent has jointly limited the opportunities for selling bulk or excess bio-power to other purchasers on the grid. Negotiated power purchase contracts are difficult to execute at fixed prices that will cover the amortized plant development/capital, operations and maintenance costs. In Oregon, the Public Utility Districts usually purchase a major portion (or in some cases all) of their electric generation supplies from BPA and thus do not need large quantities of bio-power, unless they can incorporate these alternative energy resources into their future power needs.

Another significant factor contributing to their lack of competitiveness for private investment is that the capital cost of developing biomass electric generation systems is high, especially in smaller-scale projects. These project cost related issues are sometimes further aggravated by the quoted costs of utility interconnection and time required to receive a response to requests for information. Fuel cost in situations in which transportation is needed limits options and increases risk, especially in the present rather volatile motor vehicle fuels market. One respondent stated that delivered fuel prices must be below $35 per bone-dry ton (BDT) for a project to pencil out. It was also reported that forest fuel availability from public forests was unreliable due to state and federally mandated forest plan changes and environmental litigation. Uncertainty in fuel supply and/or price will usually be a deal-breaker, as these capital-intensive technologies normally require outside financing. The third most notable barrier mentioned in the development of biomass power projects is the available warranty contract that typically comes with the equipment. Although extended warranties are available, these *product enhancements* further increase the already high project costs.

Utility Interconnection Cooperation

In most cases, suppliers did not have a significant amount of direct experience or knowledge of self-generation system interconnection with Oregon utilities. The general impression of equipment manufacturers and suppliers however, was that utility cooperation and interconnection problems were a notable issue, especially with regard to the smaller or first time developer projects. The larger landfill gas projects were reportedly less problematic, especially if the project developer was an experienced biogas generation development company. Larger biomass development companies with experience in either dedicated power or self-generation are more likely to have engineering staff with power generation and utility experience. The larger amounts of power generation are generally more worthwhile for both the utility and the project developer. They also tend to have greater technical capability and therefore can deal with the utility on a peer-to-peer basis.

Smaller self-generation projects are often perceived as a "nuisance" to the utility distribution operations personnel, as well as a potential "departing-load" customer. Interconnection requirements, even when not a great expense, are often a source of delay or frustration to the host customer/project developer. Transaction costs, uncertainty of payback and project delays imposed by the utility combine to make smaller projects less appealing to the project developer. In addition, if power is purchased by the utility the terms are often perceived to be set at the lowest possible avoided cost, and thus may not be worth the investment. These factors, coupled with the higher unit capital costs ($/kW) associated with diseconomies of scale, render the smaller biomass/biogas projects less attractive.

In addition to their electric utility interconnection experience, supply channel respondents were queried as to whether their local utilities were generally receptive to the development of biomass power facilities. The responses were generally mixed with most respondents indicating that cooperation was not a significant issue – but that perceived receptivity, particularly to the smaller projects varied by electric utility service area. In some cases, the communication of information took longer than expected with the required clarification and follow-up. The most notable area of discussion related to the ability to confirm project interconnection and plan review costs and the determination of standby power charges. In one case, the system protection requirements were perceived to be overly constraining – as they required the elimination of the possibility of *any* reverse power flows from the self-generation project.

System Operations & Maintenance Issues

Digester gas and landfill gas both pose decided difficulties in terms of the need for gas conditioning, with increased wear on generator, microturbine and heat exchanger components, and the effectiveness of emission control devices.

In addition to hydrogen sulfide (H_2S), siloxanes and halides are the most problematic contaminants. They reduce valve life in reciprocating engines and increase the frequency of gas turbine rebuilds. In addition, end of stack emission controls do not work effectively in their presence. Removal during gas conditioning is expensive. Corrosion of engines and heat exchangers is a problem that has been partially or entirely solved by utilization of plastic and stainless steel components that resist corrosion.

Hard biomass fuels present other operations and maintenance challenges. These include management of the fuel sizing and moisture content at the front end (pre-combustion), carbon build-up on the boiler heat exchangers, corrosion and erosion of the high temperature (steam generator) heat exchanger equipment, control of airborne emissions including particulate matter (total suspended particulates and PM_{10}), NOx, SOx, CO and volatile organic compounds (VOC). These operating and maintenance issues are well known and have been addressed by the industry through the incorporation of fuel processing and storage facilities to optimize the fuel input parameters and through the incorporation of various forms of air emission controls equipment to meet the specific requirements of the state and local air pollution control agency.

Development and Operating Costs

Supply channel respondents reported a broad range of capital, operating and maintenance costs. This cost information is segmented into several resource/technology categories, including: 1) hard fuel biomass, 2) large anaerobic biogas, 3) small anaerobic biogas, and 4) animal waste anaerobic digesters. After taking into consideration the differences in technologies and scales, reported capital and operating costs as reported below include a wide variance.

Capital costs for the hard fuel biomass generation facilities (including equipment and "soft" development costs) were reported to range from $1,000 to $2,000 per kW of generation capacity. Hog fuel[6] costs were reported to be in the range of $40 to $50 per bone dry ton (bdt). Operating costs for hard fuel biomass plants were not directly known by the supplier respondents.

Installed capital costs for the larger biogas generation facilities (>1.5 MW) associated with landfills and large wastewater treatment facilities (both of which require no new dedicated digestion facilities) were reported to range from $1,000 to $1,500 per kW. The reported smaller biogas facility installed costs, applicable primarily to wastewater treatment facilities (<1.5 MW) ranged from $2,000 to $3,000 per kW. Operating and maintenance costs for these biogas facilities were reported to be in the range of 1.0 to 2.0 cents per kWh.

Installed project capital costs for dairy and other animal waste digestion with electric generation were reportedly even greater, ranging from $3,000 to $7,000 per installed kW. The higher cost is primarily due to the fact that the anaerobic digester is not already present at the farm and is a major added capital component to these generation facilities. Annual maintenance costs for the dairy digester generators were in the range of 1 to 1.5 cents per kWh.

Because most suppliers do not typically stay deeply involved in the ongoing project operations phase, operating cost information was limited. Annualized maintenance costs are reported to range from 3 to 15 percent of total project costs. Note that the higher maintenance costs were associated with biogas projects that burned less conditioned fuels containing H_2S, Siloxanes and halides.

6 Hog fuel is wood residue (usually bark) from timber industries that is ground and burned for fuel.

Reported Needs for Project Support

The vast majority of supply channel stakeholders reported they would like to see an improvement in project economics. Economic viability was widely regarded as the most difficult market barrier to overcome. However, with adequate support and appropriate incentives, most respondents felt that biomass-based generation could eventually become economically viable and self-sustaining.

Financial incentive payment programs, such as the California Self-Generation Incentive Program, that provide a rebate on a percentage of the installed system costs were mentioned as the best approach for overcoming high project capital costs. Production credits, such as those offered to large wind and photovoltaic generators were also suggested by supply channel respondents. One respondent, who is heavily involved in the dairy and animal waste digester market, suggested that a production incentive that would provide the project owner a total revenue stream of 6.5 cents per kWh (including the utility energy and capacity payments) would allow most dairy waste projects to successfully move forward. Other suppliers suggested that if carbon credits were traded (as they are in Europe) the value of the project would be greatly enhanced[7].

Power purchase arrangements are another frequently mentioned program assistance measure that could improve project feasibility. Some form of renewable portfolio standard (RPS)[8] or some other mechanism was suggested as a means to increase the utilities willingness to accept excess generation and/or increase the value of purchased power. Even without utility buy-back, if the utilities were required to maintain some type of RPS it would increase their cooperativeness toward biomass generation projects. Liberalization of net sale-back provisions and reduction of costs due to perceived “unnecessary” interconnection equipment was also mentioned as a means of improving project economics.

Air permitting assistance and possible waivers of air permit requirements were regarded as helpful, especially for smaller projects such as farm scale digesters. It was pointed out that as long as the emissions (e.g. from animal waste) are non-point sources, they are not regulated. Once they are used for generation, however, a regulated point source is created, and this triggers the permit requirements. This is regarded as inherently counterproductive, in that the emissions, even from an uncontrolled generator, are less than are those from the uncontrolled non-point source.

7 It should be noted that each gram of methane not released is equivalent to 21 grams of carbon in terms of its effectiveness as a greenhouse gas. This is recognized where carbon credits or carbon trading is in effect.

8 A renewable portfolio standard is a policy that requires a certain percentage of an electric utility's energy be generated by using renewable resources.

Both air permitting and utility interconnection requirements, in addition to their cost impacts, create market barriers by adding complexity, uncertainty, and delay in the project development process. Even if ultimate costs were not affected, program support that would reduce uncertainty and clarify these requirements would improve the willingness of potential biomass generators to undertake projects. Permit streamlining and "pre-certification of air emissions" were mentioned as possible programs. Standardization of utility interconnection requirements and pre-certification of this equipment was also mentioned by respondents.

A reciprocating engine manufacturer mentioned that it is difficult to balance operating efficiency requirements with reduction in emissions using their existing engine blocks[9]. Even though this manufacturer had produced several hundred 100 to 500 kilowatt engines for biogas applications, the demand is still not sufficient to justify re-designing and manufacturing a block purpose-built for the biogas application. If the market volume were greater, this improvement in reciprocating engines could be economically achieved. An engine driven system at this scale would be useful in many wastewater treatment and agricultural applications.

1.5 Existing Incentives

In order to inquire about and understand the effects of current program support for biomass technology, existing programs and other forms of financial support for biomass technology are briefly summarized below. The following listing summarizes the state and federal project incentives available for biomass energy projects in Oregon.

State or Regional Incentives

- The Business Energy Tax Credit (BETC) covers 35% of eligible project costs for projects that produce energy using renewable resources (including biomass), save energy, or recycle waste. Businesses may take the credit over five years with an eight-year carry forward. The tax credit can cover all direct project costs, including equipment cost, engineering and design fees, materials, supplies and installation costs, loan fees and permit costs. Maintenance costs are not considered eligible project costs for the purposes of computing the tax credit. Renewable resource projects claiming the tax credit must replace at least 10 percent of the electricity, gas, or oil used; the energy can be used on site or sold. The maximum credit is $10,000,000 per project. The BETC was initiated in 1980 and has no expiration date. Through 2001, more than 5,800 Oregon energy tax credits were awarded. Altogether, those investments saved or generated energy worth about $146 million a year.[10] Businesses have invested in more than 500 renewable resource projects through the program as of year-end 2002.

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[9] Specifically, reduction in nitrogen oxides (NOx) yields increased hydrocarbon emissions.

[10] For more information, please see http://www.energy.state.or.us/bus/tax/taxcdt.htm.

- The Small-Scale Energy Loan Program (SELP) offers low-interest loans for projects that produce energy from renewable resources, conserve energy, or use recycled materials to create products. General obligation bonds fund the program. Borrowers may use loan funds to cover direct energy project costs and related project costs such as engineering and design, permit fees, loan fees and project management costs. The program targets the residential, commercial, industrial, nonprofit, and institutional sectors. Oregon Department of Energy staff engineers are available to work with engineers and designers early in a biomass project's design phase, prior to the loan process. The Department of Energy performs a comprehensive review of the project's technical feasibility once a loan application is received, and projects must be deemed practical and environmentally sound in order to receive funding.[11] About 180 renewable resource projects were financed by the SELP as of year-end 2002.
- The Private Activity Bond Committee (PAB) allocates the authority to issue bonds for "private activity" purposes to state agencies and local governments. However, the federal government limits the number of bonds states may issue for such purposes; the PAB allocates to state agencies and local governments a portion of the state private activity bond limit according to state and federal law. The bonds are tax-exempt, and provide critical financing to infrastructure projects. Bonds are typically used to fund economic development, housing, education, public works, energy, waste management and transportation projects. Each year, approximately $213 million is allocated by the State of Oregon to private activity bonds. However, no funds were allocated for fiscal year 2004. The PAB does not report information on funds allocated by business or project type.[12]
- The Bonneville Environmental Foundation (BEF) Energy Grant pays up to 33% of total capital costs for renewable projects (including biomass). Projects that produce electricity are preferred. The program includes grants, loans, and direct investments. Private persons, organizations, tribal and local governments in the Pacific Northwest (OR, WA, ID, MT) are eligible. BEF funds must not exceed 33% of total capital costs and 0% of operating costs for generating projects. BEF-funded projects sited in Oregon include: the Mohawk River watershed recovery assessment, the Solar for Schools Program (which funded installation of solar panels and education regarding solar panels in six schools in Oregon), sales of green tags to three solar and two wind facilities in Oregon, and environmentally preferred power supply to one solar and three wind facilities in Oregon.[13]
- The Energy Trust of Oregon's *Open Solicitations Program* awards grants for new renewable projects. The state public benefits charge provides the funding for the program. Each year, approximately $1 million is reserved for open solicitation incentives. While several projects have been approved for funding, only five

[11] For more information, please see http://www.energy.state.or.us/loan/selphme.htm.

[12] For more information, please see http://www.ost.state.or.us.

[13] For further information, please see http://www.b-e-f.org/accomplishments/projects.shtm.

program-funded projects are currently installed and operational, including four solar projects and one wind project.[14]

- The Bonneville Power Administration (BPA) Conservation and Renewables Discount (C&RD) Program provides a C&RD credit is a 0.5 mill discount off the BPA firm power rate; the amount of an applicant's C&RD discount is determined by multiplying 0.5 by the amount of subscription load placed upon the BPA. Customers can earn credit through the installation of conservation measures, or by making other qualifying expenditures for renewable energy, qualified research projects, or donations to qualifying organizations. Participating customers are required to submit annual reports to the BPA describing installation of approved conservation measures and/or spending, and must repay BPA for any credits not accounted for at the end of a rate period. Incentives for customers installing renewable energy systems less than 25 kilowatts in size qualify as conservation programs.

  According to the BPA's March 1, 2004 program interim report to the region, the majority of credits received for conservation measures installed occurred in public utility service areas. The majority of program savings by state for conservation measures and associated claims was reported by Washington (68% of total program conservation savings), followed by Oregon (19% of total program conservation savings). Table 2-1 provides a summary of program activity by fiscal year.[15]

[14] For further information, please see http://www.energytrust.org/RR/os/index.html.

[15] For further information, please see http://www.bpa.gov/Energy/N/Projects/cr_discount/pdf/crdreport3-1.pdf.

Table 2-1: Summary of C&RD Spending on Renewables

	FY01	FY02	FY03	Total
Residential	$6,041,630	$23,408,135	$17,887,518	$47,337,283
Commercial	693,513	2,638,809	7,044,985	10,377,307
Industrial	105,154	1,571,767	3,004,441	4,681,362
Agricultural	315,912	485,897	447,004	1,248,813
Utility System	--	63,369	493,207	556,576
Other	1,574	222,550	485,197	709,321
Low Income Wx	922,098	3,004,274	3,128,804	7,055,176
Conservation Total	**8,079,881**	**31,394,801**	**32,491,156**	**71,965,838**
Administration	--	4,161,097	4,410,086	8,571,183
Admin – Small Utils	--	503,524	501,029	1,004,553
Donations	74,030	3,867,698	4,102,061	8,043,789
RD&D Projects	--	67,910	35,467	103,377
Renewable	91,482	5,627,096	8,182,340	13,900,918
Irrigation Scheduling	966,625	328,448	120,000	1,415,073
Grand Total	**9,212,018**	**45,950,574**	**49,842,139**	**105,004,731**

Note: Based on data from C&RD tracking software, November 18, 2003

The BPA also supports select projects by providing technical assistance, such as facilitating contacts, facilitating transmission interconnection, and providing information on how self-supply affects how utilities purchase power from the BPA.

Federal Incentives

- The IRS offers an energy production tax credit (PTC) for electricity produced from "closed-loop biomass" (i.e., the plants are grown exclusively for producing energy). The PTC was originally established under the Energy Policy Act of 1992, and funded projects brought online before June 30, 1999. However, the Tax Relief Extension Act of 1999 extended the tax credit to facilities placed in service before January 1, 2002. The Economic Security and Recovery Act of 2001 included a retroactive two-year extension of the PTC from the end of 2001 through December 31, 2003.

  Slightly different versions of bills extending the PTC have been approved by both houses of Congress in 2004, but must be reconciled. The Senate passed the Jumpstart Our Business Strength (JOBS) Act on May 11, 2004, which would increase the PTC to 1.8 cents per kilowatt-hour for electricity produced and sold after December 31, 2004; energy produced and sold in 2004 would receive the original 1.5 cents per kilowatt-hour PTC, but be adjusted for inflation in subsequent years. The House passed the American Jobs Creation Act on June 17, 2004, which would extend the PTC retroactively from the PTC expiration date through January 1, 2006. The method of calculating the PTC would not change under the American Jobs Creation Act.

- The proposed Energy Policy Act also provides research and development money for biomass.[16]
- A Renewable Energy Production Incentive (REPI) was authorized under section 1212 of the Energy Policy Act of 1992, and is available to states, political subdivisions, and nonprofit electrical cooperatives that produce electric power for sales affecting interstate commerce. Plants that commenced operations between October 1, 1993 and September 30, 2003, must have begun operation before September 2003 are eligible for incentives of 1.5 cents per kWh annually for the first ten-year period of operation. Qualifying facilities are required to utilize solar, wind, geothermal (with certain restrictions as contained in the rulemaking), or biomass (except for municipal solid waste combustion) generation technologies. No new applications are currently being accepted by the DOE, though previously qualified recipients will continue to receive annual REPI incentives through fiscal year 2013, subject to the availability of funds.[17]
- Shortened depreciation lives are available for "small power production facilities" of 80 MW or less.
- Tax-exempt financing is available for projects with more than 10% private business use that either 1) supply electricity to an area no larger than two contiguous counties or one city and a contiguous county, or 2) is a solid waste disposal facility.

Farm Bill Subsidies for Farmers via Direct Grants and Low Interest Loans

- Title IX of the Farm Security and Rural Investment Act of 2002, approved by Congress and signed by President Bush in May 2002, provides $115 million to assist farmers and ranchers in developing renewable energy projects and making energy-efficiency improvements. Another $290 million will fund new biomass energy research, biodiesel fuel education, and the existing Commodity Credit Corporation subsidy program for the production of biodiesel and ethanol, bringing the Energy Title's total appropriations to $405 million through 2007.[18] For fiscal year 2003, $23 million in grants was available for eligible agricultural producers and rural small businesses to purchase renewable energy equipment and to make energy-efficiency improvements. Half of the annual grant funding is allocated to renewable energy systems, and the other half is allocated to energy efficiency improvements, but the USDA has the authority to reallocate funds between the categories as it sees fit. Grant requests cannot exceed 25% of eligible project costs,

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[16] In June 2004, the House of Representatives approved the Energy Policy Act of 2004 (H.R. 4503), based on the energy bill conference report (H.R. 6). The bill has been received, but has not yet approved by the Senate. For more information, see http://congress.org/congressorg/bill.xc?billnum=H.R.4503&congress=108#activity.

[17] For further information, please see http://www.eere.energy.gov/wip/program/repi.html

[18] The Windustry News Letter, Spring 2002

and the actual number of grants funded depends upon the quality of proposals received and the amount of funding requested.[19]

Other Incentive Forms

- Some private companies buy green tags (renewable energy credits or RECs) from customers with grid-connected renewable energy systems. Since many small- or medium-scale renewable energy projects might not produce sufficient green tags to form a quantity that can be traded on the markets, private companies such as the Mainstay Energy Rewards Program aggregates large numbers of green tags from multiple projects into quantities that can be traded on the market. The green tags are then sold and the revenue is redistributed to the original sellers of the green tags. Payments under the Mainstay Energy Rewards Program vary across the country, but typically range from 0.1 to 4.0 cents per kWh for biomass-generated electricity. Participants who do not sign a ten-year contract are assessed a $100 certification fee in order to join the program, which may be paid with future green tag sales.
- Some utilities purchase carbon credits as an incentive to reduce greenhouse gas emissions.
- Some utilities provide ad hoc development services for biomass projects, including facilitation of identification of underutilized waste treatment facilities, initiation of RFP processes for resource and supply requirements, interconnection assistance, and facilitation of power purchase agreements.
- The USDA and the DOE administer a National Biomass Initiative that solicits applications for grant money for research in bioenergy and for agricultural producers or small rural businesses to purchase renewable energy systems.[20] In fiscal year 2002, 8 grants were awarded. In fiscal year 2003, 19 grants were awarded, including one grant awarded to a technical consulting firm in Portland, Oregon to assess the feasibility of an integrated ethanol and poultry production system that will use poultry litter as an alternative source of process energy for corn/ethanol production.[21] Table 2-2 presents a summary of projects funded by the National Biomass Initiative.
- The USDA and DOE sponsor a number of programs designed to support the development of bioenergy. These programs periodically solicit applications for grants for specific projects or areas of research.

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[19] Federal Register: April 8, 2003 (Volume 68, Number 67), Notices, pp. 17009-17018, http://www.rurdev.usda.gov/rd/nofas/2003/rep040803.txt.

[20] See, for example, http://www.bioproducts-bioenergy.gov/solicitations/solicitations.asp.

[21] For more information, please see http://www.bioproducts-bioenergy.gov/pdfs/USDA-DOEJointSolicitationR&DMatrix.pdf.

Table 2-2: Summary of Projects Funded by the National Biomass Initiative

Year	Project Title	Project Location
FY02	A Second Generation Dry Mill Biorefinery	Sioux Falls, SD
FY02	A New Biorefinery Platform Intermediate	Minneapolis, MN; Redwood City, CA; Richland, WA
FY02	Making Industrial Bio-Refining Happen!	Minnetonka, MN
FY02	Integrated Corn-Based Bio-Refinery (ICBR) Project	Wilmington, DE; Golden, CO; San Diego, CA; East Lansing, MI
FY02	Advanced Biorefining of Distiller's Grain and Corn Stover Blends: Pre-Commercialization of a Biomass-Derived Process Technology	St. Louis, MO and York, NE
FY02	Separation of Corn Fiber and Conversion to Fuels and Chemicals, Phase II: Pilot-Scale Operations	Decatur, IL; Richland, WA; St. Louis, MO
FY02	Value Added Products from Hemicellulose Utilization in Dry Mill Ethanol Plants	Richland, WA; Idaho Falls, ID
FY02	Continuous Isosorbide Production from Sorbitol Using Solid Acid Catalysis	Decatur, IL; Richland, WA
FY03	Integration of Leading Biomass Pretreatment Technologies with Enzymatic Digestion and Hydrolyzate Fermentation Thermotolerant Biocatalyst for Biomass Conversion to Products	Hanover, NH
FY03	Engineering Thermotolerant Biocatalyst for Biomass Conversion to Products	Gainesville, FL
FY03	Demonstration of the PureVision Biorefinery	Ft. Lupton, CO
FY03	Platform Chemicals from an Oilseed Biorefinery	Minneapolis, MN
FY03	Advanced Biorefinery Feedstocks	Cambridge, MA
FY03	Research and Demonstration of Anaerobic System on a Large Dairy farm	Logan, UT
FY03	Animal Waste Management – Chicken Litter to Energy	Carnesville, GA
FY03	New Technologies for the Production of Methyl Esters	Ralston, IA
FY03	Heterogenous Catalyst Development for Biodiesel Synthesis	Clemson, SC

Table 2-2, continued: Summary of Projects Funded by the National Biomass Initiative

Year	Project Title	Project Location
FY03	Design and Demonstration of a Commercial Prototype for Onsite Production of High Purity Hydrogen from Farm Animal Wastes	Pittsfield, MA
FY03	Biomass Research and Development for the Production of Fuels, Chemicals, and Improved Cattle Feed	Quincy, IL; Decator, IN
FY03	Grain Value Process: Pre-Commercialization Trials	St. Paul, MN
FY03	Coupled Processes for Bioenergy Production: Biological Hydrogen Links with Microbial Fuel Cells	University Park, PA
FY03	Biopolymers and Other Value-Added Products from Distillers' Dried Grains	Ames, IA
FY03	Biomass-Fired District Energy: A Source of Economic Development and Energy Security	Tesuque, NM
FY03	Steps Towards a Biorefinery Industry in Vermont	Williston, VT
FY03	Biomass for Tomorrow's Energy and Greenhouse Gas Management Needs: An Economic, Engineering and Environmental Appraisal of Opportunities and Policies	College Station, TX
FY03	Biomass Cogeneration Demonstration Plant at Central Minnesota Ethanol Cooperative	Roseville, MN
FY03	Feasibility of an Integral System for Improving the Economic and Environmental Performance of Poultry and Ethanol Production in North Alabama	Portland, OR

3

Issues in Developing Biomass Projects

This section describes various issues that were reported during the in-depth interviews regarding biomass project development and operation. While some of the discussion presents general findings, the results are organized by fuel type where possible. Fuel types include cow manure, wastewater gas, landfill gas, and wood.

1.1 Respondent Ratings

Respondents were asked to assign a 1 to 5 rating for a list of issues that might be problematic for project development, where 1 meant the issue was not a problem and 5 meant the issue was a severe problem. Issues specifically asked about in the interviews include siting, financing, local permits, environmental permits, utility interconnection, equipment delivery, equipment warranties, net metering, power purchase agreements, power price, and capital cost. In addition, respondents were asked to report any other problematic issues not on that list. The results are presented in Table 3-1 on the following page.

Table 3-1: Reported Significance of Key Development Issues

Development Issue	Suppliers	PA's	End Users	All Respondents
Planning or Siting	2.2 (n = 5)	2.4 (n = 11)	2.3 (n = 13)	2.3 (n = 29)
Obtaining Financing	3.7 (n = 6)	4.3 (n = 11)	2.8 (n = 13)	3.5 (n = 30)
Local Permit Approvals	2.6 (n = 5)	2.9 (n = 11)	2.2 (n = 13)	2.5 (n = 29)
Environmental Approvals	3.2 (n = 6)	3.0 (n = 10)	2.8 (n = 13)	2.9 (n = 29)
Utility Interconnection	4.0 (n = 5)	3.5 (n = 11)	2.5 (n = 13)	3.1 (n = 29)
Equipment Delivery	1.7 (n = 6)	2.0 (n = 10)	1.8 (n = 13)	1.8 (n = 29)
Equipment Warranty	2.5 (n = 6)	2.0 (n = 8)	1.4 (n = 10)	1.9 (n = 24)
Billing/Net metering	3.2 (n = 5)	2.5 (n = 8)	2.3 (n = 4)	2.6 (n = 17)
Power Purchase contract	3.8 (n = 5)	3.9 (n = 10)	3.1 (n = 10)	3.6 (n = 25)
Power Price	4.8 (n = 5)	4.2 (n = 9)	4.2 (n = 10)	4.1 (n = 24)
Project capital cost	3.0 (n = 6)	4.6 (n = 10)	3.6 (n = 13)	3.6 (n = 29)

As shown, the issue rated most problematic by all respondents was power price (an overall 4.1 rating on a 1 to 5 scale). Respondents reported the low market price for power meant it was not cost effective to generate it, either for their own use or for selling to the grid. The next two issues with ratings indicating problematic issues were the power purchase agreement and the project capital cost (both rated a 3.6 overall). Interestingly, program administrators assigned slightly higher (more problematic) ratings to both of these issues than did end users or suppliers.

The results for end users were further broken down by fuel type. The results are presented in Table 3-2. While it is interesting to compare the results in this manner, it is important to keep in mind the extremely small sample sizes when considering these results. Two respondents reported two other issues not included in the interview list: qualified labor and adequate fuel supply. Both of these respondents worked with wood burning facilities.

Table 3-2: Reported Significance of Key Development Issues by End User and Fuel Type

Development Issue	Dairy Farm	Dairy Regional Digester	Wastewater	Landfills	Wood
Planning or Siting	1.5 (n = 2)	5.0 (n = 1)	1.0 (n = 2)	2.0 (n = 2)	2.7 (n = 6)
Obtaining Financing	3.5 (n = 2)	5.0 (n = 1)	3.5 (n = 2)	1.5 (n = 2)	2.5 (n = 6)
Local Permit Approvals	1.5 (n = 2)	5.0 (n = 1)	1.25 (n =2)	3.75 (n = 2)	1.8 (n = 6)
Environmental Approvals	1.5 (n = 2)	5.0 (n = 1)	1.75 (n = 2)	4.5 (n = 2)	2.7 (n = 6)
Utility Interconnection	2.5 (n = 2)	4.0 (n = 1)	1.5 (n = 2)	2.0 (n = 2)	2.7 (n = 6)
Equipment Delivery	2.0 (n = 2)	1.0 (n = 1)	1.0 (n = 2)	1.0 (n = 2)	2.3 (n = 6)
Equipment Warranty	1.0 (n = 1)	1.0 (n = 1)	1.0 (n = 2)	1.0 (n = 2)	2.0 (n = 3)
Billing/Net metering	1.0 (n = 1)	n/a	n/a	n/a	2.7 (n = 6)
Power Purchase contract	2.0 (n = 1)	2.0 (n = 1)	1.5 (n = 1)	2.0 (n = 1)	3.9 (n = 6)
Power Price	5.0 (n = 2)	5.0 (n = 1)	n/a	3.5 (n = 2)	4.1 (n = 6)
Project capital cost	5.0 (n = 2)	5.0 (n = 1)	3.6 (n = 2)	3.0 (n = 2)	3.0 (n = 6)

As shown, according to respondents, a single dairy digester would be most concerned with the price of power and the capital cost. A regional dairy digester serving multiple farms would also be concerned with these issues, in addition to siting, financing, local permits, environmental permits, and utility interconnection. A wastewater treatment plant would be most concerned with the capital cost and obtaining financing. A landfill would be most concerned with environmental permits and local permits. A wood burning plant would be most concerned with the price of power and the power purchase agreement. As stated above, however, it is important to keep in mind the small sample sizes when reviewing these results.

The remainder of this section is organized by fuel type and discusses the issues pertinent to those facilities.

1.2 Cow Manure

Preliminary research of the market for biomass related energy generation in Oregon revealed that dairy farms are the principal source of animal manure used as fuel. Therefore, this market assessment focused on cow manure rather than other types of animal waste. Because the available information and number of operational facilities in Oregon is limited, we also present in this section related facility and cost information on operating manure digesters in California that is based on other research in support of this market for the Public Interest Energy Research Program.

Currently, there are two dairy digesters operating in Oregon. Table 3-3 presents the facility names and rated system capacities. One is a regional facility and one is an on-dairy digester cogeneration system. Representatives from both facilities were interviewed for this study.

Table 3-3: Operating Dairy Digesters in Oregon[22]

Location	Facility Name	Capacity (kW)
Salem	Cal-Gon Dairy	70
Tillamook	Port of Tillamook Bay MEAD Project	400
Total		***470***

Current system output as reported in interviews: Salem 50 kW; Tillamook 400 kW (with plans for Tillamook plant expansion to 800 kW by 2005).
A dairy digester project at Three mile Canyon Farms in Boardman is planned. The project is designed to include manure digesters and reciprocating engines to generate an estimated capacity of 3.85 MW.

By contrast, within California as of late 2002, there were six operating dairy manure digesters, based on a list published in AgSTAR Digest (Winter 2003) by EPA. The estimated combined capacity of these six digesters is based on treating manure generated from 16,600 cows (with about 13,500 milk cows). The largest two facilities are Inland Empire Utilities Agency (IEUA)'s Regional Plants No. 1 (Digester # 4) and No. 5 (RP-1 and RP-5). Both RP-1 and RP-5 are relatively centrally located in the Chino Basin, and have dedicated manure digesters to process dairy manure collected mainly from Chino Basin. The estimated available processed manure is 63 dry tons total solids per day and 54 dtpd volatile solids. The current combined generation capacity of these two regional manure digestion biogas facilities which include reciprocating engines and a few micro-turbines is 700 kW. The total reported operational electric generation capacity from these six operational manure digesters in California is 865 kW. It is important to note that each of these facilities is off-setting retail purchases rather than selling the power to the market or through a power purchase agreement with their utility.

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22 Data for this table was taken from the Oregon Department of Energy website and the U.S. Department of Energy - Energy Efficiency and Renewable Energy website.

TABLE 1-6
Operating dairy manure digesters in CA, October 2002

Digester Type	Year Operational	# of Heads		Manure Handling Method	Biogas End-use	Operational Output (kWhr/hr)
mesophilic plug-flow, flexible top	1982	400	milkers	scrape	electricity and hot water	40
unheated partially covered lagoon	1998	200 ~ 300	cows (includes dry stock and heifers)	flush	flare	0
unheated partially covered lagoon	2000	200 + 50	milkers + dry	flush and scrape	electricity and hot water	25
thermophilic-mesophilic complete	2001	5,000		vacuum scrape	electricity and hot water	200
mesophilic plug flow, fixed top	2002	7,000 + 3,000	milkers + others	vacuum scrape	electricity and hot water	500
mesophilic plug-flow, flexible top	2002	650	milkers	solids separator; scrape	electricity and hot water	100

Note: 1. Source: AgSTAR Digest, Winter 2003

Power Price and Power Purchase Agreement

The two respondents representing this fuel type both reported that the current *low price of wholesale electricity* made it very difficult to cover the costs of production without some form of assistance. One respondent suggested that if green or renewable energy programs were marketed more heavily to increase demand and biogas power producers were paid a premium for green power, it would "have a big impact on these projects; one or two cents has such a big impact."

Neither respondent, however, reported that obtaining the power purchase agreement was a problem. The key element of this agreement for the regional facility clearly is the established price for the electricity purchased by the utility. It is however important to note that one of these respondents is a utility representative.

Costs and Financing

Respondents reported that based on their experience to date with smaller dairy applications in California and elsewhere, the minimum number of cows needed to viably support a digester is about 500. Respondents cited installation costs on a per animal unit (AU) basis; specifically, one respondent (a no-site dairy digester application) reported installation costs of $450 per AU (or $2,778 per kW of generating capacity). The second respondent, a 4,000 AU regional facility, reported installed digester facility costs of $2.5 million, or $625 per AU (or $8,333 per kW).

The Oregon Department of Energy reports that capital costs for a plug-flow digester on a 500-cow farm will be $230,000 to $260,000. Further, respondents reported that the capital cost of installing a manure digester system is a significant concern for dairy farmers and most likely represents the largest market barrier for farmers considering a biogas project whether it is located at their farm or at a regional digester facility.

Because the high installed costs for the digesters and generation systems, obtaining financing was also reported to be a problem. In particular, one respondent reported that no state funding was available. They were able to obtain partial funding through the Environmental Protection Agency's *AgStar Program* and the Department of Energy (DOE). However, they had to downsize the digester generation project in order to complete it within the available funding resources.

For the regional dairy digesters, a significant operating cost element is the transportation (including trucks and drivers) to deliver the collected waste from the dairies to the regional processing plant. For the plant included in this study's sample, the first year's cost for two trucks and drivers amounted to $260,000, whereas labor, facility O&M and debt service combined amount to $155,000 for the first year of operation. Based on the first six months of operation, the total digester facility revenue for the first operational year was expected approximately 30% below the projects total operating costs, thus operating at a 30% negative margin. The most significant reported revenue variation for this facility was that the final negotiated electric power purchase rate with the utility was nearly 30% below the pro-forma projections for the project; although the second leading revenue stream component, de-watered fiber residuals (compost) product volume exceeded projections by nearly 30%, and third the value of the green tags were 50% below the pro forma which resulted in a smaller contribution (~7%) to the overall first year revenue stream. It is also worth noting that there are no tipping fees charged to the participating dairies, which could add some additional revenue in the future to the project. The estimated cost of electricity production for the entire digester facility's first year of operation (including debt service and de-watering of the fiber residuals that provide about 30% of the current total revenue stream) is $0.104 per kWh. This overall production cost is expected to decline in the second year due to improvements in operating efficiencies that will result in higher electric power production levels.

In contrast, the Oregon Department of Energy publishes estimated costs for producing electricity from various biomass fuels. For cow manure, they estimate this cost at 3.7 to 5.4 cents per kWh.

Environmental Approvals

Obtaining environmental permits was reported to be a problem for a regional digester, but not for a dairy farm. The one regional digester respondent reported that it was both expensive and time consuming to test the raw input, the finished product, the fiber byproduct, and the air emissions. He further reported that individual farms do not have to do the testing.

Utility Interconnection and Net Metering

Utility interconnection was reported as a problem by the regional digester.[23] The regional digester respondent explained that it had been a frustrating process in which to participate, but they were happy with the result once completed. Regional dairy digester operations are typically too large for current Oregon net metering laws to apply; therefore, it is not an issue with this particular type of digester facility.

Siting

Siting a biomass power plant is a problematic issue when the plant is designed to serve a regional area, requiring the fuel supply to be transported to the plant and by-product material transported away from the plant. The regional dairy digester interviewed for this study reported large costs to transport cow manure from participating dairies to the digester facility and fiber/liquid residuals back to the farms for land application. They were running two trucks to transport the manure and transportation costs were the single largest expenditure in their operating budget. In order to reduce the transportation cost element, the facility has access to rail and was considering using a rail cars for transporting manure and residuals to and from the facility.

Soil Quality

Respondents reported that spreading cow manure on fields may increase nitrogen levels to the soil's detriment, whereas collecting and processing the waste in a digester helps to control the soil quality. The liquid waste remaining after the manure has been digested still possesses nutrients and can be used as a fertilizer, applied in a controlled manner. Therefore, processing the dairy waste with a digester can improve the quality of the farm soil.

Fuel Resources

The Oregon Department of Energy reports that, as of 2000, there were roughly 79 dairies operating in Oregon that were licensed for 500 or more cows. These farms could produce 1,700 million cubic feet of biogas annually through anaerobic digestion. The potential energy value of this resource is approximately one TBtu per year, which roughly translates into a generating capacity of 13.8 MW.[24]

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[23] It should be noted that the other respondent, representing a dairy farm, was a utility representative.

[24] Conversion rates were taken from the following Department of Energy website: http://www.eia.doe.gov/oiaf/analysispaper/biomass/table3.html.

1.3 Wastewater

Methane gas created from the process of treating wastewater in anaerobic digesters is another resource for electricity generation. Wastewater treatment facilities normally produce methane gas is their regular operations, then flare (burn) the gas into the outside air. By capturing it and cleaning it of substances that would otherwise harm the generating equipment, the gas can be used to produce electricity and heat.

Currently, there are nine wastewater treatment plants operating biogas facilities in Oregon. Table 3-4 presents the facility names and rated system capacities. Representatives from four of these facilities were interviewed for this study.

Table 3-4: Operating Wastewater Biogas Facilities in Oregon[25]

Location	Facility Name	Capacity (kW)
Durham	Unified Sewerage Agency Durham	1,000
Eugene/Spgfield	Regional Water Pollution Control Facility	800
Gresham	City of Gresham WWTP	250
Hillsboro	Unified Sewerage Agency Rock Creek	300
Medford	City of Medford WWTP	700
Milwaukee	Clackamas County Service Dist. #1	
Oregon City	Tri-city Service District	
Portland	City of Portland Columbia Blvd. WWTP	320
Salem	City of Salem Willow Lake WWTP	800

Current system output as reported in interviews: Milwaukee 1000 kW; Oregon City unreported; Portland 170 kW; Salem 600 to 650 kW.

Installation Costs and Financing

Capital cost and/or obtaining financing was reported to be only somewhat problematic by operators of wastewater treatment plants. As public facilities, they had access to more resources than private businesses.

Due to the limited sample and the wide variety of locations, plant sizes, and ages of equipment, the responses regarding facility costs could not be easily summarized or generalized. However, some salient points are noted below.

- One local industry A&E consultant respondent indicated that for an IC engine project operating at a wastewater treatment plant, installed cost would vary according to fuel conditioning requirements and size as follows: <500 kW: \$2,000 to \$3,000 / kW; ≤1.5MW: \$1,500 to \$ 2,000 /kW; >1.5MW: \$~1,000/kW.

25 Data for this table was taken from the Oregon Department of Energy website and the U.S. Department of Energy - Energy Efficiency and Renewable Energy website.

- Another respondent operating a system on wastewater gas using a reciprocating engine reported installation cost was roughly $1,700 per kW.
- One respondent operating a system on wastewater biogas using a 200 kW UTC phosphoric acid fuel cell reported installation cost was roughly $6,500 per kW.
- One respondent provided estimated production costs of $0.045 to 0.085 per kWh for a 250 to 280 kW system.
- Based upon cost and incentives data reported by Itron in their Third-Year Impacts Assessment of the California PUC mandated Self-Generation Incentives Program (October 18, 2004), the eligible installed cost based on one operational 420 kW Level 3-R microturbines project is $2,890/ kW. There were no fuel cells operating on renewable fuel (Level 1-R) according to reported program data.
- Respondents with wastewater treatment plants reported maintenance costs to clean and periodically rebuild engines due to buildup from hydrogen sulfide in the gas were expensive. One respondent explained that an overhaul every five years or 15,000 hours on the engine costs $50,000; a major overhaul every 50,000 hours costs $150,000; and replacing the engine costs $300,000.

Additional information on project costs was obtained from two wastewater treatment biogas generation plants operating in California since the mid 1980's. One of these plants, the Total Energy Facility in Carson, operated three gas turbine generators, three heat recovery steam generators, one steam turbine, and three gas compressors. The capital cost for this plant constructed in the 1980's was $45 million, and 95% of this amount was provided by federal and state grants. This plant reported a gross capacity of 15.5 MW and annual operating and maintenance costs of $3.2 million. Further, the plant reported that their O&M unit cost of power was $0.026 per kWh. The second plant operated one internal combustion engine, one heat recovery steam generator, and one gas compressor. This plant reported a gross capacity of 0.5 MW and annual operating and maintenance costs of $66,298 or $0.0645 per kWh.[26]

The end user interviewed for these facilities also reported that for a new 5 to 10 MW biogas fired internal combustion engine/generator or gas turbine power plant; the power production cost would be $0.035 to $0.04 per kWh. In addition, the installed cost for a microturbine generation unit of 20 kW to 250 kW was reported to be $2,250 to $3,500 per kW with annualized operating and maintenance costs of $0.05 per kWh. Fuel cells are generally more expensive to install (roughly $3,900 to $6,500+ per kW) and a significant cost is the digester gas conditioning system (required for H_2S, siloxane and other biogas impurity removal) that is required for either the microturbine or the fuel cell.

[26] Costs for both plants are based on data from their fiscal year 1996 to 1997.

Fuel Resources

The Oregon Department of Energy estimates that wastewater treatment plants are currently using all but 25% of their digester gas. The unused biogas is estimated to be 345 million cubic feet with a potential energy value of 0.2 TBtu. Further, they report that nine wastewater treatment plants in the state are currently burning their excess fuel to produce electricity. The largest of these is the plant operated by the City of Portland. Currently, this plant produces 170 kW using one fuel cell. In addition, this plant is in the process of installing four small 30 kW microturbines, which will produce an additional 120 kW, and they are considering installing additional equipment for their remote plants.

Respondents operating wastewater treatment plants reported that the gas needed to be cleaned of hydrogen sulfide and siloxanes before being burned in order to minimize damage to the equipment. In particular, one respondent using a fuel cell reported that hydrogen sulfide is detrimental to the fuel cell and had to be removed from the biogas prior to delivery to the fuel cell energy conversion stack. Therefore, they designed a flow switch that would control the level of oxygen to provide enough for cleaning the fuel without harming the fuel cell. In addition, this respondent reported that water vapor and siloxanes must be removed from the gas in order to use it in a microturbine. Another respondent reported he had to clean the gas of hydrogen sulfide and siloxanes in order to use it in their reciprocal engine. To do this, they use a piece of equipment called an "iron sponge" which removes hydrogen sulfides (H_2S) from the gas and also reduces ferrous oxide compounds. The process requires regular maintenance.

1.4 Landfill Gas

In a landfill, biodegradable materials beneath the surface come into contact with moisture and then decay to produce gases, mostly methane and carbon dioxide, which typically find their way to the surface and disperse. By collecting the landfill gas, it can be conditioned and then used to produce electricity as fuel input for a number of prime movers.

Currently, there are two landfill biogas facilities operating in Oregon. Table 3-5 presents the facility names and rated system generation capacities. Representatives from both facilities were interviewed for this study.

Table 3-5: Operating Landfill Biogas Facilities in Oregon[27]

Location	Facility Name	Capacity (kW)
Corvallis	Pacific Northwest / Coffin Butte	2,460
Eugene	Emerald People's Utility / Short Mountain	3,200
Total		***5,660***

Air Emissions

Problems with air emissions seemed to be most pronounced with end-users operating landfill biogas facilities. These respondents reported difficult and expensive procedures to meet air emission requirements including testing, engineering studies, and extensive paperwork. The problem is somewhat ironic in this application because, without a collection system, landfill gas is an uncontrolled, non-point source of potent greenhouse gas emissions. With the addition of a collection system, the emission source becomes a point source and thus subject to emission requirements. Despite the fact that even uncontrolled combustion for generation creates lower emissions than the non-point source release, stringent air pollution control requirements are often imposed on generators.

Installation and Operating Costs

The Oregon Department of Energy publishes estimated costs for producing electricity from various biomass fuels. The estimate for landfill gas is 2.9 to 3.6 cents per kWh.

The following are reported costs from the project interviews.

- One respondent operating a system on landfill gas using four reciprocating engines reported the installation costs, including the gas collection system, amounted to $793 per kW.
- One respondent operating a system using landfill gas reported that operating and maintenance costs were roughly 1.2 cents per kW. Another respondent operating a system using landfill gas reported his operating and maintenance costs were roughly 3.5 to 4 cents per kW.
- Respondents at landfills reported that the ongoing cost to perform testing, engineering studies, and reporting to meet air emission requirements was burdensome and expensive. One respondent characterized it as "thousands and thousands of dollars."

Additional information on project costs was obtained from four landfill plants operating in southern California since the late 1980's. Cost information on these four plants is presented in Table 3-6.

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[27] Data for this table was taken from the Oregon Department of Energy website and the U.S. Department of Energy - Energy Efficiency and Renewable Energy website.

Table 3-6: Cost Information Reported for California Landfill Gas Plants

Location (in CA)	Generating Equipment	Gross Capacity (MW)	Capital Cost ($ per kW)	Annual Operating & Maintenance Cost	Cost to Produce Power ($ per kWh) in 1997
Puente Hills	Steam boiler Steam turbine	50.0	$650	$6.5 million	$0.016
Puenta Hills	Gas turbine	3.9			
Palos Verdes	Steam boiler Steam turbine	13.0	$1,450	$3.0 million	$0.047
Spadra	Steam boiler Steam turbine	9.9	$2,100	$2.4 million	$0.041

Fuel Resources

The Environmental Protection Agency operates a program called the Landfill Methane Outreach Program, which promotes the use of landfill gas as a renewable energy source. The Program maintains a publicly available database of landfills in the country along with their project status. The database lists 13 landfills in Oregon, and two of these are currently operating energy production facilities. Further, the EPA identified five of the landfills as having the potential to produce sufficient biogas for economic production of electricity. The estimated potential gas to be produced from these is 4,700 million cubic feet, and the energy value of this resource is 2.4 TBtu.[28] This roughly translates into a generation capacity of 33.1 MW.

1.5 Wood

Wood as a fuel resource for biomass related electricity generation can be divided into two categories: forest residue and mill residue.[29] Forest residues include logging residues, salvageable dead wood, excess saplings, and small pole trees; however, in estimating the available quantity of this resource, only logging residues and salvable dead wood were considered. Small pole trees may have other more valuable uses. Mill residues include bark, coarse residues (chunks) and fine residues (sawdust). Most are currently used as fuel to produce heat or steam or used to produce other fiber products. In addition, wood can be

[28] According to the Oregon Department of Energy, these landfills are Columbia Ridge (Gilliam County), Klamath Falls (Klamath County), Knott Pit (Deschutes County), Northern Wasco County (Wasco County), and Roseburg (Douglas County).

[29] At the request of ETO, urban wood waste was omitted from this study as a potential resource.

grown to be used in biomass applications. Dedicated energy crops include short rotation woody crops (e.g. hybrid poplar and hybrid willow) and herbaceous crops (e.g. switchgrass). However, the Northwest region of the United States is not considered climatically suited for energy crop production. Therefore, for the purposes of this assessment, this resource was not considered.

Facilities that are currently operating in Oregon that use wood as fuel to generate electricity are presented in Table 3-7. Representatives from seven of these facilities were interviewed for this study.

Table 3-7: Operating Biomass Power & Cogeneration Facilities in Oregon Using Wood Fuel [30]

Location	Facility Name	Capacity (kW)
Albany	Weyerhaeuser Co.	45,000
Springfield	Weyerhaeuser Paper Co.	25,000
Eugene	Eugene Water & Electric Board	11,500
Springfield	Eugene Water & Electric Board	51,200
Heppner	Port of Morrow / Frontier Energy	10,000
Warm Springs	Warm Springs Forest Products	6,000
Medford	Boise Cascade	9,000
Newberg	SP Newsprint	40,000
Prairie City	Prairie Wood Products / D.R. Johnson	10,000
Riddle	Cogen II / D.R. Johnson	7,500
Roseburg	Roseburg Lumber Dillard Cplx	16,500
White City	Biomass-One	25,000
Wauna	Fort James Operating Co.	36,000
Prineville	Pine Products Corp.	5,700
Total		***298,400***

Current system output as reported in interviews: Albany 50 MW, Heppner 10 MW, Warm Springs 3 MW, Medford 8 MW, Newberg 25 to 30 MW, Riddle 11 MW.

Power Price and Power Purchase Agreement

All respondents of wood burning facilities interviewed for this study reported that the price of power and the power purchase agreement were a difficult or severe problem. The one respondent who did not report it as a problem was still operating under a lucrative PURPA[31]

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30 Data for this table was taken from the Oregon Department of Energy website and the U.S. Department of Energy - Energy Efficiency and Renewable Energy website. Facilities using strictly municipal solid waste or urban wood waste were omitted.

31 PURPA (Public Utility Regulatory Policies Act of 1978) was passed as part of the National Energy Act to encourage the development of alternative power supplies capable of displacing the inefficient use of oil and natural gas by electric utilities. PURPA requires electric utilities, when they need power, to purchase power

agreement, and therefore was receiving a much higher price for the electricity they sold than market price. Many of the respondents reported they were losing money. One of the paper product facilities reported they had closed some of their biomass cogeneration facilities because the current price of electricity was cheaper than they could produce it.

Installation and Operating Costs

The economics of building and operating biomass power plants was reported in the interviews as the key problem for this industry. Several respondents operating wood burning facilities referred to the PURPA agreements in the 1980s and stated that plants still operating on those agreements are the only ones making money on the electricity they sell today.

Not surprisingly, responses from facilities that burn wood spanned a wide range since these plants had considerably different characteristics from each other. However, Table 3-8 presents estimated costs for a dedicated plant running on wood biomass, which were developed for another recent study.

Table 3-8: Estimated Costs of a Wood Burning Plant [32]

Item	5 MW Plant	25 MW Plant	50 MW Plant
Capital cost ($/kW)	$2,400	$2,248	$2,096
Feedstock requirements (GT/year)	123,415	429,577	723,205
Fuel cost ($/GT)	$28	$47	$53

GT = Green Tons

The Oregon Department of Energy publishes estimated costs for producing electricity from various biomass fuels. The estimate for wood burning facilities is 5.2 to 6.7 cents per kWh.

Collection and Transportation

One of the ways that biomass and biogas fuels differ from other renewable fuels is that they must be physically collected and transported to a generation facility. The issue is more serious for regional plants or for plants that burn forest residue.

A recent study estimated the costs for delivering wood to a plant in Eastern Oregon. Table 3-9 shows the results from that study.

from QFs (qualifying electric power production facilities) at the utilities' avoided cost, provide back-up power to QFs, interconnect with QFs, and operate with QFs under reasonable terms and conditions (description from http://www.epsa.org).

[32] The data is from the McNeil Technologies study, op. cit.

Table 3-9: Estimated Wood Supply Costs [33]

Fuel Type	Quantity (GT/year)	Average Cost Delivered ($/GT)		
		Baker County	Union County	Wallowa County
Forest biomass	425,934	48.66	48.20	49.49
Mill chips	308,794	25.39	15.93	27.15
Veneer cores	1,458	12.46	3.00	14.22

GT = Green Tons

As shown, fuel from forests is the most expensive type of wood to collect and transport to the plant. Thus, a plant would first utilize existing supplies of wood manufacturing residue or urban wood waste from recycling programs before purchasing forest residue.

Competing Uses

Facilities that must buy wood fuel also run the risk of prices increasing due to competing uses. For example, wood product manufacturers may use most of their by-products to make particle board. Bark chips are also widely used for landscaping. The other users of these fuels drive the prices up and may cause the fuel supply to fluctuate.

Environmental Impacts

Air Emissions. For wood biomass, some respondents reported a potential positive impact on air emissions, i.e. burning the wood in a controlled facility will produce less impact on air quality than open slash burning, wildfires, or urban wood waste rotting in landfills. In addition, burning wood biomass produces less sulphur dioxide and nitrous oxide emissions than burning coal. Burning wood does produce a significant amount of carbon dioxide emissions, although some of this is consumed in time by the healthy growing forest, leaving a reduced effect.

Soil. For wood biomass, there is a concern that clearing debris from forests may deplete the soil of valuable nutrients. Soil is more exposed after thinning, thus decreasing its ability to absorb water and increasing the risk of erosion. On the other hand, forest thinning removes debris that might end up in rivers and streams and thus has a positive impact on water quality.

Forest Thinning. Using forest residue from thinning efforts creates a positive environmental impact in the region. For example, forests will have improved resistance to disease and insect infestation, a lower risk of wildfire, and reduced air emissions from slash burning.

[33] The data is from the study by McNeil Technologies, op. cit. The study chose three areas in Eastern Oregon and developed supply curves for potential biomass power plants in those areas

There are also concerns among communities that excessive forest thinning will have a negative impact on wildlife habitats, and possibly soil and water quality.

Fuel Resources

Oregon is rich in forests. Wood residue would therefore seem to be a potential rich source for biomass fuel. The Oregon Department of Energy estimates that wood residue has an energy value of 4,500 Btu per pound. In 2001, forest logging sites in Oregon generated 2.6 million bone dry tons (bdt) of logging residues. However, only 19%, or 494,000 bdt, of this could have been removed at a feasible cost. This feasible amount of logging residue could have produced eight trillion Btu of energy. This roughly translates to a generation capacity of 110 MW.

Cogeneration plants burning their own wood waste sometimes supplement their fuel stocks by purchasing hog fuel or by accepting recycled wood waste. The supply of hog fuel in the state has diminished, however, due to a number of lumber mills closing and competing industries driving up the price of the remaining resource. It sells in a price range of $15 to $30 a wet-ton, which, especially at the higher end of that range, is too expensive for facilities to purchase based on responses from end users interviewed for this study. In 2001, Oregon's sawmills generated 1.5 million bdt of hog fuel, which has the potential for 26 TBtu of energy. This roughly translates to a generation capacity of 359 MW.

Forest residue is abundant, but is expensive to collect and transport to the site. Two recent studies have estimated the potential supply of this resource along with the cost of utilizing it.[34] The report by Sampson et. al. estimates 7.4 million bone dry tons of biomass are available to be harvested annually in the Pacific Northwest. They further estimate this would yield roughly 126 million Btu of energy. The report by McNeil Technologies provided forest biomass availability for three counties in Eastern Oregon. They estimated available resources for three types of forest management activities. For non-commercial thinning, the estimate was roughly 36 to 108 thousand green tons per year depending on the yield assumption (5 to 15 green tons per acre). For timber stand improvement, the estimate was roughly 31 to 93 thousand green tons per year depending on the yield assumption (5 to 15 green tons per acre). For timber harvest residue, the estimate was roughly 292 thousand green tons per year.

For a potential new plant to take advantage of this resource, however, some guarantee of a long-term and affordable fuel supply is needed in order to finance the system installation. Currently, the means of achieving these objectives are not in place.

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[34] The subject is broader than the scope of this study allows. See McNeil Technologies, Inc., Op. Cit. and The Sampson Group, Inc., Op. Cit.

Siting

Siting a biomass power plant is a problematic issue when the plant is designed to serve a regional area, requiring the fuel supply to be transported to the plant and by-product material transported away from the plant. Two of the end-users operating wood burning facilities interviewed for this study described siting as a severe problem. The problems stem from two areas: 1) the cost of transporting the fuel to the plant and the cost of transporting product and/or by-product away from the plant, and 2) the public's negative perception regarding the location of a power plant near an urban area. Additional issues involved in choosing a potential site include proximity to a utility substation and zoning.

Utility Interconnection and Net Metering

End-users operating wood burning facilities interviewed for this study were asked if utilities were receptive to biomass facilities that produce electricity. There was a clear distinction between the responses. Respondents who produced electricity mostly to sell on the grid reported that the utilities were receptive or very receptive to these systems. Regarding additional costs or equipment that needed to be purchased for interconnection, many respondents reported that it was an expensive and time-consuming process; however, none reported that it was an insurmountable barrier or a reason to stop the project. Respondents who operated net-metered cogeneration systems, however, indicated they had run into resistance with utilities. Specifically, they reported that the utilities wanted to charge extra fees and demand charges. In one case, the respondent reported having to hire energy attorneys and consultants to get through a frustrating and expensive interconnection process.

1.6 Summary

This section discussed a number of issues relevant to the development and operation of facilities that generate electricity from biomass and biogas fuels. In particular, the section discussed power price and power purchase agreements, costs and financing issues, fuel resources, environmental impacts and utility interconnection coordination. Chief among these issues is the low power price in the Northwest. This issue, coupled with the high capital cost of installing equipment, creates an economic hurdle which developers of new plants and operators of existing plants must overcome. Currently, there is no means in the market for them to overcome it and existing plants are losing money (with the exception of those with long-term more beneficial power contracts from the 1980s).

Power price was cited as a difficult or severe problem by eight of the end-users and by four of the program administrators interviewed for this study. It was also mentioned by several of the surveyed suppliers. The overwhelming majority of respondents reported that the price of electricity in today's market does not support the operation of a biomass plant. In addition, five end-users and five program administrators rated the power purchase agreement as a difficult or severe problem.

Suppliers interviewed for this study reported that assistance with power purchase arrangements would improve project feasibility. They suggested that some form of renewable portfolio standard (RPS) or similar mechanism would increase the utilities' willingness to accept excess generation and/or increase the value of purchased power. Even without utility buy-back, if the utilities were required to maintain some type of RPS it would increase their cooperativeness toward biomass generation projects.

The major obstacles reported by end users interviewed for this study, in order of severity (most to least) are as follows:

- Respondents operating dairy digesters reported the low power price, the high capital cost, and difficulty obtaining financing as problems.
- Respondents operating wastewater treatment plants reported high capital cost, difficulty obtaining financing, and biogas fuel cleaning as problems.
- Respondents operating landfill biogas facilities reported air emission requirements, local permits, and the low power price as problems.
- Respondents operating wood burning facilities reported the low power price, the power purchase agreement, and the cost of buying and/or transporting fuel as problems.

4

Lessons Learned

The experience of other program administrators can be invaluable when designing a new program. As part of this study, administrators of biomass incentive programs in other regions were asked for suggestions and asked to relay any lessons learned from their own program experience.[35] Table 4-1 on the following pages summarizes the results of the Program Administrator interviews.

Public and Investor Education. As shown in Table 4-1, both statewide and regional program administrators emphasized the difficulties encountered in bringing a biomass project to fruition as one of the key lessons learned from administering incentive programs for such projects. Program Administrators highlighted the importance of education to promote awareness of the commodity, as lack of awareness renders the financing process for biomass projects difficult. Thus, according to Program Administrators, provision of financing for biomass projects mitigates risk for outside lenders and renders projects more fiscally feasible. Simple provision of production incentives might be insufficient to encourage significant investment in biomass projects if developers cannot obtain sufficient funding to purchase, install, and operate their systems.

Importance of the Project Review Process. Additionally, Program Administrators learned that the project review process is critical, and reviewers must be well-informed since biomass projects involve multiple fuel sources and conversion processes, and since plans often appear sound on paper but projects actually encounter numerous problems as they proceed. In fact, one respondent reported that two out of five projects in the respondent's program failed for unknown reasons. However, it should be noted that the first few projects completed within any given program will require additional effort to complete, as applicants and program administrators become more familiar with the process and learn to anticipate potential difficulties that might arise in the project development process. Thus, Program Administrators report that patience is one of the primary virtues developed from the process of administering a renewable energy incentive program.

[35] See Appendix A for a list of organizations included in the sample.

Managing Program Funds. Program Administrators also reported the importance of carefully managing program funds. Program Administrators emphasized the value of consistent guidelines and teamwork in managing an effective renewables incentive program, and suggested requiring an executed contract between the vendor and the host before committing funds. Corporate parent caps (i.e., a dollar amount or percentage limit on incentives awarded to any one corporation) were also recommended in order to spread the funds to a greater number of applicants and eliminate the situation where one parent corporation consumes a disproportionate amount of program funds. Additionally, in the interest of equity, in situations where programs funded multiple technologies, it was suggested that program funds be allocated to each eligible resource or technology.

Simplification of Program Design. Table 4-1 also presents Program Administrators' responses to the question, "What about your program would you change if you were redesigning it?" As shown, Program Administrators reported that they would have simplified aspects of their programs' design to facilitate program management and alleviate confusion. One respondent stated that an open solicitation process would be specified rather than a competitive solicitation process if the program were redesigned. Another respondent added that the percentage of project cost incentive basis would be eliminated, incentive levels would be reset, and program requirements and processes would be standardized if the program was redesigned. Another respondent stated that incentive levels would have been held stable over time if the program was redesigned.

Additional Program-Related Services. Finally, Program Administrators reported that if given the opportunity to redesign their programs, they would have provided additional services under their programs. Workshops would be held regularly to educate and provide the public with an opportunity to provide feedback on the program. More funding would be allocated to deployment and development projects, as opposed to long-term R&D projects, to fulfill public demand for relevant solutions to current problems. A more proactive role would be assumed, and alternative technologies to be incentivized would be identified.

In summary, administrators of other programs reported that, based on their experience, the administrator of a biomass incentive program should be informed enough to discriminately choose project proposals, be patient with project development knowing some will fail, manage program funds to ensure they are not consumed by a few large projects or technologies, and educate the public and investors on the value of biomass projects as investments and as resources for the environment. Program administrators should ensure that program design aspects are standardized and sufficiently clear to reduce time spent in clarifying administrative requirements and to mitigate confusion among applicants, and *should set incentive levels carefully* to ensure that technologies are appropriately incentivized.

Table 4-1: Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
NJ	Statewide clean energy rebate program	Photovoltaics, wind, biomass, renewable-fueled fuel cells	Commercial, residential	Incentives of $0.15-5.00/watt for qualifying biomass projects, up to a maximum of 30-60% of total installed cost. Incentive amounts decrease over time as the total number of installed systems increases.	There are no maximum installation size criteria to qualify, but systems must be sized to meet "local load". Systems must include at least a 5-year all-inclusive warranty.	Not specified.	
NJ	Statewide clean energy grant and financing program	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, anaerobic digestion, tidal energy, wave energy, renewable-fueled fuel cells	Commercial, nonprofits, schools, local governments, utilities, state and federal governments, institutional customers	Grant award of up to 20% of total construction costs and other qualifying costs, as well as guaranteed long-term financing for the incremental cost of construction of the project.	To qualify, projects must generate at least 1 MW at the facility or by aggregating a minimum of 1 MW of renewable electricity generation systems into one proposal. The program offers financing to prove to outside investors that the projects it funds are risk-worthy, and produce a good rate of return with a low default rate.	Originally, a production incentive was paid; however, since an extended length of time was required for systems to become operational, many participants eventually withdrew from the program since they could not obtain adequate financing to fund the entire development process. Additionally, a competitive solicitation process was originally required, which was onerous to developers; the current open solicitation process is much simpler.	Larger projects encounter difficulty obtaining financing since biomass is not a well-known commodity. It is important to ensure that when obtaining financing that the development team possess strong business experience and understanding in utility commodity purchasing.

Table 4-1 (continued): Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
OR	Regional biomass partnership program	Biomass	No specific sectors targeted	Feasibility studies, biomass assessments, and R&D in ethanol were funded; funding also encompasses the salary of a staff member who serves as the point of contact for biomass-related question in the state, keeps abreast of technologies and uses of biomass for energy, and maintains content on the state website.	Two-thirds of program funding is provided by the USDOE Biomass program, and one-third is provided by the Oregon Energy Supplier Assessment. Within each of the five program regions, the regional program distributes funds internally to states within the region.	The Program Administrator indicated that there were no changes that should have been made to the program; the only problem encountered has been lack of sufficient time and funding to adequately service the biomass market.	When trying to decide between specific projects, the proposal review process is critical, and reviewers must be well-informed. Biomass is more convoluted since there are multiple fuel sources and conversion technologies, and new and innovative technologies require careful review.
OR, primarily within utility service territory	Utility ad hoc development assistance for biomass projects	Biogas and biomass	Wastewater treatment plants, dairies, and landfills	Develops ad hoc projects, and provides any services necessary to bring biogas/biomass treatment projects to fruition (often assuming a developer role). The program does not offer training per se, but will provide guidance if requested.	Examples of ad hoc services provided by the program included facilitation of identification of underutilized waste treatment facilities, initiation of a RFP process for resource and supply requirements, working with developers of emerging technologies toward power purchase agreements, and interconnection assistance.	The production tax credit has been problematic, and has been difficult to work with.	On a federal level, more consistency in identifying what types of material qualify for funding is required. The downfall of projects is mostly economics; in a dairy, one cannot expect to fund a digester on the basis of electricity and fiber sales alone. Thus, additional incentives should be available.

Table 4-1 (continued): Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
OR	Statewide green tag sales agreement program	Wind, biomass, solar	Residential and small nonresidential customers (<30 kW)	There are no incentives offered, per se. However, the program does endorse give-aways. The program also offers some promotional support to large commercial customers.	Green tags are sold to customers.	Currently, customers can choose to purchase 100% of power or blocks in 100 kW increments. The Program Administrator felt that customers should be allowed purchase 50% of their load rather than a certain number of power blocks, since it would eliminate the effort involved in computing the number of blocks required.	Increased education is necessary, because most people are not well-informed about biomass. Convincing investors that biomass is a sound investment is crucial. While biomass projects entail considerable large, up-front commitments, in the long run, the fuel is free or very inexpensive, rendering such projects a good investment.
OR	Statewide renewables program	Renewables	Not specified	A production incentive or capacity buydown will be offered.	Annual amounts of program funding were allocated by technology. No funding was set aside for biomass, but the organization is examining options for this technology.	No changes should be made to the wind portion of the program. However, it was difficult to obtain clear information regarding PV from the PV industry when incentives were originally set. The Program Administrator should have remained firm on incentive levels over the long term.	Not specified
OR	Green tag sales agreements and funding program	Wind, biomass, solar	Residential, nonprofit, corporate, and utility customers	There are no incentives offered, per se.	Green tags are sold to customers, and new projects are funded.	The program should offer capital rather than operating revenue.	Reservation rules should be very stringent: an executed contract between the vendor and the host should be required before funds are committed, in order to prevent applicants from flooding the administrators with projects that are not likely to become feasible.

Table 4-1 (continued): Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
WI	Renewable energy grant program	Solar (solar electric, solar thermal and passive), wind, hydropower, wood waste, organic wastes, agricultural crops, and their residues. Program focuses on large projects (greater than 20 kW or 5,000 therms/yr.).	Residential, commercial, industrial, nonprofit, local government, tribal government, and institutional customers throughout the state.	Business grants of 50% of project costs, up to $10,000, are available. Feasibility study grants of 50% of project costs, up to $10,000, are available. Implementation grants of 25% of project costs, up to $35,000, are available. Grant amounts are based on estimates of annual kWh generated, or thermal energy saved and utilized. One-on-one technical and financial assistance is also offered.	On- and off-grid renewable energy projects are supported. Business and marketing grants may be utilized to assist with business plan, market recognition, employee training, and certification efforts. Technical and financial assistance offered includes renewable energy site assessments, assistance in locating contractors, assistance with grant proposals, and project implementation.	The program should have focused its resources upon one market.	Standardization of the institutional barrier process was helpful; the program now successfully boasts one standard interconnection process, form, and requirements.

Table 4-1 (continued): Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
CA	Statewide new and existing account renewables incentive program	Biomass, digester gas, geothermal, landfill gas, solar thermal, small hydro, waste tire, and wind	Not specified	Funds for existing technologies were distributed through a cents per kWh production incentive, up to 1.5 cents/kWh; funding decreased annually from 1/1/98-1/1/02. Funds for new technologies were distributed through a production incentive based on a competitive solicitation process, with a cap of 1.5 cents/kWh, and paid over a five-year period after the project began generating electricity. The amount of funds increased annually from 1/1/98-1/1/02.	The Existing Renewable Resources segment of the program supports market competition among in-state existing renewable electricity facilities through varying incentives. The New Renewable Resources segment of the program encourages prospective renewable electricity generation projects built in California through fixed production incentives.	For new accounts, delay penalties should be instituted at critical milestones (scheduling requirements). Funds unused due to delays should be reallocated. For existing accounts, target prices/actual costs should be re-honed. Categories of target prices should be established for cogeneration versus non-cogeneration applications.	Program funds should be allocated to each eligible resource or technology. Additionally, corporate parent caps should be instituted in order to prevent one entity from consuming a disproportionate share of program funds.

Table 4-1 (continued): Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
CA IOU service territorie s	Renewable Energy/Distri buted Generation incentive program	PV, fuel cells, wind, microturbines, internal combustion engines, and small gas turbines	Industrial, commercial, agricultural, and residential	For PV, renewable-fueled fuel cells, and wind, the lesser of $4.50 per watt or 50% of eligible project costs. For nonrenewable-fueled fuel cells, the lesser of $2.50/watt or 40% of eligible project costs. For renewable-fueled microturbines, internal combustion engines, or gas turbines, the lesser of $1.50/watt or 40% of project costs. For nonrenewable-fueled microturbines, internal combustion engines, or gas turbines, the lesser of $1.00/watt or 30% of eligible project costs.	Nonrenewable-fueled systems are required to meet waste heat recovery requirements as mandated by PUC 218.5. Maximum system size is capped at 1.5 MW, though maximum incentive payout amounts are capped at 1 MW. Systems must be certified to operate in parallel with the electric system grid.	The percentage of cost basis for incentives should be eliminated since a considerable amount of time is currently expended in negotiating with hosts/applicants on project costs for self-installed projects. Dollar per watt rebates should also be set at appropriate levels. More information should be made publicly available, and the program should be standardized in terms of reporting, utility interconnection requirements, air quality code requirements, insurance requirements. Program Administrators should also hold regular workshops for the public to learn about and become involved with the program.	It is useful to have concrete guidelines with no fluctuation, and for a statewide Program for Administrators to be open and willing to work as a team.
Pacific NW (OR, WA, ID, MT, AK, HI)	Regional biomass grant and technical assistance program	Biodiesel, cellulose to ethanol gasification, combustion in small village-sized applications, gasification, and pyrolysis.	Public sector and energy providers	Grants typically fund high-risk, long-term research and feasibility studies for more expensive renewable energy technologies, or those with no proven track record or history. Technical assistance is also offered through national centers, but no specific biomass training is provided.	The program is typically funded, with most programs managed directly by state energy office program managers. Each state typically receives a specific amount of funding, and the states cost-share the remainder of the budget. Budget allocations thus vary year-to-year.	Most of the program's efforts are focused upon long-term research; however, the public is more interested in solving current problems. The program should fund additional deployment and demonstration projects to demonstrate to the public the opportunities that biomass projects offer.	Patience is required to successfully develop biomass projects. The success rate of biomass projects is usually not high, as two of five projects fail for unknown reasons. It is also important to examine project details carefully.

Table 4-1 (continued): Summary of Programs and Lessons Learned from Program Administrator Interviews

Region	Program Type	Eligible Technologies	Applicable Sectors	Program Incentive/Grant/ Service Offering	Program Details	Things Program Administrators Would Have Done Differently	Key Lessons Learned
FL, NJ, PA, OH, OR, and TX	Green tag purchase agreements and technical development assistance	Wind, hydro, geothermal, biomass (NOTE: biomass is not a qualifying technology in OR)	Residential and small businesses, commercial customers (NOTE: green tags are not sold to commercial customers in OR)	The organization examines available resources to construct an affordable, attractive clean energy product for customers, and provides contractor services of marketing and supply procurement. Additionally, the organization funds the purchase of Renewable Energy Certificates/green tags from developer/owners.	The organization agrees to purchase a certain amount of MWH in green tags, which can help render projects financially feasible.	Not specified.	Green tags define the attributes of the electricity source, and the relative merits of wind tags versus biomass tags should be considered. The difference between bid and ask prices for green tags should be considered.
Pacific NW	Informational assistance on renewables	Renewables	Not specified.	Collects relevant data and provides policy recommendations regarding renewables. Also develops regional power plan.	Among other research, the organization compiles information on regional progress in meeting conservation and renewable resource goals.	Not specified.	Not specified.
Pacific NW service territory (OR, WA, ID and portions of MT, CA, NV, UT, and WY)	Technical assistance regarding digesters	Biomass	No specific sectors currently targeted	Supports select projects by providing technical assistance (providing contacts, transmission interconnection, and informational assistance on how self-supply affects how utilities purchase power from the organization).	Program Administrators are in the process of reaching a decision regarding method in which assistance for renewable energy projects will be provided since the current system is complicated.	A more proactive role should be assumed to facilitate biomass to energy projects. Much more can be done, and alternative technologies must be identified.	Patience is required. While plans may appear sound on paper, projects may actually encounter numerous problems as development proceeds. Additionally, the first projects will be complicated.

5

Key Market Opportunities

1.1 Overview

Existing biomass and biogas resources in Oregon could potentially provide a reliable source of renewable energy along with positive economic and environmental impacts. However, the economic situation today is not conducive to development of these facilities unless financial assistance is provided in some form, such as a capital cost buydown, production incentive, or a low-cost financing program.

This market assessment was meant to be a preliminary look at opportunities for the development of biomass generation and cogeneration plants in Oregon. These initial findings will be useful for conducting a second phase of more in-depth research at market opportunities in the state.

The results of the research indicate that developers of wastewater treatment plants would benefit most from a capital cost buydown, while developers of landfills and wood burning plants would benefit most from a production incentive. Developers of dairy digesters would benefit from either or both. A supply-side respondent reported that if animal waste digesters had a market for their electricity of 6.5 cents per kWh, they could get the financing needed. Therefore, a production incentive for these systems of 2.0 to 2.5 cents per kWh may be enough to get them going. Similarly, a respondent discussing wood burning plants reported that if he had the same incentives as those available now for wind projects, he could make it work.

In addition, developers of plants that burn forest residue would benefit from policy intervention to support the long-term availability of forest residue fuels. For example, the following are possible intervention opportunities, although some of these are clearly outside the influence of the Energy Trust.

- Extend the current tax production incentive to include forest fuels (currently it is limited to closed-loop biomass fuels).
- Develop green tag and green power markets to increase demand.
- Educate and promote the benefits of biomass-generated power to the public.

- Take advantage of the Healthy Forests Restoration Act of 2003, Title II, Section 203, which provides authorization to the Secretary[36] to make grants to facilities that use wood biomass as a raw material to produce electricity to offset the cost of purchasing the wood (up to $20 per green ton delivered). In addition, grants may be made to offset the costs of projects that add value to wood biomass (up to $100,000 per grant).
- Encourage modification of existing forest practices and provide coordination and support among federal agencies, state agencies, landowners, and forest managers to develop practices that will ensure long-term use of forest residue by biomass plants.
- Improve utility acceptance of biofuels projects. This could be done by means of relaxing or standardizing interconnection requirements. A biofuels or renewable portfolio standard would also provide an incentive for utilities to buy biofuel generation and even pay a market-based incentive.
- Ease air permit requirements. Unused waste gases are either flared or released as non-point sources of methane. Either alternative, especially the latter, results in increased air pollution and greenhouse gas emissions. The permitting for waste gas generation systems could be eased to reflect the environmental benefits of this generation source.

1.2 Criteria for Potential Opportunities

In order to identify the key market opportunities in which the ETO can intervene in the market, a set of criteria must be established. Desirable criteria include the following:

- Technical and/or market potential,
- Existing market infrastructure,
- Potential generating capacity, and
- Potential impact of available incentives on developing a sustainable market

Each of these aspects is discussed briefly below in the context of this assessment.

Technical and Market Potential

One key criterion is to determine the potential for near and intermediate term adoption of biomass technologies and opportunities. This entails looking at two components: 1) the available technologies and fuel resources, and 2) the potential adopters who are able and willing to take advantage of the business opportunity. The first of these components was

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[36] "Secretary" refers to either the Secretary of Agriculture with respect to National Forest System lands or the Secretary of the Interior with respect to Federal lands under the jurisdiction of the Secretary of the Interior and Indian lands.

assessed in this study. The second, true market potential was not assessed here and will require more in-depth research in those areas that warrant the effort.

Near term fuel conversion methods include direct combustion, co-firing, and anaerobic digestion. The technologies include boilers, combustors, heat recovery steam generators, fuel cells, microturbines, reciprocating engines, and small gas turbines in the short term. The near and intermediate term conversion technologies include fuel cells and microturbines. These are all currently available technologies in the market. Interviews conducted for this assessment indicated that equipment is not difficult to obtain, provided the project schedule includes at least a one-year lead time.

Available fuel resources must also be considered. Table 5-1on the following page summarizes the initial findings of the major obstacles and estimates the maximum potential generating capacity of the various biomass fuel types considered in this study.

Table 5-1: Comparison of Market Attributes by Fuel Type

Biomass Fuel Type	Current Generating Capacity (MW)[a]	Incremental Generation Resource (MW)[b]	Estimated Range of Energy Production Costs (cents per kWh)[c]	Major Obstacles Rated by End Users and Shown in Order of Descending Severity[d]
Cow manure	0.47	23.5	6.5 to 10+ (on-farm – regional)	Power price (5); capital cost (5); obtaining financing (3.5)
Wastewater biogas	4.17	4.1	4.5 to 8.5[37] [Note: 2.1- 4.0 for O&M only]	Capital cost (3.6); obtaining financing (3.5); fuel cleaning (not rated)
Landfill gas	5.66	31.7	2.9 to 3.6	Air emission requirements (4.5); Local permits (3.75); power price (3.5)
Mill residue	298.40	10.1	5.2 to 6.7	Power price (4.1); power purchase agreement (3.9); cost of buying and/or transporting fuel (Not Rated)
Forest residue		141.7		

[a] Estimates were compiled from data received from the Oregon Department of Energy website and from the U.S. Department of Energy - Energy Efficiency and Renewable Energy website and corrected for specific projects - based upon interviews for this study.
[b] Estimates in TBtu were obtained from the Oregon Department of Energy website and converted to MW using rates obtained from the United States Department of Energy website: http://www.eia.doe.gov/oiaf/analysispaper/biomass/table3.html.
[c] Estimates for landfill and wood were obtained from the Oregon Department of Energy website. The estimate for wood does not include fuel collection/transportation costs or cogeneration costs. Estimates for manure and wastewater are based upon data from survey responses collected for this study.
[d] Ratings are taken from survey responses collected for this study and are presented on a scale of 1 to 5, where 1 means not a problem and 5 means a severe problem.

Market Infrastructure

The market structure in Oregon would need to provide the following services in order to support a sustainable market in biomass-fueled electricity generation:

- **Equipment installation & project design and engineering services.** Respondents in interviews conducted for this study indicated that there are reputable firms available to provide these services. In fact, they stressed that they did not want the ETO or any government or regulatory agency to provide these services, as they preferred to use private firms.

[37] Operating costs for wastewater biogas from an interview of mostly larger wastewater biogas generation facilities in Southern California (0.5 MW to 15 MW) and were reported to be 2.0 to 6.5 cents /kWh. Therefore, costs for the smaller generation systems in Oregon would be marginally higher (estimated at 10% to 30% greater - based upon IC engine unit capacity installed cost information as a function of the system size).

- **Fuel transportation.** This service is lacking for two potential applications: 1) any regional facility that collects waste from multiple areas and 2) any facility using forest residue as a fuel source. For a regional facility, waste can be collected from multiple dairy farms or wastewater plants, but to utilize trucks or a rail system or to build pipelines to conduct the waste to the regional digester would be costly. For facilities using forest residue as a fuel source, collecting and transporting the residue would be costly. Furthermore, the facility would probably need to negotiate with multiple small transportation firms or employ their own labor, as this service is not currently being offered on a large scale.
- **Utility interconnection.** Utility interconnection is a service that will take time to develop as the need grows. Even in California, where self-generation has been heavily incented for years, utilities are still in the throes of developing procedures and experience to deal with the various configurations and needs of self-generation systems. Respondents interviewed for this study whose systems were cogeneration systems reported time-consuming and expensive problems in getting their systems on the grid. Increased demand will force the utilities to respond in a more appropriate manner, but experience in other states shows that it takes time and will be probably be an ongoing problem for years. Furthermore, there is little that incentive programs can do to alleviate the problems other than provide information and support to the customer.
- **Sale of excess generation.** This area consists of two problems for the potential biomass facility developer: 1) negotiating a power purchase agreement with an energy purchaser, and 2) the relatively low market price of electricity in Oregon today. Both of these areas were cited as major problems by respondents interviewed for this study. Furthermore, it was found that the only plants currently operating profitably in Oregon today are those that negotiated long-term contracts in the 1980's and locked in high energy and/or firm capacity prices for the power they generate. Thus, subsidizing the price of electricity is a possible intervention that ETO should consider.
- **Equipment maintenance and support services.** Biomass fuels wreak havoc on the equipment used to process them, necessitating ongoing cleaning and maintenance services. Equipment suppliers typically provide only a one-year warranty. One respondent for this study (a wastewater treatment plant) reported that negotiating a good service agreement was an important component of keeping the plant operating.

Potential Generating Capacity

One key criterion for evaluating potential opportunities is the range of generation capacity for power generation. Assuming the ETO wants to promote the displacement of fossil fuel generated electricity with renewable fuel electricity, projects that can generate more power at a lower overall cost are desirable.

Potential Impact of Incentive on Market

This criterion consists of evaluating the need of the potential opportunity and probably more importantly how much of a difference a reasonable and appropriate subsidy would make on the decision to proceed with the typical project in the Oregon market.

1.3 Summary of Opportunities in Oregon

This assessment and review of the market opportunities for Oregon's biomass resources provides an initial basis for understanding the current market status and lays the ground work for beginning to consider program support options for the various resources, technology options and market support alternatives by the Energy Trust.

Table 5-1 above presented the existing and the potential additional generation capacity from the available biomass fuel resources in Oregon that were reviewed in this study. Although the largest generation potential is forest residues, this resource also is one of the more expensive and difficult renewable energy projects to implement and currently has a number of other related market and institutional barriers and potential benefits (e.g., land/forest management agency coordination and approvals, forest fire suppression benefits, etc.) that first need to be addressed by a number of agencies at the state and federal level.

Landfill biogas and dairy/feedlots manure digesters provide the next highest additional potential for biomass generating resources, and in the case of landfill biogas, with a much lower production cost. Incenting the remaining landfills and/or wastewater plants in the state that are not already generating their own power through either *a production incentive or capital cost Buydown* might be a suitable use of ETO's available renewable program incentive dollars. The risks and potential benefits in these two approaches are discussed in Section 6 (Recommendations).

6

Program Recommendations

This section provides the Energy Trust preliminary recommendations for potential renewable program element design options resulting from this biomass market assessment. This first phase of research was meant to provide a preliminary look at market opportunities and obstacles, and a second phase is expected to examine these findings and recommendations more closely. The recommendations presented for the Energy Trust to consider include three areas:

- Target biomass markets,
- Program intervention options, and
- Recommendations for more focused research

Each of these topics is discussed below. Note that our recommendations presented here are necessarily limited in nature by the Phase I scope (and budget) for this market research. More detailed program design and options evaluation are intended following the completion of this work and subsequent to a more focused program planning and development effort during a subsequent phase of this work.

1.1 Areas to Target

The following are the potential resource and market areas considered in this assessment where a biomass incentive support program might intervene in order to develop a sustainable market:

- Dairy farms,
- Landfills with gas collection systems,
- Municipal wastewater treatment plants,
- Wood product and paper mills,
- Regional dairy/cattle digesters, and
- Regional wood burning plants using forest and/or mill residues.

In deciding the most opportune areas to target with limited program resources, considerations must be made for the potential impact the program might have on the market along with the potential for either “free ridership” and/or “spillover” effects that may result from the program.

Renewable program administrators interviewed for this study most frequently suggested *methane digesters at dairy farms* as the biomass segment in which to focus a new program. Secondly, administrators recommended focusing on landfills, and then wastewater treatment plants, and then next recommended mill residue/wood chipping plants.

Forest residue generation facilities were the least mentioned biomass resource market development opportunity by the administrators. This may be due to the need for this type of biomass generating resource to address a number of market and project development issues before sufficient and sustainable activity can be expected. For example, cooperation with state and/or federal forest management officials (and possibly private forest landowners as well) will need to be coordinated before a regional wood burning plant that uses forest residue can be sited and permitted and thus feasible. Therefore, it is unlikely that a financial incentive offered by the Energy Trust in the short term will have a large impact on this market, although such an incentive (production incentive or capital cost buydown) will certainly be needed if the other resource planning and development elements fall into place.

Similarly, the regional animal/dairy waste digesters must conquer their fuel/waste collection and residuals transportation problems and then find a way to transport the collected waste more cost effectively. Again, a financial incentive from the Energy Trust will likely help that effort, but probably would not effect a large and sustainable change in the market – which currently consists of a single 4000 animal unit facility.

Dairy farms face the hurdle of paying the up front cost of the digester and probably more importantly, learning how to properly operate and maintain the system. One dairy digester facility in Oregon recently shut down. A “market-based” production incentive that maintains an overall revenue stream from electricity generation of at least 6.5 to 7 cents per kWh may make the most sense for the on-farm dairy digesters. Further stakeholder input and related project-level economic analysis should be performed for on-farm digesters before setting either a energy production-based incentive level or a $ per kW capacity-based buydown.

Therefore the areas where the Energy Trust expanded program impact will potentially be greatest in the short- and intermediate-term[38] include: 1) existing landfills with gas collection systems in place, 2) wastewater treatment plants with existing operating digesters, 3) dairies with more than 300 to 500 animal units, and 4) wood product and paper mills with available woody biomass residues.

38 Considering program interventions for the long-term was not included in the scope of this study.

1.2 Program Intervention Options

Based on the interviews conducted for this study with existing end-users, suppliers, and administrators of renewable energy programs in other states, the most cost-effective intervention at this time would be a production incentive targeting one or more of the target markets mentioned above. The production incentive level should vary according to the average cost of production for the various technologies and fuel types. For example, it is more expensive to produce electricity by burning wood wastes than it is to produce it by burning landfill gas or wastewater biogas; thus a higher incentive level ($/kWh) would be needed to incentivize wood-waste/mill residue projects. Further, the incentive structure should have maximum values (i.e, caps) on each facility as well as parent corporations, in order to prevent one large facility (or parent corporation) from consuming a majority of biomass program funds. One alternative for the Energy Trust to consider within the production incentive program option, is not to necessarily limit the target markets to just one or two resource/technology areas (i.e., reciprocating engines using landfill gas, and engines/microturbines/fuel cells using digester gas from wastewater treatment plants or dairies) – but to put forth an open and transparent competitive solicitation for production incentives, where potential biomass resource developers submit their bid price for the production incentive over a fixed period (e.g., 5 or 7 years) that will make sense for their project – subject to a maximum $/kWh price cap that is specified in the RFP. Although this variation is more costly to administer than either a capital cost buydown or a conventional production incentive, is has the advantage of leveraging the maximum amount of biomass generation within a given amount of the Trust's program resources.

The other primary incentive option is the direct *buydown* of the initial capital cost outlay (determined on a $ per kW and/or percentage of project installed eligible cost basis) that is paid after the facility demonstrated to the Trust that it can operate at its rated level of performance. This form of program financial support for targeted renewable energy projects remains the most common in the US today. The main advantages of the buydown approach include its relative ease of administration, ability to target the buydown level for each fuel and technology option, based on its demonstrated needs. The main disadvantage of the buydown is that it does not necessarily provide the optimal amount of support for a given project site and application and it does not directly provide a market mechanism to eventually drive down the cost of new biomass projects (this can be accomplished with a scheduled reduction in the incentive level – but the timing of the reductions can be very difficult to predict given the many variables in the market.

Additionally, a promotion/informational campaign for new biomass- and biogas-generated electricity branded as *green power* with the associated positive impacts to the environment would benefit system developers in marginal ways. A greater general public acceptance and knowledge of the benefits of these systems might help developers with siting, permitting and financing issues, as well as further promote the green power market in the state.

It should be noted that both end-users and program administrators reported that technical assistance is not something the program should seek to provide. They explained that there are already many qualified engineering firms that offer their technical expertise and project development experience in these areas. Further, many developers would not welcome a state agency directing or planning their project.

1.3 Recommendations for Further Research

A second phase of follow-on research would allow a more targeted and in-depth analysis to determine the most appropriate type and amount of the incentive; and in addition the potential effect the incentive would have on each target market. Therefore, the following areas for additional research and analysis are suggested:

- Public Input from Stakeholders on *Strawman* program support option(s),
- Analysis of key market response and sustainable development opportunities,
- Discussion of current and needed future state policy considerations, and
- Additional industry and/or consumer support.

Each of these areas is discussed briefly below.

Public Input from Stakeholders on Potential Program Support Options. Before proceeding further with a final program design, the Energy Trust should present a strawman program structure that is supported by the Energy Trust's Renewable Advisory Committee and then hold one or more public workshops to gain added input on the potential program support options. This direct input from the industry and utility end-users would help form the basis for the final step of determining the best type, approach and levels of program support.

Analysis of Key Market Development Opportunities. This subsequent effort will allow a more in-depth analysis of key market development opportunities. Areas to research include the following: 1) the timing for program interventions, 2) the amount of program incentives to be made available on an annual basis, 3) the expected impact on the market, 4) the availability of suppliers and service firms, 5) a refined estimate of production cost per kWh of electricity (or some alternate cost-effectiveness indicator), and 6) the need for any other types of market development assistance. Public workshops and/or roundtable discussions with key industry stakeholders could be held to ensure major issues are understood and cooperation amongst industry groups will be forthcoming.

Discussion of State Policy Considerations. This effort would entail a review of current policy and assessment of future energy policy implications to ensure the new program supports existing and near-term state energy policy in Oregon.

Additional Industry and/or Consumer Support. This effort will gather information to consider and assess the need for other forms of industry support, including consumer education, promotion of green power in general and biomass-generated power in particular, assistance with utility net metering, interconnection and cooperation issues, assistance with regulatory agencies, and finally assistance with locating and successfully obtaining project financing.

Appendix A

Organizations Interviewed

Table 0-1 presents the sample of program administrator interviewed for this study.

Table 0-1: Program Administrator Sample

Organization	Program Name	State	Contact Name
DOE Northwest Office	Pacific Regional Biomass Program	WA	Kim Penfold and Jeff James
Energy Trust of Oregon	ETO Renewables Program	OR	Peter West
Green Mountain Energy	Green Source		John Savage
New Jersey Board of Public Utilities	Clean Energy Program	NJ	Cassandra Kling
PacifiCorp	Blue Sky Energy	OR	Bob Stull
San Diego Regional Energy Office	Self Generation Incentive Program	CA	Nathalie Osborn
WI Dept of Admin, Division of Energy	Focus on Energy	WI	Don Wichert
Portland General Electric		OR	Joe Barra
Bonneville Power Administration	Conservation and Renewables Discount Program	NW	Tom Osborn
Northwest PPC		NW	Jeff King
Oregon DOE		OR	John White
3 Phases Energy		US	Dan Kalafatas
California Energy Commission	Renewable Energy Program New Account--Production Incentive	CA	Suzanne Korosec,
California Energy Commission	Renewable Energy Program Existing Account Support	CA	Tony Goncalves Program Manager

As shown, the sample consisted of 14 respondents from both inside and outside Oregon and include true program administrators, green energy marketers, and government agency staff. Three of the interviews took place in person, and the rest were completed by telephone.

Table 0-2 below, presents the sample of suppliers interviewed for this study.

Table 0-2: Supply Channel Interview Sample

Supplier Name & Category	Fuel Type	Generation Technology	System Size Range
Caterpillar/Mfgr	Any biogas	Recip. engines	
Jenbacher/ Mfgr	Any biogas	Recip. engines	
Solar Turbines/ Mfgr	Any biogas	Small Gas turbines	3-15 MW
UTC Power/ Mfgr	Any biogas	Fuel Cell	200 kW+
Bryan & Bryan/ Mfgr Rep. & Service	Various	Various	Various
CH2MHill / A&E Services	All biomass fuels	All Technologies	Various
Ag-Pro/Five G Consulting/ Mfgr & A&E Services	Dairy biogas	Various	50 – 500 kW
Proctor Sales/ Mfgr Rep. & Service	Biomass hard fuels	Various	
Dubal & Associates/ A&E Services	Biomass hard fuels	Steam/gas turbines	Various
Brown & Caldwell Engineers/ A&E Services	WWT/landfill biogas	Recip. engines, small GT, microturbines	
Cole Industrial/ Mfgr. Rep. & Service (Cleaver Brooks Rep)	Any biogas	Various	
Resource Conservation Management/ A&E Services	Dairy & Swine biogas	Recip. Engines	< 200kW
Ingersol Rand PowerWorks/ Mfgr	All biogas	Micro-turbines/gas clean-up systems	< 200 kW/unit

Respondents were senior managers and product engineers from suppliers of electrical generation and cogeneration equipment that can use biomass-based fuels to produce electricity. The suppliers interviewed represented a range of technology types (reciprocating engines, gas turbines, steam turbines, microturbines, fuel cells (PAFC) and boilers/steam generators). Fuel sources represented in the sample include biogas from anaerobic digesters (both animal waste and municipal wastewater treatment plants), biogas from landfill off-gas collection systems, and direct combustion of forest and mill residues. Four of the interviews took place in person, and the remainder was completed over the telephone.

Table 0-3: End User Interview Sample

Facility Name	Fuel Type	Location	Reported System Size
Oregon Biomass Facilities:			
Calgon Dairy Farm Digester	Cow manure	Salem	50 kW
Port of Tillamook Bay MEAD Project	Cow manure	Tillamook Bay	400 kW
Coffin Butte Resource Project	Landfill gas	Corvallis	2.5 MW
Short Mountain Landfill Gas Project	Landfill gas	Eugene	3.2 MW
Boise Cascade	Wood	Medford	8 MW
SP Newsprint	Wood	Newberg	25 to 30 MW
Weyerhaeuser	Wood	Albany	50 MW
Port of Morrow	Wood	Heppner	10 MW
Biomass I	Wood	White City	25 MW
Warm Springs Forest Products	Wood	Warm Springs	3 MW
D.R. Johnson Cogen II	Wood	Riddle	11 MW
Clackamas Wastewater Treatment Plant	Wastewater gas	Milwaukie	100 kW
City of Portland Wastewater Treatment Plant	Wastewater gas	Portland	170 kW
Salem Wastewater Treatment Plant	Wastewater gas	Salem	600 to 650 kW
Tri City Wastewater Treatment Plant	Wastewater gas	Oregon City	
Informational and Potential Development:			
Sustainable Energy Development, Inc.	Wood		
Los Angeles County Sanitation Districts	Landfill and Wastewater gas		
Oregon Dept. of Forestry	Wood		
3 W Energy, Inc.	Wood		

Respondents were managers or engineers from 15 existing facilities in Oregon that use biomass-based fuel to produce electricity. Several other industry stakeholders were also included in the sample to provide information on the industry and potential developments. A total of 18 interviews were completed with organizations that represented a variety of fuel types, including cow manure, wastewater gas, landfill gas, and wood. Wood plants consisted of wood and paper mills and one dedicated plant. Nine of the interviews took place in person, and the rest were completed over the telephone.

Appendix B

Interview Guides

Interview guides for the following sample groups were used in the research and are attached as individual files:

- Renewable/Clean Energy Program Administrators,
- Biomass/Biogas Technology Suppliers/Service Providers, and
- Project Owners / End-users of Biomass/Biogas Energy Projects.
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Energy Trust of Oregon Biomass Assessment Program

Renewable/Clean Energy Program Administrators Survey

FIRM NAME:______________________ CONTACT: ________________________
PHONE #: ________________________ TITLE: ____________________________
DATE:___________________________ INTERVIEWER: ____________________

1.4 Introduction

Hello, my name is ______________ and I'm calling on behalf of the Energy Trust of Oregon. We are investigating the potential market for biomass based electric power in Oregon. I would like to ask you some questions regarding your experience to date with renewable energy programs. Are you available now or would another time be better for you? My questions will take about half an hour of your time.

[Note scheduled date/time – if required]: _______________________________________

[If respondent has concerns about legitimacy of the survey, provide them with following contact:]

- Ms. Sherry Secreast
  Energy Trust of Oregon
  1-503-493-888 ext. 227

1.5 General Program Discussion

First, I'd like to obtain some basic information about your program:

1. Please describe your Renewable/Clean Energy Program (or ask to confirm if details are known):
   a. Program name:
   b. General description:
   c. Resources/Technologies included and why
   d. Target market (Res/Commercial-Industrial/Ag) and why you chose to target this market
   e. Geographic area:

f. Primary Program outreach activities (and why you use these)
g. Type of Incentives offered (Buydown/Production incentive/loan) and why you chose that type of incentive
h. Types of training offered and why you chose to offer this:
i. Technical assistance offered and why you chose to offer this:
j. YR/MO program was initiated:
k. Source and annual amount of program funds:
l. Number of Years funding is currently authorized:
m. Number of Program participants to date: (list by resource/technology and program year)

2. What about your program would you change if you were redesigning it? And Why?

3. (Only If respondent is familiar with the Oregon market) At present, biomass technology for producing electricity or cogeneration is not widespread in Oregon, Why do you think this is the case?

4. (Only If respondent is familiar with the Oregon market) Are there certain areas of the state where you believe it would be more feasible or cost effective to develop biopower facilities? If yes, would you describe these areas and the main reasons for higher feasibility?

5. How would you describe the general level of awareness of biomass technology among your target market(s)? Would you say it is:
   1= low
   2= medium
   3 = high
   Why do you say that?

6. In your opinion, which market sector (e.g. industrial, agricultural) or subsector (e.g. dairy farms) would be best to focus on for a new biomass incentive program?

7. Based on your experience over the past several years, in what ways have the local distribution companies (i.e., utilities) been receptive and helpful regarding new distributed generation systems? In what ways have they been non-receptive or impeded new systems coming online?

8. In your opinion, how could a new market expansion support program best be used or designed to assist the development of new biopower projects and facilities? (Probe for areas where support is needed such as:)

a. Obtaining raw biomass input (e.g., resource acquisition cost, transportation)
b. Project planning and/or design
c. Technical assistance
d. Obtaining permits or environmental approvals
e. Incentives or Rebates on installation costs or other
f. Financing programs
g. Assistance with utility interconnection
h. Assistance with educating target markets about the existence and/or advantages of biomass project development
i. Assistance identifying target markets or customers
j. Other (identify)

Which **two** of the above types of support do you think would be most helpful?

Are there any policy considerations we should be aware of that affect your response to this question?

9. Are there other programs in your area that address these needs? (If so, get program name and contact information.)

10. (Only if familiar with Northwest market) Regarding Q#8 above, are you aware of any current programs in the Northwest that address any of these areas? If yes, which ones? Who sponsors and/or administers the program(s)?

11. In your opinion, what are the most problematic issues faced in developing biomass/biogas projects? (For each problematic issue, prompt for description and extent of problem)

    For each of the following, please rate the extent in which this issues inhibits project development using a scale of 1 to 5, where 1 means *Not A Problem* and 5 means *A Severe Problem*.

    a. Planning or siting
    b. Obtaining financing
    c. Local permit approvals
    d. Environmental approvals

e. Utility interconnection
f. Equipment delivery
g. Equipment warranty
h. Net metering requirements
i. Power purchase agreement
j. Power price
k. Up front cost
l. Other :

12. To what extent are utility *special facilities* charges or *interconnection fees* a hindrance to developing new biomass/biogas projects? (Describe nature or basis) Does this vary by utility or by type of project, or both?

13. To what degree, in your opinion, do some types of biomass fuels negatively affect equipment life or system performance? (Describe nature of impact(s) and on what types of equipment)

14. To what degree do you think harmful emissions from burning certain biomass fuels creates an image problem for this industry? (If some degree is indicated, probe how much of an issue is this? Who is concerned? To your knowledge, has this issue hindered specific projects from going forward? Ask to describe these examples)

15. What are some of the key lessons you have learned from implementing your program? (be sure that discussion includes design, marketing, implementation, other)

16. What are the most important pieces of advice you would give to an entity starting a biomass market development program now?

17. What types of methods would you suggest to provide incentives for market development for biomass/biogas resources? Why?

    a. Equipment purchase and installation services technical support
    b. Fuel supply and/or cost analysis
    c. Operating and maintenance services support
    d. $ per kWh Production incentives

e. Capital cost buydown/rebate
f. Low interest (below market) loan
g. Other (Specify)

18. Does the green tag market have an influence on the renewable/clean energy industry? If so, how?

19. Finally, we would like to talk to as many programs and individuals with knowledge and experience in this area in our study. Do you know of other programs or individuals we should talk to (especially in the PNW, California, Wisconsin, New Jersey, and New York)?

    If yes: record names and contact information

Do you have any other comments you would like to share before we conclude:

May I call you back if I have any clarifying questions?

(If respondent asks for copy of results) We will notify you when the program findings are complete and how to obtain copies of the final report.

Thank you again for participating in this discussion about your Renewable/Clean Energy Program.

Energy Trust of Oregon Biomass Assessment Program

Biomass/Biogas Technology Suppliers/Service Providers Survey

FIRM NAME:______________________ CONTACT: ________________________
PHONE #: ________________________ TITLE: ____________________________
DATE: ___________________________ INTERVIEWER: ____________________

1.6 Introduction

Hello, my name is ______________ and I'm calling on behalf of the Energy Trust of Oregon. We are investigating the potential market for biomass based electric power in Oregon. I'd like to ask you some questions regarding your experience to date with biomass projects. Are you available now or would another time be better for you? My questions will probably take about half an hour of your time.

[Note scheduled date/time – if required]: ____

[If respondent has concerns about legitimacy of the survey, provide them with following contact:]

- Ms. Sherry Secreast
  Energy Trust of Oregon
  1-503-493-8888 ext. 227

1.7 General Discussion

First, I'd like to obtain some basic information about your company/equipment:

a. Please describe the equipment or service(s) your company provides. (Probe for technology applications)
b. What is your role/ involvement in project planning or development?
c. What geographic region does your company serve?
d. What types of businesses are your customers?
e. How long has your company been involved in the biomass market?
f. How long has your company been in business?
g. Who are your main allies and/or competition in this market? (Probe for local or regional firms. Others in US market?)

The remaining questions I'll ask you have to do with the potential for developing biomass facilities within Oregon that would produce electricity, either to be sold through the grid (via wholesale markets) or used onsite (self-generation or co-cogeneration applications).

1. At present, biomass technology for producing electricity or cogeneration is not widespread in Oregon (i.e., low market saturation vs. technical potential); Why do you think this is the case?

2. Which areas of Oregon do you think are most suitable for bio-power project development? Why is this the case?

3. How readily available is the equipment or service(s) you provide in the current bio-power market? [If not available, explore reasons why (Probe for issues related to environmental regulations, manufacturing, distribution, customer demand, availability of financing, etc.)]

4. How would you describe the general level of awareness of biomass technology and opportunities among your potential customers? Would you say it is:
   a. Low
   b. Medium
   c. High

   Why do you say that?

5. Based on your experience over the past several years, in what ways have the local distribution companies (i.e., utilities) been receptive and helpful regarding new distributed generation systems? In what ways have they been non-receptive or impeded new systems coming online? [Probe for differences in simply meeting utility interconnection requirements vs. true non-receptive response to projects.]

6. In your opinion, how could a new state-subsidized program best be used/designed to assist the market development for new bio-power projects and facilities? (Probe for areas where support is needed.)

   a. Obtaining raw biomass input (collection cost, transportation, etc.)
   b. Project planning & design
   c. Specialized technical assistance
   d. Obtaining environmental permits

e. Incentives or Rebates on installation costs or other financing programs
f. Assistance with utility interconnection requirements/approval
g. financing programs
h. Assistance with educating target markets about the existence and/or advantages of biomass project development
i. Assistance identifying target markets or customers
j. Other (specify)

Which **two** of the above types of support would be most helpful for your business?

Are there any other policy considerations we should be aware of that affect your response to this question?

7. Are you aware of any programs currently available that address these areas (Referring to answer to above question)? If yes, what programs? Who sponsors and/or administers them?

8. ***(If yes)*** Have you participated in any of these? (Which? In what year(s)?)

9. ***(If yes)*** To what extent did this (these) program(s) meet your expectations? What did you like and/or dislike about the program(s)?

10. In your opinion, what are the most problematic issues faced in developing biomass/biogas projects? a) For your business? b) For your customers?

11. For each of the following, please rate the extent in which this issue is problematic to you in developing a biogas project. Use a scale of 1 to 5, where 1 means *Not A Problem* and 5 means a *Severe Problem*. [Probe for specific issues ratings = 4 or 5]

Development Issue	Your company (1-5)	For customers (1-5)
a. Planning or siting		
b. Obtaining financing		
c. Local permit approvals		
d. Environmental approvals		
e. Utility interconnection		
f. Equipment delivery		

g. Equipment warranty
h. Billing/Net metering(self-gen.)
i. Power purchase agreement
j. Power price
k. Up front cost
l. Other

12. To what extent are utility *special facilities* charges or *interconnection fees* a hindrance to developing new biomass/biogas projects? (Use a scale of 1 to 5, where 1 means *Not A Problem* and 5 means a *Severe Problem*.) [Probe for specific issues ratings = 4 or 5; Describe nature or basis of issue; Does this vary by utility or by type of project, or both?]

13. Have you experienced difficulties with certain biomass fuels with regard to erosion or corrosion of heat exchanger materials or other equipment problems? (If yes, what difficulties have you experienced?)

14. Have air emissions or emission controls been problematic in developing or operating biomass plants? If so, to what extent has the fuel type influenced these problems? (Describe)

15. What are the typical biomass generation costs for the types of projects your company develops?
    a. Overall installed cost per kW?
    b. Fuel Cost ($/BDT or $/kWh)?
    c. Annual operating and maintenance ($/kW-Yr or $/kWh)?

16. What drives these costs? What are the most critical installed capital cost and O&M cost factors?

17. Has the fuel supply and price been stable over the past several years?

Do you have any other comments you would like to share before we conclude:

May I call you back if I have any clarifying questions?

(If respondent asks for copy of results) We will notify you when the program findings are complete and how to obtain copies of the final report.

Thank you again for participating in this discussion about your Biomass/Biogas Technology/Equipment.

Energy Trust of Oregon Biomass Assessment Program

Project Owners / End-users of Biomass/Biogas Energy Projects Survey

FIRM NAME:_______________________ CONTACT: _________________________
PHONE #: _________________________ TITLE: _____________________________
DATE:____________________________ INTERVIEWER: _____________________

1.8 Introduction

Hello, my name is ______________ and I'm calling on behalf of the Energy Trust of Oregon. We are investigating the potential market for biomass based electric power in Oregon. I'd like to ask you some questions regarding your experience to date with biomass projects. Are you available now or would another time be better for you? My questions will probably take about half an hour of your time.

[Note scheduled date/time – if required]: ____

[If respondent has concerns about legitimacy of the survey, provide them with following contact:]

- Ms. Sherry Secreast
  Energy Trust of Oregon
  1-503-493-8888 ext. 227

1.9 General Discussion

1. First, I'd like to obtain some basic information about your company and the biomass system that you operate.
   a. Please describe the nature of your business.
   b. How long have you been in business?
   c. How many employees work at this location?
   d. Do you have other locations? If so, describe where and approximate size.
   e. How does your use of biomass fit into your company's overall operations?
   f. How much of your total electricity use at this location does the biomass system provide?

g. Please describe the biomass system your company operates.(Probe for technology and fuel types)
    i. Please provide the name of your equipment supplier and/or service/maintenance firm that you dealt with
h. What are the uses for the power created by your system?
i. What is the nameplate capacity and typical output of your biomass plant?
j. Is your system connected to the grid? (If yes, explore whether this was from the beginning or occurred later? If no, why not? Are they still considering it? If not still considering, why not?)
k. What was the extent of your involvement in planning and developing this project?
l. When you were in the planning stages, what were the major factors that influenced you and your company to go ahead with this project? What barriers did you encounter, if any? How were these overcome?
m. When did your system start normal operations? Has the system worked at full capacity since that time? If no, explore variability or ramp up.

2. In your opinion, what are the most problematic issues faced in developing biomass/biogas projects? For each problematic issue, prompt for description and extent of problem

3. For each of the following, please rate the extent in which this issue inhibits project development using a scale of 1 to 5 where 1 means not a problem and 5 means a severe problem.
    a. Planning or siting.
    b. Obtaining financing.
    c. Local permit approvals
    d. Environmental approvals
    e. Utility interconnection
    f. Equipment delivery
    g. Equipment warranty
    h. Billing/Net metering requirements
    i. Power purchase agreement

j. Power price
k. Up front cost
l. Other

4. In your opinion, in what ways have the local distribution companies (i.e., utilities) been receptive to new distributed generation systems? In what ways have they been non-receptive?

5. To what extent are utility *special facilities* charges or *interconnection fees* a hindrance to developing new biomass/biogas projects? (Use a scale of 1 to 5, where 1 means *Not A Problem* and 5 means a *Severe Problem*.) [Probe for specific issues ratings = 4 or 5; Describe nature or basis of issue]

6. Do you believe biomass is a "green" (environmentally friendly and sustainable) energy generating opportunity? If no, why not?

7. Have you experienced operating or equipment difficulties because of your biomass fuel feedstock? If yes, what difficulties have you experienced?

8. Have air emissions or emission controls been problematic in developing or operating your biomass plant? If so, to what extent has the fuel type influenced these problems? (Describe)

9. What are your biomass generation costs for the types of projects your company develops?
    a. Overall installed cost per kW?
    b. Fuel ($/kW)?
    c. Are there avoided waste disposal costs? If yes, please estimate.
    d. Annual operating and maintenance ($/kW)?
    e. Insurance Costs ($/kW)?

10. What drives these costs? What are the most critical installed capital cost and O&M cost factors?

11. Has the fuel supply and price been stable over the past several years?

12. At present, biomass technology for producing electricity or cogeneration is not widespread in Oregon, Why do you think this is the case?

13. In your opinion, are there certain areas of the state where it would be more feasible or cost effective to develop biopower facilities? If yes, would you describe these areas and the main reasons for higher feasibility?

14. In your opinion, how could a new state-subsidized program best be used/designed to assist the development of new biopower projects and facilities? (Probe for areas where support is needed such as:

    a. Obtaining raw biomass input (cost, transportation)
    b. Project design
    c. Technical assistance
    d. Obtaining permits
    e. Incentives or Rebates on installation costs or other financing programs
    f. Assistance with utility interconnection
    g. financing programs
    h. Other

Which two of the above would be most helpful for you?

15. Are you aware of any programs currently available that address these areas (referring to answer to above question) or others? If yes, which? Who sponsors and/or administers the program(s)?

    a. (if yes) Have you participated in any of these? (Which? What year?)

    b. (If yes**)** To what extent did this (these) program(s) meet your expectations? What did you like and/or dislike about the program(s)

    c. (If yes) In programs you have seen, do you think the incentives offered are sufficient to make it worthwhile to join a program? If no: What incentives would make it worthwhile?

16. What are some of the key lessons you have learned from participating in a program?

17. Do you have any experience with sales or marketing of green tags?
    a. (If yes) Did it affect your decision to install your biogas system?

Do you have any other comments you would like to share before we conclude:

May I call you back if I have any clarifying questions?

(If respondent asks for copy of results) We will notify you when the program findings are complete and how to obtain copies of the final report.

Thank you again for participating in this discussion about Biomass/Biogas Energy Projects.

Appendix C

Suppliers

Biomass Technology Suppliers

Near Term Technologies

- **Anaerobic Digestion Equipment**
  - Anaerobics
  - Biogas Nord GMBH
  - BTA - Biotechnische Abfallverwertung GMBH & Co KG
  - Environmental Power Corporation
  - Farmatic Biotech Energy AG
  - Kompogas AG
  - Resource Conservation Management
  - Enviroquip Inc.
  - Ondeo Degremont, Inc.
  - Smith & Loveless, Inc.
  - Temcor
  - US Filter

- **Reciprocating Engine Manufacturers**
  - AVS Aggregatebau GMBH
  - Caterpillar
  - Cummins
  - Dresser
  - Grupo Guascor
  - Jenbacher
  - Man B&W Diesel AG
  - Rolls-Royce PLC
  - Tessari M.D.
  - Wartsila Corporation
  - Westport Innovations
  - Mitsubishi Heavy Industries

- **Small Gas Turbine Manufacturers**
  - Pratt & Whitney
  - Rolls Royce
  - Schelde Heron
  - Solar Turbines
  - Turbomach SA
  - Vericor Power Systems

- **Boiler Manufacturers (Fire Tube (FT), Small Watertube (WT), Heat Recovery Steam Generator (HRSG)**
  - Patterson-Kelley
  - AESYS Technologies, LLC (FT)
  - Burnham Commercial (FT)
  - Cleaver-Brooks Division/Aqua-Chem, Inc. (FT)
  - Easco Boiler Corporation (FT)
  - Johnston Boiler Company (FT)
  - Precision Boilers, Inc. (FT)
  - Sellers Engineering Company (FT)
  - Superior Boiler Works, Inc. (FT)
  - The McBurney Corporation (FT)
  - Trenergy, Inc. (FT)
  - AESYS Technologies, LLC (WT)
  - Bryan Boilers (WT)
  - Cleaver-Brooks Division/Aqua-Chem, Inc. (WT)
  - English Boiler & Tube, Inc. (WT)
  - Trenergy, Inc. (WT)
  - Vapor Power International LLC. (WT)
  - AESYS Technologies, LLC (HRSG)
  - Alstom Power, Inc. (HRSG)
  - Chanute Manufacturing Company (HRSG)
  - Deltak LLC (HRSG)
  - Fintube Technologies, Inc. (HRSG)
  - Innovative Steam Technologies (HRSG)
  - Nebraska Boiler/Energy Recovery International/Div. of Aqua-Chem, Inc. (HRSG)
  - Nooter/Eriksen, Inc. (HRSG)
  - RENTECH Boiler Systems, Inc. (HRSG)

- Titan Fabricators, Inc. (HRSG)
- Trenergy, Inc. (HRSG)
- Vogt Power International, Inc. (HRSG)
- Wagner Plate Works (HRSG)

Near Term and Intermediate Term Technologies

- **Microturbine Manufacturers**
  - ALM Microturbine (Washington, DC)
  - Bowman Power Systems Limited
  - Capstone Turbines
  - Elliott Energy Systems (Stuart, Florida - develops and manufactures a range of microturbine generators)
  - Ingersoll-Rand PowerWorks
  - Turbec AB (Malmö, Sweden)
  - *Honeywell (left the market - interview to understand reasons for their departure)*

Intermediate Term and Long Term Technologies

- **Fuel Cell Manufacturers**
  - AFCO (Ansaldo Fuel Cells SPA, Italy)
  - Fuelcell Energy
  - IHI (Ishikawajima-Harima Heavy Industries, molten carbonate fuel cells, Japan)
  - Siemens Westinghouse Power Corporation
  - UTC Fuel Cells
  - Avista Labs
  - Ballard
  - Dais-Analytic
  - Energy Partners
  - Global Thermoelectric
  - H-Power
  - Ida Tech
  - International Fuel Cells
  - Nuvera
  - Plug Power

Service Providers

- **Engineering / Construction Management Firms**
  - CH_2MHill
  - Brown & Caldwell
  - HDR Engineering
  - Black & Veatch
- **Local installers and Service Maintenance Firms**
  - Stewart & Stevens
  - Holden

Appendix D

Existing Facilities in Oregon

Operational Landfills in Oregon

Landfill Name	Landfill City	Waste In Place (tons)	Landfill Owner Organization	Project Developer Organization	LFGE Utilization Type (Direct-Use vs Electricity)	LFGE Project Type	MW Capacity	Emission Reductions ($MMTCO_2E$)	Comments
Coffin Butte LF	Corvallis	4,500,000	Allied Waste Industries	Pacific Northwest Generating Cooperative	Electricity	Reciprocating Engine	2.4	0.102	This project, which the Pacific Northwest Generating Cooperative manages on behalf of 12 electric utility cooperatives, generates "green power" from a landfill near Corvallis, Oregon. Methane gas is harvested from the landfill and is used to power generators that produce enough electricity annually to serve an estimated 2,000 households.
Riverbend Landfill Company, Inc.	McMinnville	2,500,000	WMI	RECO	Direct	Leachate Evaporation		0.189	
Short Mountain LF	Eugene	3,410,000	Lane County	Emerald People's Utility District	Electricity	Reciprocating Engine	3.2	0.135	The Short Mountain Project's first phase became operational on February 18, 1992, 9 months after signing the contract for construction. The project's total cost was $2.6 million. The project generates about 20 million kilowatt-hours and approximately 3.2 megawatts annually - this is the equivalent of nearly 22,000 barrels of oil per year. The project provides enough electricity to power about 1,400 homes. This project will continue to produce electricity for about another 20 years.
St. Johns LF	Portland	12,000,000	Portland Metro	Palmer Capital Corporation	Direct	Direct Thermal		0.414	

Source: U.S. Environmental Protection Agency, http://www.epa.gov/lmop/proj/index.htm#1

Operational Publicly Owned Wastewater Treatment Plants in Oregon

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Baker	BAKER CITY STP	Baker City	9,880	13,350	1.4	2	2
Baker	HAINES STP	Haines	480	634	0.03	0.06	0.06
Baker	HALFWAY STP	Halfway	399	516	0.07	0.12	0.12
Baker	HUNTINGTON STP	Huntington	580	766	0.05	0.095	0.095
Baker	RICHLAND STP	Richland	175	231	0.02	0.036	0.036
Baker	SUMPTER STP	Sumpter	175	231	0.01	0.04	0.04
Baker	UNITY STP	Unity	165	218	0.02	0.04	0.04
Benton	ADAIR VILLAGE STP	Adair Village	672	916	0.07	0.318	0.318
Benton	ALPINE STP	Alpine	191	246	0.02	0.02	0.02
Benton	CORVALLIS STP	Corvallis	50,000	66,028	7	9.7	9.7
Benton	MONROE STP	Monroe	539	666	0.118	0.09	0.09
Benton	PHILOMATH STP	Philomath	4,650	6,140	0.5	0.475	0.475
Clackamas	CANBY STP	Canby	13,170	15,000	1	0.85	0.85
Clackamas	ESTACADA STP	Estacada	2,250	3,605	0.506	0.54	0.54
Clackamas	GOVERNMENT CAMP STP	Government Camp	721	1,777	0.11	0.13	0.13
Clackamas	HOODLAND/RHODEDENDRON STP	Rhododendron	4,000	5,282	0.203	0.9	0.9
Clackamas	KELLOGG CREEK STP	Oregon City	21,280	28,102	7.975	10	10
Clackamas	MOLALLA STP	Molalla	5,770	13,370	0.799	0.79	2.1
Clackamas	OAK LODGE STP	Milwaukie	35,553	46,443	4.2	4	4
Clackamas	SANDY STP	Sandy	5,655	7,467	0.5	0.5	0.5
Clackamas	TRI CITY STP	Oregon City	55,100	72,763	8.093	8.4	8.4
Clackamas	TRYON CREEK STP	Lake Oswego	51,998	60,791	6.98	8.3	8.3
Clackamas	WILSONVILLE STP	Wilsonville	13,615	17,979	1.8	2.25	2.25
Clatsop	ARCH CAPE STP	Arch Cape	268	354	0.068	0.15	0.15
Clatsop	ASTORIA SEWAGE TREAT PL	Astoria	10,000	12,200	4.2	4.2	4.2
Clatsop	CANNON BEACH STP	Cannon Beach	12,181	15,299	0.514	0.68	0.68
Clatsop	SEASIDE STP	Seaside	11,820	15,014	0.9	2.25	2.25

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Clatsop	SHORELINE SD STP	Warrenton	300	362	0.03	0.05	0.05
Clatsop	WARRENTON STP	Warrenton	6,310	8,333	0.644	0.45	0.45
Clatsop	WESTPORT STP	Wauna	238	614	0.027	0.07	0.07
Columbia	CLATSKANIE STP	Clatskanie	1,900	2,509	0.2	0.5	0.5
Columbia	RAINIER STP	Rainier	1,835	2,423	0.309	0.5	1.2
Columbia	SCAPPOOSE STP	Scappoose	4,680	10,841	0.36	0.5	0.5
Columbia	ST HELENS STP	St. Helens	9,797	12,658	30.7	41	41
Columbia	VERNONIA STP	Vernonia	2,240	2,958	0.28	1.4	1.4
Coos	BANDON STP	Bandon	2,111	5,000	0.31	0.45	0.45
Coos	COOS BAY STP 1	Coos Bay	13,784	18,202	2	2.9	2.9
Coos	COOS BAY STP 2	Coos Bay	5,113	6,752	1.63	2.02	2.02
Coos	COQUILLE STP	Coquille	4,395	6,094	0.765	1	2.62
Coos	NORTH BEND STP	North Bend	9,800	12,849	1.627	2.2	2.2
Coos	POWERS STP	Powers	750	990	0.17	0.3	0.3
Crook	PRINEVILLE STP	Prineville	6,720	14,750	0.69	1.1	2.13
Curry	BROOKINGS STP	Brookings	8,500	16,218	0.78	1.74	1.74
Curry	Camellia Park Sanitary Dist. STP	Harbor	90	90	0.007	0.013	0.013
Curry	GOLD BEACH STP	Gold Beach	2,000	2,050	0.5	0.5	0.5
Curry	PORT ORFORD STP	Port Orford	1,585	2,093	0.039	0.275	0.275
Curry	WEDDERBURN SAN DIST.	Wedderburn	870	1,149	0.03	0.09	0.09
Deschutes	BEND STP	Bend	35,750	78,333	4.31	6	6
Deschutes	LAPINE	Lapine	656	915	0.07	0.1	0.1
Deschutes	REDMOND STP	Redmond	10,604	23,337	1.46	1.3	4.2
Deschutes	SISTERS STP	Sisters	282	1,234	0.052	0.45	0.45
Douglas	CANYONVILLE STP	Canyonville	1,360	3,000	0.14	0.5	0.5
Douglas	DRAIN STP	Drain	1,165	1,538	0.139	0.3	0.3
Douglas	ELKTON STP	Elkton	180	238	0.02	0.028	0.028

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Douglas	GLENDALE STP	Glendale	770	1,017	0.049	0.25	0.25
Douglas	GLIDE-IDLEYLD STP	Glide	2,500	3,301	0.11	0.28	0.28
Douglas	MYRTLE CREEK STP	Myrtle Creek	7,967	16,070	0.875	0.96	0.96
Douglas	OAKLAND STP	Oakland	746	2,095	0.102	0.106	0.106
Douglas	REEDSPORT STP	Reedsport	4,948	6,577	0.89	1.9	1.9
Douglas	RIDDLE STP	Riddle	880	1,365	0.081	0.247	0.247
Douglas	ROSEBURG REGIONAL STP	Roseburg	20,955	27,672	3.94	7.9	7.9
Douglas	SUTHERLIN STP	Sutherlin	6,168	11,435	0.82	1.3	2.23
Douglas	WINCHESTER BAY STP	Winchester Bay	637	1,274	0.1	0.117	0.121
Douglas	WINSTON-GREEN STP	Winston	10,000	30,698	0.8	1.6	1.6
Douglas	YONCALLA STP	Yoncalla	1,095	1,446	0.08	0.14	0.14
Gilliam	ARLINGTON STP	Arlington	510	673	0.05	0.13	0.13
Gilliam	CONDON STP	Condon	850	1,122	0.07	0.072	0.072
Grant	DAYVILLE STP	Dayville	185	244	0.014	0.037	0.037
Grant	JOHN DAY STP	John Day	2,000	2,694	0.28	0.6	0.6
Grant	LONG CREEK STP	Long Creek	255	337	0.017	0.03	0.03
Grant	MOUNT VERNON STP	Mount Vernon	770	1,045	0.05	0.1	0.1
Grant	PRAIRIE CITY STP	Prairie City	1,245	1,644	0.123	0.18	0.18
Grant	SENECA STP	Seneca	225	297	0.03	0.67	0.67
Harney	BURNS STP	Burns	4,445	5,377	0.82	1.14	1.14
Hood River	CASCADE LOCKS STP	Cascade Locks	1,130	1,492	0.099	0.493	0.493
Hood River	HOOD RIVER STP	Hood River	4,500	5,942	1.23	2.6	2.6
Hood River	ODELL STP	Odell	1,050	1,387	0.15	0.5	0.5
Hood River	PARKDALE STP	Parkdale	500	660	0.05	0.1	0.1
Jackson	ASHLAND STP	Ashland	23,745	33,419	1.72	3.1	3.1
Jackson	BUTTE FALLS STP	Butte Falls	440	581	0.04	0.07	0.07
Jackson	GOLD HILL STP	Gold Hill	1,260	1,664	0.12	0.35	0.35
Jackson	MEDFORD STP	Medford	59,990	83,370	20.05	20	24

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Jackson	ROGUE RIVER STP	Rogue River	2,000	2,641	0.28	0.3	0.3
Jackson	SHADY COVE STP	Shady Cove	2,420	3,196	0.1	0.26	0.59
Jefferson	CULVER SEWAGE TRT FAC.	Culver	865	1,142	0.04	0.09	0.09
Jefferson	MADRAS STP	Madras	3,570	4,714	0.349	0.5	0.5
Jefferson	METOLIUS STP	Metolius	675	840	0.048	0.096	0.096
Josephine	CAVE JUNCTION STP	Cave Junction	1,590	2,111	0.2	0.15	0.15
Josephine	GRANTS PASS STP	Grants Pass	16,500	43,016	5.4	4	8
Klamath	BLY STP	Bly	600	792	0.09	0.11	0.11
Klamath	BONANZA STP	Bonanza	340	465	0.01	0.12	0.12
Klamath	CHILOQUIN STP	Chiloquin	795	1,050	0.1	0.2	0.2
Klamath	K-FALLS SPRING ST STP	Klamath Falls	17,000	22,450	2.8	6	6
Klamath	MALIN STP	Malin	780	1,030	0.08	0.14	0.14
Klamath	MERRILL STP	Merrill	870	1,149	0.08	0.125	0.106
Klamath	SOUTH SUBURBAN SEWAGE LAG	Klamath Falls	17,990	24,905	1.7	2	2
Lake	LAKEVIEW STP	Lakeview	2,750	3,780	0.34	1.26	1.26
Lake	PAISLEY STP	Paisley	365	482	0.02	0.05	0.05
Lane	COTTAGE GROVE STP	Cottage Grove	8,480	11,198	1.67	2	2
Lane	CRESWELL STP	Creswell	3,400	4,367	0.24	0.2	0.2
Lane	DEXTER STP	Dexter	505	667	0.04	0.062	0.062
Lane	FLORENCE STP	Florence	9,196	12,144	1.6	0.75	0.75
Lane	JUNCTION CITY STP	Junction City	4,620	6,100	0.3	0.8	0.8
Lane	LOWELL STP	Lowell	1,105	2,359	0.122	0.15	0.15
Lane	MWMC REGIONAL STP	Eugene	158,200	208,913	22.49	50	49
Lane	OAKRIDGE STP	Oakridge	3,375	4,457	0.47	0.47	0.47
Lane	VENETA WEST LAGOON	Veneta	2,561	3,382	0.53	0.2	0.2
Lane	WESTFIR STP	Westfir	300	396	0.02	0.03	0.03
Lincoln	DEPOE BAY STP	Depoe Bay	3,460	5,751	0.29	0.8	0.8

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Lincoln	LINCOLN CITY STP	Lincoln City	10,865	15,999	1.6	3	3
Lincoln	NEWPORT STP	Newport	11,771	14,922	2.33	3.2	3.2
Lincoln	SALISHAN STP	Salishan	950	1,250	0.128	0.2	0.2
Lincoln	SILETZ STP	Siletz	800	1,060	0.153	0.157	0.157
Lincoln	TOLEDO STP	Toledo	3,356	5,585	0.53	0.73	0.73
Lincoln	WALDPORT STP	Waldport	1,970	2,602	0.15	0.36	0.36
Lincoln	YACHATS STP	Yachats	1,094	1,236	0.154	0.15	0.15
Linn	ALBANY STP	Albany	41,300	64,500	5.7	8.7	11
Linn	BROWNSVILLE STP	Brownsville	1,450	1,961	0.406	0.294	0.294
Linn	HALSEY STP	Halsey	775	1,023	0.1	0.197	0.197
Linn	HARRISBURG STP	Harrisburg	2,840	3,750	0.2	0.489	0.489
Linn	LEBANON STP	Lebanon	12,895	18,940	2.86	3	4
Linn	MILL CITY	Mill City	1,670	2,205	0.059	0.093	0.093
Linn	SCIO STP	Scio	655	865	0.07	0.09	0.09
Linn	SWEET HOME STP	Sweet Home	8,085	9,210	1.725	1.38	1.38
Linn	TANGENT	Tangent	1,005	1,406	0.05	0.11	0.11
Malheur	ADRIAN STP	Adrian	130	300	0.01	0.034	0.034
Malheur	JORDAN VALLEY STP	Jordan Valley	340	449	0.02	0.047	0.047
Malheur	NYSSA STP	Nyssa	3,075	4,061	0.3	0.8	0.8
Malheur	ONTARIO STP	Ontario	11,711	17,558	2	3.06	3.06
Malheur	VALE STP	Vale	1,655	2,500	0.28	0.37	0.37
Marion	AUMSVILLE STP	Aumsville	2,945	5,432	0.23	0.335	0.335
Marion	AURORA STP	Aurora	400	845	0.025	0.079	0.079
Marion	BROOKS/HOPMERE C SEWAGE TREATMENT FACILITY	Brooks	974	1,286	0.18	0.253	0.253
Marion	DONALD STP	Donald	755	997	0.02	0.08	0.08
Marion	GERVAIS STP	Gervais	1,545	2,040	0.07	0.15	0.15
Marion	HUBBARD STP	Hubbard	2,285	3,017	0.13	0.34	0.34

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Marion	JEFFERSON STP	Jefferson	2,515	3,016	0.3	0.255	0.398
Marion	MT ANGEL STP	Mount Angel	3,030	4,001	0.36	0.61	0.61
Marion	SILVERTON STP	Silverton	6,375	8,419	0.65	2.5	2.5
Marion	ST PAUL STP	St. Paul	322	475	0.048	0.066	0.066
Marion	STAYTON STP	Stayton	6,935	9,870	1.39	1.9	1.9
Marion	WILLOW LAKE STP	Salem	137,785	181,954	31.66	35	105
Marion	WOODBURN STP	Woodburn	21,673	31,039	2	3.1	3.1
Morrow	BOARDMAN STP	Boardman	3,400	4,490	0.23	0.4	0.4
Morrow	HEPPNER STP	Heppner	1,510	1,994	0.09	0.25	0.25
Morrow	IRRIGON STP	Irrigon	2,300	3,037	0.12	0.25	0.25
Multnomah	COLUMBIA BLVD. STP	Portland	502,981	649,833	82.6	420	610
Multnomah	GRESHAM STP	Gresham	86,430	114,136	10.531	20	20
Multnomah	TROUTDALE STP	Troutdale	12,750	16,375	0.92	1.6	1.6
Polk	DALLAS STP	Dallas	10,874	14,288	1.74	2.5	2.5
Polk	FALLS CITY STP	Falls City	373	1,058	0.047	0.026	0.026
Polk	GRAND RONDE STP	Grand Ronde	595	779	0.04	0.046	0.046
Polk	INDEPENDENCE STP	Independence	6,375	8,418	0.38	0.6	0.6
Polk	MONMOUTH STP	Monmouth	11,200	13,732	0.7	0.6	0.6
Sherman	BIGGS STP	Biggs	425	561	0.05	0.079	0.079
Sherman	MORO STP	Moro	340	449	0.02	0.05	0.05
Sherman	RUFUS STP	Rufus	310	480	0.041	0.04	0.046
Sherman	WASCO SEWAGE LAGOON	Wasco	415	548	0.033	0.04	0.04
Tillamook	BAY CITY STP	Bay City	1,195	1,578	0.12	0.21	0.21
Tillamook	CLOVERDALE STP	Cloverdale	218	288	0.02	0.04	0.04
Tillamook	GARIBALDI STP	Garibaldi	1,700	2,503	0.258	0.5	2.3
Tillamook	NEHALEM STP	Nehalem	4,711	6,244	0.3	0.703	0.703
Tillamook	NESKOWIN STP	Neskowin	359	475	0.01	0.21	0.21
Tillamook	NETARTS OCEANSIDE STP	Netarts	2,734	3,525	0.119	0.4	0.4

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Tillamook	PACIFIC CITY STP	Pacific City	1,500	2,455	0.12	0.36	0.36
Tillamook	ROCKAWAY BREACH STP	Rockaway Beach	1,485	2,197	0.275	0.5	0.5
Tillamook	TILLAMOOK STP	Tillamook	4,530	7,100	0.97	1.06	1.4
Tillamook	TWIN ROCKS STP	Rockaway	800	1,056	0.109	0.1	0.308
Umatilla	ATHENA STP	Athena	1,300	1,717	0.12	0.15	0.15
Umatilla	ECHO STP	Echo	640	845	0.06	0.12	0.12
Umatilla	HERMISTON STP	Hermiston	11,600	15,318	1.4	2.94	2.94
Umatilla	MILTON-FREEWATER STP	Milton-Freewater	6,690	8,835	0.49	0.45	0.647
Umatilla	PENDLETON STP	Pendleton	17,000	22,450	2.78	5.5	5.5
Umatilla	PILOT ROCK STP	Pilot Rock	1,972	2,555	0.17	0.25	0.25
Umatilla	STANFIELD STP	Stanfield	2,079	2,436	0.123	0.224	0.224
Umatilla	UKIAH STP	Ukiah	250	330	0.04	0.07	0.07
Umatilla	UMATILLA STP	Umatilla	3,080	4,450	0.379	0.9	0.9
Umatilla	WESTON STP	Weston	695	918	0.065	0.1	0.1
Union	COVE STP	Cove	690	911	0.04	0.06	0.06
Union	ELGIN STP	Elgin	2,035	2,707	0.179	0.36	0.36
Union	LA GRANDE STP	La Grande	12,555	16,580	1.34	2.7	2.7
Union	NORTH POWDER STP	North Powder	560	739	0.04	0.137	0.137
Union	UNION STP	Union	2,070	2,733	0.23	0.365	0.365
Wallowa	ENTERPRISE STP	Enterprise	2,050	2,707	0.3	0.75	0.75
Wallowa	JOSEPH STP	Joseph	1,595	2,220	0.199	0.374	0.374
Wallowa	WALLOWA STP	Wallowa	865	1,298	0.129	0.203	0.203
Wasco	DUFUR STP	Dufur	625	825	0.044	0.043	0.043
Wasco	MAUPIN STP	Maupin	690	947	0.08	0.1	0.1
Wasco	MOSIER STP	Mosier	365	482	0.03	0.085	0.085
Wasco	THE DALLES STP	The Dalles	12,765	16,857	1.8	4.15	4.15
Washington	DURHAM REGIONAL STP	Tigard	55,500	73,291	21.8	20	26

Operational Publicly Owned Wastewater Treatment Plants in Oregon, continued…

County Name	Facility Name	City Name	Present Population Receiving Collection	Future Population Receiving Collection	Existing Flow	Present Design Flow	Future Design Flow
					* Millions of Gallons per Day *		
Washington	FOREST GROVE STP	Forest Grove	9,500	12,545	2.67	5.5	5.5
Washington	HILLSBORO WESTSIDE STP	Hillsboro	23,400	30,901	4.2	3.75	3.75
Washington	ROCK CREEK STP	Hillsboro	97,900	169,000	19	20	36.05
Wheeler	FOSSIL STP	Fossil	399	527	0.06	0.088	0.088
Yamhill	AMITY STP	Amity	1,325	1,750	0.2	0.154	0.154
Yamhill	CARLTON STP	Carlton	1,500	1,793	0.129	0.367	0.367
Yamhill	COVE ORCHARD STP	Cove Orchard	118	156	0.01	0.01	0.01
Yamhill	DAYTON STP	Dayton	1,935	1,725	0.195	0.23	0.23
Yamhill	DUNDEE STP	Dundee	2,955	3,902	0.38	0.273	0.273
Yamhill	LAFAYETTE STP	Lafayette	1,945	3,944	0.15	0.3	0.3
Yamhill	MCMINNVILLE STP	McMinnville	25,250	33,344	5.89	4	4
Yamhill	NEWBERG STP	Newberg	17,000	19,600	1.81	5	5
Yamhill	SHERIDAN STP	Sheridan	5,250	6,933	0.59	0.422	0.422
Yamhill	WILLAMINA STP	Willamina	1,875	2,476	0.11	0.22	0.22
Yamhill	YAMHILL STP	Yamhill	980	1,294	0.05	0.25	0.25

Source: U.S. Environmental Protection Agency, Office of Wastewater Management Clean Watersheds Needs Survey (2000), http://cfpub.epa.gov/cwns/populationP1_00.cfm?state=Oregon.

Operational Large Dairies and Feedlots in Oregon*

Dairy/Feedlot Name	Location	Number of Cows
Columbia River Dairy LLC	Boardman	38,000+
H4 Farms, Inc/Stage Gulch Dairies	Umatilla	12,900
Rickreall Dairy LLC	Rickreall	3,100
Veeman Dairy	St. Paul	2,000
Platt's Turner Dairy	Independence	8,000
Hazenberg Dairy	St. Paul	3,400
Slegers Inc.	Dayton, Yamhill	2,600
Bonanza View Dairy	Klamath Falls	1,900
Tom DeJong Dairy	Klamath Falls	1,560
Langell Valley Dairy	Klamath Falls	1,200
JVB Dairy	Morrow	3,200
Lochmead Farms, Inc.	Junction City	1,080
Mallorie's Dairy, Inc.	Hubbard	2,250
Misty Meadow Dairy	Tillamook	3,400
Peter Dehaan Holstein LLC	Salem	1,700
Moisan Dairy	Salem	1,400
Danish Dairy LLC	Coquille	1,200
DeJager Dairy LLC	Jefferson	1,050
Pete & Tressa Meenderinck Dairy	Jerome, Umatilla	3,000
Bar MC Feedlot	Lakeview	5,000
Farley's Feedlot	Ontario	4,200
Beef Northwest Feeders	Morrow, Malheur Counties	30,000
Arror Gap Feedlot	Albany, Linn	25,000

Note: Large dairies and feedlots are defined as those with 1,000 animals or more, as the Oregon Department of Agriculture feels that this quantity represents the minimum number of animals necessary to render biomass feasible on a dairy or feedlot.

Source: Email from Oregon Department of Agriculture to Itron, received November 24, 2004.

Estimated Area of Forest Land in Oregon by Productivity Class, Reserve Status and Owner Class (Thousands of Acres)

Owner Class	Totals All Forest Land	Higher Productivity Forest Land				Lower Productivity Forest Land			
		Active Forest	Multi-Resource	Reserved	Totals High Productivity Forest Land	Active Forest	Multi-Resource	Reserved	Totals Low Productivity Forest Land
All Oregon									
National Forest	14,417	-	6,612	6,457	13,070	-	711	636	1,347
Bureau of Land Management	2,938	-	1,005	1,406	2,411	-	405	122	527
Other Federal	218	-	7	144	151	21	1	45	67
State	941	8	786	42	836	48	9	48	105
County-Municipal	180	99	10	7	115	35	7	23	65
Total Public	18,695	107	8,420	8,057	16,584	104	1,133	874	2,111
Forest Industry	6,023	5,511	272	-	5,783	231	9	-	240
Native American	414	325	11	-	336	75	3	-	78
Other Private	3,704	2,521	123	6	2,650	1,013	41	-	1,054
Total Private	10,141	8,357	406	6	8,769	1,319	53	-	1,372
All Owners	28,836	8,464	8,826	8,062	25,353	1,423	1,186	874	3,483
Western Oregon									
National Forest	5,523	-	1,319	3,978	5,297	-	29	197	226
Bureau of Land Management	2,288	-	894	1,373	2,267	-	9	12	21
Other Federal	49	-	7	-	7	21	1	20	42
State	817	-	730	18	748	21	8	40	69
County-Municipal	163	97	8	7	111	27	2	23	52
Total Public	8,840	97	2,958	5,376	8,430	69	49	292	410
Forest Industry	4,248	3,960	217	-	4,177	67	4	-	71
Native American	36	35	1	-	36	-	-	-	-
Other Private	2,135	1,750	96	-	1,846	274	15	-	289
Total Private	6,419	5,744	315	-	6,059	341	19	-	360
All Owners	15,259	5,841	3,273	5,376	14,489	410	68	292	770

Estimated Area of Forest Land in Oregon by Productivity Class, Reserve Status and Owner Class, continued… (Thousands of Acres)

Owner Class	Totals All Forest Land	Higher Productivity Forest Land				Lower Productivity Forest Land			
		Active Forest	Multi-Resource	Reserved	Totals High Productivity Forest Land	Active Forest	Multi-Resource	Reserved	Totals Low Productivity Forest Land
Eastern Oregon									
National Forest	8,893	-	5,293	2,479	7,772	-	682	439	1,121
Bureau of Land Management	650	-	111	33	144	-	396	110	506
Other Federal	169	-	-	144	144	-	-	25	25
State	124	8	56	24	88	27	1	8	36
County-Municipal	17	3	1	-	4	8	5	-	13
Total Public	9,854	11	5,462	2,681	8,153	35	1,084	582	1,701
Forest Industry	1,775	1,551	55	-	1,606	163	6	-	169
Native American	378	290	10	-	300	75	3	-	78
Other Private	1,569	771	27	6	804	739	26	-	765
Total Private	3,722	2,612	92	6	2,710	978	34	-	1,012
All Owners	13,576	2,623	5,554	2,686	10,863	1,013	1,118	582	2,713

Notes:
− indicates that less than 500 acres found.
Totals are approximate due to rounding.
Data was subject to sampling error, which will be large for table cells with less than 100,000 acres.

Definitions:
Active Forest - Forest land available to be managed with a primary goal of commercial timber harvest.
Multi-Resource - Forest land on which timber harvest is likely balanced with production of other forest values.
Reserved - Forest land closed to commercial timber harvest by law, regulation, or forest plan requirement.
Higher productivity forest land, often called "timberland," can produce 20+ cubic feet of commercial wood per acre per year; lower productivity forest land cannot.

Sources: Forest Inventory and Analysis Program of the Pacific Northwest Research Program and the Oregon Department of Forestry, http://www.odf.state.or.us/DIVISIONS/resource_policy/resource_planning/Annual_Reports/Adjusted%20Landbase%20Table.xls.

Operating Lumber Mills/Paper Producers in Oregon Using Timber Residues [1,2]

Mill Name	City	Capacity (kW)	Comments
Boise Cascade Medford [2]	Medford	9,000	Utilizes timber residues (milling and logging residues)
Eugene F. Burrill Lumber Co.[1]	Medford	1,500	
Fort James Operating Co. (Wauna Mill)[2]	Clatskanie	25,000	Utilizes timber residues (milling and logging residues)
Prairie Wood Products[2]	Prairie City	10,000	Utilizes timber residues (milling and logging residues)
Publisher's Paper Co. (Smurfit Newsprint)[2]	Newberg	10,000	Utilizes timber residues (milling and logging residues)
Rhoden Investments Pine Product Corp.[1]		5,400	
Roseburg Forest Products (Dillard Complex)[1, 2]	Roseburg	51,500	Utilizes timber residues (milling and logging residues)
Warm Springs Forest Products Industries[1]	Warm Springs	9,000	
Weyerhauser Co.[1, 2]	Springfield	76,200	
Willamette Industries, Inc. Albany Paper Mill[1]	Albany	51,000	
Willamina Lumber Co. Tillamook Lumber Company[1]	Willamina	12,500	

Note:
This table may not present a comprehensive list of operating lumber mills/paper producers in Oregon using timber residues since data from the EIA is current only as of 1998, and data from the U.S. EERE is current only as of 2002. Thus, some lumber mills or paper producers listed may no longer utilize timber residues, and other lumber mills or paper producers not listed may currently utilize timber residues.

Sources:
[1] Obtained from Table 24: Existing Capacity at U.S. Nonutility Power Producers BY STATE, OWNER AND FACILITY, AS OF DECEMBER 31, 1998, provided by the U.S. Department of Energy (DOE) Energy Information Administration (EIA), http://www.eia.doe.gov/cneaf/electricity/ipp/t24d.txt

[2] Obtained from Operating Facilities by Technology in the State of Oregon table tracked by the U.S. Department of Energy (DOE) Energy Efficiency and Renewable Energy (EERE) web site, http://www.eere.energy.gov/state_energy/opfacbytech.cfm?state=OR#Biomass. Data was derived from the Renewable Plant Information System (REPiS) created and maintained by the National Renewable Energy Laboratory (NREL) with funding from the U.S. DOE.