ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

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Combined Heat and Power in the Pacific Northwest: Market Assessment

Task 1 – Final Report

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Combined Heat and Power in the Pacific Northwest: Market Assessment

EXECUTIVE SUMMARY

Several characteristics of the Pacific Northwest (PNW) have historically combined to make this region of the United States unique in the generation and usage of electricity and heat. These characteristics include:

- Relatively moderate demand for electricity and heat due to mild climate conditions
- Low electricity prices due to the common use of hydroelectric plants for power generation

Even with these unique characteristics, combined heat and power (CHP) has long been recognized as a cost-effective, environmentally friendly way to supply energy needs to industry in this region. However, the energy outlook for the Pacific Northwest is changing rapidly. Electricity prices are increasing in the region as demand has outgrown supply, and new sources of generating capacity are now needed to meet expanding demand. However, expansion of existing generation resources and/or construction of new hydroelectric plants are met with protest by environmentalists that serve to protect the natural resources and salmon population of the PNW.

At the same time, the PNW region's access to large quantities of reasonably priced natural gas has been enhanced through the construction of multiple pipelines from Canada. It is within this new environment that CHP can potentially play an even greater role in the region's energy picture, providing high efficiency energy supplies to industrial and commercial users with minimal environmental impact.

The results of this assessment are intended to provide regional stakeholders with an overview of the current installed capacity of CHP resources in the four Pacific Northwest states of Washington, Oregon, Idaho, and Alaska, as well as the technical and economical potential for future CHP installations in this region. This assessment also addresses the regulatory, institutional, and market barriers and incentives to CHP development in the PNW.

Existing CHP Capacity

As of May 2003, there were 146 active CHP installations in the PNW region with a total capacity of 3,854 megawatts. This baseline of existing CHP is characterized below by state, by application, by fuel, and by prime mover technology.

By State

- Oregon has the highest active CHP capacity in the region (2,253 MW). Washington has the next largest share (1,044 MW), followed by Alaska (382 MW) and then Idaho (175 MW).
- When compared to total electric generating capacity in each state, CHP makes up the highest share of the total in Alaska (19%), followed closely by Oregon (18%). CHP makes up less than 4% of the total generating capacity in Washington, the largest power producer in the region. Idaho is not much higher at 6%.
- Alaska leads in active CHP projects (82) – the majority of which are remote village diesel power systems with heat recovery for surrounding buildings. Oregon (31), Washington (21), and Idaho (12) trail in site totals.
- Alaska has the highest spark spread (high power costs / low fuel costs) making for a favorable economic environment for CHP. There are also a large number of remote facilities (villages, military bases, and seafood packing plants) where grid power is unavailable. Natural gas is used where available; oil and coal are used in remote areas.
- Idaho has the lowest power costs in the U.S., resulting in a low share of CHP as a percentage of total power generation. There are a small number of food and forest product plants currently using CHP; however, there has not been much recent CHP development activity in this state. The average age of the 12 operating CHP plants in Idaho is 20 years old.
- Oregon has recently installed many combined cycle power plants near the California border that provide steam to Oregon industrial facilities and power to both the Northwest and California power markets. Oregon has very active state incentive programs that support CHP development on the basis of energy conservation, reduction in greenhouse gas emissions, and economic development. Somewhat offsetting these positive trends, Oregon has the highest retirement rate for CHP projects in the declining pulp and paper and wood products industries.
- Washington is similar to Oregon and Idaho in industry make-up with a large number of wood product and paper plants, but refinery projects are also important. Washington is suffering from declining traditional industries as well as slumping high-tech industries. As the largest power producer in the region with the highest level of imbedded hydroelectric capacity, Washington has the lowest share of CHP capacity as a percentage of total electric generating capacity.

By Application

- Four industries account for a total of 89% of the active CHP capacity. The food industry is the largest (36%), followed by the pulp and paper (34%), oil refining (11%), and wood products (8%). These are all stable or declining industries. Another 3% of active CHP capacity in the PNW region is located at other industrial sites.
- The commercial sector accounts for only 6% of total CHP capacity in the region; though, it is important to note that this sector, by definition, includes several large projects at military bases in Alaska. Outside of these large military base systems, there is little other commercial sector CHP capacity in the PNW region.
- Alaskan Village power systems make up 2% of the CHP capacity in the region.

By Fuel

- Natural gas is, by far, the most widely used fuel in the region, fueling 79% of the active CHP capacity.
- Biomass – consisting of wood residue, black liquor, and digester gas – fuels 12% of the CHP capacity in the PNW. The use of wood residue and black liquor in traditional CHP facilities is driven by the importance of the pulp and paper and wood products industries in the region. Nearly all of these traditional facilities were installed 20 years ago and more are closing down every year. Digester gas is used at 13 water treatment plants and two dairies in the region.
- 5% of the CHP capacity is fueled by coal, which is used to power generating plants at several military bases.
- Diesel oil is the fuel of choice for 3% of the regional CHP capacity. It is used primarily for power generation in remote Alaskan village power systems.
- Methanol is used by one experimental fuel cell facility in the region.

By Prime Mover Technology

- There are nine combined cycle plants that make up 66% (2,526 MW) of the total CHP capacity in the region.
- The next largest share comes from 33 steam turbines, which represent 17% (648 MW) of the regional CHP capacity. Wood wastes at pulp and paper mills are the primary source of fuel for generating steam.
- 16 simple cycle gas turbines represent another 14% (545 MW) of the regional CHP capacity.
- 84 reciprocating engines account for about 3% (135 MW) of the total CHP capacity in the region. Most of these engines are part of diesel-fired CHP systems in remote Alaskan villages that have no other source of power.
- There are four CHP projects that use advanced technologies – fuel cells or microturbines – as the prime mover. These four installations total 1 MW of power output, which is a very small fraction of the regional CHP capacity.

Barriers to CHP

Barriers to the deployment of combined heat and power in the Pacific Northwest region can be grouped into three basic areas:

- Regulation and interaction with electricity service providers
- Siting and environmental compliance
- Market and financial barriers

Regulation and Interaction with Electricity Service Providers

The electric power structure in the Pacific Northwest, except for Alaska, is dominated by the installed hydroelectric capacity of the Federal Columbia River Power System. Bonneville Power Administration (BPA) provides a large share of the wholesale power and high-voltage transmission for the region's publicly owned power companies, investor-owned utilities, and to direct service industries. Average power costs are very low but the transition to competitive wholesale power markets has exposed BPA and its customers to considerable risk and uncertainty. The source and cost of resources to meet future power needs are highly uncertain. Economic decisions regarding CHP are hindered by this uncertainty.

Complicating the situation for CHP deployment, each utility within the PNW region sets its own interconnection guidelines. Only in Oregon are these guidelines limited by regulation to what is required by *IEEE 1547 – Standard for Interconnecting Distributed Resources with Electric Power Systems*. Also, standby or backup charges, which are often imposed by utilities on CHP customers, reduce the economic benefits of CHP. The CHP industry contends that such charges do not adequately reflect the system support provided by distributed generation.

Finally, gaining transmission access, particularly for larger projects, can be difficult. There is no mechanism beyond bilateral negotiation between the CHP project and the electric utility for allowing power to be moved to other owned facilities or to be sold to third parties.

Siting and Environmental Compliance

Siting of CHP facilities requires that the developer address siting issues concerning air quality, water quality, water usage, land use, fire/safety, noise, traffic, and environmental impact. Some states, notably Oregon, have developed a state level process to facilitate project siting. The benefits of high-efficiency CHP are recognized for the fact that they avoid other energy use and utility infrastructure investments. However, not all siting requirements are brought under this one umbrella. Environmental compliance issues, such as water quality and air quality, each have their own requirements with local and state agencies implementing federal guidelines.

Market and Financial Barriers

In order for CHP to achieve a greater market share in the PNW region, there is a need to eliminate market-related barriers. These barriers include difficulties in financing CHP projects due to tax schedules and other financial constraints, lack of customer understanding related to CHP equipment operation, uncertainty related to the cost and performance benefits of CHP, and lack of developer knowledge related to customer requirements. Education and outreach directed at developers, customers, regulators, and other regional stakeholders can help to remove these barriers by providing an understanding of how CHP technologies work, in addition to when and how different CHP technologies can be applied effectively.

Incentives for CHP

The value of CHP is becoming more recognized by a variety of groups in the Pacific Northwest. There are a number of active incentive programs at the federal, regional, and state levels, as well as organizations that are providing focus and support for CHP development.

At the federal level, the Department of Energy State Energy Program (DOE-SEP) provides funding to the states for a variety of energy programs that directly or indirectly promote CHP. The DOE-SEP has provided funding for CHP technology development and demonstration projects in renewable energy and advanced technology, for evaluation of district energy programs, development of CHP information materials, and economic development activities (e.g., economic and technical assistance, low-interest loan programs, etc.). The DOE-SEP is managed cooperatively with state level energy agencies.

Regionally, the Bonneville Power Administration provides the Conservation and Renewables Discount (C&RD). This program allows BPA customers (public utilities and investor-owned utilities) to receive cost reductions based on their implementation of energy efficiency programs, including CHP and renewable energy.

Each state has an agency that supports energy programs. The Oregon Office of Energy is the most active state agency in the four-state PNW region. Oregon supports CHP to promote the broader goals of maintaining a clean environment, minimizing the need for new energy supply, and environmental protection including reduction in emissions of carbon dioxide that contribute to global warming. Other states provide some programs that could be used to support CHP, such as financing of projects, demonstration of renewable energy programs, and targeted economic development. Alaska focuses strongly on grid isolated rural energy systems. Idaho has implemented a number of programs to support its agricultural and food industries. Washington, with the highest population and gross state product in the region, provides comparatively little support for CHP.

In addition to the incentive programs for CHP available in PNW, there are several organizations within the region that are working to promote the market deployment of CHP and to eliminate unfair market barriers. These organizations are providing a regional forum for CHP proponents and other interested parties to meet and to develop a regional action plan. The key organizations in this developing regional forum are described below:

- The Northwest CHP Consortium (formerly the 200 Market Street Consortium) is providing education, marketing effort, and financial support, and serving as a clearinghouse for applying applicable financing incentives to small-scale CHP projects in Oregon. Northwest Natural has provided the management effort to pull together a consortium that includes, in addition to their own support, local gas and electric utilities, the Department of Energy, the American Gas Association, the Bonneville Power Administration, the state of Oregon, and the city of Portland.

- A recently awarded DOE-SEP grant has provided for the establishment of the Northwest Regional Combined Cooling, Heating, and Power (CHP) Application Center to serve the needs of Alaska, Idaho, Oregon, Montana, and Washington. The Center, under the management of Washington State University Energy Program, plans to be an important resource for those interested in developing or advancing CHP projects in the region. To facilitate the development and successful operation of a broad range of CHP technologies and projects, the Northwest Regional CHP Application Center will develop a comprehensive education and outreach program.
- The DOE, with the very active support of its Western Regional Office (WRO), has hosted a number of informal and formal workshops to promote CHP within the region. Through its team building and issue identification efforts, the DOE WRO was particularly instrumental in establishing the Northwest Regional CHP Application Center (described above). The Pacific Northwest CHP Roundtable held in June 2003, brought together about 50 representatives from industry, energy service providers, government, and the utility industry to share CHP case studies and to develop a list of action items and solutions to the barriers that inhibit development of CHP in the region. The DOE WRO has also spearheaded the establishment of the CHP Pacific Northwest Initiative.
- The Oregon Office of Energy serves as a model agency in the PNW region for its recognition of the social benefits of CHP (productivity, environmental protection, conservation of natural resources, economic development and productivity, and reduction in global warming) and its innovative incentive programs.

The ongoing activities of these organizations are helping to create a greater awareness among legislators and regulators of the need to eliminate barriers and accelerate beneficial market activity. Customer awareness is also enhanced. In addition, these market-seeding activities will help reduce the costs of project development and implementation and strengthen the capabilities of performing organizations, such as energy service companies, architects and engineers, general contractors, and other project-related resources.

Technical Market Potential

The technical market potential for CHP in the PNW over the next 20 years is estimated to be 15,545 MW. Existing facilities account for 10,306 MW of this potential, and new facilities contribute 5,239 MW.

The potential for individual market applications are summarized below:

- *Large Industrial* – Over 90% of the existing CHP in the region is in large industrial systems, which represents the most active existing market in the region. The technical potential in this market is split between electric capacity that serves on-site electric needs and electric capacity that could be exported (using the site as a steam host). The technical potential for this market is 3,215 MW – approximately one-third of this capacity could be used to meet the site electrical needs and about two-thirds could be available to meet the power needs of the region as a whole. Technical CHP potential from new facilities is low because of the lack of growth of basic industries in the region. The total remaining potential for this market over the next 20 years is less than a third of the existing capacity that has already been installed.
- *Resource Recovery* – There is currently a great deal of interest in developing the resource recovery market in the PNW. However, the ultimate technical potential is relatively low at 76 MW for the PNW region.
- *Small Industrial* – The small industrial technical market potential in the PNW is 2,053 MW. However, the economics in this size range will be very difficult to justify due to the low power prices in the region. Alaska is the exception to this with both high electric rates and low fuel costs, causing system economics to be very promising.
- *Commercial/Institutional* – This is a very large part of the regional economy with a great many potential sites and favorable growth projections. The technical potential is 10,147 MW – the highest of all the applications considered for both existing and new facilities. However, the economics of CHP in this sector are extremely difficult. Alaska is the only state with significant active projects in this sector due to the more favorable gas-to-electric price ratio.
- *Alaskan Village Systems* – This is a market unique to Alaska. There is 54 MW of remaining potential in existing villages that are grid isolated and use diesel power for all of their electrical needs. The value of heat recovery has been demonstrated in many other villages, and many of the systems already have partial or complete heat recovery equipment installed but not yet in use.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the region. Identifying technical market potential is a preliminary step in the assessment of economic market potential for the region.

Economic Market Potential and CHP Deployment

While the technical market potential for CHP in the PNW is promising, the actual deployment of CHP will depend on favorable economics. Two alternative futures for CHP market penetration projections in the Pacific Northwest were considered in this assessment. The first case is termed *Business-as-Usual*. This case reflects assumptions of no improvement in current or near-term CHP technology, no incentives for CHP, and continuation of standby charges assessed on electricity customers with CHP. In addition, it is assumed that the lack of awareness of CHP and the poor economic climate for developers would limit the market penetration of systems especially in the smaller sizes. In the *Accelerated Case*, it is assumed that CHP technology improves considerably, that incentives are available to offset 15% of initial capital cost, and that standby charges are eliminated. In addition, it is assumed that there is a greater awareness of CHP due to educational outreach programs and developer activity that reduce the rate of non-adoption of economic systems.

Economic Potential

Of the 15.5 GW technical CHP potential identified for the region, it is estimated that there is an economic potential of 2.1 GW in the *Business-as-Usual* case and a 6.2 GW economic potential in the *Accelerated Case*. The share of technical potential that is deemed economical in each size range increases as the project size increases. For example, in the *Business-as-Usual* case, only 5% of the 50-500 kW technical potential is economical, while over 50% of the over 50 MW size capacity is economical. However, the changes to technology cost and performance and the incentives for CHP assumed for the *Accelerated Case* have a greater impact on increasing the economic potential for the smaller sized projects. In the smallest size bin, the economic potential is increased by a factor of six whereas in the largest size bin, economic potential is increased by only 50%.

The distribution of economic potential by state shows that Alaska has the highest economic potential under the *Business-as-Usual* case. However, in the *Accelerated Case*, Washington and Oregon see a much greater addition to economic potential. In Alaska, 86% of its CHP technical potential is economical under *Business-as-Usual* assumptions. Consequently, there is little room for improvement in the accelerated case. In contrast, the other three states see only a 4 to 10% share of their technical potential that is economical under *Business-as-Usual* assumptions. This economic share increases to 25-35% in the *Accelerated Case*.

The year 2025 cumulative market penetrations by technology for each scenario were estimated by CHP technology. Under *Business-as-Usual* conditions, the cost and performance of emerging technologies like microturbines and fuel cells are predominantly outside of a competitive range. With technology improvement, the share of each of these technologies increases dramatically. More moderate improvements in established technologies such as reciprocating engines and gas turbines also increase market penetration but to a lesser degree.

Economic and Environmental Benefits

Increased CHP market penetration in the Pacific Northwest will produce economic benefits, energy savings, and a potential reduction in pollutant emissions for the region. In the *Business-as-Usual* case, benefits of $318 million annually and energy savings of 54 trillion Btu/year are produced by the cumulative market penetration to year 2025. In the *Accelerated Case*, annual benefits (by 2025) due to CHP deployment equal $885 million (in 2002 dollars). The associated annual energy savings are 167 trillion Btu/year.

Significant NO_x and CO_2 emissions reductions are achievable by the deployment of CHP compared to the emissions associated with existing thermal power production. For the *Business-as-Usual* and *Accelerated Case* respectively, NO_x emissions would be reduced by 15 to 53 thousand tons per year. CO_2 emissions would be reduced by 6 to 22 million tons per year.

Recommended Actions to Increase CHP Deployment

The comparison of the *Business-as-Usual* scenario and the *Accelerated Case* show that there is a significant economic and environmental benefit to be earned by supporting CHP technology and market development in the region. It is important that both the Federal Government and the states work toward the removal of barriers and to provide incentives that promote deployment.

At the Federal level, this support should include:

- Continued support for prime mover technology development and CHP systems integration
- Support for advanced technology demonstration projects in the region
- Education and outreach to raise awareness among all stakeholders, including facility managers, policy makers, regulators, utilities, and end users
- Analysis of the impacts of CHP deployment on regional transmission constraints
- Economic analysis of CHP impacts to provide a basis for streamlining interconnection; reducing standby charges; and implementing or increasing incentives to support climate goals, energy savings, and economic development goals
- Creation of utility partnerships to develop and strengthen the system-wide benefits of CHP deployment.

At the State level, support should include:

- Establish a streamlined procedure for CHP interconnection
- Encourage the development of an economic methodology for setting standby power tariffs that reflect the diversity of CHP outages on the system
- Establish fair avoided cost rates with increased state oversight
- Require utilities to implement cost-based wheeling of power over the distribution grid
- Encourage the use of integrated resource planning to buy the lowest cost resources for proposed generation, transmission, and distribution projects
- Tax and investment incentives for CHP projects that meet efficiency, cost, economic development, or environmental goals
- Develop or improve state-level facility siting procedures to streamline the process of siting energy facilities.

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1. INTRODUCTION

The power produced by hydroelectric generation on the Columbia River Basin has dominated the energy economy of the Pacific Northwest (PNW) since the major dams were constructed in the 1930s. This inexpensive power has attracted industry to the region, has maintained retail power prices at a very low level, and has supplied customers throughout the Western United States with electricity. Continued growth in the region, however, has created a two-tier market structure. Low-cost hydroelectric power remains as the base; but in order to meet growing demand, an increasingly larger share of power must be provided by new conventional power plants or by nontraditional sources such as wind-power, conservation, or combined heat and power (CHP) from distributed generation.

To better incorporate CHP into the Pacific Northwest's energy plans, policymakers and regulators need to know the extent of the potential impact that CHP can have on the region, and need to understand the regulatory, institutional, and market hurdles that presently constrain wider CHP market development in the region.

In March 2002, Oak Ridge National Laboratory (through UT-Battelle) commissioned Energy and Environmental Analysis, Inc. (EEA) to conduct a study of CHP market potential in the Pacific Northwest states of Washington, Oregon, Idaho, and Alaska. This assessment was completed in four segments over 28 months:

- First, a baseline of existing CHP in each state was developed, and the current market and regulatory environment for CHP within each state was reviewed.
- Next, the technical market potential for CHP in each state was estimated in terms of market segment and application, system size, and technology fit. This potential was quantified in terms of the number of facilities where CHP is applicable, and the MW of CHP capacity represented by these facilities.
- Subsequently, the critical market and regulatory hurdles to CHP development in each state were identified, along with the incentives for CHP deployment in the PNW at the federal, regional, and local levels.
- Finally, the economic potential, energy savings, and environmental benefits that CHP represents for each state was estimated.

This report presents the results of all four segments of the CHP market study. The remainder of the report is organized into the following sections:

2. **Existing CHP Installations and Capacity** – This section provides a baseline of existing CHP in each state.
3. **CHP Barriers and Incentives** – This section provides an overview of the critical hurdles and incentives to CHP development in each state.
4. **Technical Market Potential** – This section estimates the *technical* market potential for CHP in the PNW. It identifies applications and markets for CHP by industry category, application, size, and state.
5. **Economic Market Potential** – This section estimates the *economic* market potential for CHP in the PNW. It presents an economic model for evaluating the economic potential and two scenarios of long-term CHP market penetration in the region by size, state, and CHP technology.
6. **Recommendations for Federal Action** – This section provides selected recommendations for federal activities that may help stimulate the CHP market in the PNW.

2. EXISTING CHP INSTALLATIONS AND CAPACITY[1]

146 active CHP installations were identified in the four-state Pacific Northwest (PNW) region of Alaska, Idaho, Oregon, and Washington. These installations comprise a cumulative generating resource of 3,854 MW. This section characterizes these existing CHP installations in terms of location, ownership, capacity, prime mover, primary fuel source, and application. This existing baseline of CHP installations in the PNW paints a picture of how CHP currently competes in the region, as well as provides a starting point for the determination of future CHP market potential.

Several sources were used to compile the list of active installations. The primary source is the Energy and Environmental Analysis, Inc. (EEA) Combined Heat and Power Database, which contains information on approximately 2,200 CHP installations in the United States. This database was originally constructed from Federal Energy Regulatory Commission (FERC) Qualifying Facility (QF) Applications and updated with Energy Information Administration (EIA) Form 860A and 860B data, in addition to various other sources. Using this database as a starting point, the study team then used several other information sources to verify the data and to identify additional CHP installations:

- Northwest Power and Conservation Council (recently renamed from the Northwest Power Planning Council) database of all active power plants in the power region served by the Columbia River Basin (ID, OR, MT, WA)[2]
- Database of *Alaska Village Projects* provided by the Alaska Energy Authority[3]
- Information from the Oregon Office of Energy[4]
- Information from the Washington State University Energy Program[5]
- Online search for CHP projects in the four-state PNW region

2.1 Electricity Usage and Price in the Region

To put the evaluation of existing CHP into context, a brief summary of the electric power market in the region is provided. **Figure 2-1** shows that, overall, the region produced 194 trillion kWh in 2001. Washington has the highest amount of power generation in the four-state region analyzed (ranked 12th in the U.S.). Oregon has about half the power production of Washington (ranked 24th in the U.S.). Idaho and Alaska are comparatively much smaller in power production (ranked 43rd and 49th respectively). Taken as a whole, the four-state PNW region accounts for less than 5% of the total U.S. power production.

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1 The results presented in this section are derived from the "Subtask 1-1 Deliverable," which was delivered to ORNL in May 2003.

2 *Existing Generation Projects*, a computer spreadsheet available from the Northwest Power and Conservation Council Website at www.nwppc.org, and personal communication with Jeff King.

3 Personal Communication, Peter Crimp.

4 Online data at www.energy.state.or.us, and personal communication with Mark Kendall.

5 Personal Communication, John Ryan.

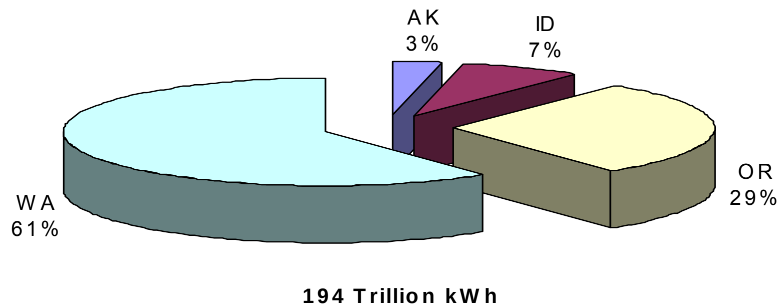
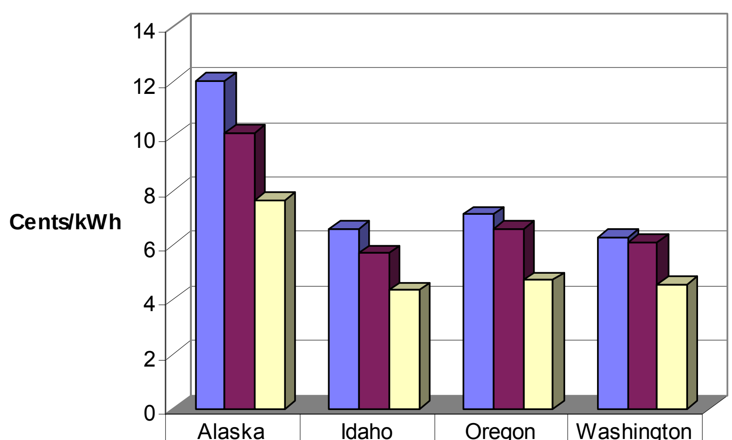


Figure 2-1. Total Power Generation in the PNW Region

Outside of Alaska, the PNW region is dominated by low-cost hydroelectric capacity that has kept retail electric rates in Idaho, Oregon, and Washington among the lowest in the nation. **Figure 2-2** compares average retail electricity costs by customer class and state. Alaska power rates are almost twice as high as the other states in the region and are among the highest in the U.S. The dominant energy source for power production in Alaska is natural gas, though a large number of isolated communities are dependent on diesel fuel for power production.



	Alaska	Idaho	Oregon	Washington
Residential	12.05	6.59	7.12	6.29
Commercial	10.13	5.71	6.59	6.11
Industrial	7.65	4.34	4.72	4.56

Figure 2-2. Average 2002 Retail Power Costs by State (EIA)

2.2 Existing CHP Site Identification and Analysis

There are 146 active CHP installations with a total capacity of 3,854 megawatts in the PNW region. **Figures 2-3** and **2-4** show the breakdown by state. In spite of having overall electric production that is less than half that of Washington, Oregon has over twice the capacity of installed CHP and leads the entire region with 58% of the total regional CHP capacity. Oregon has the highest active CHP capacity in the region due, in large part, to recent large merchant plant installations concentrated close to the California border. Washington has the next largest share (27%), followed by Alaska (10%) and Idaho (5%).

Alaska leads in active installations (82) – the majority of which are remote village diesel power systems with heat recovery for surrounding buildings. Oregon (31), Washington (21), and Idaho (12) trail in site totals.

When compared to total electric generating capacity in each state, CHP makes up the highest share of the total in Alaska (19%) followed closely by Oregon at 18%. Washington, the largest power producer in the region has less than a 4% share for CHP while Idaho is at 6%.

A complete listing of the existing CHP installations in the four-state region is provided in **Appendix A**.

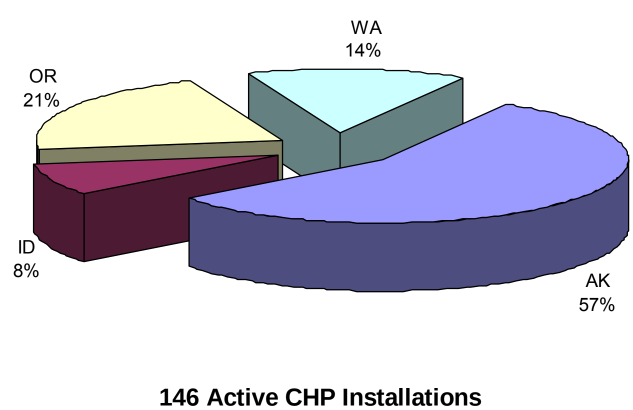


Figure 2-3. Existing CHP Installations by State

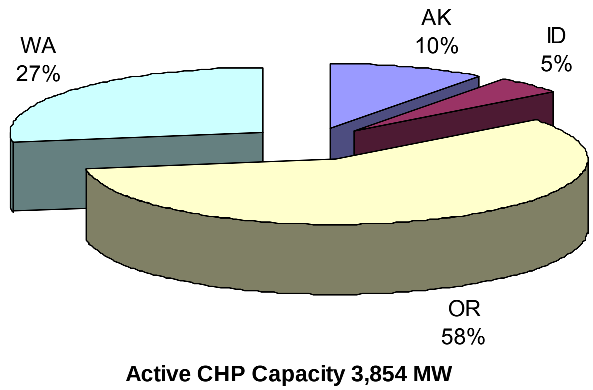


Figure 2-4. Existing CHP Capacity by State

Figure 2-5 provides the breakdown of capacity and installations by prime mover technology type. There are nine combined cycle plants that make up two-thirds of total CHP capacity in the region. The next largest share comes from steam turbines (17%), primarily burning wood wastes at pulp and paper mills. Simple cycle gas turbines represent another 14% of the regional CHP capacity. Reciprocating engine installations represent about 4% of total capacity; most of which are diesel-fired systems in remote Alaskan villages with no other source of power. There are four installations in the PNW region that utilize advanced technologies – either fuel cells or microturbines – as the prime mover. The advanced technologies represent a combined capacity of about 1 MW, which is a very small fraction of the total installed CHP capacity in the region.

Prime Mover	Sites	MW
Steam Turbine	33	648
Combined Cycle	9	2,526
Gas Turbine	16	545
Advanced Tech.*	4	1
IC Engine	84	135

* Fuel Cell, Microturbine

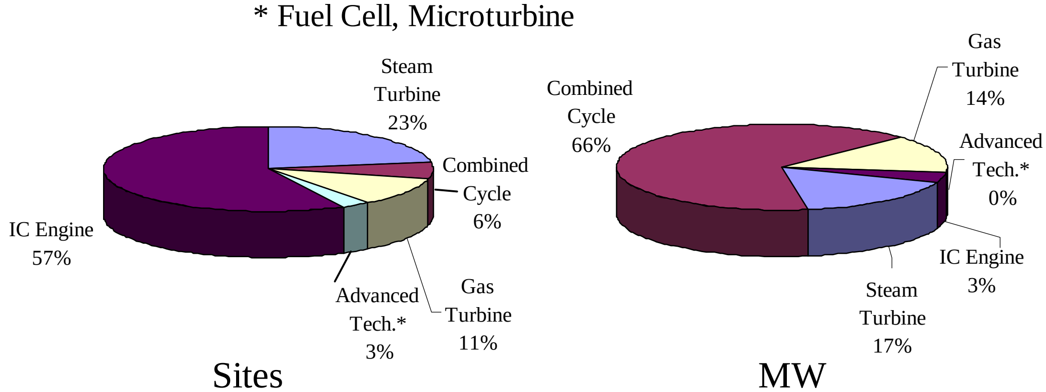


Figure 2-5. Existing CHP Installations and Capacity by Prime Mover

Figure 2-6 shows the breakdown of existing CHP capacity by end-use application. Four industries account for a total of 89% of the active CHP capacity. The food industry is the largest, followed by the pulp and paper, oil refining, and wood product industries. Another 3% of the regional CHP capacity is located at "other industrial" sites. The commercial sector accounts for 6% of total capacity; though, it is important to note that this sector, by definition, includes several large projects at military bases in Alaska. Outside of these large military base systems, there is little other commercial sector activity in the region. Finally, 2% of the CHP capacity is made up of Alaskan Village power systems.

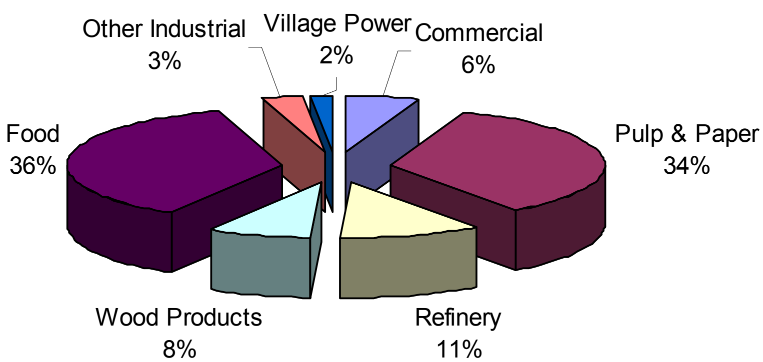


Figure 2-6. Existing CHP Capacity by Application

Natural gas is the predominant fuel powering CHP in the PNW region, supplying nearly 80% of installed CHP capacity (see **Figure 2-7**). Biomass is the next most important fuel source, supplying 12% of installed CHP capacity in the region. The primary sources of biomass-derived fuels are black liquor and wood waste, but biomass also includes digester gas from sewage treatment plants and dairy feedlots. Coal is used as a fuel primarily in the remote Alaskan military bases. Diesel oil is the predominant fuel in the Alaskan Village power systems.

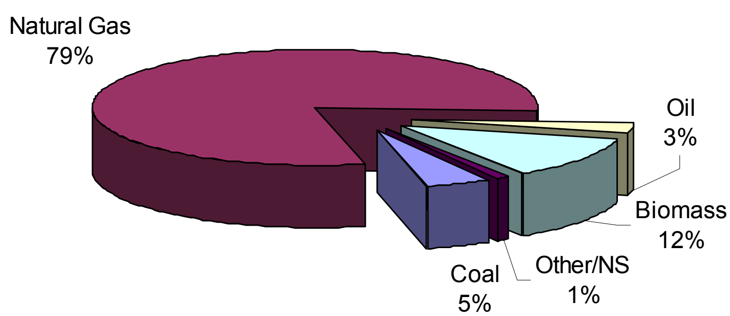


Figure 2-7. Existing CHP Capacity by Fuel Type

Figure 2-8 shows the size breakdown of existing CHP installations by state. Smaller projects are concentrated in Alaska; the village power systems range in size from 100 kW to 8.5 MW. Oregon has the next largest amount of small-sized CHP installations, resulting from a number of active incentive programs. The 20-50-MW sites in Alaska are mostly military bases and the University of Alaska at

Fairbanks. The largest CHP installations are concentrated in Oregon and Washington and consist of third-party combined cycle plants with industrial steam hosts.

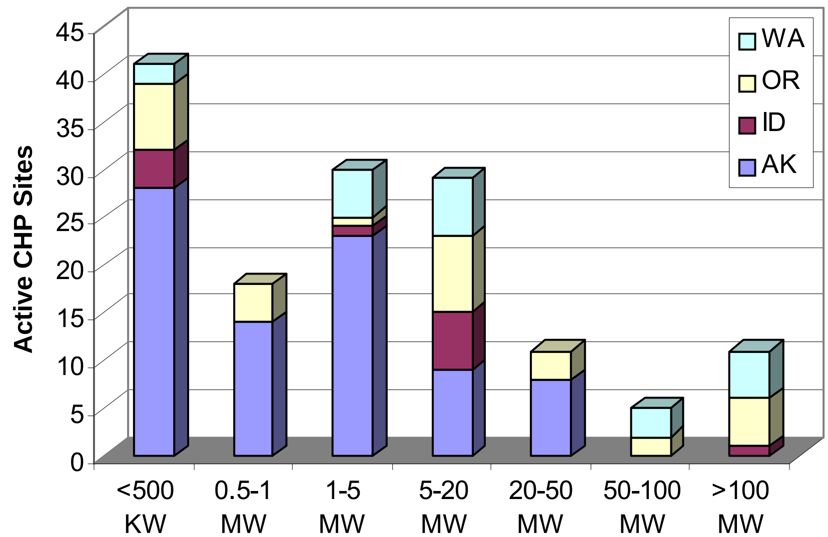


Figure 2-8. Existing CHP Installations by Size and State

2.3 Suspension of Operations and Retirement of Older Sites

The Northwest Power and Conservation Council (NPPC) database lists 39 CHP generators that are not being run or have been retired. Almost all of these systems are wood/waste-fired steam plants in the pulp and paper and wood products industries. The average age of these inactive or retired plants is more than 30 years old, which is probably understated as the oldest plants often lack data for initial year of operation. The majority of retirements have been in Oregon.

2.4 Summary of Existing CHP Installations

<u>2.4.1 State Profiles</u>

Alaska has the highest spark spread (high power costs / low fuel costs), making for a favorable economic environment for CHP. There are also a large number of remote facilities (villages, military bases, and seafood packing plants) where grid power is unavailable. Natural gas is used where available; oil and coal are used in remote areas. Alaska also has the highest share of CHP as a percentage of total generating capacity of the four states in the region.

Idaho has the lowest power costs in the U.S., which results in a low share of CHP as a percentage of total power generation. There are a small number of food and forest product CHP plants; however, there has not been much recent CHP development activity in the state. The average age of the operating CHP plants in Idaho is 20 years old.

Oregon has the highest total CHP capacity in the region. There have been many combined cycle power plants recently installed near the California border that provide steam to Oregon industrial facilities and power to both the Northwest and California power markets. Oregon has very active state incentive programs that support CHP development on the basis of energy conservation, reduction in green house gas emissions, and economic development. Somewhat offsetting these positive trends, Oregon has the highest retirement rate for CHP projects in the declining pulp and paper and wood products industries.

Washington is similar to Oregon and Idaho in industry make-up with a large share of paper and wood product plants, but refinery installations are also important. Washington is suffering from declining traditional industries as well as slumping high-tech industries. As the largest power producer in the region with the highest level of imbedded hydroelectric capacity, Washington has the lowest share of CHP capacity as a percentage of total power production capacity.

2.4.2 Fuel-Use Profile

As in all other regions of the country, natural gas is, by far, the most widely used fuel for CHP in the Pacific Northwest region. Where natural gas is not available in the remote areas of Alaska, diesel oil is used for power generation in village power systems, and coal is used to power generating plants at several military bases. The importance of the pulp and paper and wood products industries in the region brings with it the traditional CHP systems using wood waste and black liquor. Nearly all of these traditional facilities were installed 20 or more years ago, and an increasing amount of traditional facilities are closing down every year. Digester gas is used at thirteen water treatment plants and two dairies in the region. Finally, methanol is used by one experimental fuel cell facility.

2.4.3 Application Profile

Industrial use dominates the market for CHP in the PNW region, but it is concentrated in older, stable or declining industries. Large combined cycle plants are tied more to the economics of the overall Western regional power markets than to the needs of the Pacific Northwest. With the exception of Alaska, there are a very limited number of commercial buildings that have CHP projects outside of large campus power and steam systems. For example, there is one hospital project in Washington, which is the only commercial sector CHP system in the state. Village power systems based on diesel generators with heat recovery are very common in Alaska, although heat recovery is used at only one-third of such systems. The village power plant and heat recovery system for St. Paul Island in Alaska is an advanced system combining diesel generators and wind power turbines. Anaerobic digesters for waste water treatment and dairy manure treatment is an emerging market; most use internal combustion engines to generate power from the digester gas, but a number are using fuel cells and microturbines.

3. CHP BARRIERS AND INCENTIVES[6]

This section provides a description of the barriers and incentives to CHP deployment in the region. These factors affect the economic potential of market penetration for CHP in the region. This section is based on a number of sources as indicated but has relied particularly on information exchanged at an all day meeting of regional stakeholders.[7]

3.1 Barriers to CHP

Kimberly Clark, a manufacturer of paper tissues in Everett, Washington, needed six years from the point at which they reached an internal go-ahead decision on a 52-MW CHP project until the unit was finally on-line and in commercial operation in 1996. The project required a complicated ownership and operating agreement between Kimberly Clark and the Snohomish Public Utility District.[8]

Washington State University engineering staff spent $2 million developing a CHP project for the university. The otherwise economical project was eventually dropped because of the inability to successfully negotiate with the local electric utility that wanted $11 million to provide interconnection, back up service, and power wheeling.

Developing a CHP project from concept to start-up is a complicated process. An individual or a business facility trying to undertake actions to reduce power and fuel costs seems like a simple idea. However, there are barriers within this process that must be addressed:

- Will the equipment work?
- How will the system be interconnected with the electric grid? Is transmission access needed?
- Will changes in future power and fuel costs make this project economically obsolete?
- Is a power or steam contract needed? What are the terms?
- Where will the financing come from and how much will it be? Who will own and operate the facility?
- How will the existing electric service provider be affected and how will they react?
- What are the environmental impacts and what will it cost to address them?
- What about other land use issues such as water use, land use, fire and safety regulations, etc.?

Significant barriers to CHP development in the PNW region are discussed in this section. These barriers include:

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[6] The results presented in this section are derived from the "Subtask 1-4 Deliverable," which was delivered to ORNL in September 2003.

[7] *Pacific Northwest Combined Heat and Power Roundtable: Proceedings*, Northwest Power and Conservation Council and U.S. Department of Energy, Portland, Oregon, June 24, 2003.

[8] "Snohomish County PUD and Kimberly-Clark Corporation Cogeneration Project," *Pacific Northwest Combined Heat and Power Roundtable*, Northwest Power and Conservation Council and U.S. Department of Energy, Portland, Oregon, June 24, 2003.

- Electric utility responses to CHP (back up power costs, interconnection access and costs, utility lost revenues to CHP, transmission access, wheeling and power sales agreements)
- State-level electric industry restructuring (utility control of resource decisions)
- Bonneville Power Administration (BPA) post-2006 role as a power supplier
- Potential role of a Regional Transmission Operator (RTO)
- Natural gas availability and pricing
- CHP facility siting
- Environmental compliance
- Technology uncertainty
- Market-related barriers (commitments required by industry, availability of financing, credit issues, lack of awareness.)

In this context, a barrier is defined as a condition that keeps the CHP market from reaching an economic equilibrium, such as lack of knowledge, exercise of monopoly power, imperfections in measurement that lead to uneconomic application of controls, etc. Whether or not CHP competes at the gas and electric rates expected for the region is evaluated as part of the economic market analysis in **Section 5**. The price competitiveness of CHP, therefore, is not itself defined as a market barrier.

3.1.1 Electric Utility Responses to CHP

A CHP project generally requires continued interaction with the local electric distribution utility to provide interconnection to the power grid, standby service, and supplementary service. Other services may be desired as well, such as a purchase agreement for excess power production or access to the power grid to *wheel* the power to another owned site or for a third-party purchase. For the past 25 years, there have been federal requirements under the Public Utilities and Regulatory Policies Act of 1978 (PURPA) that require certain levels of cooperation from utilities toward qualifying CHP facilities. The success of PURPA in eliminating utility imposed barriers to CHP implementation has been mixed. While certainly stimulating the market growth for CHP that has occurred in the last 20 years, the requirements of PURPA have fallen far short of creating an environment in which CHP competes equally with other utility and non-utility power options. In a restructured electric power industry, the value of on-site generation to the generating customer, the utility, and the ratepayer in general needs to be re-examined so that pricing and operating rules fairly reflect the benefits of on-site generation.

Grid Interconnection

The optimal economic use of distributed generation (DG) for most customers requires integration with the utility grid for back-up, supplemental power needs, and, in selected cases, for selling generated power. The key to the ultimate market success of small on-site generation is the ability to safely, reliably, and economically interconnect with the utility grid system. However, grid interconnection requirements for self-generators, as they exist today, are a significant barrier to more widespread economic deployment of smaller DG systems.

Interconnect requirements for on-site generation have an important function. They ensure that the safety and reliability of the electric grid is protected, and the utilities have ultimate responsibility for system safety and reliability. For the utilities, there are three primary issues. First, the safety of the line personnel must be maintained at all times. Utilities must be assured that DG and other on-site generation facilities cannot feed power to a line that has been taken out of service for maintenance or as the result of damage. Second, the safety of the equipment must not be compromised. This directly implies that an on-site system failure must not result in damage to the utility system to which it is connected or to other customers. And third, the reliability of the distribution system must not be compromised.

These basic concerns are important and legitimate. However, non-standardized, out-dated, and in some cases, overly stringent interconnect requirements have long been a barrier to widespread deployment of small on-site generation technologies. Interconnect requirements vary by state and/or utility and are often not based on state-of-the-art technology or data. Compliance often requires custom engineering and lengthy negotiations that add cost and time to system installation. These requirements can be especially burdensome to smaller systems (i.e., under 500 kW). Non-standardized requirements also make it difficult for equipment manufacturers to design and produce modular packages. The lack of uniformity from state to state, as well as from utility to utility within a given state, lessens the economic payback for on-site generation, no matter the market segment or type of end-use application.

A national interconnection model standard – 1547 – developed by the Institute of Electric and Electronics Engineers (IEEE) will provide a uniform standard for interconnection of distributed resources with electric power systems.[9] Currently, each of the four states in the PNW region allows utilities to set their own interconnection standards. Adoption of IEEE 1547 at the state level would help to minimize project costs associated with unnecessary hardware or inspections, as well as the cost of project delay.

Standby/Back-up Charges

On-site generation usually requires back-up power to cover downtime for routine system maintenance or for unplanned outages. Standby rates are a fixed monthly charge for reserved generation and distribution capacity to provide this back-up power. Generally, standby service is billed based on the rated capacity of the self-generation unit or customer peak demand whichever is lower. Should a customer actually require back-up power, additional charges are invoked that reflects the cost of supplying power to a self-generation customer during an outage. These back-up charges often contain an additional demand charge. These charges as currently configured may not necessarily reflect a utility's actual cost, nor do they necessarily reflect the diversity of DG resources on the system.

A fair calculation of the true costs of these services and competitive means for supplying them are essential to ensure the economic implementation of on-site generation. However, state regulators struggling with the larger issues of restructuring are in general unaware of the importance of standby fees and back-up charges on the economic viability of on-site generation. Education and outreach are needed to bring this issue to the forefront in rate discussions. Alternative approaches such as designing standby fees based on the statistical probability that some level of on-site generation on a system will be operable even if individual units are down need to be evaluated and promoted. Similarly, unreasonable performance requirements on customer-owned units can easily negate the customer value of distributed generation and must be avoided.

Status of Power Industry Restructuring

In the past decade, there has been a movement to restructure the electric power industry. The goal of this restructuring is to allow competitive forces to drive the generation of power. The competition

[9] http://grouper.ieee.org/groups/scc21/1547/

is fostered by an open-access transmission system for power delivery and a separation of generation, transmission, and distribution functions. It was believed that this competition would bring lower cost power to a greater percentage of power users. In fact, restructuring did provide a mechanism in which the benefits of competition could flow through to customers. However, as experience in California and other regions has shown, bringing competition into the power industry brought with it a host of other problems including price volatility, degradation of system reliability, and financial insolvency for some of the nation's largest utilities.

The negative repercussions in California and other areas resulting from the imperfect attempts to provide a fair competitive environment for power have pretty much put a stop to restructuring activities in the PNW region. As a low-cost-power region, there was never the motivation for restructuring that there was in the high-cost regions. Today in the PNW region, only Oregon is proceeding with a program of retail electric industry restructuring. The restructuring activities that have occurred state-by-state in the PNW region are described in **Appendix B**.

Of course, movement toward a competitive wholesale power market continues nationally affecting all regions, including the Pacific Northwest. Within the PNW region, these trends are best understood within the context of what the future role of the Bonneville Power Administration (BPA) will be.

3.1.2 Bonneville Power Administration Role

A critical near-term barrier to CHP – cited by industrial customers and utilities at the Northwest Power and Conservation Council CHP Roundtable – is the uncertain role of BPA in power supply after 2006.

The Bonneville Power Administration is a federal agency, under the U.S. Department of Energy, that markets wholesale electrical power and operates and markets transmission services in the Pacific Northwest. The power comes from 31 federal hydroelectric projects that comprise the Federal Columbia River Power System (FCRPS), one nonfederal nuclear plant, and several other nonfederal power plants. About 45 percent of the electric power used in the Northwest comes from BPA. BPA's transmission system accounts for about three-quarters of the region's high-voltage grid, and includes major transmission links with other regions. BPA is a self-funding agency, which pays for its costs through power and transmission sales. Both power and transmission are sold at cost, and BPA repays any borrowing from the U.S. Treasury with interest. BPA's customers include publicly owned and investor-owned utilities, as well as some large industries. BPA also sells or exchanges power with utilities in Canada and the Western United States.

The basic issue for BPA is whether or not they will be responsible for planning and procuring needed new capacity for their customers or whether their customers will have to find other sources of supply. In particular, the direct-service industries (DSIs) in the region only have a five-year commitment for power from BPA. They have asked for certainty regarding their sources of power after 2006 so that they can make investment decisions regarding their plants. These companies see their access to cost-based federal power as an important economic factor in operating these plants.

Some utilities and independent power producers wish to make decisions soon regarding investments in existing and new power plants, which could require capital funding. This capital is needed to ensure that the region has the necessary power supply to support a healthy economy. However, capital often can be difficult to secure without clear evidence of future customers and the ability to reach them.

These entities would like an understanding of what power supply role BPA will play in the wholesale marketplace after 2006. If BPA must supply power for loads greater than the capability of the existing federal system after 2006, it will need to begin making arrangements for augmenting the federal system soon.

Currently, there is an extensive public debate ongoing that involves the Northwest Governors, BPA's customers, the Northwest Power and Conservation Council, other interested groups, and the courts. It is expected that a resolution of these issues will be forthcoming soon.

Another area of uncertainty lies in BPA's transmission business and proposed development of *RTO West*, a regional transmission organization (RTO) that a coalition of utilities in the Northwest United States and British Columbia are working to develop. The coalition includes Avista Corporation, Bonneville Power Administration, British Columbia Hydro and Power Authority, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, and Sierra Pacific Power Company.

It is hoped that RTO West can eliminate the "rate pancaking" that occurs when power moves across individually owned transmission lines and provide better price signals for placement of generating resources.

3.1.3 Facility Siting

Siting of major CHP facilities has become increasingly difficult. *Not-in-my-backyard* (NIMBY) is a prevalent attitude. Facilities must address air quality, water quality, water usage, land use, noise, traffic, and economic issues. In order to ensure consistency in the achievement of federal and state regulations and desired social goals, most states have taken the authority away from local government agencies and brought the siting and permitting process under state control. These state-level siting processes were designed to address the large-scale power systems of the regulated power industry. In many states, there are minimum sizes for which state control is taken. In Washington, the minimum size threshold for a power plant is 250 MW. In Oregon, the threshold is 25 MW.[10] In Idaho and Alaska, there are no specific state-level siting exemption statutes.

A large share of the potential CHP market both in the PNW and in the U.S. as a whole will be below 50 MW. For projects below the state siting size threshold, local control of siting will be in force. Many local jurisdictions are ill equipped to handle facility siting. Lack of experience with CHP technologies has led many local permitting agencies to exercise an extreme form of caution and conservatism that makes it difficult for projects to be approved. Contentious, lengthy siting processes have significant economic and social costs in the form of higher electricity costs and lost generation opportunities and also the introduction of strong divisions within a community that limits the ability for positive action.

An assessment of CHP barriers prepared by the Washington State University Energy Program provides an eloquent description of the siting problem:[11]

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[10] R. Gordon Bloomquist, et *al*., *Combined Heat & Power: Legal, Institutional, Regulatory*, WSUCEEP01-013, Washington State University Energy Program, March 2001.

[11] Bloomquist, *op cit.*

> Contentious, lengthy siting processes have significant economic and social costs, the former ultimately resulting in higher electricity costs or lost opportunities for the development of cost-effective generation, and the latter degrading a community's cohesiveness, regardless of the issue. …Few local jurisdictions have public involvement standards and procedures for major projects such as energy facilities. Further, they rarely have trained staff to facilitate or negotiate complex projects among strongly adversarial groups.

Alaska Siting Issues

In the state of Alaska, the Regulatory Commission only regulates public utilities. Hence on-site CHP does not need a certificate from the commission as long as the load is used entirely on-site. However, the sale of excess capacity to the grid would require a Certificate of Public Necessity from the Regulatory Commission. Alaska does not have a specific state level oversight of facility siting. In remote areas – and most of Alaska is not connected to an electrical utility grid – local controls have been minimal.

Idaho Siting Issues

The Idaho Public Utilities Commission (PUC) only issues Certificates of Public Convenience and Necessity for new regulated utility plants. Unregulated (merchant) plants do not require PUC approval, but they must have the approval of the Idaho Department of Environmental Quality for their proposed air and/or water emissions. Local planning and zoning officials deal with the actual site development. However, the PUC acts as the mediator of disputes between a developer and local planning and zoning officials.

Oregon Siting Issues

In 1975, the Oregon Legislature established the Energy Facility Siting Council. The Council has the responsibility to make sure that large energy facilities are located, built, and operated in ways that protect the environment and public health and safety.

No one may build a large energy facility in the state until the Council has issued a site certificate for the facility, which ensures that the facility meets the Council's siting standards. The site certificate binds state and local jurisdictions to the Council's action and requires them to issue permits, licenses, and certificates for construction and operation of the facility. The Council monitors the construction of the facility, and, after the facility is built, the Council monitors its operation.

Oregon law exempts high-efficiency cogeneration facilities from the site certificate requirement. Under Council rules, a "high-efficiency cogeneration facility" means an energy facility that sequentially produces electrical and useful thermal energy from the same fuel source. The criteria for exemption are that the facility, under normal operating conditions, have a useful thermal energy output of no less than 33 percent of the total energy output or:

- For an energy facility with a nominal electric generating capacity of 50 MW or more, a fuel chargeable to power heat rate of no greater than 5,550 Btu per kWh
- For an energy facility with a nominal electric generating capacity of less than 50 MW, a fuel chargeable to power heat rate of no greater than 6,000 Btu per kWh

The Council has the authority to revise the heat rate values periodically to take into account improvements in technology.[12]

Washington Siting Issues

Chapter 80.50 of the Revised Code of Washington (RCW) includes the laws that the Energy Facility Site Evaluation Council (EFSEC) must follow in siting and regulating major energy facilities. Title 463 of the Washington Administrative Code (WAC) includes regulations by which the EFSEC functions under state and federal law. The rule only applies to plants that are 350 MW or greater. When an application to site a facility is submitted to the EFSEC, it is augmented by representatives from particular cities, counties, or port districts potentially affected by the project.

The EFSEC was created in 1970 to provide "one stop" licensing for large energy projects. By establishing the EFSEC, the State Legislature centralized the evaluation and oversight of large energy facilities into a single location within the state government. The Legislature called for "balancing" demand for new energy facilities with the broad interests of the public. As part of the balancing process, protection of environmental quality, safety of energy facilities, and concern for energy availability are all to be taken into account by the EFSEC.

The EFSEC responsibilities include siting large natural gas and oil pipelines, electric power plants above 350 megawatts and their dedicated transmission lines, new oil refineries or large expansions of existing facilities, and underground natural gas storage fields. The EFSEC's authority does not extend to hydro-based power plants, to smaller electric plants, or to general transmission lines.

As of May 8, 2001, energy facilities of any size that exclusively use alternative energy resources (wind, solar, geothermal, landfill gas, wave or tidal action, or biomass energy) can opt-in to the EFSEC review and certification process.

The EFSEC has been delegated authority by the U.S. Environmental Protection Agency (EPA) to issue permits under the Federal Water Pollution Control Act and the Federal Clean Air Act for facilities under its jurisdiction. The EFSEC also ensures that effective and coordinated nuclear emergency response plans are in place and satisfactorily tested for the WNP-2 nuclear power plant located at Hanford, Washington.

3.1.4 Environmental Compliance

Environmental permitting is part of facility siting issues, but at the same time, it is a different process, reporting to different local, state, and federal agencies. The time and analysis required for compliance can delay projects and add to the cost. In addition, the requirements for environmental control technologies can add to the cost of the project. In the PNW region, environmental requirements are the strictest in Oregon and Washington. NO_x control is required for all but the smallest applications. In Idaho and Alaska, emission control requirements are minimal except for major source requirements for large industrial applications. There are no special requirements or exemptions for CHP in these states. **Appendix C** provides a state-by-state description of project characteristics that fall under different parts of the federal air quality regulations.

[12] http://www.energy.state.or.us/siting/juris.htm

3.1.5 Market Issues

Financial Barriers

Tax policies can significantly affect the economics of investing in new equipment such as on-site power generation. On-site power generation systems do not fall into a specific tax depreciation category. On-site generation equipment can qualify for one of several categories depending on configuration and ownership, so that the resulting depreciation period can range from five to 39 years. Existing depreciation policies may foreclose certain ownership arrangements for on-site generation, increasing the difficulty of raising capital and discouraging development.

The distributed generation community believes that a five- to seven-year depreciation schedule more accurately reflects the economic life of on-site generation equipment. The Department of Energy (DOE) and Environmental Protection Agency (EPA) have been working with the White House staff and the Department of Treasury to review existing depreciation categories for on-site generation equipment and to consider investment tax credits for CHP. Treasury is considering allowing on-site equipment in buildings to qualify for a 15-year depreciation schedule, similar to on-site generation equipment in industrial applications and significantly shorter than the current 25- to 39-year depreciation schedules for building applications.

Customer Needs and Perceptions

While interest in distributed and on-site generation has grown, a number of market-related barriers exist that constrain market acceptance:

- On-site generation is still not considered part of most users' core business and, as such, is often subject to higher investment hurdle rates than competing internal options.
- Small distributed generation technologies, microturbines in particular, have improved significantly since the early 1990s and are gaining greater market acceptance. Most users, however, remain unaware of the cost and performance benefits that may be available.
- Customer requirements and needs are yet to be fully analyzed and understood by equipment manufacturers and developers.

The criteria for a customer to implement on-site generation or any energy management strategy are complex and becoming even more complicated as the industry evolves. Key issues from the customer's perspective are outlined below.

Very large energy-using facilities typically have engineering, marketing, and legal staff devoted solely to energy procurement and energy facility management. For smaller industrial and commercial customers, however, this capability generally does not exist in-house. Businesses may not want to devote their capital and staff resources to an area like owning and operating a CHP facility. Concerns about technology performance, future costs, maintenance issues, noise, and the need to revise environmental operating permits create a difficult environment for CHP.

Energy service companies (ESCOs) help to bridge this gap, but must first overcome the initial resistance of businesses and financial institutions to complicated and "unproven" technology. Consumer education programs and successful technology/application demonstration programs can reduce the general resistance to CHP. However, beyond this activity, it will be important to eliminate barriers to streamline the process of siting, permitting, interconnecting, financing, and contracting for CHP facilities.

3.2 Incentives for CHP

While there are many hurdles that remain in the way of the widespread implementation of CHP, the PNW region has also established a number of incentives to encourage utilities, industry, and consumers to adopt CHP. Some of these incentives are discussed below.

3.2.1 Conservation and Renewables Discount – Bonneville Power Administration

The Bonneville Power Administration (BPA) offers the Conservation and Renewables Discount (C&RD) program to their customers (public utilities, investor-owned utilities, and direct service customers) to encourage the development of more energy-efficient technologies, renewable resources, and new distributed energy technologies in the Pacific Northwest.[13] The goal of this program is to realize substantial value through lower energy costs, less pollution emissions, less investment in transmission and distribution (T&D) infrastructure, better customer service, and higher reliability by taking advantage of these resources and technologies. This goal has become especially important since the region is not in a power surplus situation, and new generation resources are being developed.

Project funds are available from a base credit of 0.5 mills/kWh and equal about $30 million annually. An additional 0.25 mills/kWh, about $15 million annually, is potentially made available from BPA's dividend sharing. Supplemental funds will be made available if spending in renewables is less than $6 million annually and spending on low-income weatherization is less than $4 million annually.

The utility customers of BPA direct the spending themselves, and are credited an appropriate amount on their BPA bill. Partial requirements customers (i.e. mainly the investor-owned utilities) receive a prorated credit on their investments. Such spending must be considered incremental to the utility's base spending, and the impacts on power consumption must be specified (deemed) at a level determined by technical advisors to the program – the Regional Technical Forum (RTF) of the Northwest Power and Conservation Council.

In the case of the small-scale CHP plants being developed by the Northwest CHP Consortium (spearheaded by Northwest Natural in Portland), the incentive available is up to $5,000 per site. As previously stated, the maximum credit is applied for projects within municipal utility territories that rely on BPA for their full power requirements.

The BPA C&RD is available throughout the Pacific Northwest region, not just in Oregon. Though, it should be noted that the BPA defines its region to include the four states in the Columbia River watershed – Idaho, Montana, Oregon, and Washington; Alaska is not included.

3.2.2 State Energy Programs – Application of Federal Funds

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[13] *Bonneville Power Administration: An Explanation and Description of the Conservation and Renewables Discount*, Northwest Power Planning Council, Regional Technical Forum, Online Text
http://www.nwcouncil.org/energy/rtf/crd/description.htm#1.4

The Department of Energy State Energy Program (DOE-SEP) provides funding to states to design and carry out their own energy efficiency and renewable energy programs. The Western Regional Office (WRO) of the DOE manages the SEP in the Pacific Northwest. The programs are administered by state agencies:

- Rural Research & Development Department, Alaska Housing Finance Corporation – http://www.ahfc.state.ak.us/
- Idaho Department of Water Resources – http://www.idwr.state.id.us/energy/
- The Oregon Office of Energy – http://www.energy.state.or.us/
- The Energy Policy Division of the Department of Community, Trade & Economic Development – http://www.energy.cted.wa.gov/

CHP-relevant DOE-SEP grants in the Pacific Northwest include the following:

- In 2003, just under $300,000 was provided to establish the Northwest Regional Combined Cooling, Heating and Power (CHP) Application Center to serve the needs of Alaska, Idaho, Oregon, Montana, and Washington. The Center, under the management of Washington State University Energy Program (WSUEP), plans to be an important resource for those interested in developing or advancing CHP projects in the region. To facilitate the development and successful operation of a broad range of CHP technologies and projects, it will develop a comprehensive education and outreach program.
- In 2003, $100,000 was provided to install an experimental hydrogen-fueled PEM fuel cell at Central Washington University. The grant includes amounts for education and outreach.
- In 2002, Oregon received $65,000 for a microturbine CHP system with uninterruptible power supply (UPS) and absorption cooling.
- In 2002, the Washington State University Energy Program (WSUEP) received a $100,000 grant to determine the technical and economic feasibility of serving a multi-block redevelopment area in Seattle through an integrated distributed energy system.
- In 2001, Idaho received $75,000 for a program to educate the livestock industry on anaerobic digestion (AD), with the goal of installing five AD systems in the Magic Valley by 2005. This project involves a complete design and feasibility analysis for the installation of an AD system at a specific dairy selected by an oversight committee. This grant is in addition to a $40,000 grant to promote AD provided in 2000.
- In 1999, a $189,000 grant was made to WSUEP to develop a comprehensive guidebook to help potential combined heat and power (CHP) developers navigate the legal, institutional, regulatory, and environmental maze critical to widespread development of the technology at Industries of the Future (IOF) industrial sites.
- Numerous energy projects of the Alaska Energy Authority, described in the next section, are supported by DOE-SEP formula grants and investment in National Energy Priorities.

For small-scale CHP projects below 500 kW, the anticipated funding through DOE-SEP grants is expected to be in the range of $300-500/kW.

3.2.3 Alaska Incentive Programs

The Alaska Energy Authority (AEA) was created by the state legislature in 1976 to provide affordable power to promote and develop the economic welfare of all Alaska residents. The AEA has a particular focus on rural energy systems. Alaska has more than 118 independent utilities serving a total population of fewer than 622,000 and covering an enormous range of geographic and economic diversity. Emergency responses to utility systems and fuel storage failures are provided, as necessary, to protect the life, health, and safety of rural Alaskans.[14] The AEA operates a number of programs that could be applied to promote CHP projects or that indirectly create an environment of energy awareness in which CHP could more easily be promoted.

The AEA and Denali Commission[15] have initiated a joint solicitation to provide grants and low-interest loans for energy cost reduction and CHP projects. About $5 million has been awarded to date. The program focuses on rural areas. The grant structure is complicated, but for CHP projects, about half of the project cost is eligible for grants and the remaining portion is eligible for loans from the *Power Project Loan Fund.* The Power Project Loan Fund provides loans to local utilities, local governments, or independent power producers for the development or upgrade of electric power facilities, including conservation, bulk fuel storage, and waste energy conservation, or potable water supply projects. Loan term is related to the life of the project. Interest rates vary between tax-exempt rates at the high end and zero on the low end. Approximately $3 million per year has been made available for loans in the recent past.

Under a program called *Rural Power Systems Upgrades*, the AEA provides operational, technical, and emergency assistance for village power systems. This program is focused on promoting efficient and safe operation of their systems. In a related program, *Rural Technical Assistance* (RTA), technical assistance is provided to rural utilities in evaluating deficiencies and needs with respect to the collective energy systems and facilities within a community. Both of these programs help to create a more knowledgeable and receptive environment for expansion of the number of heat recovery systems in use by rural power systems. Other programs, such as *Meter Installation and Data Acquisition* and *Emergency Preventio*n help to strengthen the technical capabilities of rural power systems operation.

The AEA *Energy Conservation Program* promotes energy efficiency in schools and other large facilities. The Rebuild America Program, part of SEP, in Alaska is called *Rural Alaskans Conserve Energy* (RACE). This program provides energy audits and technical assistance in the rural village power systems – many of which have heat recovery systems in place.

The AEA also supports renewable energy development. The *Alaska Bioenergy Program* provides financial and technical assistance for using wood and waste to produce power, heat, and processed fuels. The program is funded in part by the U.S. Department of Energy. Recent projects include waste wood-to-ethanol production in Southeast Alaska, wood-fired district heating in rural interior Alaska, biomass resource assessment, and analysis of small waste-to-energy feasibility.

The *Coal and Natural Gas Program* seeks to develop small coal and natural gas-fueled energy systems suitable for rural locations. Recent projects include the preparation of a computer screening model for small coal-fired thermal energy stations and assessment of the economics of developing local natural gas resources for rural energy production. Work is conducted in cooperation with the University of North Dakota Energy and Environmental Research Center.

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[14] Online Description of Programs, http://www.aidea.org/aea.htm.

[15] The Denali Commission is an innovative federal-state partnership established by Congress in 1998 to provide critical utilities, infrastructure, and economic support throughout Alaska.

Under the *Fuel Cells and Energy Storage* program – the AEA provides funding and technical support for fuel cell and energy storage development in Alaska. Partners include Chugach Electric Association, Copper Valley Electric Association, the University of Alaska Energy Center, Sandia National Laboratory, and the U.S. Department of Energy.

3.2.4 Idaho Incentive Programs

The mission of the Idaho Energy Division of the Department of Water Resources (DWR) is "to promote and support communities' participation with cost-effective energy conservation programs and the utilization of renewable energy resources by providing training, technical assistance, information, and financial support to consumers, producers, and policy makers."[16] Programs relevant to CHP include a strong focus on renewable fuels and support for CHP-intensive industries such as the food industry and forestry products through the DOE-SEP *Industries for the Future* program.

Biomass has supplied approximately nine percent of the total energy used in Idaho in recent years and there is enough biomass waste (forest and logging residue, municipal solid waste, agricultural residues, animal waste, agricultural processing residue) to supply all the energy Idaho uses. The *Bioenergy Program* is designed to promote the effective use of locally grown, renewable biomass energy resources. It does this by providing technical assistance, offering educational workshops, and sharing costs for demonstration projects. Through support of the U.S. Department of Energy's Pacific Northwest and Alaska Regional Bioenergy Program and the state of Idaho, the program maintains a full-time technical staff person to provide assistance to people interested in bioenergy project development. The technical assistance includes evaluation of plans, referral to equipment vendors and other technical experts, and assessment of biomass feedstock supply and bioenergy product markets.

The Idaho Bioenergy Program has sponsored several demonstration projects. These include an on-the-road demonstration of bio-diesel with the University of Idaho, a new wood pellet mill feedstock dryer at the Jensen Lumber mill in southeast Idaho, a biogas cleaning system at the Nampa Wastewater Treatment Plant, and a small backpressure turbine at the Ceda-Pine Veneer mill in Samuels. The Idaho Bioenergy Program was also instrumental in the decision of the University of Idaho to install its wood-fired boiler for campus heating and cooling.

Low Interest Energy Loans for energy conservation or renewable energy are offered at 4% with a five-year repayment requirement. Energy savings must be at least 10% of the project cost. Residential loans are from $1,000 to $10,000. For commercial, agricultural, schools, hospitals, health care, or renewable energy, the loan awards may range from $1,000 to $100,000.

The DWR also helps to bring facilities (minimum 50,000 square feet) together with performance contractors for third party financing of energy efficiency projects. Two large universities in the state, a military installation, and a number of local governments have participated in the program.

The Idaho Public Utilities Commission (IPUC) has established avoided cost rates for cogeneration and small power producing projects that are smaller than 10 MW. For these projects, the IPUC sets the avoided cost rate in a range of from 4.5 to 5.5 cents/kWh. These rates are typically higher than prevailing industrial electric rates, encouraging simultaneous buying and selling for CHP projects in this size range.

[16] Online program description http://www.idwr.state.id.us/energy/

3.2.5 Oregon Incentive Programs

The Oregon Office of Energy (OOE) is the most active of the state energy programs in the PNW region. There are a number of incentives being offered in Oregon that are designed to promote CHP and renewable energy use.

Business Energy Tax Credit (BETC)

The OOE has instituted the Business Energy Tax Credit (BETC). The BETC is available for Oregon businesses that invest in energy conservation, recycling, renewable energy resources, or less polluting transportation fuels.[17] The tax credit is 35% of eligible project costs – the incremental cost of the system or equipment that is beyond standard practice. The tax credits are taken over a five-year period (10%, 10%, 5%, 5%, 5%) or may be carried forward for up to eight years. About $100 million in tax credits have been provided to date. A tax-exempt public entity or non-profit organization may take advantage of the BETC by using the *pass-through option*. In this case, the tax-exempt entity passes through the tax credit to a business partner with tax liability for a lump-sum cash payment.

CHP projects are eligible for the tax credit but must exceed a standard of 6,800 Btu/kWh by 10% and have a simple payback of one to 15 years. For small CHP systems used in demonstration projects or for projects using renewable fuels, the entire amount of the investment is eligible for the credit. Otherwise, only the portion of the investment that is considered beyond standard practice for heat recovery is eligible.

Oregon Small Scale Energy Loan Program

Low interest loans are available for a variety of energy efficiency projects including waste heat and renewable energy programs.[18] Terms of the loans vary by the type and size of the project. The program has provided nearly $300 million in low interest loans for energy projects to date. CHP, district heating, and methane gas recovery are among the list of eligible projects. The current rate available for a CHP project is 4.25%. The loans also qualify as matching funds for grants from other programs, specifically Federal programs. Many Federal grant programs (see discussion of DOE State Energy Programs in this section) will not allow state government money to be used as matching funds. In this case, since all of the money is repaid by the project, Oregon has an exemption from this restriction.

Energy Trust of Oregon

The Energy Trust of Oregon (ETO)[19] began operation as a nonprofit, charitable organization in March 2002 to fulfill a mandate to invest "public purposes funding" for energy efficiency, conservation, and renewable energy resources in Oregon. The mandate emerged from 1999 energy restructuring legislation (Senate Bill 1149) that included a 3% public purposes charge to the rates of the two largest investor-owned utilities. Subsequent action by the Oregon Public Utility Commission encouraged the startup of a new nonprofit organization to administer the funds created by the legislation. A portion of

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[17] Personal Communication, Mark Kendall, Senior Energy Analyst, Technology Development, Oregon Office of Energy, and OOE Online Description, http://www.energy.state.or.us/bus/tax/taxcdt.htm.

[18] Personal Communication, Mark Kendall, Online Description http://www.energy.state.or.us/loan/selphme.htm

[19] http://www.energytrust.org/

the funding also is dedicated to low-income housing energy assistance and K-12 school energy conservation efforts.

In an agreement between the Energy Trust and the PUC, specific guidelines were established for implementing programs to ensure that the Energy Trust meets the intent of the sponsoring legislation. These guidelines include:

- Program funding will seek to encourage the development of competitive markets for energy efficiency services and renewables as a long-term outcome.
- Public purpose funding will be competitively bid except when circumstances warrant an alternative approach.
- Individual conservation programs will be designed to be cost-effective and will be independently evaluated on a regular basis. This guideline should not restrict investment in pilot projects, educational programs, demonstrations, or the like.
- A majority of the conservation funds will be spent or committed in the year the funds are received.
- All classes and geographic areas of funding consumers should benefit from the public purpose expenditures.
- The organization will work to complement, not compete with, existing programs.

The Energy Trust's original funding source is the grant agreement with the PUC that dedicates funds collected by utilities into the Energy Trust. However, the Energy Trust expects to draw funding from other sources to complement the resources provided by SB 1149. Additional funds potentially include public purposes funding from natural gas utilities, funding from government energy programs, and grants from charitable foundations. SB 1149 requires spending at least 80 percent of the conservation funds from utilities within the service area of the utility that collected the funds.

The ETO supports a wide range of projects. The ETO recognizes that CHP could help to meet their goal of reducing electricity demand by 300 MW and that improved use of thermal output could make some forms of renewable generation more economic in support of their goal of 10% renewable electric production in Oregon by 2012. The ETO's approach to CHP projects was spelled out in a written Policy Statement:[20]

- Cost-effective use of thermal output from fossil generators or other equipment, regardless of fuel sources, may be considered by Energy Trust staff to be a "program-eligible energy efficiency" for activities funded under the current PUC grant agreement and under the PUC decoupling agreement with Northwest Natural (Order 02-634 dated September 12, 2002), provided that:
    - Energy Trust funding is needed for the efficient use of the thermal output to proceed.
    - Energy Trust funding is unlikely to result in the siting of additional fossil generation.
    - The end-use of energy reduced is in a location, customer type, and fuel type covered by the PUC grant agreement or the decoupling agreement, or a future agreement with another funder.
    - The energy user must continue to place loads on the utilities covered by the Energy Trust funding agreement.

[20] *Board Decision – Combined heat and Power Policy*, Energy Trust of Oregon, Inc., December 19, 2002.

- Any CHP projects supported by the Energy Trust must have significant use of thermal output.
- For fossil-fueled CHP projects that generate more than 500 kW in generating capacity:
    - The Energy Trust should not pay more than the incremental cost of an efficient heat recovery system over standard-practice heat recovery for similar units.
    - Energy Trust investments in CHP heat recovery must be cost-effective as efficiency investments and consistent with other applicable program rules.
- For up to three small-scale CHP demonstration projects (less than 500 kilowatts in generating capacity per year), the Energy Trust may help pay a portion of the cost for heat utilization equipment. These projects may include fossil-fueled plants where the waste heat is used to reduce direct use of electricity or fossil fuels. These projects must be part of a broader project to transform a portion of the small generation market to high-efficiency heat recovery.

The ETO has further delineated this policy to provide preferential support for small CHP projects less than 500 kW and to reiterate that CHP from renewable fuels qualifies under renewable guidelines. The heat recovery portions of larger projects are supported to the extent they can show in incremental improvement to their heat recovery efficiency.

For small CHP projects, the ETO is providing $5,000 per site to support engineering services to optimize the integration with site thermal needs. In the renewable fuels CHP area, ETO has made a commitment to help fund the Threemile Canyon Farms biogas project in Boardman, Oregon. The farm is home to more than 20,000 dairy cows. The biogas equipment will capture methane from cow manure and burn it to generate electricity. This project will deliver 3.85 average megawatts per year for 15 years at a cost of $1.5 million. The project is scheduled to be installed in 2004. The ETO will pay at the rate of avoided generation for 15 years.

Climate Trust of Oregon

The Climate Trust of Oregon (CTO) is a nonprofit organization formed in 1997 in response to landmark Oregon legislation requiring new power plants to counter their global warming impact. This standard requires new power plants to offset a significant portion (approximately 17%) of their carbon dioxide emissions. A plant developer may choose to meet part or all of its reduction target by paying mitigation funds to a “qualified nonprofit.” This nonprofit in turn must use the funds to carry out projects that avoid, sequester, or displace the carbon dioxide the plant will emit in excess of the required standard. The CTO conforms to the requirements of the law and is recognized as a qualified nonprofit. The CTO uses the funds to acquire and manage contracts for offset projects from mitigation measures such as renewable energy, energy efficiency, energy system decarbonization, and forest carbon sequestration.

Standards are 17% below the most efficient gas-fired power plant in the U.S. The current standard is based on the most efficient base-load plant efficiency of 6,800 Btu/kWh (HHV) with an emission rate of 0.79 lbs. CO_2/kWh. The offset can be made through CHP either directly or by monetary transfer to the Climate Trust. The monetary path requires a payment of $0.85/short ton of carbon dioxide plus *selection and contracting funds*.[21]

[21] Selection and contracting funds equal 10% of the offset funds up to $500,000 and 4.286% of additional offset funds. On smaller projects, contracting funds equal 20% of the first $250,000 and 4.286% above that.

For the small projects being pursued by the Northwest CHP Consortium (spearheaded by Northwest Natural in Portland) with excellent heat recovery, Climate Trust payments of $100-200/kW are expected.

CHP Natural Gas Rate

In addition to the efforts of the Oregon Office of Energy, Northwest Natural has announced its intent to establish an experimental DG rate for natural gas – a temporary five-year rate reduction for distributed generation.[22] Northwest Natural is a driving force behind the Northwest CHP Consortium, composed of both public and private funding sources, whose aim is to stimulate market development for small CHP systems in the Northwest.[23] The Consortium has a near-term goal of reaching 15 MW of market penetration for CHP. In their first project, a microturbine with absorption cooling at an office building in downtown Portland, the gas cost was reduced from $0.76/therm to $0.42/therm, a 45% reduction. The experimental rate will be based on the customer's load characteristics and will involve a reduction in the margin on both the transport and commodity. The Oregon PUC has not yet formally approved the rate.

3.2.6 Washington Incentive Programs

The Office of Trade and Economic Development provides a variety of services to Washington State business. The Energy Policy Division provides input to the governor and the legislature on energy policy. Through an advisory committee, a number of strategy issues have been identified:

- Methods to create new electricity capacity
- Obstacles to and incentives for new generation and transmission (in a hydro environment)
- Methods to encourage demand management, distributed generation, energy efficiency, and conservation
- Improvements in coordination between state and regional planning
- Strategies and options to reduce greenhouse gas emissions from state government activities

Through conservation surcharges, the investor-owned utilities (IOUs) operating in Washington collect funds for energy efficiency programs applicable to both gas and electricity use.

The Washington Department of Revenue used to provide exemption from excise tax for utility investments in conservation and cogeneration from renewable energy. However, this program was terminated in 1999. Efforts are underway in the state legislature to reinstate this program.

Another program aimed primarily at economic development in rural and poor urban areas also provides an incentive to CHP. *The Distressed Area Sales/Use Tax Deferral Program* grants a deferral for manufacturing, research and development, or computer-related businesses (excluding utilities) locating in

[22] Chris Galati, Director of Conservation & Technology, Northwest Natural Gas, Introductory Remarks CHP Consortium Board Meeting, April 15, 2003.

[23] Originally called the 200 Market Building Consortium, after the address of the first project, the Northwest CHP Consortium is funded by Northwest Natural, Oregon Office of Energy, City of Portland, BPA, Pacific Power & Light, Russell Development, the Industrial Center, and the American Gas Foundation (an entity of the American Gas Association), and the Gas Technology Institute.

specific geographic areas. The sales/use taxes on qualified construction and equipment costs are waived for qualifying projects. While the program is intended primarily for capital investments related to the main business, "cogeneration facilities that are part of a manufacturing facility qualify on the portion that is used to generate power for on-site consumption." In addition, at least one qualified employment position must be created for every $750,000 of investment on which the deferral is requested.

3.2.7 Net Metering Programs

Alaska Net Metering

Alaska does not have a net metering or interconnection standard promulgated by the State Regulatory Commission.

Idaho Net Metering

In 2002, the Idaho PUC issued Order No. 28951, which allowed Idaho Power to file a new net metering tariff, Schedule 84. This schedule made net metering available only to residential and small commercial customers generating up to 25 kW from wind, solar, biomass, hydro, or fuel cells. In August 2002, the PUC issued Order No. 29094 amending Idaho Power's Schedule 84 to include other schedules, such as large commercial and irrigation. This allows net-metered projects up to 100 kW for schedules other than residential and small commercial. Excess kWh generation per month is paid at 85% of the Mid-Columbia market price for non-firm energy. Total enrollment cannot exceed 2.9 MW, or 0.1% of Idaho Power's peak demand in 2000. Idaho Power credits its residential and small commercial customers for their excess generation at the retail rate.

Avista Utilities, which serves the northern part of Idaho, allows net metering to all customers generating up to 25 kW of electricity using solar, wind, biomass, hydropower, or fuel cells. Enrollment is limited to 0.1% of 1996 peak demand, or 1.52 MW. Excess generation is credited to the customer's monthly bill and used to reduce the bill for the following period. At the end of the year, any remaining credits are granted to Avista. These requirements are a result of the 1999 PUC Order No. 28035, which allowed Avista to add net metering to its Schedule 62.[24]

In 2003, Utah Power & Light Company instituted Electric Service Schedule 135 to allow net metering to residential and small-commercial customers generating up to 25 kW of electricity using solar, wind, biomass, or hydropower. Also, for irrigation and large commercial customers, net metering is allowed when generating up to 100 kW. Enrollment is limited to 0.1% of the company's Idaho retail peak demand in 2002. Residential and small-commercial customers are credited the current retail rate for excess energy they produce, while irrigation and large commercial customers are credited 85% of Dow Jones Mid-Columbia rates.[25]

In 2002, Idaho Power enacted net metering for solar thermal electric, photovoltaic, wind, and fuel cells up to 25 kW. There is a limit in this program of 0.5% of a utility's historic single-hour peak load. If there is a net excess sell-back in a given billing period, the excess is purchased at avoided cost or credited to the following month.[26]

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[24] http://www.avistautilities.com/assets/tariffs/id/ID_062.pdf

[25] http://www.rnp.org/News/pr_IDNetMeterJune03.html

[26] http://www.puc.state.id.us/tariff/approved/Electric/approved.htm

Oregon Net Metering

Oregon's statewide net metering law, passed July 1999, allows net metering for customers with solar, wind, or hydropower systems up to 25 kW. All customer classes are eligible, but enrollment is limited to a total installed capacity of 0.5% of a utility's historic single-hour peak load. Above this installed capacity, net metering eligibility can be limited by regulatory authority. Net excess generation is either purchased at avoided cost or credited to the customer's next monthly bill. At the end of an annual period, any unused credit is granted to the electric utility. This credit is then either granted to customers enrolled in the utility's low-income assistance programs, credited to the generating customer, or "dedicated to other use." Rates are in place for Portland General Electric[27] and Pacific Power.[28]

Washington Net Metering

Washington's net metering law, enacted March 1998, allows net metering for customers with solar, wind, and hydropower systems of 25 kW or less that are intended primarily to offset part or all of the customer's requirements for electricity. Then in 2000, EH 2334 added fuel cells as another type of eligible technology. All customer classes are eligible for enrollment, which is limited to a statewide installed generating capacity of 0.1% of the utility's 1996 peak demand. Net excess generation is credited to the customer's next monthly bill. At the beginning of each calendar year, any remaining unused kilowatt-hour credit accumulated during the previous year must be granted to the utility, without any compensation to the customer. Puget Sound Energy, Pacific Power, and Avista have net metering tariffs.[29]

3.3. Summary of CHP Climate in the Pacific Northwest

The barriers to deployment of CHP in the PNW region can be grouped into three basic areas: regulation and interaction with electricity service providers, siting and environmental compliance, and market and financial barriers. There are also a number of active incentive programs in the region and organizations that are providing focus and support for CHP development.

3.3.1 Barriers from Regulation and Interaction with Electricity Service Providers

The electric power structure in the Pacific Northwest, except for Alaska, is dominated by the installed hydroelectric capacity of the Federal Columbia River Power System. Bonneville Power Administration provides a large share of the wholesale power and high-voltage transmission for the region's publicly owned power companies, investor-owned utilities, and to direct service industries. Average power costs are very low, but the transition to competitive wholesale power markets has exposed BPA and its customers to considerable risk and uncertainty. The source and cost of resources to meet future power needs are highly uncertain. Economic decisions regarding CHP are hindered by this uncertainty.

[27] Portland General Electric, Rate 203: Net Metering Service.

[28] Pacific Power, Rate 135: Net Metering Service Optional for Qualifying Consumers.

[29] Avista and Pacific Power tariffs previously cited, Puget Sound Energy, Electric Schedule 150.

Each utility within the PNW region sets its own interconnection guidelines. Only in Oregon, are these guidelines limited by regulation to what is required by IEEE 1547 standard. Backup charges imposed on CHP customers reduce the economic benefit and do not adequately reflect the system support provided by distributed generation.

Gaining transmission access, particularly for larger projects, can be difficult. There is no mechanism beyond bilateral negotiation between the CHP project and the electric utility for allowing power to be moved to other owned facilities or to be sold to third parties.

3.3.2 Siting and Environmental Compliance

Siting of CHP facilities requires that the developer address siting issues concerning air quality, water quality, water usage, land use, fire/safety, noise, traffic, and environmental impact. Some states, notably Oregon, have developed a state level process to facilitate project siting. The benefits of high efficiency CHP are recognized for the fact that they avoid other energy use and utility infrastructure investments. However, not all siting requirements are brought under this one umbrella. Environmental compliance issues such as water quality and air quality each have their own requirements with local and state agencies implementing federal guidelines.

3.3.3 Market and Financial Barriers

In order for CHP to achieve a greater market share in the PNW region, there is a need to eliminate market-related barriers. These barriers include difficulties in financing CHP projects due to tax schedules and other financial constraints, lack of customer understanding related to CHP equipment operation, uncertainty related to the cost and performance benefits of CHP, and lack of developer knowledge related to customer requirements. Education and outreach directed at developers, customers, regulators, and other regional stakeholders can help to remove these barriers by providing an understanding of how CHP technologies work, in addition to when and how different CHP technologies can be applied effectively.

3.3.4 Active Incentive Programs

The value of CHP is already recognized by some organizations. There are also federal, regional, and state programs providing incentives for CHP development.

At the federal level, the Department of Energy State Energy Program provides funding to the states for a variety of energy programs that directly or indirectly promote CHP. The DOE-SEP has provided funding for CHP technology development and demonstration projects in renewable energy and advanced technology, for evaluation of district energy programs, development of CHP information materials, and economic development activities such as economic and technical assistance and low interest loan programs. The DOE-SEP is managed cooperatively with state level energy agencies.

Regionally, the Bonneville Power Administration provides the Conservation and Renewables Discount (C&RD). This program allows BPA customers (public and investor owned utilities) to receive cost reductions based on their implementation of energy efficiency programs, including CHP and renewable energy.

Each state has an agency that supports energy programs. The Oregon Office of Energy is the most active state agency in the four-state PNW region. Oregon supports CHP to promote the broader goals of maintaining a clean environment, minimizing the need for new energy supply, and environmental protection including reduction in emissions of carbon dioxide that contribute to global warming. Other states provide some programs that could be used to support CHP, such as financing of projects, demonstration of renewable energy programs, and targeted economic development. Alaska focuses strongly on grid isolated rural energy systems. Idaho has implemented a number of programs to support its agricultural and food industries. Washington, with the highest population and gross state product in the PNW region, provides comparatively little support for CHP.

3.3.5 Organizations Driving CHP in the PNW

There are several organizations within the PNW region that are working to promote the market deployment of CHP and to eliminate unfair market barriers. These organizations are providing a regional forum for CHP proponents and other interested parties to meet and to develop a regional action plan. The key organizations in this developing regional forum are described below:

- The Northwest CHP Consortium, formerly the 200 Market Street Consortium, is providing education, marketing effort, financial support, and a clearinghouse for applying applicable financing incentives to small-scale CHP projects in Oregon. Northwest Natural has provided the management effort to pull together a consortium that includes, in addition to their own support, local gas and electric utilities, the Department of Energy, the American Gas Association, the Bonneville Power Administration, the State of Oregon, and the City of Portland.
- A recently awarded DOE-SEP grant has provided for the establishment of the Northwest Regional Combined Cooling, Heating, and Power (CHP) Application Center to serve the needs of Alaska, Idaho, Oregon, Montana, and Washington. The Center, under the management of the Washington State University Energy Program, plans to be an important resource for those interested in developing or advancing CHP projects in the region. To facilitate the development and successful operation of a broad range of CHP technologies and projects, it will develop a comprehensive education and outreach program.
- The DOE with the very active support of the Western Regional Office (WRO), formerly the Seattle Regional Office, has hosted a number of informal and formal workshops to promote CHP within the region. Through its team building and issue identification efforts, the WRO was particularly instrumental in establishing the Northwest Regional CHP Application Center. The Pacific Northwest CHP Roundtable held in June 2003, brought together about 50 representatives from industry, energy service providers, government, and the utility industry to share CHP cases studies and to develop and list of action items and solutions to barriers that inhibit CHP development in the region. The WRO has also spearheaded the establishment of the CHP Pacific Northwest Initiative.
- The Oregon Office of Energy serves as a model agency in the region for its recognition of the social benefits of CHP (productivity, environmental protection, conservation of natural resources, economic development and productivity, and reduction in global warming) and its innovative incentive programs.

The ongoing activities of these organizations are helping to create a greater awareness among legislators and regulators of the need to eliminate barriers and accelerate beneficial market activity. Customer awareness is also enhanced. In addition, these market-seeding activities will help reduce the costs of project development and implementation and to strengthen the capabilities of performing organizations, such as energy service companies, architects and engineers, general contractors, and other project-related resources.

4. TECHNICAL POTENTIAL[30]

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, multi-family residential, and resource recovery market sectors. The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meet the thermal and electric load requirements for CHP.
- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.
- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the region. Identifying technical market potential is a preliminary step in the assessment of economic market potential for the Pacific Northwest region.

The remainder of this section is organized into the following subsections:

- Regional Growth Forecast – evaluation of historical growth by sector and estimation of future growth as a basis for determining CHP from new facilities
- Large Industrial Market – investigation of industrial CHP applications over 5 MW
- Commercial and Small Industrial Markets – evaluation of smaller CHP applications
- Resource Recovery Markets – description of resource recovery in the region and evaluation of CHP from digester gas in sewage treatment and farming applications
- Alaskan Village Market – assessment of CHP in remote Alaskan villages
- Summary of Technical Potential

[30] The results presented in this section are derived from the "Subtask 1-2 Deliverable," which was delivered to ORNL in July 2003.

4.1 Regional Growth Forecast

The technical market potential for CHP in the Pacific Northwest (PNW) depends not only on the characteristics of existing facilities but also on the expected growth rates for the future. In 2001, the region had a combined gross state product (GSP) of $409 billion dollars. **Figure 4-1** shows the state-by-state shares of this total. Washington accounts for over half of the total economic activity of the region, and Oregon comprises about a third. Idaho and Alaska are comparatively much smaller with a combined 15% share.

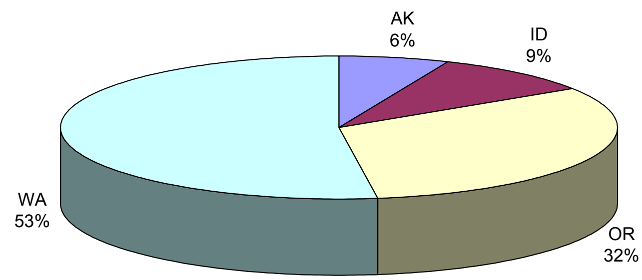


Figure 4-1. State-by-State Share of the Combined Gross State Product (2001)

The region experienced strong economic growth during the late 1980s and mid to late 1990s, but it is currently gripped by recession with the combined effects of declines in aerospace and high-tech industries at one end of the spectrum and basic industries at the other. The annual real growth rates for the region are shown in **Figure 4-2**. **Figure 4-3** shows the state-by-state contribution to real GSP between 1986 and 2001.

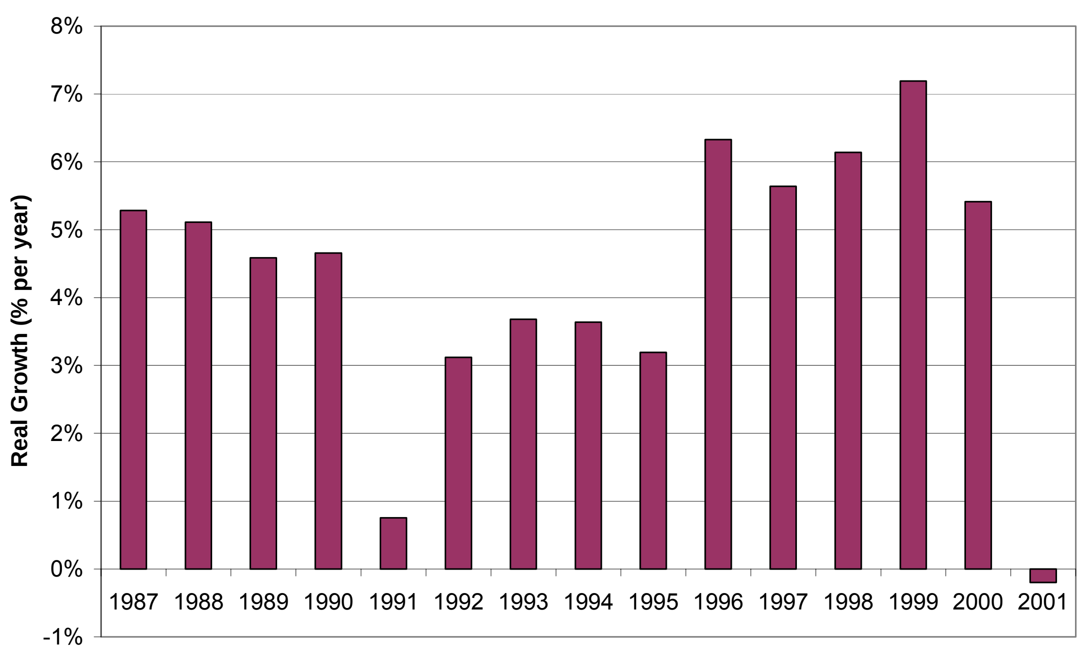


Figure 4-2. Regional Annual Real Growth Rates in Gross State Product

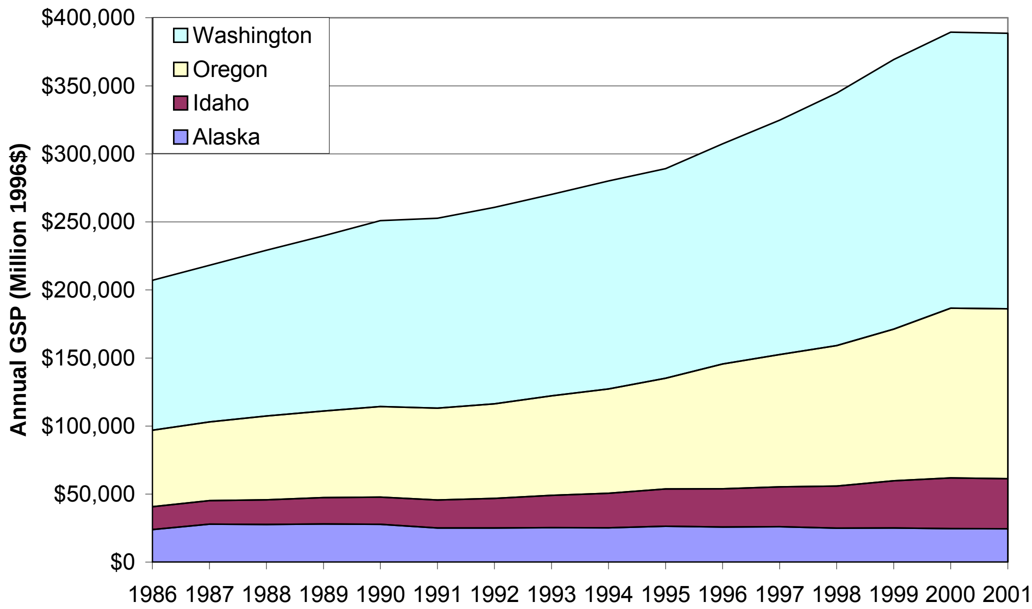
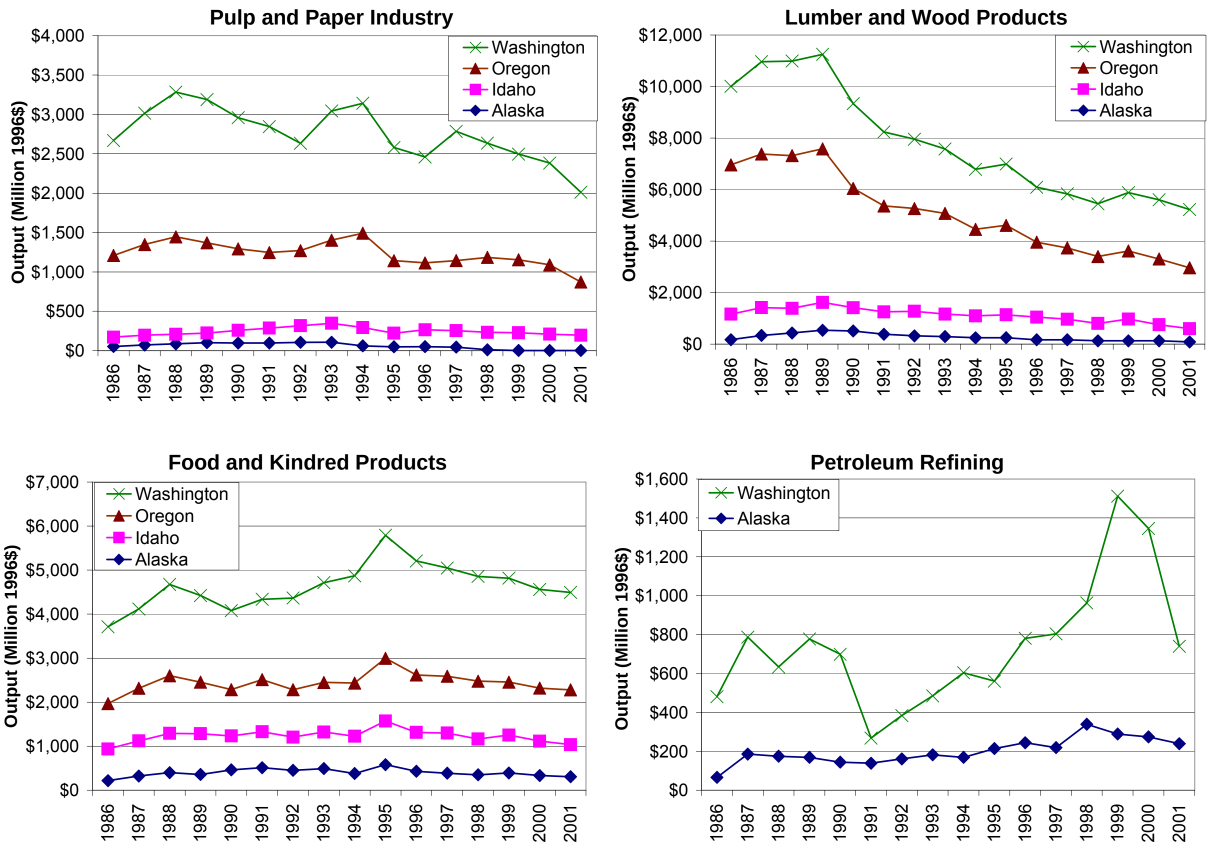


Figure 4-3. Regional Real Gross State Product (1986-2001)

As reported in **Section 2**, four industries make up 89% of the existing CHP capacity in the PNW region. These industries are food (SIC 20), pulp and paper (SIC 26), refineries (SIC 29), and wood products (SIC 24). All of these industries are in decline in the PNW. **Figure 4-4** shows the real growth trends by state for these four industries. Both the pulp and paper and wood products industries have been in decline since the 1980s. Pulp and paper has declined by nearly 40% and wood products by over 50% since the peak years in the late 1980s. The food industry has declined by 23% since its peak year in 1995. Petroleum refining is important in only Alaska and Washington – both states refining Alaskan crude oil. The industry has experienced wide volatility in recent years. It is unlikely that there will be another greenfields refinery in the region; therefore, additional CHP capacity would need to be tied to existing facilities.

The sector-by-sector and state-by-state growth rates (1997-2001) were used as a basis for defining CHP potential from new facilities over a twenty year forecast period. The Bureau of Economic Analysis tabulates these figures.[31] In cases where the sector was declining, growth rates were assumed to be zero. In cases where sectors have grown very rapidly in the last five years, the future growth rate estimate was capped at 5% per year. In some basic sectors, such as food sales and apartments, that have shown declines during the five-year period, moderate growth rates were estimated. **Appendix D** contains the real GSP by sector and state for the four states plus the five- and 10-year growth rates and the estimated growth rates for the 20-year forecast period (unadjusted).

[31] Bureau of Economic Analysis, U.S. Department of Commerce (http://www.bea.doc.gov/bea/regional/gsp)



Note: Economic activity depicted as stack charts – highest line equals region total

Figure 4-4. Growth Trends in the Four Industries with the Largest Installed CHP Capacity in the PNW

4.2 Large Industrial Markets

Large industrial systems represent a distinct market segment that was analyzed separately. Of the existing 3,855 megawatts of CHP capacity in the four-state PNW region, 97.5% of it is in systems larger than 5 MW.

4.2.1 Analytical Approach

The technical market potential for large industrial CHP systems in the region was analyzed using the Major Industrial Plant Database (MIPD)[32] for industrial systems with potential capacity of 5 MW and greater. The MIPD contains comprehensive information about roughly 16,000 industrial plants in the U.S. These plants cover 19 manufacturing sectors and 90% of U.S. industrial natural gas consumption.

[32] Major Industrial Plant Database, HIS Energy, Houston, TX

The database contains basic information about the sites as well as information about the energy profiles of each site, including electricity and gas usage, demand, fuel use, operations data, boiler data, steam draw, and cogeneration ability. The MIPD was used in this study to identify industrial sites that have an electric demand greater than 5 MW, as well as sites with a steam draw of greater than 25,000 lbs/hour. The steam draw was used to determine the size of a CHP system that would meet the site steam needs. This figure was compared with the on-site electricity demand to determine the CHP capacity that would meet on-site needs. Excess capability was defined as CHP export capacity. Finally, the individual sites were matched with existing CHP sites to determine remaining technical potential.

4.2.2 Large Industrial CHP Technical Market Potential

Using the MIPD, 120 industrial facilities were identified that had 5 MW or more of electricity demand. Of these sites, 30 had no steam demand and were thus eliminated. Of the remaining 90 sites, 69 had steam demand of more than 25,000 lbs/hour (capable of supporting a 5-MW or greater CHP system with full thermal utilization), 18 had steam demand greater than zero and less than 25,000 lbs/hour (capable of supporting a CHP system smaller than 5 MW), and three had zero steam demand in the database but were identified as having CHP already. Of these 90 sites, 21 have CHP systems identified in the CHP baseline assessment reported in **Section 2**. The technical CHP potential of these 90 sites was determined as follows:

- For each site, a potential CHP capacity was calculated based on the steam demand at the site. The steam-to-electric ratio used in the calculation of potential CHP electric capacity varied based on the application. All applications in the paper industry (SIC 26) were assumed to be met by steam turbine generators providing 20,000 Btu/kWh of process steam. This assumption was based on the prevalence of chemical recovery and hog fuel boilers in this industry. In other industries, all sites with steam demand greater than 500,000 lbs/hr (equivalent to a 100-MW simple cycle gas turbine system) were assumed to have a CHP potential based on a combined cycle gas turbine – roughly 3,000 Btu/kWh. All other sites were evaluated based on the thermal-to-electric ratio of a simple cycle gas turbine – roughly 5,000 Btu/kWh. The steam demand at the site was converted to an electrical generation capacity, using the appropriate thermal-to-electric ratio for the site.
- The potential CHP capacity, based on steam demand, was then compared to the site electrical demand. Potential CHP capacity that was less than or equal to the site electric demand was termed *On-site CHP Potential*. Potential CHP capacity that was greater than the site electrical demand was split between two categories, *On-site CHP Potential* (equal to the site electric demand) and *CHP Export Potential* (all capacity above the site electrical demand).
- For sites with existing CHP systems, the electric capacity of the existing CHP system was compared to the electric demand for the facility. The existing CHP capacity was split into two categories: *On-site CHP Potential* (power output capable of meeting site demand) and *CHP Export Potential* (excess capacity above the site electrical demand). If the existing CHP capacity was below the calculated CHP potential based on steam demand, the shortfall is added to remaining CHP technical potential.
- The existing CHP on-site capacity and export potential is subtracted from the total potential figures leaving remaining *On-site CHP Potential* and remaining *CHP Export Potential*.

The results of this analysis are summarized in **Tables 4-1** and **4-2**. **Table 4-1** shows that there is a total remaining CHP technical market potential of 3,075 MW – this total is split between on-site CHP potential of 960 MW and CHP export potential of 2,115 MW. **Table 4-2** shows the breakdown by size for the PNW region as a whole. The state and size breakdown is shown at the end of this section in **Table 4-4**.

Table 4-1. CHP Technical Market Potential by Industry and State for Large Industrial Markets

SIC2	Industry Description	State				Region Total
		AK	ID	OR	WA	
On-site CHP Potential (MW)						
20	Food	0	205	103	27	335
24	Lumber and Wood	0	23	51	33	106
26	Paper	0	0	156	122	279
28	Chemicals	1	10	23	25	59
29	Petroleum Refining	4	0	0	81	85
33	Primary Metals	0	0	5	28	33
36	Electronic Equipment	0	0	6	0	6
37	Transportation Equipment	0	0	7	45	52
38	Instrumentation	0	0	5	0	5
	Total On-site Potential	**5**	**239**	**356**	**360**	**960**
CHP Export Potential (MW)						
20	Food	0	28	6	24	59
24	Lumber and Wood	0	6	688	28	722
26	Paper	0	0	20	229	249
28	Chemicals	409	49	17	11	486
29	Petroleum Refining	0	0	0	568	568
33	Primary Metals	0	0	0	9	9
36	Electronic Equipment	0	0	22	0	22
37	Transportation Equipment	0	0	0	0	0
38	Instrumentation	0	0	0	0	0
	Total Export Potential	**409**	**83**	**753**	**870**	**2,115**

Table 4-2. CHP Technical Market Potential by Industry and Size Range for Large Industrial Markets

SIC2	Industry Description	5-20 MW		20-50 MW		> 50 MW		Total Large Industrial	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food	12	66	4	28	5	241	21	335
24	Lumber and Wood	13	64	3	25	1	17	17	106
26	Paper	5	21	7	151	4	107	16	279
28	Chemicals	6	43	2	16	1	0	9	59
29	Petroleum Refining	1	4	0	0	1	81	2	85
33	Primary Metals	2	20	0	0	1	13	3	33
36	Electronic Equipment	1	6	0	0	0	0	1	6
37	Transportation Equip.	1	7	3	45	0	0	4	52
38	Instrumentation	0	0	1	5	0	0	1	5
	Total On-site Potential	**41**	**231**	**20**	**269**	**13**	**459**	**74**	**960**

The largest on-site CHP potential is in the food, paper, and wood product industries. These industries account for three-quarters of the large industrial on-site CHP potential. The largest export potential is in the lumber and wood products, refining, paper, and chemical industries. These four industries represent 96% of the CHP export potential.

Based on the sectoral growth rates for each state described in **Section 4.1**, an estimate of CHP potential from new facilities was made (see **Table 4-3**). Because of zero or low growth rates in the basic industries, the potential from new facilities is much lower than for the existing large industrial base.

Table 4-3. Estimate of On-site CHP Potential from New Large Industrial Facilities (2002-2022)

SIC2	Industry Description	State				Region Total
		AK	ID	OR	WA	
On-site CHP Potential (MW)						
20	Food	0	0	0	0	0
24	Lumber and Wood	0	0	0	9	9
26	Paper	0	0	0	0	0
28	Chemicals	0	17	38	41	96
29	Petroleum Refining	0	0	0	0	0
33	Primary Metals	0	0	6	7	13
36	Electronic Equipment	0	0	9	0	9
37	Transportation Equipment	0	0	12	0	12
38	Instrumentation	0	0	0	0	0
	Total On-site Potential	**0**	**17**	**66**	**57**	**140**

4.3 Commercial and Small Industrial Markets

The commercial sector and small industrial applications were analyzed together using a detailed database of existing commercial and industrial facilities in the region.

4.3.1 Analytical Approach

The following approach was used to estimate the technical market potential for CHP in the commercial/institutional and small industrial sectors:

- Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities. Data sources include the DOE EIA *1995 Commercial Buildings Energy Consumption Survey (CBECS)*, the DOE *1994 Manufacturing Energy Consumption Survey (MECS)*, and various market summaries developed by the Gas Technology Institute (formerly the Gas Research Institute) and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.
- Quantify the number and size distribution of target applications. Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* was utilized to identify potential CHP sites by SIC code or application. The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional, and industrial facilities. In addition, for select SICs, limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). The *MarketPlace Database* was used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatts.
- Estimate CHP potential in terms of MW capacity. Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads limited electric capacity.

Target CHP Applications

The simplest integration of CHP into the commercial and industrial sectors is in applications that meet the following criteria:

- Relatively coincident electric and thermal loads
- Thermal energy loads in the form of steam or hot water
- Electric-to-thermal (steam and hot water) demand ratios in the 0.5 to 2.5 range
- Moderate to high operating hours (greater than 4,000 hours per year)

Commercial CHP

A review of energy consumption intensity data for commercial/institutional building types as presented in the 1995 CBECS is shown in **Table 4-4**. Electric intensities are taken directly from the CBECS data for each building type. Space heating and water heating data in CBECS reflect fuel energy inputs for each category. These fuel inputs were modified to reflect building thermal demands using a conversion efficiency of 85%. The building types are compared in terms of energy intensity and electric/thermal energy ratio (E/T). Energy intensity, measured in kilowatt-hours per square foot, is an indication of the importance of energy use in the application.

Table 4-4. Energy Intensities for Commercial/Institutional Buildings

Sector	Electric Use (Trillion Btu)	Electric Intensity (kWh/sqft)	Space Heating (1,000 Btu/sqft)	Water Heating (1,000 Btu/sqft)	E/T Ratio (Total)	E/T Ratio (Water Heating)
Education	221	8.4	32.8	17.4	0.67	1.94
Health Care	211	26.5	55.2	63	0.9	1.69
Lodging	187	15.2	22.7	51.4	0.82	1.19
Food Service	166	36	30.9	27.5	2.47	5.25
Food Sales	119	54.1	27.5	9.1	5.93	23.86
Office	676	18.9	24.3	8.7	2.3	8.72
Mercantile/Service	508	11.8	30.6	5.1	1.33	9.29
Public Assembly	170	12.7	53.6	17.5	0.72	2.91
Public Order	49	11.3	27.8	23.4	0.89	1.94
Religious Worship	33	3.5	23.7	3.2	0.52	4.39
Warehouse/Storage	176	6.4	15.7	2	1.45	12.85
Other	75	22	59.6	15.3	1.18	5.77
Apartment Buildings	--	5,875 kWh/unit	N/A	25 MMBtu/unit	N/A	0.8

Applications with high energy intensity are more likely to have large electric loads and to be interested in finding ways to reduce energy costs. Electric/thermal energy ratio is the ratio of electric power used to thermal energy used, measured in like units. The outputs from available CHP technologies have electric to thermal ratios in the range of 0.5 to 2.5. Thermal energy output is usually in the form of steam or hot water.

Thermal loads most amenable to CHP systems in commercial/institutional buildings are space heating and hot water requirements. The simplest thermal load to supply is hot water. Retrofits to the existing hot water supply are relatively straightforward, and the hot water load tends to be less seasonally dependent than space heating, and therefore, more coincident to the electric load in the building.

Meeting space heating needs with CHP can be more complicated. Space heating is seasonal by nature, and is supplied by various methods in the commercial/institutional sector, centralized hot water or steam being only one. For these reasons, primary targets for CHP in the commercial/institutional sectors are those building types with electric-to-hot water demand ratios consistent with the range of the CHP system. These include education, health care, lodging, and certain public order and public assembly applications. Office buildings, and certain warehousing and mercantile/service applications, can be target applications for CHP if space heating needs can be incorporated.

Table 4-5 presents the specific building types most amenable to engine-driven CHP based on an analysis of existing CHP in the commercial/institutional sectors and a review of available building energy characteristics.

Table 4-5. CHP Target Applications for Commercial Sector Based on Existing Technology

Application	CHP System Size	Thermal Demand
Hotels/Motels	100 kW to 1+ MW	Domestic hot water, space heating, pools
Nursing Homes	100 kW to 500 kW	Domestic hot water, space heating, laundry
Hospitals	100 kW to 5+ MW	Domestic hot water, space heating, laundry
Schools	50 kW to 500 kW	Domestic hot water, space heating, pools
Colleges/Universities	300 kW to 30 MW	Centralized space heating, domestic hot water
Commercial Laundries	100 kW to 800 kW	Hot water
Car Washes	100 kW to 500 kW	Hot water
Health Clubs/Spas	50-500 kW	Domestic hot water, space heating, pools
Country/Golf Clubs	100 kW to 1 MW	Domestic hot water, space heating, pools
Museums	100 kW to 1+ MW	Space heating, domestic hot water
Correctional Facilities	300 kW to 5 MW	Space heating, domestic hot water
Water Treatment/Sanitary	100 kW to 1 MW	Process heating
Large Office Buildings*	100 kW to 1+ MW	Space heating, domestic hot water
Apartment Buildings	50 kW to 1+ MW	Domestic hot water, space heating

* *Greater than 100,000 square feet*

Technology development efforts targeted at heat-activated cooling/refrigeration and thermally regenerated desiccants could expand the application of engine-driven CHP by increasing the thermal energy loads in certain building types. Use of CHP thermal output for absorption cooling and/or desiccant dehumidification could increase the size and improve the economics of CHP systems in existing CHP markets such as schools, lodging, nursing homes, and hospitals. Use of these advanced technologies in applications such as restaurants, supermarkets, and refrigerated warehouses provides a base thermal load that opens these applications to CHP. **Table 4-6** includes potential CHP target applications that are often currently marginal because of inadequate thermal loads but that would be future target applications based on the use of these advanced technologies.

Table 4-6. CHP Target Applications for Commercial Sector Based on Advanced Technology

Application	CHP System Size	Thermal Demand
Extended Service Restaurants	50 kW to 300 kW	Domestic hot water, absorption cooling, desiccants
Supermarkets/Grocery	100 kW to 500 kW	Desiccants, domestic hot water, space heating
Refrigerated Warehouses	300 kW to 5 MW	Desiccants, domestic hot water
Medium Office Buildings*	100 kW to 500 kW	Absorption cooling, space heating, desiccants

* *50,000-100,000 square feet*

Small Industrial CHP

Table 4-7 lists the primary industrial applications for CHP based on an analysis of existing CHP and a review of industrial energy characteristics such as E/T ratios and thermal energy needs (e.g., hot water, low- and high-pressure steam).

Table 4-7. CHP Target Applications for Small Industrial Sector

SIC	Application	E/T Ratio	Thermal Demand
20	Food Processing	0.4-1.0	Hot water, low-pressure steam
22	Textiles	0.5-1.5	Hot water, low-pressure steam
24	Lumber/Wood	2.0-5.0	Low-pressure steam, direct heat
25	Furniture	1.5-3.0	Low-pressure steam, direct heat
26	Paper Products	0.8-2.0	Medium- to high-pressure steam
28	Chemicals	0.4-1.0	Low- to high-pressure steam
30	Rubber/Plastic Products	1.0-3.0	Low-pressure steam, direct heat
33	Primary Metals	0.5-4.0	Medium- to high-pressure steam
34	Fabricated Metals	0.75-3.0	Low-pressure steam, direct heat
35	Machinery	2.0-4.0	Hot water, low-pressure steam
37	Transportation Equipment	1.2-2.2	Hot water, low-pressure steam
38	Instruments	1.0-2.5	Hot water, low-pressure steam
39	Miscellaneous Manufacturing	2.0-4.0	Hot water, low-pressure steam

As described earlier, the iMarket, Inc. *MarketPlace Database* was utilized to identify the number of existing facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatts. Office buildings and apartment buildings are exceptions to this approach. The *MarketPlace Database* includes information on individual tenants within an office building, but not on the building as a whole. The number of office building sites amenable to CHP was derived from CBECS data on office buildings with peak electric demand of 250 kW or greater (about 73,000 buildings nationwide). The number of apartment buildings amenable to CHP was derived from the EIA *Residential Energy Consumption Survey*. The survey estimates that there are approximately 11,800 apartment buildings nationwide with peak electric demand of 330 kW or greater. Assuming a load factor of 20%, this roughly correlates to average electric loads of 70 to 100 kW and greater.

The technical potential for CHP in terms of MW capacity was estimated assuming that the CHP systems would be sized to meet the average electric demand for most applications. For the majority of the target markets there is a reasonable match between electric-to-thermal ratios of the application and the power-to-heat output of existing CHP technologies. Sizing to meet average electric demand supplies thermal needs for these applications and maximizes the energy efficiency of CHP deployment. It should be noted that the existing CHP capacity described in the large industrial analysis includes a number of large installations that are sized to sell significant amounts of excess power to the grid.

The estimate of technical potential for small industrial CHP in this study assumes all power will be used on-site. A mean system size was calculated for each size category assuming a log normal distribution and applied to the number of establishments contained in each category. The exceptions to this methodology are office buildings, restaurants, refrigerated warehouses, schools, museums, and supermarkets in the commercial sector and lumber, furniture, metals, machinery, transportation equipment, and instruments in the small industrial sector. Thermal loads in these applications are generally inadequate to support CHP systems sized to the average electric demand based on current CHP technologies. Megawatt capacities for these applications were reduced using factors that better reflect the electric-to-thermal ratio of these applications based on CBECS and MECS averages.

4.3.2 Commercial CHP Technical Market Potential

The commercial/institutional market consists of business establishments and government facilities in SIC 40 through SIC 97. As described above, only specific markets with appropriate electric and thermal consumption characteristics were evaluated.

Table 4-8 summarizes the remaining on-site CHP potential for the commercial/institutional sector for the PNW region as a whole. There are over 11,000 sites with an onsite CHP potential of 5,636 MW. There is a large technical potential for office buildings (due to the sheer size of that market), apartment buildings, educational facilities, hotels, restaurants, and hospitals. It should be noted here that this estimate is strictly to identify applications with appropriate thermal and electric loads; there is no representation, yet, of the economic viability of these sites. The state-by-state breakdowns of this analysis are shown in **Appendix E**.

Table 4-8. CHP Technical Market Potential by Industry and Size Range for Existing Facilities in Commercial/Institutional Markets

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	46	6.9	64	48.0	9	22.5	2	25.0	0	0.0	121	102.4
494/495	Water Treatment/ Sanitary	94	14.1	101	75.8	18	45.0	4	50.0	0	0.0	217	184.9
54	Food Sales	804	108.9	15	9.0	6	13.1	0	0.0	0	0.0	825	131.0
581	Full Service Restaurants	1,037	144.9	289	201.0	22	50.0	0	0.0	0	0.0	1,348	395.9
7011	Hotels/ Motels	856	128.4	211	158.3	105	262.5	10	125.0	0	0.0	1,182	674.2
721	Laundries	49	7.4	17	12.8	0	0.0	0	0.0	0	0.0	66	20.1
7542	Carwashes	166	24.9	3	2.3	1	2.5	0	0.0	0	0.0	170	29.7
7991	Health Clubs	292	43.8	23	17.3	2	5.0	0	0.0	0	0.0	317	66.1
7992/7	Golf Clubs	173	26.0	50	37.5	2	5.0	0	0.0	0	0.0	225	68.5
805	Nursing Homes	181	27.2	231	173.3	24	60.0	0	0.0	0	0.0	436	260.4
806	Hospitals & Health Care	78	11.7	95	71.3	116	290.0	9	112.5	0	0.0	298	485.5
822	Colleges & Universities	129	19.4	38	28.5	29	72.5	17	212.5	3	225.0	216	557.9
821/4/9	Elementary/ Secondary Schools	1,358	189.5	343	242.6	32	78.8	4	43.8	0	0.0	1,737	554.7
8412	Museums	99	14.9	13	9.8	5	12.5			0	0.0	117	37.1
9223	Prisons	44	6.6	31	23.3	39	97.5	2	25.0	0	0.0	116	152.4
	Apartments	556	83.4	130	97.5	66	165.0	13	162.5	1	75.0	766	583.4
	Office Buildings	2,287	325.3	480	341.1	116	274.3	20	241.3	2	150.0	2,905	1,331.9
	Total	**8,249**	**1,183.1**	**2,134**	**1,549.0**	**592**	**1,456.1**	**81**	**997.5**	**6**	**450.0**	**11,062**	**5,635.7**

Based on the state-by-state sectoral growth rates (see **Appendix D**), an estimate of CHP technical market potential was made for new facilities between 2002-2022. **Table 4-9** summarizes this potential by state for both existing and new facilities.

Table 4-9. CHP Technical Market Potential (2002-2022) by State and Size Range for Existing and New Facilities in Commercial/Institutional Markets (MW Capacity)

SIC2	Industry Description	State				Region Total
		AK	ID	OR	WA	
Technical CHP Potential – Existing Facilities (MW)						
4222	Refrigerated Warehouse	16	8	27	51	102
494/495	Water treatment/Sanitary	50	13	38	84	185
54	Food Sales	7	5	42	77	131
581	Full Service Restaurants	12	31	141	212	396
7011	Hotels/Motels	43	118	188	325	674
721	Laundries	1	3	7	9	20
7542	Carwashes	1	8	9	12	30
7991	Health Clubs	5	8	24	29	66
7992/7	Golf Clubs	0	14	22	32	68
805	Nursing Homes	5	37	72	147	260
806	Hospitals and Health Care	33	130	134	189	485
822	Colleges and Universities	18	54	290	196	558
821/4/9	Elementary/Secondary Schools	32	36	166	321	555
8412	Museums	1	18	8	10	37
9223	Prisons	17	26	32	76	152
	Apartments	27	39	165	353	583
	Office Buildings	112	26	431	763	1,332
	Total	**380**	**576**	**1,796**	**2,885**	**5,636**
Technical CHP Potential – New Facilities (MW)						
4222	Refrigerated Warehouse	0	2	0	8	10
494/495	Water treatment/Sanitary	0	0	18	57	76
54	Food Sales	8	3	69	49	129
581	Full Service Restaurants	13	52	232	350	648
7011	Hotels/Motels	9	0	92	158	259
721	Laundries	0	3	1	4	8
7542	Carwashes	2	13	4	18	37
7991	Health Clubs	0	12	3	4	19
7992/7	Golf Clubs	0	20	2	4	27
805	Nursing Homes	8	43	51	116	219
806	Hospitals and Health Care	54	153	95	149	452
822	Colleges and Universities	28	63	257	164	513
821/4/9	Elementary/Secondary Schools	49	42	147	269	508
8412	Museums	1	20	5	16	42
9223	Prisons	0	27	32	47	105
	Apartments	9	19	36	171	236
	Office Buildings	70	26	242	887	1,225
	Total	**252**	**498**	**1,288**	**2,473**	**4,511**

4.3.3 Small Industrial CHP Technical Market Potential

Small industrial markets were also analyzed using the *MarketPlace Database*. The net remaining CHP technical market potential for existing small industrial facilities is shown in **Table 4-10**. There are 5,200 sites and nearly 1,500 MW of potential CHP capacity remaining. The biggest potential is in the food industry, with significant potentials in chemicals, wood products, and transportation equipment.

Table 4-10. CHP Technical Market Potential by Industry and Size Range for Existing Facilities in Small Industrial Markets

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food & Kindred Products	536	80	134	101	171	428	841	608
22	Textile Mill Products	38	4	5	3	3	6	46	13
24	Lumber & Wood Products-except furniture	646	19	100	15	189	95	935	129
25	Furniture & Fixtures	145	7	11	2	3	2	159	11
26	Paper & Allied Products	73	11	27	20	27	68	127	99
28	Chemicals & Allied Products	155	23	39	29	45	113	239	165
29	Petroleum Refining & Related Industries	12	2	5	4	9	23	26	28
30	Rubber & Miscellaneous Plastic Products	232	10	56	13	55	41	343	64
33	Primary Metal Industries	58	2	30	6	33	21	121	28
34	Fabricated Metals	576	26	52	12	40	30	668	68
35	Machinery	745	28	60	11	50	31	855	70
37	Transportation Equipment	234	18	48	18	52	65	334	101
38	Instruments	237	18	20	8	30	38	287	63
39	Miscellaneous Manufacturing Industries	209	8	12	2	12	8	233	18
	Total	**3,896**	**256**	**599**	**243**	**719**	**966**	**5,214**	**1,465**

New facility potential was estimated in the same manner as for the commercial sector. The state-by-state breakdown of potential CHP capacity for existing and new facilities in the small industrial sector is shown in **Table 4-11**.

Table 4-11. CHP Technical Market Potential (2002-2022) by State and Size Range for Existing and New Facilities in Small Industrial Markets (MW Capacity)

SIC2	Industry Description	State				Region Total
		AK	ID	OR	WA	
CHP Potential – Existing Facilities						
20	Food and Kindred Products	8.0	106	202	292	608
22	Textile Mill Products	0.0	0	5	8	13
24	Lumber and Wood Products, Except Furniture	0.4	19	67	43	129
25	Furniture and Fixtures	0.0	1	5	5	11
26	Paper and Allied Products	0.0	0	36	62	99
28	Chemicals and Allied Products	0.9	3	70	91	165
29	Petroleum Refining and Related Industries	5.9	0	10	12	28
30	Rubber and Miscellaneous Plastic Products	0.0	4	24	36	64
33	Primary Metal Industries	0.0	1	15	13	28
34	Fabricated Metals	0.3	7	25	36	68
35	Machinery	0.1	7	32	31	70
37	Transportation Equipment	0.3	5	27	68	101
38	Instruments	0.1	1	23	39	63
39	Miscellaneous Manufacturing Industries	0.0	1	7	9	18
	Total	**15.9**	**157**	**547**	**745**	**1,465**
CHP Potential – New Facilities						
20	Food and Kindred Products	0.0	0	0	0	0
22	Textile Mill Products	0.0	0	0	3	3
24	Lumber and Wood Products, Except Furniture	0.0	0	0	11	11
25	Furniture and Fixtures	0.0	2	7	7	16
26	Paper and Allied Products	0.0	0	0	0	0
28	Chemicals and Allied Products	0.0	6	116	150	271
29	Petroleum Refining and Related Industries	0.0	0	0	0	0
30	Rubber and Miscellaneous Plastic Products	0.1	5	0	60	65
33	Primary Metal Industries	0.0	1	19	3	23
34	Fabricated Metals	0.0	0	0	0	0
35	Machinery	0.1	12	54	51	116
37	Transportation Equipment	0.5	7	45	0	53
38	Instruments	0.0	2	0	7	9
39	Miscellaneous Manufacturing Industries	0.0	1	6	12	19
	Total	**0.7**	**37**	**246**	**304**	**588**

4.4 Resource Recovery Markets

Recovery of biomass fuel supplies 12% of the current CHP market in the PNW region. Perhaps more significantly, excluding Alaska, biomass-fueled CHP makes up nearly 60% of the total number of active projects in Idaho, Oregon, and Washington. Forestry, wood, and paper industries make up the largest share of biomass projects. However, the use of biogas from anaerobic digesters in sewage treatment plants and animal feedlot operations is an important source of additional CHP potential for the region.

The sources of biomass-derived fuels in the region are as follows[33] (resources with CHP potential are indicated in bold):

- *Forest residues* – Woody material that is a byproduct of logging operations can be used for fuel. To date, it has not been cost-effective to utilize this resource, other than localized uses for firewood, due to the costs of collection. However, logging operations are now subject to slash removal, which would be more likely to bring forest residues to centralized points for recovery.
- ***Mill residues*** – Also called hog fuel, mill residues are widely collected and utilized for steam production and CHP. Residues are a quantifiable percentage of lumber and plywood production. The wood products industry is declining in the region, so opportunities for additional systems may be limited. In fact, many CHP plants based on mill residues are currently inactive or have been shut down.
- ***Chemical recovery boilers*** – The pulp industry uses chemicals (black liquor) to convert wood into fiber for paper production. There are 39 recovery boilers in the region with an estimated steam capacity of 11.5 million pounds of steam per hour. Six of the 20 mills in the region have the capability to generate electricity from their recovery boilers – though many are currently idle. The Northwest Power and Conservation Council estimates that there is currently 150 MW of electric generating capacity with a total potential of 400 MW.[34]
- *Municipal solid waste* – There are currently four waste-to-energy facilities generating power in the region with a combined capacity of 55 MW. If all available municipal solid waste were used for electricity production in Idaho, Oregon, and Washington they could support electricity generation of 290 MW. The existing facilities are not CHP, and typically such plants do not incorporate heat recovery for thermal applications.
- *Agricultural field residues* – Based on biomass material estimates made by the Northwest Power and Conservation Council, there is a quantity of agricultural residues that could support power production of 900 to 1,400 MW in the PNW region. Collection, transportation, and storage costs would be quite high, so the current economic potential from this resource appears limited.
- *Landfill gas* – Primarily composed of organic matter, trash decomposes over time. In landfills this results in the production of methane gas. The annual gas production from 23 landfills in Washington and Oregon equals 7.4 trillion Btu/year. This has the potential for 70 MW of electricity generation. Additional landfills are being added in the Eastern portions of the PNW states that, with water management, could provide an additional 100 MW of

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[33] Jim D. Kerstetter, *Biomass Briefing Paper*, Northwest Power and Conservation Council, Washington State University Energy Program.

[34] Kerstetter, *op cit*.

electricity generation. There are currently five landfill projects producing electricity with a combined capacity of 18.5 MW and an additional two projects in the planning stages with 26.5 MW.[35] These projects are not CHP projects.

- ***Animal manure*** – Concentrated animal feeding operations (cattle, swine, and poultry) produce large quantities of manure. Liquid treatment of the manure by anaerobic digestion creates a biogas fuel that can be burned in a variety of prime movers for electricity production. These projects are classified as CHP because the heat is typically fed to the digesters to keep them in an optimal gas production range.
- ***Sewage treatment*** – Water treatment systems with tertiary treatment (anaerobic digesters) also have potential for power generation. There are currently 14 projects in the PNW region with an electricity production capacity of 9.9 MW.

This section focuses on biogas applications – animal feedlot operations and sewage treatment facilities. The potential from mill residues and chemical recovery boilers is incorporated into the power and steam analysis of the industrial markets.

4.4.1 Wastewater Treatment

Anaerobic digesters reduce the organic content of wastewater and decrease the amount of sludge disposal required. The digester gas generated in the process is often used as boiler fuel to supply heat for the digesters and for other treatment facility uses. There are 14 projects in the PNW region that produce electricity from digester gas and use the waste heat for warming the digesters. **Table 4-12** shows the state-by-state breakdown for the existing projects and for the technical potential. The table shows that existing plants have already captured more than half of the total potential.

Table 4-12. CHP Technical Market Potential from Sewage Treatment Facilities

States	Active Projects[36]	Current Capacity (MW)	Total Potential (MW)	Remaining Potential (MW)
Alaska[37]	0	0.0	1.8	1.8
Idaho	2	0.3	1.3	1.0
Oregon[38]	9	5.3	7.2	1.9
Washington[39]	3	4.3	7.1	2.8
Total	**14**	**9.9**	**17.5**	**7.6**

35 Northwest Power and Conservation Council, existing and new power plant databases.

36 Current projects and capacities from Subtask 1-1 Deliverable and NWPPC Powerplant database.

37 Alaska and Idaho potentials estimated based on ratio of population in cities over 100,000 compared to the average for Oregon and Washington.

38 Oregon technical potential based on resource estimate on the Oregon website (http://www.energy.state.or.us/biomass/Resource.htm).

39 Based on James D. Kerstetter, 1998 *Washington State Directory of Biomass Energy Facilities*, Washington State University Energy Program, December 1998.

4.4.2 Animal Wastes

The use of wet treatment methods and anaerobic digestion for manure treatment is expanding. There are a number of important benefits in addition to the value of the energy production:

- Odor control is perhaps the biggest driver.
- Control of coliform bacteria is also very important. Digesters operating at 95 °F and above destroy 99% of coliform bacteria. In addition, wet treatment greatly reduces flies and eliminates weed seeds in animal digestive tracts.
- Control of excessive nutrient run-off into local streams that result from manure spreading on area fields is achieved.
- Methane emissions that contribute to global warming are reduced.
- Finally, there are fertilizer and fiber by-products that result from anaerobic digestion.

The primary source of concentrated animal wastes in the region is from dairy farms. The PNW region represents 8% of all U.S. dairy farm receipts. Idaho is the sixth largest dairy state where dairy is the number one farm product. Dairy is also the top farm product in Washington and the third biggest in Oregon.[40] Dairy is not important in Alaska due to the severe climate conditions. **Table 4-13** shows the number of dairy cattle in the four states in the region and the number of dairy farms by size of herd that have at least 100 cows. The table also shows the share of total animals in the state represented by each size category.

Table 4-13. Dairy Cattle and Number of Dairy Farms by State and Size of Herd

State	Dairy Cows x1000	# of Sites	100-199 Cows/Site	% of State Cows	200-499 Cows/Site	% of State Cows	500+ Cows/Site	% of State Cows
Alaska	1	30	0	0%	0	0%	0	0%
Idaho	366	950	140	5%	150	12%	180	78%
Oregon	95	800	170	19%	100	28%	45	45%
Washington	247	950	180	11%	200	26%	140	59%
Region Totals	**709**	**2,730**	**490**	**9%**	**450**	**19%**	**365**	**67%**

Idaho is the biggest producer of dairy in the region, followed by Washington and Oregon. Over 95% of the total number of animals in each state is represented by the three farm size categories shown.

Table 4-14 shows the power production potential for these farms if they all were to use wet treatment with anaerobic digestion. Power production potential is assumed to be 0.1 MW per 1,000 cows. There is a total technical CHP potential of 67.3 MW. Current technology and economics point to a threshold of 500+ animals required to make the system economical. In this size range, there is a technical CHP potential of 47.4 MW.

[40] Patrick Mazza, *Harvesting Clean Energy for Rural Development: Biogas*, Clean Energy Solutions, February 2002.

Table 4-14. CHP Technical Market Potential from Dairy Operations by State and Size of Herd

State	Size of Herd			Total Potential (MW)
	100-199 Cows/Site	200-499 Cows/Site	500+ Cows/Site	
Alaska	0	0	0	0
Idaho	1.9	4.4	28.5	34.8
Oregon	1.8	2.7	4.3	8.7
Washington	2.7	6.4	14.6	23.7
Totals (MW)	**6.4**	**13.5**	**47.4**	**67.3**

Note: Assumption of 0.1 MW per 1,000 cows

Swine and poultry also produce concentrated wastes that could be incorporated into anaerobic digestion and electric power production using the digester gas. The potential for energy production in the PNW region, shown in **Table 4-15**, is much less than for dairy farms. There is an additional 4.4 MW of technical potential from these operations.

Table 4-15. CHP Technical Market Potential from Swine and Poultry Operations by State and Number of Animals

States	Number of Swine (x 1,000)	Electric Potential from Swine (MW)	Number of Poultry (x 1,000)	Electric Potential from Poultry (MW)
Alaska	2	0.02	N/A	N/A
Idaho	45	0.45	879	0.31
Oregon	45	0.45	2,459	0.88
Washington	51	0.51	4,952	1.77
Totals (MW)	**143**	**1.43**	**8,290**	**2.96**

Note: Source of animal population estimates is the U.S. Department of Agriculture. Animal-to-electricity ratios are based on manure production – 10 pigs or 280 chickens equal one cow, and it is assumed that 1,000 cows equal 0.1 MW of electricity.

With all possible co-product credits and offsets included, a digester CHP system could be economically feasible today for larger dairy operations (i.e., dairies with 500 or more cows) or for a cooperating group of smaller dairies within a local area. Portland General Electric (PGE) has been seeking financial backing to construct one of the largest biodigesters in the U.S. Serving several operations with up to 25,000 cows, this facility would be located in Boardman, Oregon and would generate 4 MW of power. PGE has already installed a 100-kW generator at a 500-cow dairy in Salem, Oregon. The Port of Tillamook is planning a digester to process the waste from over 2,000 cows. Other projects are being developed for Sunnyside, WA and Myrtle Point, OR.[41]

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[41] *Harvesting Clean Energy for Rural Development: Biogas*, Climate Solutions Special Report, February 2002.

4.5 Alaskan Village Market

Diesel generators usually supply electricity in remote Alaskan villages that do not have access to a larger power grid. The waste heat from these systems is often used for heating surrounding buildings such as schools, community buildings, and community laundry facilities called *washeterias*. As reported in **Section 2**, there are 54 such systems currently utilizing heat recovery from diesel engines. These systems have a nameplate capacity of 61 MW, though the average utilization factor of these isolated systems is only 22%. There are 154 village power systems in total, with an estimated capacity of 115 MW. Therefore, the total remaining CHP technical market potential in this market is 98 sites and 54 MW. These results are summarized in **Table 4-16**.

Table 4-16. CHP Technical Market Potential at Alaskan Villages

Status	Sites	MW
Active CHP at remote villages	54	60.7
Heat recovery installed but not used or in limited use	40	30.3
No heat recovery installed	58	23.6
Total Remaining Potential	**98**	**53.9**

4.6 Summary of Technical Potential

The CHP technical market potential by state and by application type is summarized in **Table 4-17**. This estimate is disaggregated by individual market sector based on the sectoral analyses described in this report. Determining technical market potential, the focus of this section, is only an intermediate step in the overall process of determining the economic market potential for CHP in the PNW region.

Also shown in **Table 4-17** is a qualitative description of economic potential by application. A detailed assessment of economic market potential is the focus of the next section of this report. However, in an effort to put the technical market potential into context, a qualitative assessment of economic potential was made for each sector.

In general, the highest economic potential is expected from large systems of more than 5 MW that are capable of operating with net power costs in the 4-5 cents per kilowatt-hour range, even lower for systems in the 50+ MW range. Resource recovery systems will also have a high potential in the region due to low fuel costs and available "green" subsidies and incentives. Penetrating the smaller packaged CHP market in the bulk of commercial and small industrial applications will be very difficult. Except for Alaska where potential will be much higher, power costs are currently below what available CHP technology can provide even after thermal credits are considered. **Figure 4-5** shows a breakdown of this market into qualitative categories of low, moderate, and high potentials. Only about 3,200 MW of the total potential is in the high economic potential category with another 800 MW judged to be moderate.

Table 4-17. Summary of CHP Technical Market Potential by State and Application (MW Capacity)

CHP Type	AK	ID	OR	WA	Total	Economic Potential
Existing Facilities (MW)						
Large Industrial – On Site	5	239	356	360	960	High
Large Industrial – Export	409	83	753	870	2,115	High especially in OR
Resource Recovery	2	36	11	27	76	Moderate to high
Small Industrial	16	157	547	745	1,465	Low to moderate
Commercial	380	576	1,796	2,885	5,636	Low except AK
Alaskan Village Systems	54	0	0	0	54	Moderate
New Facilities (2002-2022) (MW)						
Large Industrial – On Site	0	17	66	57	140	High
Small Industrial	1	37	246	304	588	Low to moderate
Commercial	252	498	1,288	2,473	4,511	Low except AK
Total Technical Potential	**1,119**	**1,643**	**5,063**	**7,721**	**15,544**	

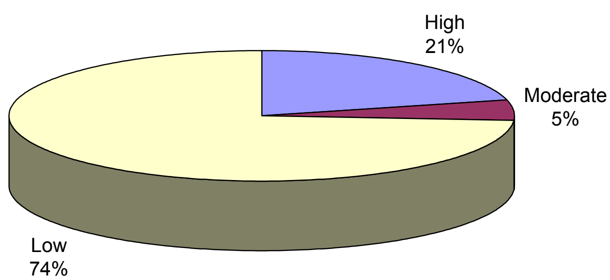

Figure 4-5. Comparison of Total Technical Market Potential by Economic Potential

The individual market applications are summarized below:

- *Large Industrial* – Over 90% of the existing CHP in the region is in large industrial systems, which represents the most active existing market in the region. The technical potential in this market is split between electric capacity that serves on-site electric needs and electric capacity that could be exported (using the site as a steam host). The technical potential for this market is 3,215 MW – approximately one-third of this capacity could be used to meet the site electrical needs and about two-thirds could be available to meet the power needs of the region as a whole. Technical CHP potential from new facilities is low because of the lack of growth of basic industries in the region. The total remaining potential for this market over the next 20 years is less than a third of the existing capacity that has already been installed.
- *Resource Recovery* – There is currently a great deal of interest in developing this market. The ultimate technical potential is low at 76 MW for the PNW region, but the economic potential is moderate to high.

- *Small Industrial* – The small industrial technical market potential in the PNW is 2,053 MW. However, the economics in this size range will be very difficult to justify due to the low power prices in the region. Alaska is the exception to this with both high electric rates and low fuel costs, causing system economics to be very promising.
- *Commercial/Institutional* – This is a very large part of the regional economy with a great many potential sites and favorable growth projections. The technical potential is 10,147 MW – the highest of all the applications considered for both existing and new facilities. However, the economics of CHP in this sector are extremely difficult. Alaska is the only state with significant active projects in this sector due to the more favorable gas-to-electric price ratio.
- *Alaskan Village Systems* – This is a market unique to Alaska. There is 54 MW of remaining potential in existing villages that are grid isolated and use diesel power for all of their electrical needs. The value of heat recovery has been demonstrated in many other villages, and many of the systems already have partial or complete heat recovery equipment installed but not yet in use.

5. ECONOMIC POTENTIAL[42]

This section describes the expected CHP market penetration by technology and size range for high- and low-growth scenarios that are designed to provide boundaries on the range of expected outcomes for the region. In addition to the market penetration estimates themselves, this section describes the analytical framework, the fuel and power price assumptions, and the characterization of applicable CHP technologies.

5.1 Analytical Framework

Figure 5-1 provides a graphical depiction of the market penetration analytical framework used to estimate CHP market penetration. There are four basic components to this framework:

- Technical Market Potential – The output of this analysis is an estimate of the technically suitable CHP applications by size and by industry. This estimate – described in **Section 4** – is derived from the screening of market databases.
- Energy Price Estimation – Present and future fuel prices are estimated to provide inputs into the CHP net power cost calculator. These prices are derived from external data sources including the Energy Information Administration, the Northwest Power and Conservation Council, and the EEA gas supply model.
- Technology Characterization – For each size range, a set of applicable CHP technologies is selected for evaluation. These technologies are characterized in terms of their capital cost, heat rate, non-fuel operating and maintenance costs, and available thermal energy for process use on-site. Both current and expected future technology characteristics are evaluated based on a prior study undertaken for the National Renewable Energy Laboratory and the Gas Research Institute.[43]
- Market Deployment – Within each market size, the competition among applicable technologies is evaluated. Based on this competition, the economic market potential is estimated and shared among competing CHP technologies. The rate of market penetration by technology is then estimated using a market diffusion model.

The development of the technical market potential was explained in detail in the previous section. Each of the three remaining pieces of the analytical framework is described in the following sections.

[42] The results in this section are being presented for the first time in this deliverable.

[43] *Gas-Fired Distributed Energy Resource Technology Characterizations*, National Renewable Energy Laboratory, October 2003.

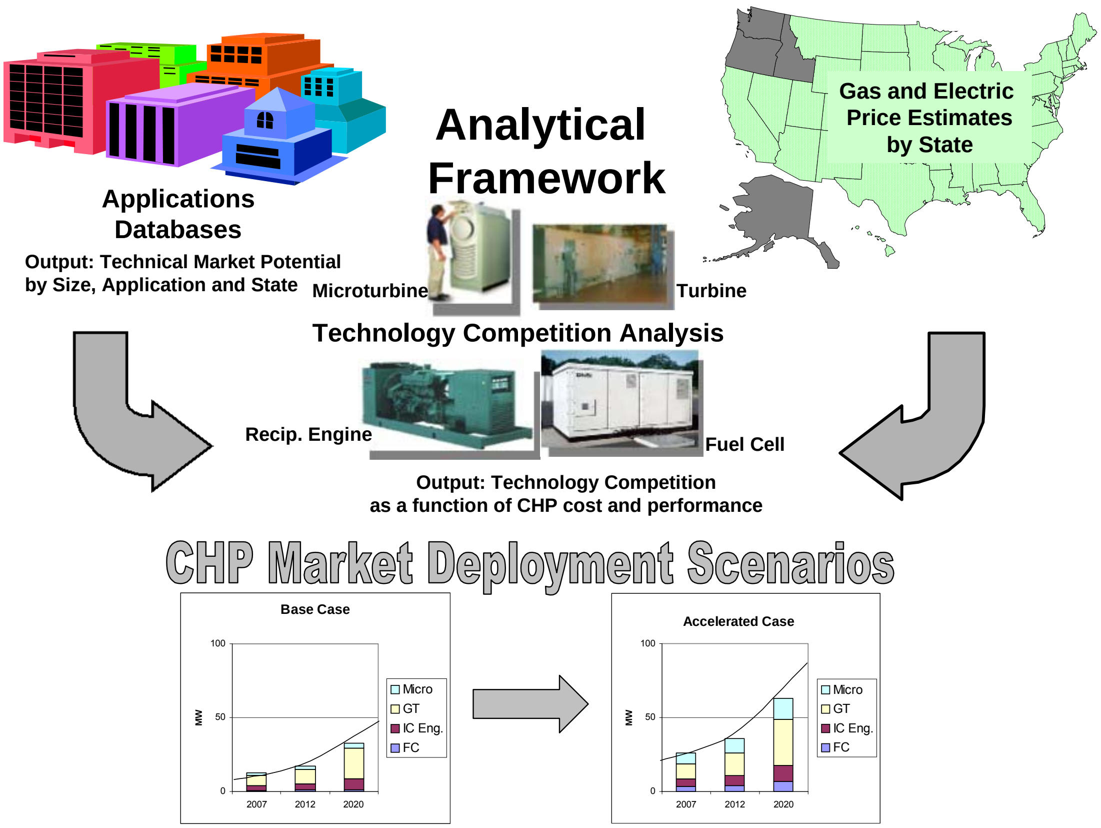

Figure 5-1 Analytical Framework for Evaluating CHP Market Penetration

5.2 Current and Future CHP Technology Cost and Performance

There are a large number of distributed power generation technologies that can be used for combined heat and power applications. The applicable technology types and their associated cost and performance depend on the electric capacity of the proposed project. This section describes the cost and performance of four main types of prime movers configured for CHP in various sizes.[44] Appropriate technologies were then chosen to reflect the economic competition within each of the six market size bins used for the determination of technical market potential in **Section 4**.

[44] "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL Report TP-620-34783, November 2003.

5.2.1 Reciprocating Engines

Reciprocating internal combustion (IC) engines represent a widespread and mature technology for power generation. Reciprocating engines are used for all types of power generation, from small portable gensets to larger industrial engines that power generators of several megawatts. Spark ignition engines for power generation use natural gas as the preferred fuel – although they can be set up to run on propane or gasoline. Diesel-cycle, compression ignition engines operate on diesel fuel or heavy oil, or they can be set up in a dual-fuel configuration that can burn primarily natural gas with a small amount of diesel pilot fuel. Reciprocating engines offer low first cost, easy start-up, proven reliability when properly maintained, and good load-following characteristics. Drawbacks of reciprocating engines include relatively high noise levels, relatively high air emissions, and the need for regular maintenance. The emissions profiles of reciprocating engines have been improved significantly in recent years by the use of exhaust catalysts and through better design and control of the combustion process. Gas-fired reciprocating engines are well suited for packaged CHP in commercial and light industrial applications of less than 5 MW. Smaller engine systems usually produce hot water, while larger systems can be designed to produce low-pressure steam.

Table 5-1 shows the current specifications and likely 2020-year specifications for gas-fired reciprocating engines in CHP applications.

Table 5-1. Current and Advanced Reciprocating Engine Specifications

	System 1	System 2	System 3	System 4	System 5
Current Technology Specifications (2000)					
Electricity Capacity (kW)	100	300	1,000	3,000	5,000
Electric Heat Rate (Btu/kWh HHV)	11,500	10,967	10,035	9,700	9,213
Electrical Efficiency (%)	29.7%	31.1%	34.0%	35.2%	37.0%
Installed Cost -- CHP (2003 $/kW)	$1,350	$1,160	$945	$935	$890
O&M Costs	$0.018	$0.013	$0.009	$0.009	$0.008
Fuel Input	1.15	3.29	10.04	29.10	46.07
Total Recoverable Heat (MMBtu/hr)	0.56	1.52	3.70	9.84	16.66
Economic Life Years	10	10	15	15	15
Net Power Costs	$0.075	$0.066	$0.056	$0.057	$0.052
Advanced Technology Specifications (2020)					
Electricity Capacity (kW)	100	300	1,000	3,000	5,000
Electric Heat Rate (Btu/kWh HHV)	10,500	10,185	8,638	8,322	7,935
Electrical Efficiency (%)	32.5%	33.5%	39.5%	41.0%	43.0%
Installed Cost -- CHP (2003 $/kW)	$1,000	$930	$840	$830	$790
O&M Costs	$0.012	$0.010	$0.008	$0.008	$0.008
Fuel Input (MMBtu/hr)	1.05	3.06	8.64	24.97	39.68
Total Recoverable Heat (MMBtu/hr)	0.49	1.35	2.90	8.00	13.00
Economic Life Years	10	10	15	15	15
Net Power Costs	$0.061	$0.058	$0.051	$0.050	$0.048

Source: "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL Report TP-620-34783, November 2003 and internal EEA estimates

5.2.2 Gas Turbines

Gas turbines for distributed generation applications are an established technology in sizes from several hundred kilowatts up to about 50 MW. Gas turbines produce high-quality heat that can be used to generate steam for on-site use or for additional power generation (combined-cycle configuration). Gas turbines can be set up to burn natural gas or a variety of petroleum fuels, or they can have a dual-fuel configuration. Gas turbine emissions can be controlled to very low levels using water or steam injection, advanced dry combustion techniques, or exhaust treatment such as selective catalytic reduction (SCR). Maintenance costs per unit of power output are among the lowest of distributed generation technology options. Low maintenance and high-quality waste heat make gas turbines an excellent match for industrial or commercial CHP applications larger than 5 MW. Technical and economic improvements in small turbine technology are pushing the economic range into smaller sizes as well.

An important advantage of CHP using gas turbines is the high-quality waste heat available in the exhaust gas. The high-temperature exhaust gas is suitable for generating high-pressure steam, making gas turbines a preferred CHP technology for many industrial processes. In simple cycle gas turbines, hot exhaust gas can be used directly in a process or by adding a heat-recovery steam generator (HRSG) that uses the exhaust heat to generate steam or hot water. Because gas turbine exhaust is oxygen-rich, it can support additional combustion through supplementary firing. A duct burner can be fitted within the HRSG to increase the steam production at lower-heating-value (LHV) efficiencies of 90% and greater. In larger sizes, it is economical to use a portion of the steam generating capability to make additional power. This configuration is called a combined cycle (CC) plant. Very high electric efficiencies are achievable with a combined cycle power plant.

Table 5-2 shows the current specifications and likely 2020-year specifications for gas-fired combustion turbines in CHP application.

5.2.3 Microturbines

Microturbines are very small combustion turbines that are currently offered in a size range of 30 kW to 250 kW. Microturbine technology has evolved from the technology used in automotive and truck turbochargers and auxiliary power units for airplanes and tanks. Several companies have developed commercial microturbine products and are in the early stages of market entry. A number of other competitors are developing systems and planning to enter the market within the next few years. In the typical configuration, the turbine shaft, spinning at up to 100,000 rpm, drives a high-speed generator. The generator’s high-frequency output is converted to the 60-Hz power used in the United States by sophisticated power electronics controls. Electrical efficiencies of 23-26% are achieved by employing a recuperator that transfers heat energy from the exhaust stream back into the combustion air stream.

Microturbines are compact and lightweight, with few moving parts. Many designs are air-cooled, and some even use air bearings, thereby eliminating the cooling water and lube oil systems. Low-emission combustion systems, which provide emissions performance approaching that of larger gas turbines, are being demonstrated. The microturbine’s potential for low emissions, reduced maintenance, and simplicity promises to make on-site generation much more competitive in the 30 to 300 kW size range characterized by commercial buildings or light industrial applications. Microturbines for CHP duty are typically designed to recover hot water or low-pressure steam.

Table 5-2. Current and Advanced Gas Turbine Specifications

	GT-3.4	GT-5	GT-25	GT-40	CC-260
Current Technology Specifications (2000)					
Electricity Capacity (kW)	3,400	5,000	25,000	40,000	260,000
Electric Heat Rate (Btu/kWh HHV)	13,800	12,590	9,945	9,220	7,937
Electrical Efficiency (%)	0.0%	27.1%	34.3%	37.0%	43.0%
Installed Cost -- CHP (2003 $/kW)	$1,100	$1,024	$800	$702	$590
O&M Costs	$0.006	$0.006	$0.005	$0.004	$0.004
Fuel Input	46.92	62.95	248.63	368.80	2063.67
Total Recoverable Heat (MMBtu/hr)	20.60	25.00	89.90	127.30	443.56
Economic Life Years	15	15	15	15	15
Net Power Costs	$0.063	$0.061	$0.050	$0.046	$0.045
Advanced Technology Specifications (2020)					
Electricity Capacity (kW)	3,400	5,000	25,000	40,000	260,000
Electric Heat Rate (Btu/kWh HHV)	11,500	10,500	8,865	8,595	7,300
Electrical Efficiency (%)	29.7%	32.5%	38.5%	39.7%	46.8%
Installed Cost -- CHP (2003 $/kW)	$900	$840	$705	$660	$530
O&M Costs	$0.006	$0.005	$0.004	$0.004	$0.004
Fuel Input (MMBtu/hr)	39.10	52.50	221.63	343.80	1898.00
Total Recoverable Heat (MMBtu/hr)	15.98	20.30	77.30	115.50	409.24
Economic Life Years	15	15	15	15	15
Net Power Costs	$0.055	$0.051	$0.045	$0.044	$0.041

Source: "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL Report TP-620-34783, November 2003 and internal EEA estimates

Table 5-3 shows the current or near-term specifications and likely 2020-year specifications for gas-fired microturbines in CHP application.

5.2.4 Fuel Cells

Fuel cells produce power electrochemically, more like batteries than conventional generating systems. Unlike storage batteries, however – which produce power from stored chemicals – fuel cells produce power when hydrogen fuel is delivered to the cathode of the cell, and oxygen in air is delivered to the anode. The resultant chemical reactions at each electrode create a stream of electrons (or direct current) in the electric circuit external to the cell. The hydrogen fuel can come from a variety of sources, but the most economic is steam reforming of natural gas – a chemical process that strips the hydrogen from both the fuel and the steam.

Several different liquid and solid media can be used inside fuel cells – phosphoric acid (PAFC), molten carbonate (MCFC), solid oxide (SOFC), and proton exchange membrane (PEMFC). Each of these media comprises a distinct fuel cell technology with its own performance characteristics and development schedule. PAFCs are in commercial market development now, with 200-kW units delivered to more than 120 customers worldwide. PEMFC, MCFC, and SOFC technologies are now in early market introduction and demonstration.

Table 5-3. Current and Advanced Microturbine Specifications

	System 1	System 2	System 3	System 4	System 5
Current and Near-Term Technology Specifications (2000 to 2005)					
Electricity Capacity (kW)	30	70	100	250	
Electric Heat Rate (Btu/kWh HHV)	15,075	13,545	13,125	13,080	
Electrical Efficiency (%)	22.6%	25.2%	26.0%	26.1%	
Installed Cost -- CHP (2003 $/kW)	$2,262	$1,926	$1,769	$1,600	
O&M Costs	$0.020	$0.015	$0.015	$0.013	
Fuel Input	0.45	0.95	1.31	3.27	
Total Recoverable Heat (MMBtu/hr)	0.19	0.33	0.47	1.12	
Economic Life Years	10	10	10	10	
Net Power Costs	$0.110	$0.099	$0.094	$0.089	
Advanced Technology Specifications (2020)					
Electricity Capacity (kW)	50	110	160	350	500
Electric Heat Rate (Btu/kWh HHV)	10,660	9,750	8,980	8,980	8,750
Electrical Efficiency (%)	32.0%	35.0%	38.0%	38.0%	39.0%
Installed Cost -- CHP (2003 $/kW)	$1,400	$1,091	$900	$870	$770
O&M Costs	$0.014	$0.012	$0.012	$0.010	$0.012
Fuel Input (MMBtu/hr)	0.53	1.07	1.44	3.14	4.38
Total Recoverable Heat (MMBtu/hr)	0.19	0.31	0.41	1.09	1.24
Economic Life Years	10	10	10	10	10
Net Power Costs	$0.077	$0.069	$0.063	$0.057	$0.059

Source: "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL Report TP-620-34783, November 2003 and internal EEA estimates

Fuel cells promise higher efficiency than generation technologies based on heat engine prime movers. In addition, fuel cells are inherently quiet and extremely clean running. Similar to microturbines, fuel cells require power electronics to convert direct current to 60-Hz alternating current. Many fuel cell technologies are modular and capable of application in small commercial and even residential markets; other fuel cell technologies operate at high temperatures in larger sized systems that would be well suited to industrial CHP applications.

Table 5-4 shows the current or near-term specifications and likely 2020-year specifications for various fuel cell types and sizes in CHP application. For this analysis, emerging fuel cell types were assumed to have better economic potential in both the near term and in 2020 than the currently available PAFC.

Table 5-4. Near-Term and Advanced Fuel Cell Specifications

	PEMFC	SOFC	PEMFC	MCFC	MCFC
Near-Term Technology Specifications (2005)					
Electricity Capacity (kW)	10	100	150	250	2,000
Electric Heat Rate (Btu/kWh HHV)	11,370	7,580	9,750	7,930	7,420
Electrical Efficiency (%)	30.0%	45.0%	35.0%	43.0%	46.0%
Installed Cost -- CHP (2003 $/kW)	$5,500	$3,620	$3,800	$5,000	$3,250
O&M Costs	$0.033	$0.033	$0.023	$0.043	$0.033
Fuel Input	0.11	0.76	1.46	1.98	14.84
Total Recoverable Heat (MMBtu/hr)	0.04	0.19	0.72	0.44	3.56
Economic Life Years	10	10	10	10	15
Net Power Costs	$0.183	$0.136	$0.126	$0.177	$0.115
Advanced Technology Specifications (2020)					
Electricity Capacity (kW)	10	100	150	250	2,000
Electric Heat Rate (Btu/kWh HHV)	9,750	6,820	8,980	6,920	6,820
Electrical Efficiency (%)	35.0%	50.0%	38.0%	49.3%	50.0%
Installed Cost -- CHP (2003 $/kW)	$2,200	$1,800	$1,700	$2,100	$1,600
O&M Costs	$0.019	$0.015	$0.012	$0.020	$0.014
Fuel Input (MMBtu/hr)	0.10	0.68	1.35	1.73	13.64
Total Recoverable Heat (MMBtu/hr)	0.04	0.14	0.66	0.40	3.00
Economic Life Years	10	10	10	10	15
Net Power Costs	$0.093	$0.079	$0.070	$0.090	$0.067

Source: "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL Report TP-620-34783, November 2003 and internal EEA estimates

The estimated net power costs for reciprocating engines, gas turbines, microturbines, and fuel cells are shown in **Figure 5-2**. The graphs show declining net power costs as the scale of the CHP system becomes larger. Fuel cells and microturbines are emerging technologies that are aimed at the smaller scale markets for CHP. Current costs are very high, but technology advances are expected to bring costs down considerably. The established technologies – reciprocating engines in the smaller scale applications and gas turbines in larger applications – are more competitive today with moderate improvements (10-20%) expected from technology advances. Both the current/near-term and advanced technology specifications were used to evaluate alternative market penetration tracks for the Pacific Northwest.

In **Section 4**, the technical market potential was determined for each application. For each of these applications (e.g., large industrial, small industrial, commercial, resource recovery, Alaska Village system), the technical potential was evaluated in discrete market sizes defined in terms of CHP capacity in MW. There are six market size bins that are covered by the analysis in **Section 4.** In the economic market analysis in this section, technologies applicable to each market size were used in a competitive market model to determine both the economic market potential for CHP in that size bin and also the market penetration by technology as a function of their relative costs and performance. **Table 5-5** shows the technologies selected for the competitive market analysis by market size bin.

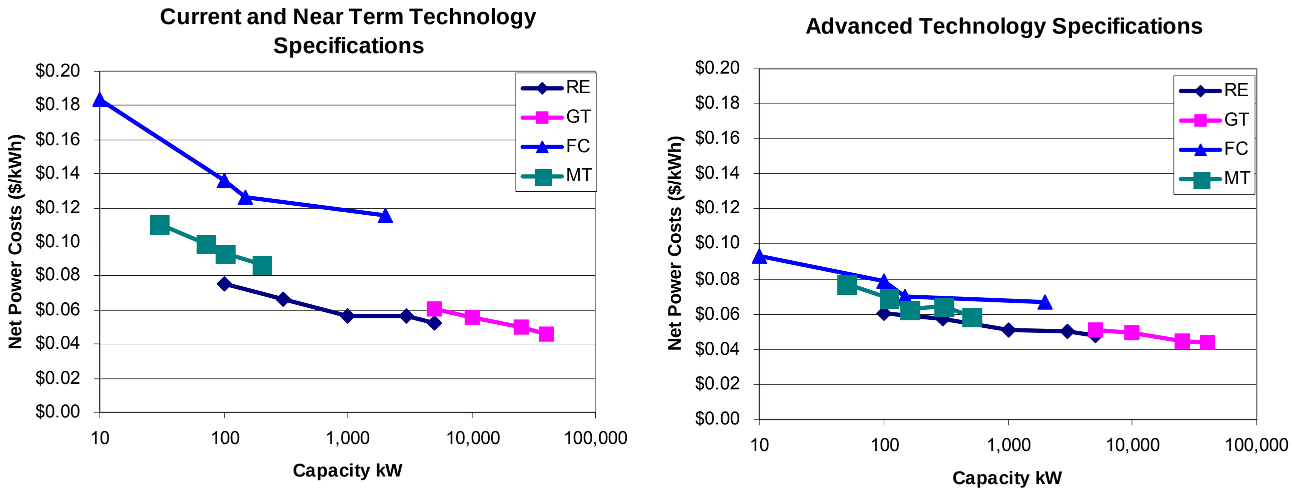

Figure 5-2. CHP Net Power Costs for Current and Advanced Technologies

Table 5-5. Competitive Technologies Used in Economic Market Analysis by Market Size

Market Size Bins	Competing Technologies
50 - 500 kW	100 kW RE
	100 kW MT
	200 kW PEMFC
500 - 1,000 kW	300 kW RE (multiple units)
	250 kW MT (multiple units)
	200 kW PEMFC (multiple units)
1 - 5 MW	3 MW RE
	3 MW GT
	2 MW MCFC
5 - 20 MW	5 MW GT
	2 MW MCFC (multiple units)
20 - 50 MW	25 MW GT
> 50 MW	40 MW GT (multiple units)
	260 MW GT-CC

In the markets below 1 MW, reciprocating engines are the established technology with emerging competition from fuel cells and microturbines. Gas turbines begin competing with reciprocating engines in the 1-5 MW size range along with industrial-sized molten carbonate fuel cells. Above 5 MW, gas turbines take over as the technology of choice. In the largest size category, simple cycle gas turbines compete with combined cycle systems that include a steam turbine bottoming cycle for more power production and higher efficiency.

As shown in **Table 5-6**, some additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. All applications less than 20 MW were assumed to have an electric load factor of 80% (7,008 full load hours/year) and an 80% utilization of recoverable thermal energy. In the large gas turbine projects of 20 MW and larger, 90% electric load factor and 90% utilization of recoverable thermal energy are assumed.

Table 5-6. Assumptions Used in Economic Potential Analysis

Parameter	Assumption
Economic Life of CHP Technology	10 years – for technologies with < 1 MW power output
	15 years – for technologies with ≥ 1 MW power output
Amortization Discount Rate	10%
Electric Load Factor	80% – for applications with < 20 MW load
	90% – for applications with ≥ 20 MW load
Utilization of Recoverable Thermal Energy	80% – for applications with < 20 MW load
	90% – for applications with ≥ 20 MW load

5.3 Current and Future Energy Prices in the Region

Current electricity prices in Idaho, Oregon, and Washington are among the lowest in the United States. Alaska, on the other hand, has electric prices that are among the highest in the nation. **Figure 5-3** shows the average industrial power prices for 2002 for the 114 separate public and private power companies in the PNW region. The prices are shown as a function of average industrial customer size in order to show the relationship between customer size and price. Average prices for the largest industrial customers range from 2 to 5 cents/kWh in the Columbia River Basin. Alaska prices are much higher.[45] By overlaying even the advanced CHP technology power costs onto this curve, it can be seen in **Figure 5-4** that competition for CHP based on historical prices would be very difficult. Alaska is the exception.

[45] Ten of the isolated Alaskan Power systems have prices that range from 23 to 53 cents/kWh and are not shown on the figure.

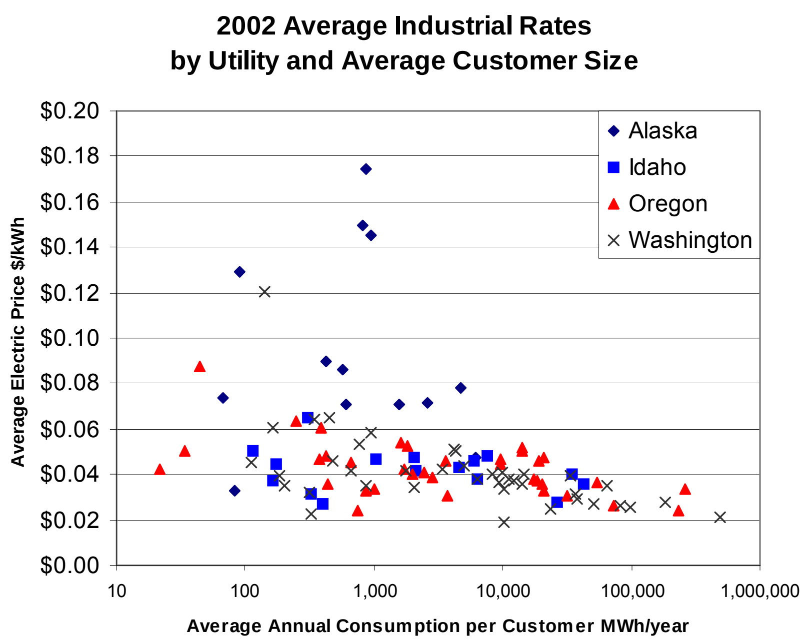

Figure 5-3. Average 2002 Industrial Electric Prices by State, Utility, and Average Customer Size

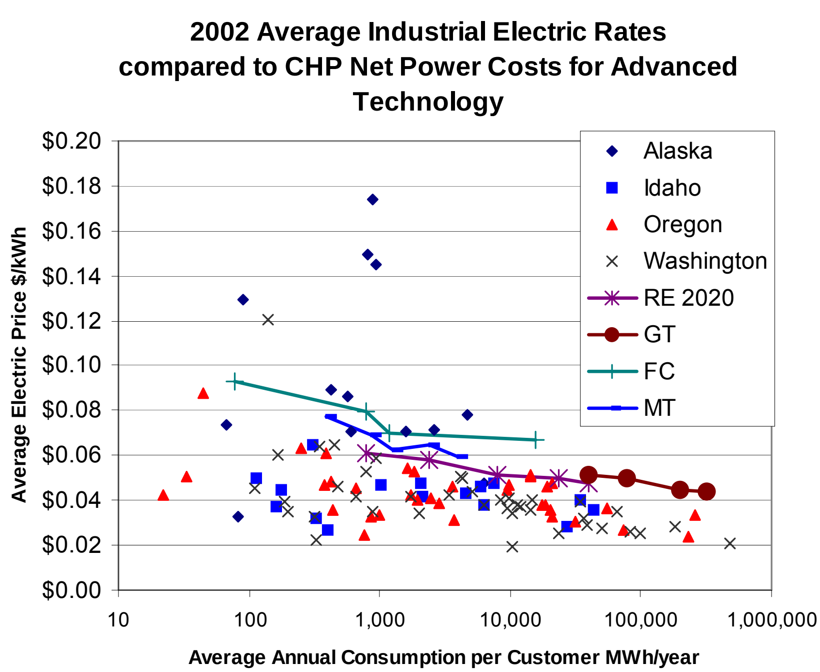

Figure 5-4. Comparison of 2002 Industrial Prices and Advanced CHP Net Power Costs

These historically low power prices are expected to rise over the next twenty years for a number of reasons. Growth in power demand will require significant investments in thermal power generation plants, a departure from historical reliance on low-cost hydroelectric power. This thermal power production will act to raise the wholesale power prices for the region. Growth in power demand in California will exert similar pressure on prices and capacity. It is also expected that the Bonneville Power Administration will alter its historical methods of pricing and prioritizing low cost hydroelectric capacity throughout the region. To determine the effect of these trends, the wholesale electricity price forecasts of the Northwest Power and Conservation Council (in preparation of their *5th Power Plan*[46]) were analyzed. The Northwest Power and Conservation Council current case was chosen for the electric power and natural gas price track.[47] **Table 5-7** summarizes the assumptions for the Northwest Power and Conservation Council's 5th Power Plan Current Case.

Table 5-7. Summary of Assumptions Underlying the Northwest Power and Conservation Council's Current Trends Forecast

Parameter	Assumption
Hydropower	Average hydropower conditions
Fuel prices	5th Plan revised draft forecast, Medium case (April 2003)
Loads	5th Plan revised draft sales forecast, Medium case (April 2003)
Existing and planned resources	Resources in service Q1 2003 Additions under construction Q1 2003 Retirements scheduled Q1 2003 75% of state renewable portfolio standard and system benefit charge target acquisitions are secured 50% of forecast Demand Response potential by 2025
New resource options (market-driven development)	Gas-fired combined-cycle Wind Coal steam-electric Gas-fired simple-cycle Central-station solar photovoltaics Suspended projects > 25% complete
Inter-regional transmission	2003 WECC path ratings Scheduled upgrades Q1 2003
Climate change policy	Oregon CO_2 standard, phased in, escalating in cost
Renewable resource incentives	Continued federal production tax credit Green tag revenue, escalating in value
Intermittent resource penetration limit	20-25% of installed capacity by load-resource area

Figure 5-5 shows the wholesale price track for three delivery points in the PNW region. Prices are shown rising rapidly and then stabilizing. The average mid Columbia Basin price for the forecast period of 2005 to 2025 is $36.67/MWh. For this analysis, prices for Washington and Oregon were based on the PNW Westside price, and prices for Idaho were based on the Southern Idaho price track.

[46] *Wholesale Electricity Price Forecast for the Draft Fifth Power Plan*, Northwest Power and Conservation Council, April 21, 2004, (preliminary draft, not approved by the Council.)

[47] Northwest Power and Conservation Council, op. cit.

Delivered prices were estimated from current retail prices in the region. **Table 5-8** shows the markups that were used in the economic analysis.

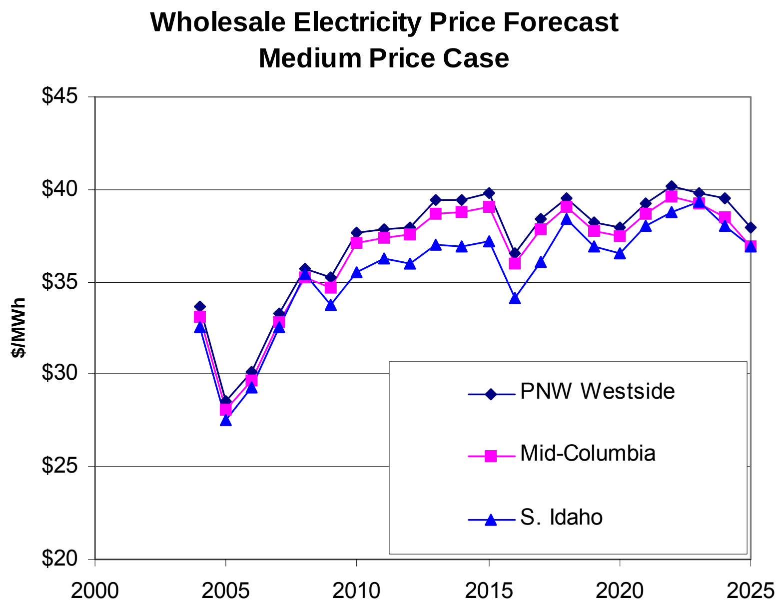

Figure 5-5. Forecast of Wholesale Power Prices

Table 5-8. Retail Electric Price Markups Compared to Wholesale Prices ($/kWh)

Market Size	AK	ID	OR	WA
50-500 kW	$0.038	$0.021	$0.032	$0.028
500kW to 1 MW	$0.025	$0.014	$0.022	$0.020
1-5 MW	$0.013	$0.008	$0.013	$0.012
5-20 MW	$0.011	$0.006	$0.011	$0.010
20-50 MW	$0.009	$0.004	$0.009	$0.008
>50 MW	$0.000	$0.000	$0.000	$0.000

The natural gas price forecasts from the Northwest Power and Conservation Council current case are shown in **Figure 5-6.** The price forecast does not attempt to address the issue of volatility that can be plainly seen in the historical data. For this study, the Western and Eastern (of the Cascade Mountains) electric utility price was used as the starting point (**Figure 5-7**) with markups estimated as a function of the market size bin (**Table 5-9**).

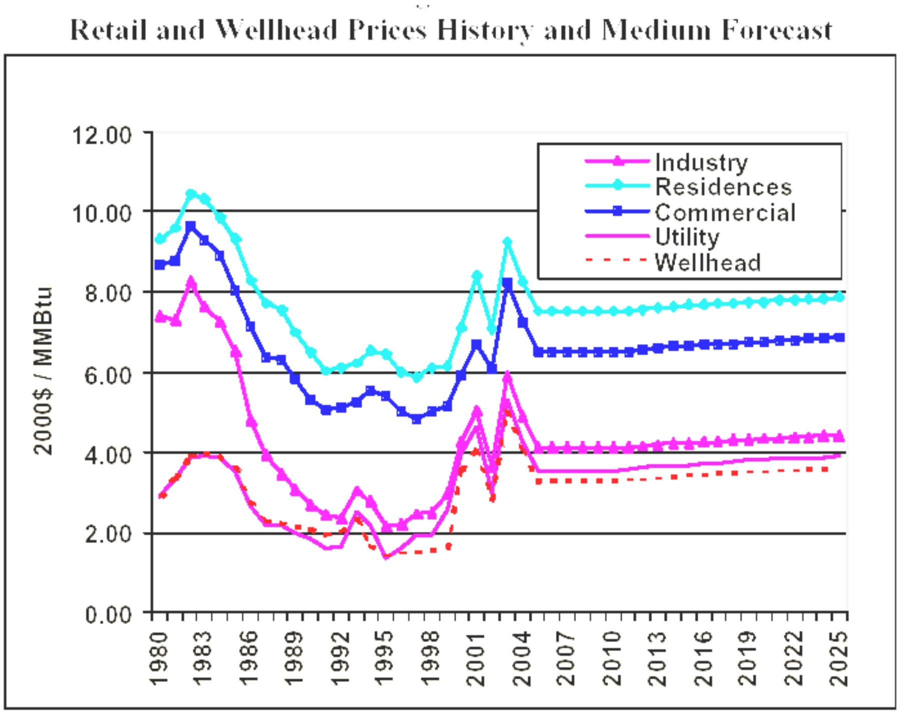

Figure 5-6. **Northwest Power and Conservation Council Medium Gas Price Case – Delivered Prices**

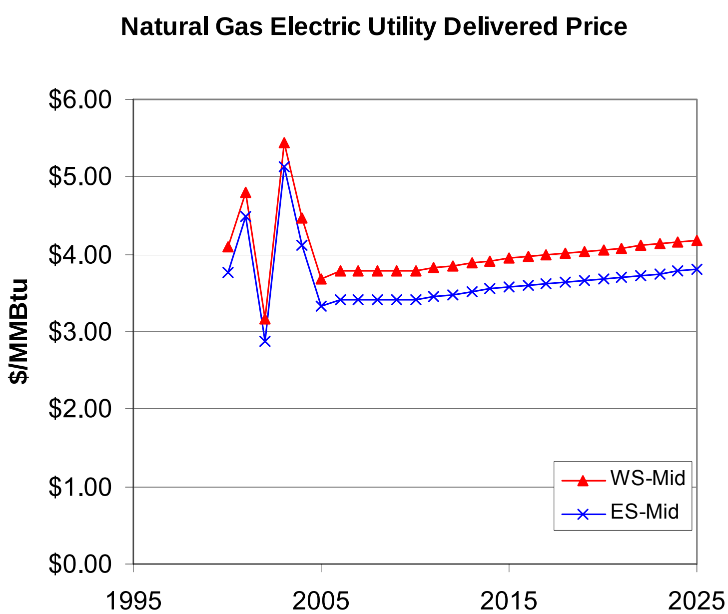

Figure 5-7. **Northwest Power and Conservation Council Medium Gas Price Case – Electric Utility Delivered Price**

Table 5-9. Delivered Natural Gas Price Markups Compared to Electric Utility Price

Customer Size	$/MMBtu
50-500 kW	$2.80
500 -1000 kW	$1.00
1 - 5 MW	$0.50
5 -20 MW	$0.25
20 -50 MW	$0.00
> 50 MW	$0.00

The situation in Alaska is considerably different than in the other three states in the PNW region. The Alaska Energy Authority bases their long-term energy planning on constant real dollar energy pricing; that is, in real terms, today's prices are expected to persist into the future. That same method was used for this study. The electricity and gas prices assumed for Alaska are based on the 2002 prices. The assumptions regarding prices are shown in **Table 5-10**.

Table 5-10. Alaska Energy Price Assumptions by Market Size

Market Size	Electric	Gas
	$/kWh	$/MMBtu
50-500 kW	$0.101	$3.41
500kW to 1 MW	$0.089	$3.22
1-5 MW	$0.077	$2.72
5-20 MW	$0.074	$2.47
20-50 MW	$0.072	$2.22
>50 MW	$0.064	$2.22

The calculated standard deviation of electric prices on the individual utility data (**Figure 5-3**) was over $0.15/kWh due to the number of isolated village power systems with costs of over $0.50/kWh. This variance was not thought to reflect the range of prices that would be seen by the sites comprising the technical potential for Alaska, so a standard deviation of $0.02/kWh was used to reflect price variation within the grid connected portion of the state.

5.4 Economic Market Potential

The economic market potential is determined based on a comparison of the net power costs from the competing CHP technologies with the delivered electric and natural gas prices within that market size and geographical area. The rate of market penetration is then estimated from this potential using a technology diffusion model. Two scenarios are analyzed: *Business-as-Usual* and an *Accelerated Case*. The overall economic and environmental benefits of the CHP market penetration in each scenario are calculated. This section describes the approach, the market results, and the associated benefits.

5.4.1 Competitive Model

There are three main objectives of the analysis that the model is designed to address:

1. Determine the overall economic potential for CHP by market size and by state.

2. Determine the market share of competing CHP technologies.

3. Determine the market penetration of CHP over a 20-year forecast period (2005-2025).

Electric rates are determined by state as described in **Section 5.3**. Three electric prices are used for each state – the mean price, the mean price plus 0.67 standard deviation, and the mean price minus 0.67 standard deviation. The standard deviation was calculated from the 114 utility prices shown previously in **Figures 5-3** and **5-4**. Assuming a normal distribution, the mean price is assumed to relate to 50% of the market and the higher and lower prices for 25% each. A single natural gas price is used for each state and size category.

For each size-state-fuel price category, the allocation of market share by technology is determined as a *logit* function as shown below:

$$\boxed{MS_{kt} = \frac{COST_{kt}^{-v}}{\sum_{k=1}^{J} COST_{kt}^{-v}}}$$

MS_{kt} = Market share in time period t for technology k

$COST_{kt}$ = Net power cost in time period t for technology k

v = variance parameter representing cost homogeneity

j = CHP technologies competing within the market

The key factor in this equation is the variance parameter. An extremely low value, such as 1, means that new equipment market shares are distributed almost evenly among all competing technologies, even if their annual costs differ significantly. An extremely high value, such as 10, means that the most cost-effective equipment gains a very high majority of the market share – a 25% cost advantage would yield a 90% market share. For this analysis, the variance parameter was given a value of 4 based on assumptions used in other energy technology market analyses.[48]

The economic payback[49] is then calculated for each of the competitive technologies selected for a given market size bin. A weighted-average payback of the competing technologies is then calculated based on the market shares. Based on this average payback, an economic acceptance share (as a percent of the technical market potential) is calculated. For paybacks of two years or less, the economic acceptance share equals 100%; that is, it is assumed that all sites within the technical potential would

[48] John A. "Skip" Laitner and Alan H. Sanstad, "Learning by Doing on Both the Demand and Supply Sides: Implications for Electric Utility Investments in a Heuristic Model," EXCETP Workshop, Paris, France, January 22-23, 2003.

[49] Payback is defined as the number of years required for the project annual savings to recoup the initial investment. It is calculated as the capital cost divided by the annual savings. The annual savings equal the avoided electric costs plus the avoided gas use for boiler fuel less then fuel and non-fuel operating and maintenance costs of the CHP system.

ultimately adopt CHP for that application in that state. For paybacks of 10 years or more, the economic acceptance share equals zero; there would be no market penetration of CHP for that application. The economic acceptance share varies between these 0% and 100% points in a linear fashion as shown in **Figure 5-8**.

The product of the technical market potential multiplied by the weighted average economic acceptance factor is defined as the economic market potential for that size/fuel price bin.

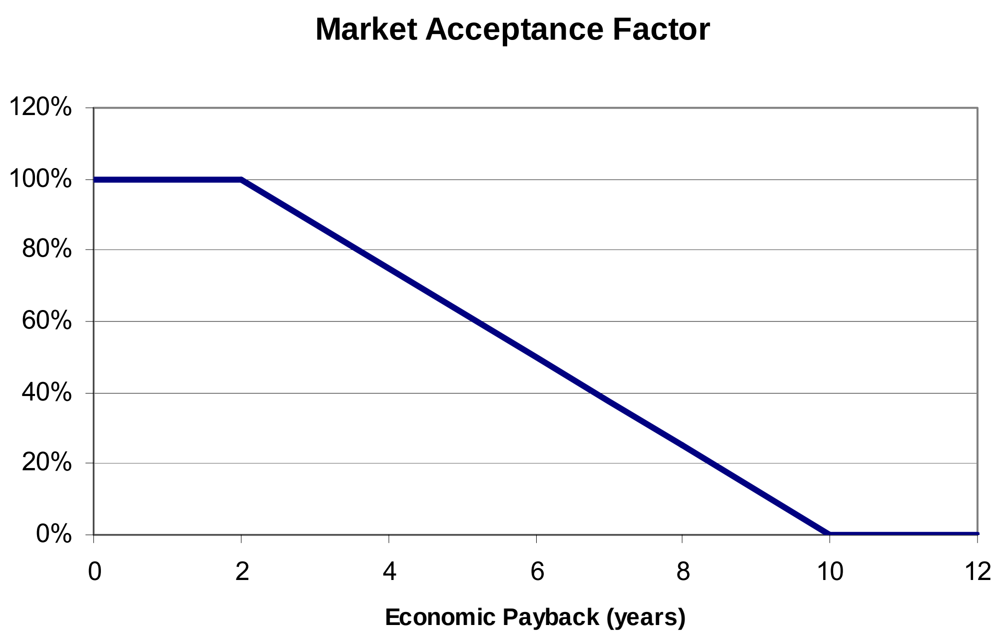

Figure 5-8.
Market Acceptance Share Assumptions in the Market Screening Model

The market penetration of this economic potential is then determined using a simple technology diffusion model.[50]

$$a(t_2 - t_1) = Ln\left[\frac{\left(\dfrac{1 - MS_1}{MS_1}\right)}{\left(\dfrac{1 - MS_2}{MS_2}\right)}\right]$$

a = adoptive influence

t_i = equals time period i

MS_i = market share in time period i

Ln = natural logarithm

[50] Anna Monis Shipley, Skip Laitner, and R. Neal Elliott, "Market Diffusion Theory and the Penetration of Combined Heat and Power," ACEEE, 2000. (The market diffusion model was described in the background section of this paper. The approach used by the authors of the cited paper is not the same approach developed for this study.)

This model defines a factor called *adoptive influence* based on the rate of change in market penetration for a given technology. For a range of historical market penetrations of energy technologies, this value varies between 0.38 and 0.49[51]. For this analysis a value of 0.46 was assumed. This value reflects full penetration of CHP from a starting market share of 1% over a 25-year period. This value for adoptive influence was then used to estimate the market share of CHP in year 10 (2015) and year 20 (2025). The market penetration by technology was allocated based on the competitive market share analysis previously described.

5.4.2 Scenario Assumptions

Two alternative futures for CHP market penetration in the Pacific Northwest were considered. The first case is termed *Business-as-Usual*. This case reflects assumptions of no improvement in current or near-term CHP technology, no incentives for CHP, and continuation of standby charges assessed on electricity customers with CHP. In addition, it is assumed that the lack of awareness of CHP and the poor economic climate for developers would limit the market penetration of systems, especially in the smaller sizes. In the *Accelerated Case*, it is assumed that CHP technology improves considerably, that incentives are available to offset 15% of initial capital cost, and that standby charges are eliminated. In addition, it is assumed that there is a greater awareness of CHP due to education programs and developer activity that reduce the rate of non-adoption of economic systems. The assumptions for the two cases are summarized in **Table 5-11**.

Table 5-11. Market Penetration Scenario Assumptions

Assumptions	Business-As-Usual	Accelerated Case
Electricity and Gas Prices	Northwest Power and Conservation Council 5th Power Plan, Business as Usual	Northwest Power and Conservation Council 5th Power Plan, Business as Usual
CHP Standby Charges	\$4/kW/month for sizes up to 20 MW \$3/kW/month for 20 MW and above	None
Technology Assumptions	Current and Near-Term Cost and Performance Specs	Year 2020 Cost and Performance Specs
CHP Incentives	No incentives (including discontinuation of current Oregon incentive programs	T&D benefit, climate benefit, and economic development benefits estimated to equal 15% of capital costs
Market Restrictions Due to Non-Economic Factors	30% of economic potential in small markets assumed to be non-adopters due to lack of awareness, resistance, or capital rationing; percentage decreases in larger size bins	20% in lowest size range declining to zero in large sizes; based on greater awareness, education, greater developer activity, etc.

[51] Shipley, Laitner, and Elliott, op. cit.

5.4.3 Economic Potential and Market Penetration Estimates

The market model was used to estimate the economic market potential and cumulative market penetrations (2015 and 2025) for all of the commercial and industrial sizes analyzed in **Section 4** plus the resource recovery potential. The resource recovery potential was assumed to completely fall into the 50-500 kW size range.[52] The Alaskan Village Market was not included in this framework, but was analyzed separately. The rationale for separating these projects is that, unlike the other technical market potential, the generating capacity is already in place, what is being added is just the heat recovery equipment.

The *Business-as-Usual* and *Accelerated Case* results are summarized in **Tables 5-12, 5-13**, and **5-14**. Of the 15.5 GW technical potential identified for the region, it is estimated that there is a 2.1 GW economic potential in the *Business-as-Usual* case and a 6.2 GW economic potential in the *Accelerated Case*. The share of technical potential that is economical in each size range increases as the project size increases. For example, in the *Business-as-Usual* case, only 5% of the 50-500 kW technical potential is economical while over 50% of the over 50 MW size capacity is economical. However, the changes to technology cost and performance and to the incentives for CHP assumed for the *Accelerated Case* have a greater impact on increasing economic potential for the smaller sized projects. In the smallest size bin, the economic potential is increased by a factor of six, whereas in the largest size bin, economic potential is increased by only 50%.

Table 5-12. Technical and Economic Potential (in MW) by Market Size

	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	20-50 MW	> 50 MW	Total MW
Technical Potential*	2,565	3,135	3,980	2,646	1,818	1,346	15,490
Econ. Potential Business-as-Usual	127	242	223	378	422	714	2,107
Econ. Potential Accelerated Case	798	1,307	1,118	1,144	678	1,105	6,151

* Does not include Alaskan Village Technical Potential

The distribution of economic potential by state shows that Alaska has the highest economic potential under the *Business-as-Usual* case. However, in the *Accelerated Case*, Washington and Oregon see a much greater addition to economic potential. In Alaska, 86% of its CHP technical potential is economical under *Business-as-Usual* assumptions. Consequently, there is little room for improvement in the *Accelerated Case*. In contrast, the other three states see only a 4 to 10% share of their technical potential that is economic under *Business-as-Usual*. This economic share increases to 25-35% in the *Accelerated Case*.

It should be noted that all of the 50-500 kW economic potential for Idaho, Oregon, and Washington in the *Business-as-Usual* case are resource recovery projects. The total economic potential for resource recovery projects is 27 MW in the *Business-as-Usual* case and 67 MW in the *Accelerated Case* (out of a total technical potential of 76 MW).

Table 5-13. Economic Potential by State and by Market Size (MW Capacity)

[52] The resource recovery analysis assumed that the technologies used in the 50-500 kW natural gas analysis could be used in the biogas applications without derating. Capital and O&M costs were not changed explicitly, but a *fuel preparation charge* of $1.00/MMBtu was used as a fuel price for the analysis.

	AK	ID	OR	WA
Economic Potential Business as Usual				
50-500 kW	101	9	6	11
500 -1000 kW	117	0	36	90
1 - 5 MW	139	0	23	61
5 -20 MW	149	0	120	110
20 -50 MW	0	5	147	270
> 50 MW	410	63	53	189
Total	**916**	**76**	**384**	**731**
Economic Potential Accelerated Case				
50-500 kW	144	43	212	399
500 -1000 kW	160	53	417	678
1 - 5 MW	167	92	320	539
5 -20 MW	166	96	524	358
20 -50 MW	0	16	233	429
> 50 MW	410	127	124	444
Total	**1,046**	**427**	**1,831**	**2,847**

As previously described, the economic potential is defined as the estimated market acceptance level for that share of the market with economic paybacks of less than 10 years, based on the weighted average technology mix. Market penetration was also estimated by technology and market for the years 2015 and 2025. The year 2025 cumulative market penetrations by technology for each scenario are given in **Table 5-14**.

Under *Business-as-Usual* conditions, the cost and performance of emerging technologies, like microturbines and fuel cells, are predominantly outside of a competitive range. With technology improvement, the share of each of these technologies increases dramatically. More moderate improvements in established technologies such as reciprocating engines and gas turbines also increase market penetration but to a lesser degree.

Table 5-14. Cumulative Market Penetration by Technology (MW Capacity)

Technology	Business as Usual	Accelerated Case
Reciprocating Engine	472	1,589
Microturbine	53	815
Fuel Cell	16	562
Gas Turbine	691	1,421
Gas Turbine CC	482	772
Total	**1,695**	**5,105**

As previously noted, the economic potential for growth in the use of heat recovery in the Alaska village power systems is not included in the foregoing analysis. In these systems, the power generating equipment is already in place; it is the heat recovery equipment that needs to be added to convert these small power generators to CHP status. According to the Alaska Energy Authority, it is estimated that all of the remaining CHP potential of 98 sites and 54 MW of capacity will be converted to CHP operation over the next 20 years.[53] These facilities as a group have an annual average load factor of only 22%. Nevertheless, in spite of these light loadings, complete conversion of the 98 remaining village power systems to CHP operation could save almost 4 million gallons per year of diesel fuel with an associated cost savings of about $5.5 million per year.

5.4.4 Economic and Environmental Benefits

CHP market penetration will produce economic benefits, energy savings, and a potential reduction in environmental emissions for the region.

Table 5-15 shows the energy savings and direct economic benefits for CHP to the users. The energy savings are based on avoiding average thermal power generation at 33% efficiency with additional savings of 6% due to avoided line losses. The economic benefits are based on the reduction in CHP users' annual energy bills net of CHP operating costs and amortized capital charges. In the *Accelerated Case*, by the end of the forecast period, annual benefits due to CHP deployment equal $885 million (in 2002 dollars). The associated annual energy savings are 167 trillion Btu/year.

Table 5-15. Annual Energy and Economic Benefits of Cumulative CHP Market Penetration to 2025

Benefits	2015	2025
Business as Usual		
Savings (Millions $/year)	$161.2	$318.4
Energy Savings (10^{12} Btu/year)	27.3	53.9
Accelerated Case		
Savings (Millions $/year)	$448.2	$885.0
Energy Savings (10^{12} Btu/year)	84.8	167.5

There are also potential environmental benefits to be derived from CHP deployment, depending on the assumptions used for the power that is avoided. It was assumed for this analysis that all of the region's low cost hydroelectric capacity, as well as the more limited nuclear and renewable energy capacity, would run regardless of the level of CHP market penetration. It was, therefore, assumed that the avoided power would be a mix of the average thermal generation for the region. The characteristics of this thermal generation are shown in **Table 5-16**. Because 43% of the region's thermal power production is from coal plants, average unit emissions for SO_2, NO_x, and CO_2 are comparatively high compared with gas-fired CHP technology.

Tables 5-17 and 5-18 show the NO_x and CO_2 emissions reductions that can be expected for the *Business-as-Usual* scenario and *Accelerated Case* respectively for the cumulative CHP market penetration compared with the average thermal power mix of the region. NO_x emissions would be reduced by 15 to 53 thousand tons per year. CO_2 emissions would be reduced by 6 to 22 million tons per year.

[53] Personal Communication with Peter Crimp, Alaska Energy Authority.

Table 5-16. Thermal Power Production by State and Associated Emissions for the Electric Power Industry (2002)

	Alaska	Idaho	Oregon	Washington	Region Total
Thermal Power Production (MWh)					
Coal	575,288	90,673	3,779,684	8,660,805	13,106,450
Petroleum	962,369	65	6,704	73,302	1,042,440
Natural Gas	3,778,162	328,988	7,812,894	4,719,311	16,639,355
Thermal Power Total	**5,315,819**	**419,726**	**11,599,282**	**13,453,418**	**30,788,245**
Emissions Reported (Thousands of Short tons)					
SO_2 Emissions	4	3	12	19	38
NO_x Emissions	11	1	10	20	42
CO_2 Emissions	4,205	314	7,534	12,878	24,931
Unit Emissions Calculated (lb/MWh)					
SO_2 Emissions	1.50	14.30	2.07	2.82	2.47
NO_x Emissions	4.14	4.77	1.72	2.97	2.73
CO_2 Emissions	1,582	1,496	1,299	1,914	1,620

Table 5-17. Net Change in NO_x and CO_2 Emissions for 2025 Cumulative Market Penetration – *Business-as-Usual*

Technology	Market Pen.	Emissions Rate	CHP Emissions	Avoided Boiler Emissions	Avoided Utility Emissions	Net Change
	MW	lb/MWh	tons/year	tons/year	tons/year	tons/year
NO_x Comparison						
Reciprocating Engine	472	1.79	2,953	276.3	4,783	-2,106
Microturbine	53	0.53	99	32.6	539	-473
Fuel Cell	16	0.05	3	6.1	163	-167
Gas Turbine	691	0.40	1,090	363.7	7,883	-7,157
Gas Turbine CC	482	0.26	494	120.3	5,497	-5,123
Emission Totals			**4,638**	**799**	**18,864**	**-15,025**
CO_2 Comparison						
Reciprocating Engine	472	1,203	1,988,177	979774.7	2,837,987	-1,829,584
Microturbine	53	1,605	298,919	115488.7	319,815	-136,385
Fuel Cell	16	1,170	66,004	21781.2	96,873	-52,651
Gas Turbine	691	1,309	3,565,877	1289391.3	4,677,864	-2,401,378
Gas Turbine CC	482	929	1,764,554	426517.3	3,261,671	-1,923,634
Emission Totals			**7,683,530**	**2,832,953**	**11,194,209**	**-6,343,632**

Table 5-18. Net Change in NO_x and CO_2 Emissions for 2025 Cumulative Market Penetration – *Accelerated Case*

Technology	Market Pen.	Emissions Rate	CHP Emissions	Avoided Boiler Emissions	Avoided Utility Emissions	Net Change
	MW	lb/MWh	tons/year	tons/year	tons/year	tons/year
NO_x Comparison						
Reciprocating Engine	1,589	0.54	3,028	930.9	16,110	-14,012
Microturbine	815	0.11	314	499.3	8,261	-8,447
Fuel Cell	562	0.05	89	214.3	5,694	-5,820
Gas Turbine	1,421	0.10	560	747.7	16,207	-16,395
Gas Turbine CC	772	0.08	243	192.8	8,807	-8,756
Emission Totals			**4,235**	**2,585**	**55,080**	**-53,430**
CO_2 Comparison						
Reciprocating Engine	1,589	1,092	6,079,237	3300374.5	9,559,768	-6,780,905
Microturbine	815	1,098	3,134,610	1770283.8	4,902,324	-3,537,998
Fuel Cell	562	884	1,739,433	759723.1	3,378,908	-2,399,198
Gas Turbine	1,421	1,132	6,339,901	2650904.8	9,617,384	-5,928,387
Gas Turbine CC	772	853	2,596,043	683408.2	5,226,171	-3,313,537
Emission Totals			**19,889,224**	**9,164,694**	**32,684,556**	**-21,960,026**

As an alternative assumption, many analysts would argue that future CHP deployment would not affect power production from existing capacity, but would offset the need for new capacity. This new capacity would most probably be in the form of large, efficient gas-fired combined cycle plants. If the CHP deployment shown were compared to new combined cycle capacity, there still would be a reduction in annual CO_2 emissions of 1 to 6 million tons/year due to the efficient utilization of the prime mover waste heat in CHP applications. NO_x emissions would increase, however. Most of this increase would be attributed to the penetration of lean-burn reciprocating engines. If it were assumed that these engines were controlled with exhaust gas cleanup (e.g., selective catalytic reduction) to the levels of a rich burn engine with a three-way catalyst, then the NO_x emissions picture improves. In the *Business-as-Usual* case, there would be 1,000 tons per year more emissions due to CHP deployment; but in the *Accelerated Case*, with improved technology, NO_x emissions would be 1,000 tons/year less.

6. RECOMMENDATIONS FOR REGIONAL ACTION

The comparison of the *Business-as-Usual* scenario and the *Accelerated Case* shows that there is a significant economic and environmental benefit to be earned by supporting CHP technology and market development in the region. It is important that both the Federal Government and the states work toward the removal of barriers and to provide incentives that promote deployment.

6.1 Federal Actions

At the Federal level, this support should include:

- Continued support for prime mover technology development and CHP systems integration
- Support for advanced technology demonstration projects in the region
- Education and outreach to raise awareness among all stakeholders, including facility managers, policy makers, regulators, utilities, and end users
- Analysis of the impacts of CHP deployment on regional transmission constraints
- Economic analysis of CHP impacts to provide a basis for streamlining interconnection; reducing standby charges; and implementing or increasing incentives to support climate goals, energy savings, and economic development goals
- Creation of utility partnerships to develop and strengthen the system-wide benefits of CHP deployment.

6.2 State Actions

At the State level, support should include:

- Establish streamlined procedures for CHP interconnection.
- Encourage the development of an economic methodology for setting standby power tariffs that reflect the diversity of CHP resources on the system.
- Establish fair avoided cost rates with increased state oversight.
- Encourage utilities to implement cost-based wheeling of power over the distribution grid.
- Encourage the use of integrated resource planning to buy the lowest cost resources for proposed generation, transmission, and distribution projects.
- Tax and investment incentives for CHP projects that meet efficiency, cost, economic development, or environmental goals.
- Develop or improve state-level facility siting procedures to streamline the process of siting energy facilities.

APPENDIX A: EXISTING CHP DATA TABLES

Table A-1. Active Alaska Combined Heat and Power Projects (Excluding Village Power)

Facility Name (EEA Database)	City	State	kW Cap.	Fuel	Prime Mover	SIC	1st Year
Agrium, Inc. (Nikiski Cogen. Project)	Nikiski	AK	40,000	Gas	Gas Turbine	2873	2001
Alaska Energy Management Corp.	Healy	AK	25,000	Coal	Steam Turb.	3900	1984
Alaska Pulp Corporation	Wrangell	AK	2,600	Wood	Steam Turb.	2421	NA
Alyeska Seafoods Inc	Unalaska	AK	4,400	Oil	R. Engine	2091	1986
Anchorage Mail Processing Center	Anchorage	AK	1000	Gas	Fuel Cell	4311	2000
Aurora Energy LLC	Fairbanks	AK	29,000	Coal	Steam Turb.	4939	1952
Clear AFS	Nothern Alaska	AK	30,000	Coal	Steam Turb.	9711	NA
Columbia-Ward Fisheries, Ekuk	Ekuk/Dillingham	AK	360	Oil	R. Engine	2091	1990
E.C. PHILLIPS	n.a.	AK	250	Oil	R. Engine	3900	1987
Eielson Air Force Base Central Heat	Eielson AFB	AK	33,500	Coal	Steam Turb.	9100	1969
Elmandorf AFB	Anchorage	AK	30,000	Gas	Gas Turbine	9711	NA
Erickson AFB	Alutian Islands	AK	10,000	Oil	R. Engine	9711	NA
Icicle Seafoods, Inc., Bering Star	Dutch Harbor	AK	1,700	Oil	R. Engine	2091	1979
KODIAK OILFIELD HAULERS, INC.	Deadhorse	AK	994	Gas	R. Engine	4212	1995
North Star Inn	Deadhorse	AK	5,000	Gas	R. Engine	7011	NA
Northwest Arctic Energy, LLC	Deadhorse	AK	555	Gas	R. Engine	6512	1997
Petrostar Valdez Refinery/Cooper Valley	Valdez	AK	7,900	Oil	Gas Turbine	2911	1996
Prudhoe Bay Hotel	Prudhoe Bay	AK	950	Gas	Gas Turbine	7011	NA
Tanadgusix Corp.	St. Paul Island	AK	300	Oil	R. Engine	2400	2000
Tesoro Alaska Petroleum Corp .	North Kenai	AK	8,000	Gas	Gas Turbine	2911	1988
U S Army-Ft Wainwright	Fort Wainwright	AK	22,500	Coal	Steam Turb.	9711	1955
U.S. Coast Guard	Kodiak	AK	6,200	Gas	Gas Turbine	9711	NA
Union Chemical	Kenai	AK	17,575	Gas	Gas Turbine	2800	1977
UNISEA	Dutch Harbor	AK	15,000	Oil	R. Engine	2092	1990
University of Alaska Fairbanks	Fairbanks	AK	21,100	Coal	Steam Turb.	8220	2000
Utility Capital Corp., Glenhallen Cogen.	Glennallen	AK	325	Oil	R. Engine	6512	1998
Utility Capital Corp., Yakutat Cogen.	Yakutat	AK	705	Oil	R. Engine	2091	1997
Westward Seafoods Inc	Dutch Harbor	AK	6,600	Oil	R. Engine	2091	1991
Total	**28 Active Projects**		**321,514**	**kW**			

Table A-2. Alaska Rural Village Diesel Engine CHP Systems

Electric Supplier	Village	Capacity kW	Thermal Use
Alaska Power & Telephone	Allakaket	430	School
Alaska Power & Telephone	Bettles	760	Local housing
Alaska Village Electric Cooperative	Alakanuk	1120	Water treatment plant
Alaska Village Electric Cooperative	Brevig Mission	439	School
Alaska Village Electric Cooperative	Emmonak	2108	Water treatment plant
Alaska Village Electric Cooperative	Goodnews Bay	495	City office, clinic, water and sewer
Alaska Village Electric Cooperative	Grayling	495	School
Alaska Village Electric Cooperative	Kaltag	475	School
Alaska Village Electric Cooperative	Koyuk	539	School
Alaska Village Electric Cooperative	Mekoryuk	364	Powerhouse and living quarters
Alaska Village Electric Cooperative	New Stuyahok	509	School
Alaska Village Electric Cooperative	Saint Mary's	2130	Church and cold storage building
Alaska Village Electric Cooperative	Saint Michael	771	Washeteria
Alaska Village Electric Cooperative	Savoonga	850	Water treatment plant
Alaska Village Electric Cooperative	Scammon Bay	654	City offices and clinic.
Alaska Village Electric Cooperative	Shaktoolik	639	Water tank
Alaska Village Electric Cooperative	Shungnak	895	Water plant
Alaska Village Electric Cooperative	Togiak	1050	School
Andreanof Electric Corporation	Atka	150 Est	City buildings
Chalkyitsik Village Energy System	Chalkyitsik	100 Est	School
Chignik Bay Plant # 1	Chignik	525	School, public works and the firehouse.
Chignik Lagoon Power Utility	Chignik Lagoon	300 Est	School
Eagle Power Company	Eagle	400 Est	School
Elfin Cove Electric Utility	Elfin Cove	200 Est	Community Center
Galena Electric Utility	Galena	3850	Multiple city buildings
Golovin Power Utilities	Golovin	300 Est	Multiple city buildings
Gwitchyaa Zhee Utility Company	Fort Yukon	1435	Pump house
Kipnuk Light Plant	Kipnuk	1,000 Est	City Council office
Kotlik Electric Service	Kotlik	600 Est	Multiple city buildings
Levelock Electric Cooperative Inc.	Levelock	250 Est	School
Manley Utility Company Inc.	Manley Hot Springs	150 Est	Store/garage and hangar
Manokotak Power Company	Manokotak	100 Est	Schools
McGrath Light and Power	McGrath	2285	FAA building.

Table A-2 cont'd. Alaska Rural Village Diesel Engine CHP Systems

Electric Supplier	Village	Capacity kW	Thermal Use
Naknek Electric Association	Naknek	8507	Multiple city buildings and residences
Naterkaq Light Plant	Chefornak	450 Est	Water and sewer plant
North Slope Borough Power & Light	Anaktuvuk Pass	1315	Multiple city buildings
North Slope Borough Power & Light	Kaktovik	2720	School, washeteria, water plant
North Slope Borough Power & Light	Nuiqsut	2720	School, washeteria, water plant
North Slope Borough Power & Light	Point Hope	2925	Multiple city buildings
North Slope Borough Power & Light	Point Lay	1470	Washeteria
North Slope Borough Power & Light	Wainwright	1620	Municipal building
Nunam Iqua Electric Inc.	Nunam Iqua	350 Est	Washeteria
Perryville Electric Utility	Perryville	250 Est	School
Pilot Point Electric Utility	Pilot Point	250 Est	School
Saint George Municipal Electric Utility	Saint George	250 Est	Multiple city buildings
Saint Paul Municipal Electric Utility	Saint Paul	2,200 Est	Motor pool and public works building
Sand Point Electric Inc.	Sand Point	2,000 Est	Shop, living quarters, and office building.
Tanalian Electric Cooperative	Port Alsworth	300 Est	School
Teller Power Company	Teller	450 Est	Store and two homes
Tlingit-Haida Regional Electrical Authority	Angoon	1530	School
Tlingit-Haida Regional Electrical Authority	Kake	2585	City shop, cold storage facility and the smokery
Unalakleet Valley Electric Cooperative	Unalakleet	2040	Multiple city buildings
Ungusraq Power Company	Newtok	200 Est	Water tank
Venetie	Venetie	200 Est	Water treatment plant
Total	**54 Active Projects**	**60,700**	**kW**

Notes: All systems are diesel engine generators. Capacity figures listed as estimated were based on annual generation figures assuming the average 22% load factor for this type of system. Only those systems providing heat to a separate facility were included; about 40 other village power systems provide heat just for the powerhouse itself.

Table A-3. Active Idaho Combined Heat and Power Projects

Facility Name (NWPPC Database)	City	State	kW Cap.	Fuel	Prime Mover	SIC	1st Year
Amalgamated Sugar (Nampa) 1 - 3	Nampa	ID	9,300	Coal	Steam Turb.	2062	1968
Amalgamated Sugar (Twin Falls) 1-3	Twin Falls	ID	7,000	Coal	Steam Turb.	2062	1994
Evergreen Forest Products	New Meadows	ID	6,300	Wood Residue	Steam Turb.	2421	1983
Forest Fuels, Inc.	Samuels	ID	300	Wood	Steam Turb.	2421	1994
Glenns Ferry Cogeneration	Glenns Ferry	ID	10,000	Natural Gas	Combined Cycle	20	1996
Nu-West Industries, Sulfuric Acid Plant	Conda	ID	2,800	Waste	Gas Turbine	2891	1992
Penta Post Company	Tuttle	ID	400	Wood	Steam Turb.	2491	1992
Pocatello Wastewater	Pocatello	ID	100	Wastewater Gas	R. Engine	49	1985
Potlatch – Lewiston (1-4)	Lewiston	ID	113,000	Black Liquor	Steam Turb.	2621	1950
Rupert Cogeneration	Rupert	ID	10,000	Natural Gas	Combined Cycle	2034	1996
Simplot Pocatello	Pocatello	ID	15,900	Natural Gas	Steam Turb.	2870	1986
West Boise Wastewater	Boise	ID	200	Wastewater Gas	R. Engine	49	1991
Total	**12 Active Projects**		**175,300**	**kW**			

Table A-4. Active Oregon Combined Heat and Power Projects

Facility Name (NWPPC Database)v	City	State	kW Cap.	Fuel	Prime Mover	SIC	1st Year
200 Market Street	Portland	OR	30	Natural Gas	Microturbine	65	n.a.
Alan David LLC (Ferreira Farm)	Beaver	OR	40	biogas	R. Engine	2	n.a.
Biomass One LP	WHITE CITY	OR	25,000	WOOD	Steam Turb.	24	1985
Blue Heron Paper	Oregon City	OR	15,000	Natural Gas	Steam Turb.	26	n.a.
Co-Gen I (Johnson Lumber)	RIDDLE	OR	7,500	WOOD	Steam Turb.	24	1987
Co-Gen II (Prairie Wood Products)	PRARIE CITY	OR	7,500	WOOD	Steam Turb.	24	1986
Columbia Blvd. Wastewater Fuel Cell	Portland	OR	200	biogas	Fuel Cell	49	n.a.
Coyote Springs 1	Boardman	OR	245,000	Natural Gas	Combined Cycle	20	1995
Curtis Livestock Ranch	Klamath Falls	OR	500	Natural Gas	R. Engine	2	n.a.
Durham Wastewater Plant	Durham	OR	2,000	biogas	R. Engine	49	n.a.
Eugene/Springfield Wastewater	Springfield	OR	840	biogas	R. Engine	49	n.a.
Fort James Wauna Paper Mill	Clatskanie	OR	27,000	Wood	Gas Turbine	26	1996
Frontier Energy	Heppner	OR	10,000	Wood	Steam Turb.	24	2001
Gresham Wastewater Plant	Gresham	OR	200	biogas	R. Engine	49	n.a.
Hermiston Generating Co (Lamb-Weston)	HERMISTON	OR	474,000	Natural Gas	Combined Cycle	20	1996
Hermiston Power Project (Simplot)	Hermiston	OR	630,000	Natural Gas	Combined Cycle	20	2002
Kellogg Creek Wastewater Plant	Milwaukie	OR	n.a.	biogas	R. Engine	49	n.a.
Klamath Cogeneration Project	Klamath Falls	OR	484,000	Natural Gas	Combined Cycle	26	2001
Medford Wastewater Plant	Medford	OR	700	biogas	R. Engine	49	n.a.
PGE Earth Advantage National Center	Portland	OR	3	Methanol	Fuel Cell	49	n.a.
Pope and Talbot Paper Mill	Halsey	OR	93,000	Natural Gas	Gas Turbine	26	n.a.
Rock Creek Wastewater Plant	Hillsboro	OR	300	biogas	R. Engine	49	n.a.
Roseburg Forest Products Co	Dillard	OR	45,000	WAST	Steam Turb.	24	1955
SierraPine Medite	Medford	OR	6,000	Natural Gas	Gas Turbine	26	2001
SP Newsprint	OREGON CITY	OR	5,000	unknown	Steam Turb.	24	1977
Tri-City Service District	Oregon City	OR	200	biogas	R. Engine	49	n.a.
Wah Chang	Albany	OR	14,000	Natural Gas	R. Engine	33	2001
Warm Springs Forest Products	WARM SPRINGS	OR	6,000	WOOD	Steam Turb.	24	n.a.
West Linn Paper Co.	West Linn	OR	n.a.	Natural Gas	Steam Turb.	26	n.a.
Weyerhaeuser Co (Springfield Plant)	Springfield	OR	51,200	Natural Gas	Gas Turbine	26	1953
Willamette Industries	ALBANY	OR	102,000	Natural Gas	Gas Turbine	26	1995
Willow Lake Wastewater	Salem	OR	825	biogas	R. Engine	49	n.a.
Total	**32 Active Projects**		**2,253,038**	**kW**			

Table A-5. Active Washington Combined Heat and Power Projects

Facility Name (NWPPC Database)	City	State	kW Cap.	Fuel	Prime Mover	SIC	1st Year
Bremerton Wastewater	Bremerton	WA	140	Biogas	R. Engine	49	n.a.
Colville Indian Precision Pine (7.5MW)	Omak	WA	7,500	Wood	Steam Turb.	24	2002
Daishowa	Port Angeles	WA	n.a.	Oil	Steam Turb.	24	n.a.
Georgia Pacific	BELLINGHAM	WA	160,000	Natural Gas	Combined Cycle	26	1993
Georgia-Pacific (Camas)	CAMAS	WA	50,000	Wood	Steam Turb.	26	1996
Grays Harbor Paper	Hoquiam	WA	4,400	Wood	Steam Turb.	26	n.a.
Kettle Falls GT	Kettle Falls	WA	6,500	Natural Gas	Gas Turbine	49	2002
Kimberly Clark (Everett)	EVERETT	WA	52,200	Wood	Steam Turb.	26	1996
King County Dept-Natural Res	Seattle	WA	3,900	Biogas	R. Engine	49	1983
Longview Fibre Company	LONGVIEW	WA	131,780	Natural Gas	Gas Turbine	26	1996
March Point Cogeneration	ANACORTES	WA	140,000	Natural Gas	Combined Cycle	29	1991
Port Townsend Paper Company	PORT TOWNSEND	WA	14,500	unknown	Steam Turb.	26	1990
SDS Lumber Co	Bingen	WA	5,000	Wood	Steam Turb.	24	1985
Spokane Wastewater	Spokane	WA	300	Biogas	R. Engine	49	n.a.
Sumas Cogeneration	SUMAS	WA	125,000	Natural Gas	Combined Cycle	24	1993
Tenaska Washington Partners	FERNDALE	WA	262,000	Natural Gas	Combined Cycle	29	1994
University of Washington	Seattle	WA	5,000	Natural Gas	Steam Turb.	82	1969
Vaagen Bros. Lumber, Inc.	COLVILLE	WA	4,000	Wood	Steam Turb.	24	1979
Valley Medical Center	RENTON	WA	3,592	Natural Gas	R. Engine	80	1997
Weyerhaeuser Cosmopolis	COSMOPOLIS	WA	15,000	Wood	Steam Turb.	26	1990
Weyerhaeuser Longview Mill	LONGVIEW	WA	51,400	Wood	Steam Turb.	24	1978
Whatcom Co. MSW	Ferndale	WA	2,000	Waste	Steam Turb.	49	1986
Total	**22 Active Projects**		**1,044,212**	**kW**			

Table A-6. Northwest Power and Conservation Council List of Idle and Retired CHP Projects in ID, OR, and WA

Facility	State	Fuel	Capac. MW	Status	Facility	State	Fuel	Capac. MW	Status
Boise Cascade (Emmett)	ID	Wood Residue	14.0	Idle	Gorge Energy (SDS Lumber) 1	WA	Wood Residue	3.5	Idle
DAW (Diamond Int.) Forest Products	OR	Wood Residue	10.0	Idle	Quality Veneer & Lumber	WA	Wood Residue	5.0	Idle
Crater Lake Lumber Company	OR	Wood Residue	2.5	Idle	Quality Veneer & Lumber	WA	Wood Residue	7.5	Idle
Weyerhaeuser - Cottege Grove	OR	Wood Residue	4.0	Idle	ITT Rayonier - Port Angeles	WA	Black Liquor	13.0	Idle
Lane Plywood	OR	Wood Residue	1.0	Idle	West Point Treatment Plant 2	WA	Wastewater Gas	1.3	Idle
University of Oregon	OR	Wood Residue	5.5	Idle	Pine Products Corporation	OR	Wood Residue	5.7	no CHP
Willamette Steam 2 & 3	OR	Natural Gas	25.0	Idle	Rayonier (ex Wood Power, Inc.)	ID	Wood Residue	6.8	Retired
Crown Pacific (Formerly Gilchrist)	OR	Wood Residue	1.5	Idle	Ellingson Lumber	OR	Wood Residue	2.8	Retired
Collins Wood Products	OR	Wood Residue	7.5	Idle	WTD Industries	OR	Wood Residue	6.0	Retired
Boise Cascade (LaGrand)	OR	Wood Residue	4.6	Idle	Weyerhaeuser - North Bend	OR	Wood Residue	4.0	Retired
Georgia-Pacific (Lebanon)	OR	Wood Residue	2.0	Idle	Willamette Industries - Dallas	OR	Wood Residue	4.5	Retired
North Powder	OR	Wood Residue	7.0	Idle	Willamette Industries - Foster	OR	Wood Residue	4.5	Retired
Amalgamated Sugar (Nyassa) 1 - 3	OR	Coal	14.0	Idle	Snow Mountain Pine	OR	Wood Residue	8.0	Retired
Ochoco Lumber Company	OR	Wood Residue	unk.	Idle	Blue Mountain Forest Products	OR	Wood Residue	3.5	Retired
Weyerhaeuser (Springfield) 1	OR	Black Liquor	7.5	Idle	Boise Cascade (Medford)	OR	Wood Residue	8.5	Retired
Weyerhaeuser (Springfield) 2	OR	Black Liquor	5.0	Idle	Willamette Industries - Sweet Home	OR	Wood Residue	6.0	Retired
Tillamook Lumber	OR	Wood Residue	12.5	Idle	Edward Hines Lumber	OR	Wood Residue	unk.	Retired
Warm Springs Forest Products 1	OR	Wood Residue	3.0	Idle	Weyerhaeuser (Everett)	WA	Black Liquor	12.5	Retired
Burrill Lumber	OR	Natural Gas	1.5	Idle	Great Western Malting	WA	Natural Gas	20.1	Retired
Husky Industries	OR	Wood Residue	5.0	Idle	**Total**			**256.3**	**MW**

APPENDIX B: ELECTRIC INDUSTRY RESTRUCTURING BY STATE[54]

Alaska

Regulatory Orders

9/01: The Regulatory Commission of Alaska issued an order ending the inquiry into retail electric utility restructuring and competition in Alaska and closing docket R-9710. According to the RCA's order, "projections of any potential benefits are too speculative at this time."

7/99: The legislature disbanded the Public Utility Commission and assigned its responsibilities to the newly named Regulatory Commission of Alaska (RCA). Five new commissioners were sworn in July 1, 1999.

Legislation

5/99: Under Title 42 Chapter 4 Section 10 of the Alaska State Code, the Alaska Public Utility Commission became the Regulatory Commission of Alaska with five new commissioners.

8/98: The Alaska State Legislative Joint Committee on Utility Restructuring, established to develop recommendations for the legislature on electric industry restructuring (due in January 1999) conducted its first hearing. The Alaska Rural Electric Cooperative Association stated that due to the isolation and unique characteristics of Alaska's rural electric industry, it should be left out of any restructuring plans. Chugach Electric Association, the State's largest electric utility, stated that consumers would benefit if the State embraced a broad policy of allowing competition.

5/98: House Concurrent Resolution No. 34 established a Joint Committee on Electric Utility Restructuring.

Investigative Studies

6/99: The final version of CH2M Hill's Study of Electric Utility Restructuring in Alaska requested by the PUC was presented on June 30, 1999. Most of the recommendations targeted the Railbelt (Anchorage and Fairbanks). Included were: consideration of retail pilot programs, encouragement of power trading markets, creation of a central dispatch point and an ISO, and consolidation of administrative functions and introduction of new technologies such as fuel cells and microturbines for rural systems.

[54] Reproduced from Energy Information Administration (EIA) Website
http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html

3/99: The Alaska State Legislature Joint Committee issued its report, Recommendations to the Alaska State Legislature and Alaska Public Utilities Commission Regarding a Retail Pilot Program. The report recommended the 21st legislature address restructuring and decided if statutory changes for the PUC are necessary to implement pilot programs or retail access.

10/98: Black and Veatch issued their Power Pooling/Central Dispatch Planning Study Final Report to the Alaska Public Utilities Commission and the Rainbelt Utilities.

Retail Access Additional Information

1/99: Chugach rejected Matanuska's offer and contended that the savings projected by the merger could easily be achieved through competition; Chugach will continue to push for statewide competition.

10/98: Matanuska Electric Association, Chugach's largest wholesale customer, offered to buy out Chugach. Chugach's assets are valued at $486 million. Chugach officials were surprised by the offer and are withholding judgment.

6/98: PUC rejected Chugach's argument and affirmed the PUC's authority to regulate retail wheeling.

1/98: Chugach Electric Association, the State's largest utility, urged to PUC and legislators to allow retail competition in Anchorage and surrounding areas. HB 235 primarily failed because Chugach would not support it unless it was amended to allow retail wheeling in Anchorage and surrounding areas.

8/00: The U.S. Postal Service (USPS) and the Chugach Electric Association, Alaska's largest electric utility, announced that the nation's largest commercial fuel cell system began generating power at the Anchorage Mail Processing Center. The 1-MW system consists of five fuel cells manufactured by International Fuel Cells. The Chugach Electric Association, Inc. installed and will operate the system for the USPS.

Idaho

Regulatory Orders

9/97: The PUC hosted technical workshops to discuss public purpose program costs as part of unbundling.

7/97: The PUC began proceedings on electric restructuring.

Legislation

12/98: The legislative committee concluded that deregulation would boost electric prices in the State, and recommended against restructuring.

3/97: HB 399 was enacted, directing the PUC to establish a committee to obtain information on the costs of supplying electricity to consumers. Utilities are required to unbundle costs of electric service and report to the PUC.

5/97: Governor signed an executive order creating the Governor's Council on Hydroelectric and River Resources that will establish guidelines for electric industry restructuring in Idaho.

Investigative Studies

1/99: The Legislative Council Committee on Electric Utilities Restructuring issued its final report. The report recommends a slow approach to retail competition. Idaho is a low cost state for electricity and concerned about prices rising under a competitive market. The legislature reestablished the study committee.

1/98: The PUC issued the Electric Costs Report to the Governor and Legislature. The report contains the findings on the unbundled average costs for utilities in Idaho compared to national averages.

Stranded Costs Allowed Recovery

8/97: Public hearings were held on the issue of stranded costs.

Pilot Programs Utilities

2/98: The PUC approved Washington Water Power Company pilot program, MOPS II, for approximately 6,000 consumers. The pilot will offer customers a portfolio consisting of four rate options: Traditional Energy Service, Monthly Market Rate, Annual Market Rate, and Standard Offer Service.

4/97: 2-year pilot program began for residential and commercial customers of WWPC in Idaho.

4/97: Idaho Power's pilot program for 900 customers will begin 7/97 and go through 6/99.

Oregon

Regulatory Orders

11/02: According to an Oregon Public Utility Commission press release, the Commission approved a request by Industrial Customers of Northwest Utilities (ICNU) to implement a five-year plan for large commercial and industrial customers of Portland General Electric with an hourly demand of 1 MW or more to choose their own electric supplier. These customers will be required "to pay a fixed transition charge." Despite having the opportunity to choose their own supplier since March 1, 2002, eligible customers had been discouraged by variable transition charges. The customers who choose this option will "give up receiving the standard cost-of-service rate for at least five years." However, if they give two years notice they "can switch to any PGE option available to new customers for service after 2007." Eligible customers have until November 8, 2002 to decide.

9/00: The Oregon Public Utilities Commission (PUC) has passed the first set of rules governing electricity restructuring in Oregon. Beginning October 1, 2001, large commercial and industrial customers will have the opportunity to choose alternative suppliers. Small commercial and residential customers will continue to be regulated. Electric utilities are required to file resource plans by November 1, 2000. The plans must identify what aspects of their businesses will remain regulated to serve residential and small commercial customers.

Legislation

3/02: According to Oregon's electric restructuring law, commercial and industrial customers of Portland General Electric and PacifiCorp will be eligible for direct access (the ability to purchase power from a certified Electricity Service Supplier) on March 1, 2002. In the event that an ESS pulls the plug on non-residential customers, PGE and PacifiCorp provide default service. Residential customers are not eligible for direct access, but they will have "a portfolio of energy options to choose from including electricity from a variety of renewable energy resources." The 12-member portfolio advisory committee recommended these options to the Public Utility Commission. PGE and PacifiCorp will continue to offer their renewable energy products, "Blue Sky" and "Clean Wind." All Oregon electric customers have the option to retain "cost-of-service" based rates, but all customers will be assessed "a 3 percent public purpose charge...to fund and encourage energy conservation and development of renewable energy." According to the PUC approved grant agreement, the Energy Trust of Oregon will administer funds collected for conservation and renewable energy. The Oregon Housing and Community Services Agency will continue to collect "a low-income bill assistance fee" from Portland General Electric and PacifiCorp customers.

8/01: Legislation, HB 3633, was enacted to revise Oregon's restructuring law. Act 3633 delays the date for implementing retail access for large customers from October 2001 to March 2002. Most other provisions of Oregon's plans for restructuring are also delayed 6 months to March 2002, including offering a portfolio of rate options to residential customers, the collection of public purpose funds, and the requirement for utilities to unbundle the costs of generation, transmission, distribution, ancillary services, customer services, public purpose programs, and taxes. An exception was made to allow collection of funds for low-income assistance programs, which may begin in October 2001.

8/01: HB 3502 was enacted. The legislation amends the power of the Public Utility Commission to not only obtain fair and reasonable rates, but also to balance the interests of the utility investor and the consumer in establishing fair and reasonable rates. Fair and reasonable rates are defined as those that provide adequate revenue for both operating expenses and capital costs, with a return to the equity holder that is commensurate with the return on investment in other enterprises of similar risk and sufficient to ensure confidence in the utility's financial integrity.

7/99: The restructuring bill, SB 1149, was signed by the governor. The bill is somewhat different from the other States that have passed restructuring legislation in that residential consumers will not have retail access, but will be offered a choice of pricing plans by the utilities and regulated by the PUC. The bill allows the PUC to suspend restructuring if it jeopardizes access to low-cost power from BPA, and it allows municipals to choose whether or not to participate. The bill imposes a 3 percent public benefits charge for energy conservation and low-income programs on consumers. Residential consumers are offered a portfolio of options, including market-based prices, rate-regulated prices, and green prices for energy, while businesses and industrials will have retail access beginning October 1, 2001. The PUC is given authority to determine stranded costs. Another provision allows the governor to appoint the chair of the PUC and remove commissioners for cause, and a net metering law for customer-installed generators less than 25kW (and limited customer generators to one half of one percent of the utility's single-hour peak). The bill affects consumers of IOU's in the State (PacifiCorp and Portland General Electric).

Investigative Studies

12/02: The Oregon Public Utility Commission recently released a report to the state Legislature on whether residential customers should participate in retail competition. According to a PUC press release, the report "concluded there would be few, if any, suppliers competing for residential customers," and "the cost of implementing a competitive residential power market exceeds the likely benefits at this time."

Retail Access Schedule

3/02: According to Oregon's electric restructuring law, commercial and industrial Portland General Electric and PacifiCorp customers will be eligible for direct access on March 1, 2002. PGE and PacifiCorp customers will provide default service. Residential customers are not eligible for direct access, but they will have "a portfolio of energy options to choose from including electricity from a variety of renewable energy resources."

9/00: Beginning October 1, 2001, large commercial and industrial customers will have the opportunity to choose alternative suppliers. Small commercial and residential customers will continue to be regulated. Electric utilities are required to file resource plans by November 1, 2000.

7/99: The restructuring legislation will allow direct access for industrial and large commercial consumers beginning October 1, 2001. Residential consumers will not have direct access to suppliers under restructuring, but will be provided a portfolio of pricing options, including a "green" rate, a market-based rate, and a traditional regulated rate.

Utility Plans

2/98: Portland General Electric's deregulation plan, which could become a model for the State, faces opposition from The Oregon Intervenor Coalition that includes PacifiCorp, Washington Water Power, and consumer groups. Portland's plan calls for selling all its generation and allowing all customers to choose competitive generation suppliers. The coalition prefers a "portfolio model" for customer choice. The portfolio model would allow large industrial customers to shop for power suppliers, but small customers would continue to be served by the incumbent utilities and be offered a menu of plans to choose from. Options would include current, market, or "green" rates.

Additional Information

6/02: The Oregon PUC issued its monthly status report for June 2002 that tracks what portfolio options residential customers have chosen based on service territory. Also the report tracks what percentage of nonresidential customers has chosen cost of service, market options or direct access based on load. No nonresidential customers have chosen direct access as of June 1, 2002. Nonresidential customers are the only customers allowed to choose a certified electricity service supplier.

Public Benefits Programs Renewables

8/00: The largest solar photovoltaic project in the northwestern U.S. was dedicated in Ashland, Oregon. The 25-kilowatt renewable energy project will produce enough energy to fully power the Ashland police station and parts of Southern Oregon University and the Oregon Shakespearean Festival. The project is being funded by the City of Ashland, the Bonneville Power Administration, Avista Energy, the Bonneville Environmental Foundation, Southern Oregon University, the Oregon Shakespearean Festival, and the State of Oregon Office of Energy.

1/00: The Oregon PUC approved Portland General Electric to offer a choice of renewable energy products to customers. For $5 a month, a customer can purchase a 100-kWh block of "green" energy, either "Clean Wind Power" or "Salmon-Friendly Power." Half of the funds collected from the sale of these products will go directly to new wind facility construction or salmon habitat restoration.

Other Programs

3/02: Utilities will spend $10 million a year on low-income assistance in their territories. SB 1149 provides for a low-income assistance fund through the 3-percent public purpose fee each utility collects from its customer. Residential customers will be charged 35 cents a month, and nonresidential customers will be charged .035 cent/kWh for low-income assistance starting March 1, 2002. The Oregon Housing and Community Services Agency will work with community action agencies to distribute the money.

9/99: Ashland, Oregon's net metering program, "progressive solar panel push," encourages installation of solar panels and the ability to sell excess power back to the local utility.

Funding Mechanisms

3/02: As of March 1, 2002, a 3-percent public purpose fee will be added to each customer bill to fund conservation, renewable energy, and low-income assistance programs.

11/01: The Energy Trust of Oregon's Board of Directors signed the PUC's final grant agreement on November 28, 2001. The Energy Trust of Oregon will administer funds collected for conservation and renewable energy. All customers will be assessed a 3-percent public benefits charge starting March 1, 2002.

10/00: The Oregon PUC has approved a plan to establish a non-profit organization to oversee money collected from Portland General Electric and PacifiCorp for conservation and renewable energy projects. The 1999 Oregon restructuring law requires the two utilities to collect a 3 percent public benefits charge from all customers starting October 1, 2001, when competition begins in the State.

Pilot Programs Utilities

7/98: Pacific Power has filed a proposal with the PUC for a "portfolio" pilot program for residential and small commercial consumers and direct access for large industrial consumers.

7/98: Portland General Electric's pilot program involving four Oregon cities will end as the two participating energy companies, Enron and Electric Lite, both discontinued marketing to consumers.

1/98: PacifiCorp filed a pilot program plan for residential and small commercial customers in Klamath County, Oregon. The pilot program would allow customers to select from a "portfolio" of pricing options for electricity and would go through June 1999. Another proposed pilot program will allow schools and customers with demands greater than 5 MW in PacifiCorp's service territory to choose alternative generation suppliers for up to 50 percent of their load. Additionally, all of their large customers in Klamath County would be allowed retail access.

10/97: PUC approved Portland General Electric pilot program which will allow 50,000 customers in four cities to choose alternative generation suppliers. Large industrial customers could begin to choose immediately, and residential customers by December 1997.

Washington

Regulatory Orders

5/01: The Washington Utilities and Transportation Commission announced a settlement between Puget Sound Energy and the utility's large industrial customers. The utility's six largest industrial customers will be allowed to buy power from any source, including other utilities, power marketers and each other.

12/95: WUTC issued its final guidelines after a yearlong inquiry into retail wheeling and restructuring issues, favoring a gradual approach.

Legislation

5/98: Several bills were passed by the legislature: a net metering bill to allow net metering for on customer site generation from solar, wind, and small (under 25 kW) hydro; and an unbundling bill to require generation, distribution, transmission, control area services, and programs to benefit the public (i.e., low-income, conservation) to be shown as separate charges for the purpose of preparing a report to the State legislature. The bill did not require utilities to offer unbundled services to consumers.

4/98: HB 2831 passed the legislature and the Governor is expected to sign it. The bill requires utilities to study and submit reports on unbundling their costs and the quality of service and reliability. Reports must be submitted by 9/98, and the WUTC will provide a consolidated report to the legislature by 12/98.

Investigative Studies

12/98: The WUTC delivered a report to the legislature per Bill 6560, on retail consumer protections.

5/98: WUTC completed Phase I of its investigation into electric restructuring concluding the pace nationwide is faster than expected.

Pilot Programs Utilities

6/98: The MOPS II pilot that will allow WWPC's customers to choose the type of electric power they want to buy will begin 7/1/98.

2/98: WWPC is selling blocks of wood and wind powered electricity in its pilot program.

12/97: Washington Water Power filed a new pilot program with the WTUC, "More Options for Power Service II," to replace their previous one. The pilot will allow about 7,800 customers in Washington and Idaho to choose among five energy service alternatives without changing energy service providers. The portfolio of options includes traditional energy service, variable market rate options, a "standard rate offer" based on BPA's preference rate, and a renewable resource rate. The pilot is scheduled to begin in 1998 and go through 5/2000.

8/97: PUC approved 2-year Pilot program submitted by Puget Sound Energy for 10,000 customers. The pilot will begin 11/1/97 and go through 12/99.

Additional Information

12/00: Two publicly owned utilities have had to raise their rates due to high wholesale prices in the western states. Snohomish Public Utility increased rates by 35 percent, effective in January 2001. Tacoma Power is considering a surcharge on bills of 86 percent, an unprecedented increase of between $70 and $100 monthly in the cost of electricity for Tacoma's residential consumers.

12/96: Regional study entitled Comprehensive Review of the Pacific Northwest Energy System is completed and accepted by four Northwest governors.

APPENDIX C: AIR QUALITY REQUIREMENTS BY STATE

Alaska

Alaska air quality regulations are under the control of the Alaska Department of Environmental Conservation.[55] There are no emission regulations pertaining solely to CHP applications. **Table C-1** provides a summary of air emission regulations for small electric generators.

Table C-1. Alaska Air Emissions Regulation Thresholds for Small Electric Generators

Attainment	There are two areas in non-attainment for PM and two areas in non-attainment for carbon monoxide CO.
NSR Threshold	PTE 250 tons of any criteria pollutant in attainment areas. 100 tons of PM or CO in non-attainment areas.
Minor Source Permitting Exemption	PTE 100 tons per year.
Minor Source Treatment	Opacity and PM limits.
Emergency Generating Limits	None.

<u>De Minimus Exemptions</u>

To be exempted from permitting, a source must have a potential to emit less than 100 tons of all criteria pollutants. State notification is required. All units, regardless of exemption must meet 20% opacity and 0.05 grains of PM averaged over 3 hours

<u>Minor Source Permitting</u>

Sources with a potential to emit greater than 100 tons per year must obtain a Title V operating permit. If a source wishes to avoid the operating permit the state will issue a minor source permit that includes a fuel or operating limit to ensure the source stays minor. No other controls will be required, but sources are still subject to the opacity and PM limits above.

There is a 30 day public comment period for permits and the whole process can take up to 60 days.

[55] www.state.ak.us/dec/dawq/aqm/regulati.htm

Major NSR/PSD

A potential to emit 250 tons per year of a criteria pollutant triggers PSD. In non-attainment areas a potential to emit 100 tons per year of CO or PM triggers NSR.

Emergency Engines

There are no special provisions for emergency units.

Idaho

Air emissions in Idaho are regulated by the Department of Environmental Quality.[56] There are no emission regulations pertaining solely to CHP applications. **Table C-2** provides a summary of air emission regulations for small electric generators.

Table C-2. Idaho Air Emissions Regulation Thresholds for Small Electric Generators

Attainment	Three Areas are in moderate non-attainment for PM and one area for CO.
NSR Threshold	PTE 250 tons of any criteria pollutant in attainment areas. 100 tons in non-attainment areas.
Minor Source Permitting Exemption	See list below.
Minor Source Treatment	Modeling required, controls unlikely.
Emergency Generating Limits	200 hours per year.

De Minimus Exemptions

Units are exempted from permitting based on the following sizes and operating limits:

- 100 hp or smaller = unlimited operation
- 101-200 hp = less than 450 hrs/month
- 201-400 hp = less than 225 hrs/month
- 401-600 hp = less than 150 hrs/month

No state notification is required, but a letter is recommended and owners must keep operating records.

56 http://www.deq.state.id.us/

Minor Source Permitting

Sources with a potential to emit less than 250 tons per year of all criteria pollutants in attainment areas and 100 tons per year in non-attainment areas will not be subject to controls of any kind. A unit may be subject to modeling if any hazardous air pollutants (HAPs) are released by the unit. If modeling shows the emissions unit contributes to a violation of the NAAQS, then controls are required. Controls would most likely be restriction on the hours of operation, or perhaps a limit on the type (i.e. fuel sulfur content) of fuel combusted.

There is a 30-day public comment period and the entire permitting process takes about 135-150 days.

Major NSR/PSD

A potential to emit 250 tons per year of a criteria pollutant triggers PSD in attainment areas and 100 tons per year triggers NSR in non-attainment areas.

Emergency Engines

An emergency engine that does not operate more than 200 hours per year is exempt from permitting. No state notification is required, but a letter is recommended. The operator must document operation.

In terms of CHP, Idaho is fairly lenient when it comes to permitting. The state does not require BACT analysis for Minor Sources. There are no emission control requirements for sources that emit less than 250 tons per year of a criteria pollutant. This limit drops to 100 tons per year for so called "Designated Facilities," which are defined as fossil-fuel fired steam electric plants of more than 250 million BTU's per hour heat input. In a recent permit, for a combined-cycle plant with GE turbines, the DEQ set the NOx threshold at 2.5 ppm by dry volume for a 24-hour average.

Oregon

Air emissions are regulated by the Oregon Department of Environmental Quality.[57] **Table C-3** is a summary of air emission regulations for small electric generators.

[57] http://www.deq.state.or.us/aq/

Table C-3. Oregon Air Emissions Regulation Thresholds for Small Electric Generators

Attainment	Several counties are in moderate non-attainment for PM and one is in non-attainment for CO.
NSR Threshold	250 tons of criteria pollutants. 100 tons of PM or CO in non-attainment areas.
Minor Source Permitting Exemption	None.
Minor Source Treatment	Varies with type of permit.
Emergency Generating Limits	200 hours per year.

<u>De Minimus Exemptions</u>

There are no exemptions for small sources. Sources that do not emit do not have to be permitted, but all emitting sources do.

<u>Minor Source Permitting</u>

The state has a general permit for sources smaller than 25 MW. A detailed explanation of the permit is available. However the general permit is not available for turbines and units burning natural gas. These units must obtain a standard minor source permit. A typical minor source permit requires low NO_x burning technology, but requirements could vary depending on the unit and location. In addition, sources are limited to 20% opacity and 0.1 grains per dry cubic foot of PM.

In addition, units that emit greater than the following are subject to ambient impact analysis:

- NO_x, VOC and SO_2: 40 tons/year
- CO: 100 tons/year
- PM: 25 tons/year
- PM_{10}: 15 tons/year
- Lead: 0.6 ton/year

Oregon adopted regulations governing the issuance of a general permit for minor source electric generating units. The permit is available for stationary or portable facilities of up to 25 MW, powered by reciprocating internal combustion engines burning diesel or dual-fuel that emit less than 39 tons of NOx per year (*natural gas engines and units in Lane County are not eligible for this permit). The rules were adopted on August 10, 2001 and became effective on January 1, 2002. EGUs electing to apply for a general permit will fall under the requirements of section AQGP-018 of Oregon's permitting requirements. This regulation requires the permittee to self-classify their generator as Tier 1, Tier 2 or Tier 3. Based on the tier level and unit size the general permit will limit operating hours for a unit site according to the table below.

- Tier 1 – Emissions greater than 0.016 lb NO_x/hp-hr (7.26 g/hp-hr). Generators are classified as Tier 1, unless a Source Test shows that the NO_x emission rate falls into the Tier 2 or Tier 3 range.
- Tier 2 – Emissions between 0.008 lb NO_x/hp-hr and 0.016 lb NO_x/hp-hr (3.63-7.26 g/hp-hr).
- Tier 3 – Emissions of 0.008 lb NO_x/hp-hr or less (3.63 g/hp-hr).

Operating limits are based on the size and tier level of the source based on a sliding scale shown in **Figure C-1**. The double logarithmic scale shows that the permitted operating hours in each tier are inversely proportional to the system capacity.

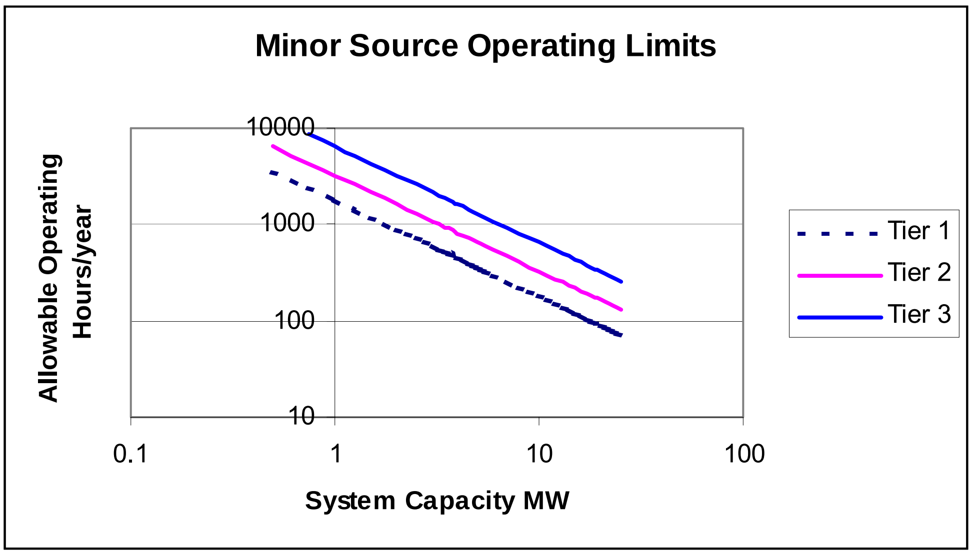

Figure C-1. Minor Source Electric Generating Unit Operating Limits

Not later than January 1, 2002, all generators used for power production under this rule, must be equipped with an exhaust emission control system or systems that are designed and certified by the manufacturer(s) to reduce PM, CO and VOC emissions. Particulate filters alone do not satisfy this requirement. The control system must be specifically designed to reduce CO and VOC as well as PM. The use of fuel catalysts does not satisfy this requirement, unless the manufacturer or supplier demonstrates to the Department's satisfaction, through rigorous testing, that the fuel catalyst is at least as effective as exhaust emission control systems in reducing emissions of PM, CO, and VOC. This requirement does not outline any minimum levels of reduction. The permit includes tons per year limits according to the schedule shown in **Table C-4**.

Table C-4. Emissions Limits on Minor Source Electricity Generating Units

Pollutant	Limit (tons/year)
PM	24
PM_{10}	14
SO_2	39
NO_x	39
CO	99
VOC	39

Other specific limits include:

- In the Ashland and Medford areas, PM limits are 4.5 tons/year and 49 lbs/day.
- Units installed prior to 1970 cannot exceed 40% opacity for more than 3 minutes, while newer units cannot exceed 20% in the same amount of time. Units in Clackamas, Columbia, Multnomah, and Washington Counties cannot exceed 20% opacity for more than 30 seconds.
- The PM limit for units installed prior to 1970 is 0.2 grains per cubic foot. Later units are limited to 0.1 grains.
- The diesel fuel burned by these units cannot have a sulfur content of more than 0.05% by weight.
- All units are required to monitor and record total hours of operation and analyze emissions for sulfur content unless a certificate guaranteeing the percent of sulfur was obtained prior to the burning of the fuel.
- Each February operators must submit a report with the following information: major maintenance, operating parameters, tier level, records of all excess emissions, summary of any complaints received by permittee, and a list of permanent changes made to the plant or control equipment.
- An annual compliance fee of $900 will be assessed.

Major NSR/PSD

250 tons of any criteria pollutant triggers PSD. 100 tons of PM or CO triggers NSR in non-attainment areas.

Emergency Engines

Emergency generators do not have to be permitted and they do not have to notify the state before construction. Units taking this exemption can only be used for emergency purposes (blackouts and maintenance) up to 600 hours per year. However, if the unit emits 10 tons per year or more of a criteria pollutant or 5 tons of PM in a non-attainment area it will have to obtain a permit regardless. Officials are considering requiring registration for these units, but nothing is currently under development.

Washington

There are no emission regulations pertaining solely to CHP applications. **Table C-5** provides a summary of air emission regulations for small electric generators.

Table C-5. Washington Air Emissions Regulation Thresholds for Small Electric Generators

Attainment	Three Areas are in non-attainment for PM (1 serious, 2 moderate) and two areas for CO (1 serious, 1 moderate).
NSR Threshold	70 or 100 tons of PM in non-attainment areas. 50-100 tons of CO in non-attainment area. 250 tons of any other pollutant.
Minor Source Permitting Exemption	Based on PTE.
Minor Source Treatment	State BACT.
Emergency Generating Limits	None.

<u>De Minimus Exemptions</u>

Sources with a potential to emit less than the thresholds listed below are exempt from permitting. State notification is required for these sources.

- PM_{10} – 0.75 tons/year
- NO_x, SO_2, and VOCs – 2.0 tons/year
- CO – 5.0 tons/year
- Lead – 0.005 tons/year
- Ozone depleting substances – 1.0 tons/year

The owner/operator may begin actual construction on the project thirty-one days after the permitting agency receives the summary, unless the permitting agency notifies the owner/operator within thirty days that the proposed new source requires a notice of construction application.

<u>Minor Source Permitting</u>

A state BACT analysis for the appropriate pollutant will be required for all minor sources with a potential to emit more than the de minimus levels listed above. However, sources may take permit limits to avoid BACT. The cost threshold for state BACT is approximately $2,000 per ton, however officials are more concerned with NO_x so the threshold may be a little higher for this pollutant. A unique analysis must be completed for each permit.

A permit requires a 30-day public comment. The whole permitting process usually takes around 120 days.

Major NSR/PSD

If the unit is located in an attainment area, then a potential to emit 250 tons of any criteria pollutant triggers PSD. A potential to emit 70 tons of PM in the serious non-attainment and 100 tons in the moderate non-attainment areas triggers NSR. 50 tons per year of CO triggers NSR in the non-attainment area.

Emergency Engines

There is no special treatment or provision for emergency units.

APPENDIX D: SECTOR GROWTH RATES BY STATE

Table D-1. Real Sector GSP and Estimated Growth Rates for Alaska (Millions of Chained 1996$)

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Total GSP	**25,130**	**25,438**	**25,268**	**26,355**	**25,774**	**26,056**	**24,920**	**25,064**	**24,725**	**24,490**	**-1.02%**	**-0.26%**	**0.0%**
Private industries	**19,629**	**19,933**	**19,963**	**21,265**	**20,772**	**21,162**	**20,087**	**20,371**	**20,010**	**19,690**	**-1.06%**	**0.03%**	**0.0%**
Agriculture, forest, fish	432	529	454	452	405	415	373	398	422	420	0.73%	-0.28%	15.7%
Farms	20	21	27	24	24	31	32	40	38	30	4.56%	4.14%	144.1%
Agricultural services	412	507	427	428	381	384	343	361	386	389	0.42%	-0.57%	8.7%
Mining	6,138	5,799	5,604	7,095	6,778	6,770	5,233	5,242	4,489	4,097	-9.58%	-3.96%	0.0%
Metal mining	195	141	179	192	235	490	671	991	878	1,069	35.39%	18.55%	165.3%
Coal mining	14	16	17	21	22	22	22	32	34	40	12.70%	11.07%	165.3%
Oil & gas	5,928	5,639	5,390	6,876	6,494	6,253	4,563	4,322	3,681	3,234	-13.01%	-5.88%	0.0%
Nonmetallic minerals	11	11	17	21	26	21	28	26	22	36	6.72%	12.59%	165.3%
Construction	902	1,017	1,101	1,103	1,069	1,067	1,053	1,069	1,046	1,072	0.06%	1.74%	1.1%
Manufacturing	1,206	1,243	1,066	1,290	1,107	1,036	1,056	1,013	943	853	-5.08%	-3.40%	0.0%
Durable goods	371	342	306	320	253	251	207	204	211	181	-6.48%	-6.93%	0.0%
Lumber & wood	321	292	249	251	170	171	128	126	126	88	-12.34%	-12.14%	0.0%
Furniture and fixtures	2	2	3	3	3	4	5	3	3	3	0.00%	4.14%	0.0%
Stone, clay, glass	19	19	20	19	18	19	19	19	19	21	3.13%	1.01%	85.3%
Primary metals	4	2	3	3	13	11	9	10	5	6	-14.33%	4.14%	0.0%
Fabricated metals	6	6	6	16	16	12	12	11	14	15	-1.28%	9.60%	0.0%
Industrial machinery	4	5	6	8	12	11	13	9	10	20	10.76%	17.46%	165.3%
Electronic equipment	(L)	(L)	(L)	1	1	1	2	1	1	2	14.87%	--	165.3%
Motor vehicles	(L)	(L)	(L)	(L)	1	1	1	1	(L)	1	0.00%	--	0.0%
Other transport. equip.	9	8	10	10	12	15	13	15	20	18	8.45%	7.18%	165.3%
Instruments and related	3	4	4	5	4	4	3	2	3	3	-5.59%	0.00%	0.0%
Misc. manufacturing	2	2	4	4	3	3	4	8	9	8	21.67%	14.87%	165.3%
Electronic equip. & instr.	4	4	4	5	4	5	4	3	4	4	0.00%	0.00%	0.0%
Nondurable goods	838	900	759	970	855	786	846	806	730	669	-4.79%	-2.23%	0.0%
Food & kindred products	451	492	380	581	430	387	349	390	333	307	-6.52%	-3.77%	0.0%
Tobacco products	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	--	--	--
Textile mill products	1	1	(L)	2	(L)	1	1	1	1	1	--	0.00%	--
Apparel & textile	2	2	2	2	2	2	2	2	3	3	8.45%	4.14%	165.3%
Paper products	105	107	61	48	50	44	11	2	1	(L)	--	--	--
Printing & publishing	76	68	76	52	47	46	46	49	46	42	-2.22%	-5.76%	0.0%
Chemicals	62	64	73	77	79	85	74	47	48	58	-5.99%	-0.66%	0.0%
Petroleum products	161	182	169	214	244	219	339	289	274	239	-0.41%	4.03%	0.0%
Rubber & plastics	2	2	2	2	2	3	4	3	4	6	24.57%	11.61%	165.3%
Leather products	1	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	--	--	--
Transportation & utilities	3,622	3,801	4,017	3,774	3,772	4,020	4,025	4,060	4,353	4,341	2.85%	1.83%	75.4%
Transportation	2,838	2,977	3,196	2,989	2,939	3,158	3,150	3,119	3,268	3,207	1.76%	1.23%	41.8%
Railroad transportation	0	0	0	0	0	0	0	0	0	0	--	--	--
Local & interurban	58	57	54	53	51	59	62	62	60	64	4.65%	0.99%	148.0%
Trucking and warehousing	190	183	185	185	186	178	177	166	172	177	-0.99%	-0.71%	0.0%
Water transportation	108	121	137	136	139	132	131	121	139	142	0.43%	2.77%	8.9%

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Transportation by air	519	587	716	631	729	725	676	694	807	814	2.23%	4.60%	55.4%
Pipelines, excl. natural gas	1,906	1,964	2,026	1,908	1,755	1,988	2,034	2,008	2,007	1,926	1.88%	0.10%	45.0%
Transportation services	70	72	76	75	80	82	83	78	82	82	0.50%	1.59%	10.4%
Communications	480	517	522	504	516	531	575	643	762	853	10.58%	5.92%	165.3%
Electric, gas, & sanitary	301	304	295	279	317	331	300	298	326	294	-1.50%	-0.24%	0.0%
Wholesale trade	620	639	712	673	741	777	882	912	925	926	4.56%	4.09%	143.9%
Retail trade	1,419	1,430	1,511	1,579	1,627	1,727	1,781	1,854	1,877	1,960	3.79%	3.28%	110.6%
F.I.R.E.	2,361	2,474	2,441	2,440	2,399	2,397	2,506	2,594	2,683	2,776	2.96%	1.63%	79.3%
Depository institutions	379	408	393	395	393	375	364	371	360	340	-2.86%	-1.08%	0.0%
Nondepository institution	56	73	48	57	62	92	69	66	95	166	21.77%	11.48%	165.3%
Security brokers	20	23	26	26	40	53	55	67	85	83	15.72%	15.29%	165.3%
Insurance carriers	115	117	108	107	100	103	99	85	85	84	-3.43%	-3.09%	0.0%
Insurance agents	84	76	76	72	67	60	71	74	68	70	0.88%	-1.81%	19.1%
Real estate	1,697	1,756	1,798	1,789	1,757	1,727	1,819	1,931	1,978	1,984	2.46%	1.57%	62.6%
Holding and investment	23	36	-5	-3	-20	-12	19	2	18	47	-218.64%	7.41%	0.0%
Depository & Nondepository	435	481	440	452	455	465	433	440	449	483	1.20%	1.05%	27.0%
Services	2,796	2,829	2,856	2,879	2,874	2,960	3,058	3,100	3,190	3,247	2.47%	1.51%	62.9%
Hotels & lodging	191	194	201	209	218	206	194	209	237	229	0.99%	1.83%	21.8%
Personal services	91	93	92	91	91	83	92	91	88	92	0.22%	0.11%	4.5%
Business services	448	448	442	417	411	472	476	469	449	451	1.87%	0.07%	45.0%
Auto repair & parking	138	134	144	159	153	146	157	210	213	223	7.83%	4.92%	165.3%
Misc. repair services	59	60	75	86	87	66	56	49	51	47	-11.59%	-2.25%	0.0%
Motion pictures	22	28	19	17	17	15	15	14	13	15	-2.47%	-3.76%	0.0%
Amusement and rec.	99	85	97	105	113	104	134	125	112	114	0.18%	1.42%	3.6%
Health services	738	733	731	732	769	809	821	845	942	1,003	5.46%	3.12%	165.3%
Legal services	163	164	152	152	121	139	131	131	131	130	1.45%	-2.24%	33.2%
Educational services	45	48	49	46	53	61	63	66	66	67	4.80%	4.06%	155.4%
Social services	161	168	158	162	165	168	174	176	182	189	2.75%	1.62%	72.2%
Other services	478	493	492	503	471	503	554	516	504	543	2.89%	1.28%	76.7%
Membership organizations	146	164	185	181	187	173	176	185	185	140	-5.62%	-0.42%	0.0%
Private households	17	17	18	18	18	17	20	17	17	15	-3.58%	-1.24%	0.0%
Business & Other services	927	941	934	921	881	975	1,030	985	952	994	2.44%	0.70%	62.0%
Government	5,484	5,488	5,292	5,091	5,002	4,895	4,828	4,700	4,720	4,807	-0.79%	-1.31%	0.0%
Federal civilian	1,319	1,345	1,243	1,184	1,214	1,217	1,230	1,199	1,244	1,233	0.31%	-0.67%	6.4%
Federal military	1,367	1,369	1,240	1,157	1,126	1,096	1,105	1,092	1,109	1,141	0.27%	-1.79%	5.4%
State and local	2,802	2,779	2,810	2,750	2,662	2,582	2,493	2,411	2,369	2,436	-1.76%	-1.39%	0.0%

(L) Less than $500,000
Source: Bureau of Economic Analysis, U.S. Department of Commerce
http://www.bea.doc.gov/bea/regional/gsp/

Table D-2. Real Sector GSP and Estimated Growth Rates for Idaho (Millions of Chained 1996$)

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Total GSP	21,783	23,654	25,331	27,395	28,101	29,322	31,015	34,688	37,089	36,832	5.56%	5.39%	165.3%
Private industries	18,315	20,091	21,653	23,673	24,328	25,359	26,983	30,538	32,807	32,397	5.90%	5.87%	165.3%
Agriculture, forest, fish	1,828	2,022	1,784	1,844	1,795	1,839	2,126	2,478	2,578	2,725	8.71%	4.07%	165.3%
Farms	1,565	1,749	1,503	1,563	1,510	1,536	1,767	2,151	2,252	2,398	9.69%	4.36%	165.3%
Agricultural services	267	278	280	282	285	302	356	353	359	370	5.36%	3.32%	165.3%
Mining	178	174	194	232	219	196	244	262	212	214	-0.46%	1.86%	0.0%
Metal mining	97	109	131	148	135	121	196	214	158	143	1.16%	3.96%	25.9%
Coal mining	(L)	(L)	(L)	0	0	0	0	(L)	(L)	0	--	--	--
Oil & gas	(L)	(L)	(L)	1	1	2	2	2	2	1	0.00%	--	0.0%
Nonmetallic minerals	78	63	62	82	83	73	57	59	57	68	-3.91%	-1.36%	0.0%
Construction	1,346	1,494	1,746	1,787	1,852	1,847	1,842	1,934	1,958	2,002	1.57%	4.05%	36.6%
Manufacturing	3,114	3,777	4,377	5,711	5,661	6,167	6,611	9,031	10,476	9,063	9.87%	11.27%	165.3%
Durable goods	1,676	2,223	2,724	4,073	4,066	4,557	5,121	6,589	8,366	7,105	11.81%	15.54%	165.3%
Lumber & wood	952	877	846	887	876	800	678	848	630	513	-10.15%	-6.00%	0.0%
Furniture and fixtures	17	18	24	31	32	39	44	49	47	43	6.09%	9.72%	165.3%
Stone, clay, glass	48	37	52	55	52	57	44	61	48	59	2.56%	2.08%	65.7%
Primary metals	6	9	11	11	13	12	14	18	21	22	11.10%	13.87%	165.3%
Fabricated metals	99	117	134	148	143	141	134	123	139	134	-1.29%	3.07%	0.0%
Industrial machinery	438	463	394	459	1,042	1,028	1,345	1,460	1,775	1,767	11.14%	14.97%	165.3%
Electronic equipment	240	696	1,168	2,280	1,715	2,304	2,710	4,003	6,157	4,802	22.87%	34.93%	165.3%
Motor vehicles	44	55	65	63	78	66	77	93	108	97	4.46%	8.23%	139.2%
Other transport. equip.	35	38	46	60	57	59	57	55	69	54	-1.08%	4.43%	0.0%
Instruments and related	16	15	15	17	18	21	30	29	27	25	6.79%	4.56%	165.3%
Misc. manufacturing	25	28	30	42	41	44	63	49	56	47	2.77%	6.52%	72.7%
Electronic equip. & instr.	250	708	1,182	2,298	1,733	2,325	2,742	4,023	6,151	4,810	22.65%	34.41%	165.3%
Nondurable goods	1,572	1,659	1,731	1,639	1,595	1,614	1,528	2,391	2,298	2,064	5.29%	2.76%	165.3%
Food & kindred products	755	831	846	993	883	910	813	863	782	729	-3.76%	-0.35%	0.0%
Tobacco products	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	(L)	--	--	--
Textile mill products	3	2	2	2	2	3	3	5	4	3	8.45%	0.00%	165.3%
Apparel & textile	7	9	10	10	9	10	9	8	9	8	-2.33%	1.34%	0.0%
Paper products	212	240	232	173	214	210	221	224	208	195	-1.84%	-0.83%	0.0%
Printing & publishing	187	167	182	175	172	167	160	182	174	171	-0.12%	-0.89%	0.0%
Chemicals	374	361	395	237	265	263	277	1,084	1,084	924	28.38%	9.47%	165.3%
Petroleum products	1	2	1	2	2	3	2	3	5	3	8.45%	11.61%	165.3%
Rubber & plastics	28	39	49	46	40	41	39	44	59	49	4.14%	5.76%	125.2%
Leather products	10	11	14	7	6	7	6	5	6	5	-3.58%	-6.70%	0.0%
Transportation & utilities	1,827	2,020	2,158	2,277	2,383	2,315	2,356	2,513	2,667	2,688	2.44%	3.94%	61.9%
Transportation	724	756	843	882	920	909	912	946	988	961	0.88%	2.87%	19.1%
Railroad transportation	203	192	217	236	221	222	194	201	218	214	-0.64%	0.53%	0.0%
Local & interurban	21	21	24	24	23	26	29	29	32	33	7.49%	4.62%	165.3%
Trucking and warehousing	362	384	416	435	467	453	475	493	506	493	1.09%	3.14%	24.2%
Water transportation	7	7	7	6	7	7	7	7	10	10	7.39%	3.63%	165.3%
Transportation by air	78	91	112	115	127	134	136	143	150	134	1.08%	5.56%	23.9%
Pipelines, excl. natural gas	17	21	19	18	22	21	22	22	21	20	-1.89%	1.64%	0.0%

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Transportation services	36	41	47	50	53	47	47	48	52	55	0.74%	4.33%	16.0%
Communications	394	423	454	452	454	443	528	596	693	824	12.66%	7.66%	165.3%
Electric, gas, & sanitary	708	842	862	943	1,010	962	917	976	994	929	-1.66%	2.75%	0.0%
Wholesale trade	1,340	1,395	1,550	1,541	1,736	1,945	2,178	2,370	2,498	2,543	7.93%	6.62%	165.3%
Retail trade	2,210	2,332	2,541	2,572	2,783	2,998	3,232	3,446	3,699	3,958	7.30%	6.00%	165.3%
F.I.R.E.	2,956	3,129	3,255	3,384	3,466	3,429	3,627	3,766	3,903	3,908	2.43%	2.83%	61.6%
Depository institutions	650	682	687	714	731	563	564	570	572	534	-6.09%	-1.95%	0.0%
Nondepository institution	52	66	64	65	79	112	129	126	144	165	15.87%	12.24%	165.3%
Security brokers	30	39	47	55	74	91	129	138	185	168	17.82%	18.80%	165.3%
Insurance carriers	237	243	254	246	238	246	259	255	267	276	3.01%	1.54%	80.9%
Insurance agents	184	168	171	164	156	151	162	169	162	161	0.63%	-1.33%	13.5%
Real estate	1,817	1,926	2,055	2,156	2,189	2,270	2,383	2,507	2,592	2,605	3.54%	3.67%	100.6%
Holding and investment	3	19	-20	-16	-1	4	14	17	18	28	-294.73%	25.03%	0.0%
Depository & Nondepository	701	748	750	779	810	672	687	690	706	682	-3.38%	-0.27%	0.0%
Services	3,756	3,942	4,164	4,329	4,433	4,635	4,836	5,095	5,348	5,493	4.38%	3.87%	135.7%
Hotels & lodging	156	163	175	201	201	196	188	190	195	188	-1.33%	1.88%	0.0%
Personal services	143	156	163	154	148	155	169	173	169	172	3.05%	1.86%	82.4%
Business services	450	508	575	572	611	690	725	846	905	940	9.00%	7.64%	165.3%
Auto repair & parking	220	233	256	263	268	280	307	359	368	384	7.46%	5.73%	165.3%
Misc. repair services	88	86	92	92	86	83	85	77	87	78	-1.93%	-1.20%	0.0%
Motion pictures	21	25	23	25	28	27	32	27	24	27	-0.72%	2.54%	0.0%
Amusement and rec.	108	107	115	139	147	178	165	175	182	184	4.59%	5.47%	145.5%
Health services	1,220	1,239	1,284	1,322	1,424	1,460	1,517	1,558	1,656	1,730	3.97%	3.55%	117.8%
Legal services	182	183	192	191	177	191	197	206	215	220	4.45%	1.91%	138.7%
Educational services	98	106	110	110	108	111	113	117	123	131	3.94%	2.94%	116.5%
Social services	106	117	137	150	161	176	192	196	205	215	5.96%	7.33%	165.3%
Other services	825	874	885	953	911	924	974	1,005	1,053	1,099	3.82%	2.91%	111.8%
Membership organizations	115	116	127	125	133	135	139	139	139	110	-3.73%	-0.44%	0.0%
Private households	27	28	29	31	31	30	34	31	31	27	-2.73%	0.00%	0.0%
Business & Other services	1,275	1,382	1,460	1,525	1,521	1,613	1,699	1,851	1,958	2,040	6.05%	4.81%	165.3%
Government	3,497	3,579	3,687	3,723	3,773	3,962	4,038	4,185	4,337	4,463	3.42%	2.47%	95.8%
Federal civilian	809	814	859	776	720	810	805	804	844	834	2.98%	0.30%	80.0%
Federal military	334	359	323	312	309	336	347	350	350	356	2.87%	0.64%	76.2%
State and local	2,356	2,408	2,507	2,635	2,744	2,816	2,887	3,030	3,142	3,271	3.58%	3.34%	101.9%

(L) Less than $500,000
Source: Bureau of Economic Analysis, U.S. Department of Commerce
http://www.bea.doc.gov/bea/regional/gsp/

Table D-3. Real Sector GSP and Estimated Growth Rates for Oregon (Millions of Chained 1996$)

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Total GSP	69,392	73,009	76,642	81,330	91,709	97,097	103,218	111,388	124,781	124,847	6.36%	6.05%	165.3%
Private industries	59,426	62,862	66,338	71,002	81,083	85,849	91,877	99,209	112,811	112,449	6.76%	6.59%	165.3%
Agriculture, forest, fish	2,412	2,533	2,662	2,645	2,633	3,063	3,117	3,467	3,593	3,480	5.74%	3.73%	165.3%
Farms	1,626	1,698	1,769	1,659	1,651	2,056	2,027	2,299	2,539	2,337	7.20%	3.69%	165.3%
Agricultural services	800	849	906	986	982	1,020	1,089	1,181	1,133	1,166	3.49%	3.84%	98.8%
Mining	83	87	100	93	113	124	132	134	141	153	6.25%	6.31%	165.3%
Metal mining	1	1	1	1	2	2	1	2	3	3	8.45%	11.61%	165.3%
Coal mining	4	5	(L)	0	0	0	0	0	0	0	--	-100.00%	--
Oil & gas	(L)	(L)	1	(L)	2	4	5	4	2	2	0.00%	--	0.0%
Nonmetallic minerals	77	80	98	92	110	119	125	127	137	148	6.11%	6.75%	165.3%
Construction	3,216	3,445	3,868	4,196	4,945	5,133	5,114	4,886	4,939	4,565	-1.59%	3.56%	0.0%
Manufacturing	11,532	12,981	13,586	16,153	22,577	24,488	28,187	34,126	47,057	48,033	16.30%	15.34%	165.3%
Durable goods	8,257	9,507	9,823	12,338	18,858	20,696	24,396	30,576	44,324	45,952	19.50%	18.73%	165.3%
Lumber & wood	3,991	3,908	3,362	3,476	2,913	2,767	2,597	2,642	2,553	2,365	-4.08%	-5.10%	0.0%
Furniture and fixtures	125	149	173	169	138	141	166	182	185	174	4.75%	3.36%	152.7%
Stone, clay, glass	216	206	247	251	268	287	293	270	276	259	-0.68%	1.83%	0.0%
Primary metals	643	611	686	739	812	841	783	855	981	998	4.21%	4.49%	128.2%
Fabricated metals	517	586	628	650	658	707	704	686	734	603	-1.73%	1.55%	0.0%
Industrial machinery	659	690	803	1,125	1,160	1,444	1,963	1,673	2,213	1,831	9.56%	10.76%	165.3%
Electronic equipment	1,217	2,211	2,581	4,250	11,110	12,505	16,197	23,939	39,395	44,230	31.83%	43.23%	165.3%
Motor vehicles	408	471	505	605	451	658	748	792	833	662	7.98%	4.96%	165.3%
Other transport. equip.	428	304	275	281	299	338	194	221	255	160	-11.76%	-9.37%	0.0%
Instruments and related	682	632	724	801	872	840	945	660	923	651	-5.68%	-0.46%	0.0%
Misc. manufacturing	198	211	214	194	177	205	181	208	231	206	3.08%	0.40%	83.5%
Electronic equip. & instr.	1,726	2,762	3,215	5,003	11,982	13,333	17,079	24,028	39,210	43,027	29.13%	37.93%	165.3%
Nondurable goods	3,407	3,574	3,900	3,878	3,719	3,799	3,872	3,902	3,978	3,674	-0.24%	0.76%	0.0%
Food & kindred products	1,076	1,126	1,208	1,424	1,305	1,291	1,317	1,204	1,205	1,244	-0.95%	1.46%	0.0%
Tobacco products	0	0	(L)	(L)	0	0	0	0	0	0	--	--	--
Textile mill products	65	67	70	65	63	57	57	51	45	43	-7.35%	-4.05%	0.0%
Apparel & textile	66	68	76	80	78	90	78	84	103	107	6.53%	4.95%	165.3%
Paper products	954	1,056	1,198	921	850	890	952	927	881	675	-4.51%	-3.40%	0.0%
Printing & publishing	830	770	818	806	750	798	780	855	883	772	0.58%	-0.72%	12.3%
Chemicals	177	192	220	233	270	277	312	380	460	464	11.44%	10.12%	165.3%
Petroleum products	38	41	36	41	44	33	37	50	43	31	-6.76%	-2.02%	0.0%
Rubber & plastics	182	229	257	291	346	349	333	345	356	344	-0.12%	6.57%	0.0%
Leather products	15	15	16	17	14	16	12	11	12	12	-3.04%	-2.21%	0.0%
Transportation & utilities	5,609	5,725	6,042	6,262	6,715	6,625	6,583	7,014	7,652	7,168	1.31%	2.48%	29.8%
Transportation	2,365	2,472	2,724	2,784	2,976	3,020	3,035	3,099	3,200	2,879	-0.66%	1.99%	0.0%
Railroad transportation	270	269	281	275	274	279	271	278	300	297	1.63%	0.96%	38.0%
Local & interurban	111	113	116	120	125	155	146	152	161	160	5.06%	3.72%	165.3%
Trucking and warehousing	1,235	1,281	1,365	1,396	1,469	1,431	1,445	1,435	1,471	1,316	-2.18%	0.64%	0.0%
Water transportation	167	169	195	190	203	191	184	185	224	219	1.53%	2.75%	35.5%
Transportation by air	376	431	527	562	642	689	708	761	740	587	-1.78%	4.56%	0.0%
Pipelines, excl. natural gas	6	7	7	7	9	10	9	8	14	9	0.00%	4.14%	0.0%

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Transportation services	206	207	235	235	254	265	271	284	296	296	3.11%	3.69%	84.4%
Communications	1,468	1,513	1,609	1,715	1,704	1,613	1,611	1,836	2,271	2,456	7.59%	5.28%	165.3%
Electric, gas, & sanitary	1,782	1,742	1,708	1,762	2,034	1,991	1,934	2,090	2,221	1,919	-1.16%	0.74%	0.0%
Wholesale trade	5,435	5,604	6,163	6,276	6,896	7,893	8,681	8,976	9,646	9,270	6.10%	5.48%	165.3%
Retail trade	6,123	6,402	6,828	7,015	7,661	8,348	8,846	9,395	9,901	10,269	6.03%	5.31%	165.3%
F.I.R.E.	12,094	12,575	12,934	13,413	13,588	13,873	14,705	14,875	15,442	15,318	2.43%	2.39%	61.5%
Depository institutions	2,093	2,160	2,099	2,275	2,169	1,577	1,914	1,859	1,934	1,866	-2.96%	-1.14%	0.0%
Nondepository institution	277	344	320	328	406	586	705	676	757	910	17.52%	12.63%	165.3%
Security brokers	187	248	312	331	442	536	665	766	952	974	17.12%	17.94%	165.3%
Insurance carriers	1,107	1,258	1,246	1,253	1,220	1,444	1,403	1,350	1,457	1,372	2.38%	2.17%	59.9%
Insurance agents	559	532	573	534	502	520	563	587	588	583	3.04%	0.42%	81.9%
Real estate	7,771	7,911	8,255	8,560	8,725	9,133	9,403	9,646	9,854	9,752	2.25%	2.30%	56.1%
Holding and investment	124	160	142	142	123	114	98	79	63	70	-10.66%	-5.56%	0.0%
Depository & Nondepository	2,366	2,504	2,417	2,599	2,575	2,142	2,596	2,513	2,657	2,704	0.98%	1.34%	21.6%
Services	13,303	13,817	14,477	15,125	15,956	16,362	16,820	17,408	17,954	18,109	2.56%	3.13%	65.9%
Hotels & lodging	481	489	496	539	564	545	530	534	563	541	-0.83%	1.18%	0.0%
Personal services	498	529	563	544	529	546	580	583	567	548	0.71%	0.96%	15.2%
Business services	2,441	2,692	2,997	3,215	3,543	3,823	3,897	4,205	4,305	4,406	4.46%	6.08%	139.2%
Auto repair & parking	719	757	838	867	939	904	956	1,014	1,034	1,033	1.93%	3.69%	46.5%
Misc. repair services	297	302	268	279	276	249	241	220	225	192	-7.00%	-4.27%	0.0%
Motion pictures	114	126	121	144	158	188	194	180	179	178	2.41%	4.56%	61.1%
Amusement and rec.	386	383	417	459	500	567	609	599	608	513	0.51%	2.89%	10.8%
Health services	4,692	4,678	4,780	4,854	5,073	5,122	5,132	5,313	5,593	5,801	2.72%	2.14%	71.0%
Legal services	829	782	779	856	817	814	870	924	956	987	3.85%	1.76%	113.0%
Educational services	380	404	428	436	453	474	496	523	524	531	3.23%	3.40%	88.8%
Social services	524	585	632	668	689	684	739	797	830	864	4.63%	5.13%	147.3%
Other services	1,406	1,510	1,537	1,656	1,791	1,835	1,954	1,920	1,989	2,028	2.52%	3.73%	64.4%
Membership organizations	453	486	523	508	522	513	510	503	491	436	-3.54%	-0.38%	0.0%
Private households	91	95	97	102	101	99	112	99	101	86	-3.16%	-0.56%	0.0%
Business & Other services	3,847	4,201	4,534	4,871	5,335	5,658	5,851	6,126	6,294	6,434	3.82%	5.28%	111.5%
Government	10,033	10,198	10,340	10,343	10,625	11,248	11,368	12,213	12,213	12,567	3.41%	2.28%	95.7%
Federal civilian	2,210	2,196	2,260	2,047	1,808	2,151	2,138	2,133	2,227	2,136	3.39%	-0.34%	94.8%
Federal military	303	303	311	305	305	309	307	309	324	327	1.40%	0.77%	32.1%
State and local	7,525	7,702	7,774	7,992	8,512	8,789	8,923	9,768	9,661	10,101	3.48%	2.99%	98.3%

(L) Less than $500,000
Source: Bureau of Economic Analysis, U.S. Department of Commerce
http://www.bea.doc.gov/bea/regional/gsp/

Table D-4. Real Sector GSP and Estimated Growth Rates for Washington (Millions of Chained 1996$)

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Total GSP	144,389	148,188	152,882	153,987	161,779	172,216	185,474	198,264	202,812	202,470	4.59%	3.44%	145.3%
Private industries	121,519	124,895	129,487	130,497	138,344	147,499	160,325	173,023	177,359	176,003	4.93%	3.77%	162.0%
Agriculture, forest, fish	4,541	4,553	4,495	4,510	4,610	4,607	4,819	5,243	5,777	5,350	3.02%	1.65%	81.4%
Farms	2,779	2,850	2,779	2,712	2,954	2,975	3,088	3,368	4,037	3,444	3.12%	2.17%	84.8%
Agricultural services	1,760	1,706	1,715	1,787	1,657	1,634	1,728	1,874	1,877	1,904	2.82%	0.79%	74.3%
Mining	288	295	384	368	392	339	460	563	525	483	4.26%	5.31%	130.5%
Metal mining	83	73	156	140	155	60	195	341	272	190	4.16%	8.63%	125.8%
Coal mining	53	52	57	62	68	66	72	80	85	100	8.02%	6.55%	165.3%
Oil & gas	4	3	7	6	10	5	5	4	2	5	-12.94%	2.26%	0.0%
Nonmetallic minerals	144	161	164	161	159	203	206	197	206	207	5.42%	3.70%	165.3%
Construction	7,573	7,440	7,656	7,281	7,707	8,034	8,441	8,869	9,068	8,541	2.08%	1.21%	50.8%
Manufacturing	20,869	21,028	21,388	20,189	21,260	22,044	24,817	26,157	26,218	26,373	4.40%	2.37%	136.8%
Durable goods	15,063	14,479	14,545	13,277	14,382	15,046	18,017	18,634	18,943	20,248	7.08%	3.00%	165.3%
Lumber & wood	2,691	2,498	2,332	2,374	2,130	2,099	2,049	2,264	2,296	2,259	1.18%	-1.73%	26.5%
Furniture and fixtures	163	159	150	158	176	182	207	207	218	216	4.18%	2.86%	126.9%
Stone, clay, glass	461	408	487	502	497	576	714	560	593	562	2.49%	2.00%	63.5%
Primary metals	859	686	706	889	823	789	903	812	875	870	1.12%	0.13%	24.9%
Fabricated metals	565	553	694	985	822	843	826	790	868	810	-0.29%	3.67%	0.0%
Industrial machinery	779	898	847	950	1,267	1,585	2,033	2,056	3,140	2,820	17.35%	13.73%	165.3%
Electronic equipment	343	427	507	717	932	1,226	1,543	2,220	2,988	3,790	32.39%	27.16%	165.3%
Motor vehicles	401	551	572	706	634	741	943	998	916	821	5.31%	7.43%	165.3%
Other transport. equip.	8,037	7,489	7,393	4,808	5,963	5,950	7,727	7,757	6,636	7,929	5.86%	-0.14%	165.3%
Instruments and related	764	630	603	730	621	542	622	512	658	648	0.85%	-1.63%	18.6%
Misc. manufacturing	297	347	400	470	516	544	539	757	725	636	4.27%	7.91%	130.8%
Electronic equip. & instr.	995	1,004	1,082	1,430	1,552	1,754	2,135	2,533	3,359	3,902	20.25%	14.64%	165.3%
Nondurable goods	5,760	6,528	6,830	6,915	6,878	7,000	6,858	7,557	7,336	6,389	-1.46%	1.04%	0.0%
Food & kindred products	2,083	2,267	2,435	2,793	2,590	2,459	2,379	2,359	2,241	2,214	-3.09%	0.61%	0.0%
Tobacco products	(L)	(L)	0	0	0	0	0	0	0	0	--	--	--
Textile mill products	56	60	63	58	62	62	65	61	69	67	1.56%	1.81%	36.4%
Apparel & textile	186	241	241	225	205	234	223	199	209	218	1.24%	1.60%	27.9%
Paper products	1,363	1,640	1,650	1,438	1,345	1,640	1,451	1,343	1,292	1,141	-3.24%	-1.76%	0.0%
Printing & publishing	1,160	1,284	1,192	1,175	1,171	996	939	1,079	1,042	948	-4.14%	-2.00%	0.0%
Chemicals	461	501	468	505	534	606	711	794	866	899	10.98%	6.91%	165.3%
Petroleum products	223	303	435	347	537	585	624	1,223	1,072	501	-1.38%	8.43%	0.0%
Rubber & plastics	276	275	315	369	421	420	452	486	543	538	5.03%	6.90%	165.3%
Leather products	15	15	15	15	13	13	11	8	9	15	2.90%	0.00%	77.3%
Transportation & utilities	10,513	11,214	11,844	12,847	14,166	14,157	14,419	15,274	17,577	17,371	4.16%	5.15%	126.1%
Transportation	4,357	4,481	4,877	4,955	5,485	5,599	5,686	5,808	6,080	5,841	1.27%	2.97%	28.6%
Railroad transportation	377	399	422	337	444	434	438	416	450	442	-0.09%	1.60%	0.0%
Local & interurban	153	164	166	169	172	205	222	250	259	266	9.11%	5.69%	165.3%
Trucking and warehousing	1,489	1,517	1,614	1,682	1,790	1,739	1,802	1,821	1,895	1,859	0.76%	2.24%	16.3%
Water transportation	698	717	748	810	892	911	871	816	857	815	-1.79%	1.56%	0.0%
Transportation by air	1,075	1,107	1,279	1,294	1,545	1,625	1,640	1,755	1,797	1,556	0.14%	3.77%	2.9%
Pipelines, excl. natural gas	24	23	21	22	28	31	31	36	49	38	6.30%	4.70%	165.3%

Industry	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	5 year Growth	10 year Growth	20 Year Estimate
Transportation services	547	561	628	647	614	657	681	713	776	865	7.10%	4.69%	165.3%
Communications	3,683	4,256	4,358	4,938	5,385	4,764	5,039	5,568	7,473	7,965	8.14%	8.02%	165.3%
Electric, gas, & sanitary	2,464	2,474	2,600	2,954	3,296	3,790	3,694	3,918	4,133	3,753	2.63%	4.30%	68.1%
Wholesale trade	10,383	10,634	11,337	11,137	12,266	13,452	15,150	15,906	16,916	16,720	6.39%	4.88%	165.3%
Retail trade	13,173	13,541	14,326	14,570	15,553	17,074	18,550	20,200	22,186	22,548	7.71%	5.52%	165.3%
F.I.R.E.	26,295	27,360	27,733	28,424	29,035	30,792	32,691	34,035	35,143	35,826	4.29%	3.14%	131.8%
Depository institutions	4,095	4,291	3,961	4,096	3,835	3,407	3,460	3,711	3,919	4,096	1.33%	0.00%	30.1%
Nondepository institution	522	699	561	547	648	866	1,021	1,085	1,152	1,340	15.64%	9.89%	165.3%
Security brokers	475	600	711	678	895	1,111	1,414	1,582	1,952	2,151	19.17%	16.30%	165.3%
Insurance carriers	1,988	2,146	2,085	2,209	2,151	2,491	2,455	2,308	2,544	2,494	3.00%	2.29%	80.7%
Insurance agents	1,103	1,014	1,025	973	915	942	986	1,005	944	974	1.26%	-1.24%	28.4%
Real estate	17,956	18,343	19,146	19,727	20,466	21,897	23,276	24,330	24,696	24,821	3.93%	3.29%	116.3%
Holding and investment	259	376	272	218	125	120	172	156	170	231	13.07%	-1.14%	165.3%
Depository & Nondepository	4,613	4,996	4,519	4,638	4,482	4,251	4,436	4,751	5,022	5,354	3.62%	1.50%	103.6%
Services	27,994	28,915	30,355	31,205	33,357	36,992	41,027	46,708	44,398	43,305	5.36%	4.46%	165.3%
Hotels & lodging	947	967	994	1,077	1,151	1,110	1,063	1,056	1,096	1,079	-1.28%	1.31%	0.0%
Personal services	983	1,045	1,037	1,006	986	1,028	1,071	1,090	1,056	1,079	1.82%	0.94%	43.4%
Business services	5,645	5,841	6,840	7,741	9,676	12,928	16,060	20,786	17,501	16,146	10.78%	11.08%	165.3%
Auto repair & parking	1,371	1,429	1,510	1,584	1,654	1,744	1,850	1,958	2,004	2,073	4.62%	4.22%	146.7%
Misc. repair services	523	504	556	493	484	461	459	429	441	379	-4.77%	-3.17%	0.0%
Motion pictures	181	201	199	203	211	207	205	200	194	199	-1.16%	0.95%	0.0%
Amusement and rec.	898	918	971	1,045	1,157	1,240	1,237	1,273	1,348	1,195	0.65%	2.90%	13.8%
Health services	8,609	8,731	8,705	8,843	9,071	9,181	9,410	9,800	10,190	10,495	2.96%	2.00%	79.2%
Legal services	1,707	1,646	1,653	1,726	1,609	1,794	1,825	1,926	2,048	2,087	5.34%	2.03%	165.3%
Educational services	615	653	688	736	760	757	823	841	870	885	3.09%	3.71%	83.9%
Social services	861	947	996	1,025	1,042	1,076	1,112	1,144	1,198	1,220	3.20%	3.55%	87.9%
Other services	4,502	4,811	4,874	4,437	4,267	4,199	4,659	5,004	5,191	5,408	4.85%	1.85%	158.0%
Membership organizations	990	1,047	1,153	1,102	1,109	1,101	1,086	1,087	1,138	1,004	-1.97%	0.14%	0.0%
Private households	162	169	174	181	179	176	200	177	181	154	-2.96%	-0.51%	0.0%
Business & Other services	10,153	10,657	11,722	12,182	13,942	17,123	20,712	25,788	22,678	21,539	9.09%	7.81%	165.3%
Government	22,898	23,318	23,405	23,499	23,435	24,719	25,176	25,319	25,549	26,504	2.49%	1.47%	63.6%
Federal civilian	4,672	4,740	4,927	4,491	3,959	4,843	4,811	4,905	5,079	4,962	4.62%	0.60%	146.8%
Federal military	3,155	3,166	3,223	3,305	3,414	3,467	3,317	3,288	3,347	3,441	0.16%	0.87%	3.2%
State and local	15,070	15,412	15,261	15,702	16,062	16,409	17,043	17,121	17,120	18,093	2.41%	1.85%	61.0%

(L) Less than $500,000
Source: Bureau of Economic Analysis, U.S. Department of Commerce
http://www.bea.doc.gov/bea/regional/gsp/

APPENDIX E: TECHNICAL POTENTIAL – DETAILED STATE TABLES

Table E-1. Small Industrial CHP Technical Potential – Alaska

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food & Kindred Products	33	5	4	3	0	0	37	8
22	Textile Mill Products	0	0	0	0	0	0	0	0
24	Lumber & Wood Products (except furniture)	13	0	0	0	0	0	13	0
25	Furniture & Fixtures	0	0	0	0	0	0	0	0
26	Paper & Allied Products	0	0	0	0	0	0	0	0
28	Chemicals & Allied Products	1	0	1	1	0	0	2	1
29	Petroleum Refining & Related Industries	1	0	1	1	2	5	4	6
30	Rubber & Miscellaneous Plastic Products	1	0	0	0	0	0	1	0
33	Primary Metal Industries	0	0	0	0	0	0	0	0
34	Fabricated Metals	6	0	0	0	0	0	6	0
35	Machinery	2	0	0	0	0	0	2	0
37	Transportation Equipment	4	0	0	0	0	0	4	0
38	Instruments	1	0	0	0	0	0	1	0
39	Miscellaneous Manufacturing Industries	0	0	0	0	0	0	0	0
	Total	**62**	**6**	**6**	**5**	**2**	**5**	**70**	**16**

Table E-2. Small Industrial CHP Technical Potential – Idaho

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food & Kindred Products	43	6	10	8	37	93	90	106
22	Textile Mill Products	1	0	0	0	0	0	1	0
24	Lumber & Wood Products (except furniture)	109	3	15	2	26	13	150	19
25	Furniture & Fixtures	12	1	0	0	1	1	13	1
26	Paper & Allied Products	2	0	0	0	0	0	2	0
28	Chemicals & Allied Products	8	1	3	2	0	0	11	3
29	Petroleum Refining & Related Industries	2	0	0	0	0	0	2	0
30	Rubber & Miscellaneous Plastic Products	25	1	6	1	2	2	33	4
33	Primary Metal Industries	6	0	2	0	0	0	8	1
34	Fabricated Metals	56	3	5	1	4	3	65	7
35	Machinery	79	3	5	1	5	3	89	7
37	Transportation Equipment	18	1	4	2	2	3	24	5
38	Instruments	17	1	0	0	0	0	17	1
39	Miscellaneous Manufacturing Industries	23	1	0	0	1	1	24	1
	Total	**401**	**22**	**50**	**17**	**78**	**117**	**529**	**157**

Table E-3. Small Industrial CHP Technical Potential – Oregon

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food & Kindred Products	191	29	41	31	57	143	289	202
22	Textile Mill Products	9	1	0	0	2	4	11	5
24	Lumber & Wood Products (except furniture)	290	9	56	8	100	50	446	67
25	Furniture & Fixtures	58	3	3	1	2	2	63	5
26	Paper & Allied Products	20	3	11	8	10	25	41	36
28	Chemicals & Allied Products	57	9	12	9	21	53	90	70
29	Petroleum Refining & Related Industries	5	1	2	2	3	8	10	10
30	Rubber & Miscellaneous Plastic Products	101	5	20	5	20	15	141	24
33	Primary Metal Industries	26	1	14	3	18	11	58	15
34	Fabricated Metals	238	11	26	6	11	8	275	25
35	Machinery	308	12	31	6	24	15	363	32
37	Transportation Equipment	82	6	9	3	14	18	105	27
38	Instruments	84	6	7	3	11	14	102	23
39	Miscellaneous Manufacturing Industries	80	3	7	1	4	3	91	7
	Total	**1,549**	**97**	**239**	**85**	**297**	**366**	**2,085**	**547**

Table E-4. Small Industrial CHP Technical Potential – Washington

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW
20	Food & Kindred Products	269	40	79	59	77	193	425	292
22	Textile Mill Products	28	3	5	3	1	2	34	8
24	Lumber & Wood Products (except furniture)	234	7	29	4	63	32	326	43
25	Furniture & Fixtures	75	3	8	2	0	0	83	5
26	Paper & Allied Products	51	8	16	12	17	43	84	62
28	Chemicals & Allied Products	89	13	23	17	24	60	136	91
29	Petroleum Refining & Related Industries	4	1	2	2	4	10	10	12
30	Rubber & Miscellaneous Plastic Products	105	5	30	7	33	25	168	36
33	Primary Metal Industries	26	1	14	3	15	9	55	13
34	Fabricated Metals	276	12	21	5	25	19	322	36
35	Machinery	356	13	24	5	21	13	401	31
37	Transportation Equipment	130	10	35	13	36	45	201	68
38	Instruments	135	10	13	5	19	24	167	39
39	Miscellaneous Manufacturing Industries	106	4	5	1	7	4	118	9
	Total	**1,884**	**131**	**304**	**137**	**342**	**478**	**2,530**	**745**

Table E-5. Commercial CHP Technical Potential – Alaska

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	4	0.6	1	0.8	1	2.5	1	12.5	0	0	7	16.4
494/495	Water Treatment/ Sanitary	1	0.2	10	7.5	2	5.0	3	37.5	0	0	16	50.2
54	Food Sales	26	3.9	1	0.8	1	2.5	0	0	0	0	28	7.2
581	Full Service Restaurants	31	4.7	10	7.5	0	0	0	0	0	0	41	12.2
7011	Hotels/ Motels	94	14.1	25	18.8	4	10.0	0	0	0	0	123	42.9
721	Laundries	5	0.8	0	0	0	0	0	0	0	0	5	0.8
7542	Carwashes	7	1.1	0	0	0	0	0	0	0	0	7	1.1
7991	Health Clubs	20	3.0	2	1.5	0	0	0	0	0	0	22	4.5
7992/7	Golf Clubs	1	0.2	0	0	0	0	0	0	0	0	1	0.2
805	Nursing Homes	6	0.9	2	1.5	1	2.5	0	0	0	0	9	4.9
806	Hospitals & Health Care	6	0.9	9	6.8	10	25.0	0	0	0	0	25	32.7
822	Colleges & Universities	17	2.6	1	0.8	1	2.5	1	12.5	0	0	20	18.3
821/4/9	Elementary/ Secondary Schools	88	13.2	18	13.5	2	5.0	0	0	0	0	108	31.7
8412	Museums	7	1.1	0	0	0	0	0	0	0	0	7	1.1
9223	Prisons	5	0.8	2	1.5	6	15.0	0	0	0	0	13	17.3
	Apartments	23	3.5	5	3.8	3	7.5	1	12.5	0	0	32	27.2
	Office Buildings	205	30.8	41	30.8	10	25.0	2	25.0	0	0	258	111.5
	Total	**546**	**81.9**	**127**	**95.3**	**41**	**102.5**	**8**	**100.0**	**0**	**0**	**722**	**379.7**

Table E-6. Commercial CHP Technical Potential – Idaho

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	4	0.6	7	5.3	1	2.5	0	0	0	0	12	8.4
494/495	Water Treatment/ Sanitary	14	2.1	11	8.3	1	2.5	0	0	0	0	26	12.9
54	Food Sales	104	3.9	4	0.8	1	0.6	0	0	0	0	109	5.3
581	Full Service Restaurants	142	10.7	42	15.8	4	5.0	0	0	0	0	188	31.4
7011	Hotels/ Motels	131	19.7	28	21.0	16	40.0	3	37.5	0	0	178	118.2
721	Laundries	7	1.1	3	2.3	0	0	0	0	0	0	10	3.3
7542	Carwashes	32	4.8	1	0.8	1	2.5	0	0	0	0	34	8.1
7991	Health Clubs	31	4.7	5	3.8	0	0	0	0	0	0	36	8.4
7992/7	Golf Clubs	30	4.5	6	4.5	2	5.0	0	0	0	0	38	14.0
805	Nursing Homes	14	2.1	36	27.0	3	7.5	0	0	0	0	53	36.6
806	Hospitals & Health Care	11	1.7	24	18.0	24	60.0	4	50.0	0	0	63	129.7
822	Colleges & Universities	10	1.5	3	2.3	0	0	4	50.0	0	0	17	53.8
821/4/9	Elementary/ Secondary Schools	189	14.2	39	14.6	1	1.3	1	6.3	0	0	230	36.3
8412	Museums	13	2.0	5	3.8	5	12.5	0	0	0	0	23	18.2
9223	Prisons	0	0	5	3.8	9	22.5	0	0	0	0	14	26.3
	Apartments	42	6.3	10	7.5	5	12.5	1	12.5	0	0	58	38.8
	Office Buildings	169	7.6	36	8.1	9	6.8	1	3.8	0	0	215	26.2
	Total	**943**	**87.2**	**265**	**147.2**	**82**	**181.1**	**14**	**160.0**	**0**	**0**	**1,304**	**575.5**

Table E-7. Commercial CHP Technical Potential – Oregon

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	13	2.0	13	9.8	1	2.5	1	12.5	0	0.0	28	26.7
494/495	Water Treatment/ Sanitary	27	4.1	28	21.0	5	12.5	0	0.0	0	0.0	60	37.6
54	Food Sales	238	35.7	5	3.8	1	2.5	0	0.0	0	0.0	244	42.0
581	Full Service Restaurants	345	51.8	85	63.8	10	25.0	0	0.0	0	0.0	440	140.5
7011	Hotels/ Motels	284	42.6	61	45.8	30	75.0	2	25.0	0	0.0	377	188.4
721	Laundries	19	2.9	6	4.5	0	0.0	0	0.0	0	0.0	25	7.4
7542	Carwashes	52	7.8	1	0.8	0	0.0	0	0.0	0	0.0	53	8.6
7991	Health Clubs	94	14.1	10	7.5	1	2.5	0	0.0	0	0.0	105	24.1
7992/7	Golf Clubs	59	8.9	18	13.5	0	0.0	0	0.0	0	0.0	77	22.4
805	Nursing Homes	72	10.8	58	43.5	7	17.5	0	0.0	0	0.0	137	71.8
806	Hospitals & Health Care	16	2.4	26	19.5	30	75.0	3	37.5	0	0.0	75	134.4
822	Colleges & Universities	36	5.4	16	12.0	9	22.5	8	100.0	2	150.0	71	289.9
821/4/9	Elementary/ Secondary Schools	343	51.5	106	79.5	9	22.5	1	12.5	0	0.0	459	166.0
8412	Museums	32	4.8	4	3.0	0	0.0	0	0.0	0	0.0	36	7.8
9223	Prisons	11	1.7	11	8.3	9	22.5	0	0.0	0	0.0	31	32.4
	Apartments	184	27.6	43	32.3	22	55.0	4	50.0	0	0.0	253	164.9
	Office Buildings	646	96.9	136	102.0	33	82.5	6	75.0	1	75.0	822	431.4
	Total	**2,471**	**370.7**	**627**	**470.3**	**167**	**417.5**	**25**	**312.5**	**3**	**225.0**	**3,293**	**1,795.9**

Table E-8. Commercial CHP Technical Potential – Washington

SIC	Industry	50-500 kW		500 kW-1 MW		1-5 MW		5-20 MW		> 20 MW		Total	
		Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
4222	Refrigerated Warehouse	25	3.8	43	32.3	6	15.0	0	0.0	0	0.0	74	51.0
494/495	Water Treatment/ Sanitary	52	7.8	52	39.0	10	25.0	1	12.5	0	0.0	115	84.3
54	Food Sales	436	65.4	5	3.8	3	7.5	0	0.0	0	0.0	444	76.7
581	Full Service Restaurants	519	77.9	152	114.0	8	20.0	0	0.0	0	0.0	679	211.9
7011	Hotels/ Motels	347	52.1	97	72.8	55	137.5	5	62.5	0	0.0	504	324.8
721	Laundries	18	2.7	8	6.0	0	0.0	0	0.0	0	0.0	26	8.7
7542	Carwashes	75	11.3	1	0.8	0	0.0	0	0.0	0	0.0	76	12.0
7991	Health Clubs	147	22.1	6	4.5	1	2.5	0	0.0	0	0.0	154	29.1
7992/7	Golf Clubs	83	12.5	26	19.5	0	0.0	0	0.0	0	0.0	109	32.0
805	Nursing Homes	89	13.4	135	101.3	13	32.5	0	0.0	0	0.0	237	147.1
806	Hospitals & Health Care	45	6.8	36	27.0	52	130.0	2	25.0	0	0.0	135	188.8
822	Colleges & Universities	66	9.9	18	13.5	19	47.5	4	50.0	1	75.0	108	195.9
821/4/9	Elementary/ Secondary Schools	738	110.7	180	135.0	20	50.0	2	25.0	0	0.0	940	320.7
8412	Museums	47	7.1	4	3.0	0	0.0	0	0.0	0	0.0	51	10.1
9223	Prisons	28	4.2	13	9.8	15	37.5	2	25.0	0	0.0	58	76.5
	Apartments	307	46.1	72	54.0	36	90.0	7	87.5	1	75.0	423	352.6
	Office Buildings	1,267	190.1	267	200.3	64	160.0	11	137.5	1	75.0	1,610	762.8
	Total	**4,289**	**643.4**	**1,115**	**836.3**	**302**	**755.0**	**34**	**425.0**	**3**	**225.0**	**5,743**	**2,884.6**