CLEAN ELECTRICITY OPTIONS FOR THE PACIFIC NORTHWEST

AN ASSESSMENT OF EFFICIENCY AND RENEWABLE POTENTIALS THROUGH THE YEAR 2020

A REPORT TO THE NW ENERGY COALITION

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Michael Lazarus, David von Hippel, Stephen Bernow
Tellus Institute
http://www.tellus.org
Email: mlaz@tellus.org

Acronyms

4th Plan –The 1998 Northwest Power Planning Council report *Northwest Power in Transition: Opportunities and Risks, Fourth Northwest Power Plan*.

aMW– Average Megawatt, a unit for expressing electrical energy output, equal to the output of 1 MW plant operating at 100% capacity factor, or 8760 MWh/year.

BGCC – Biomass Gasification Combined Cycle power plant

CHP – Combined heat and power systems, often referred to as cogeneration

CFL – Compact Fluorescent Light

DSM – Demand-Side Management

GHG – Greenhouse Gas

NAECA - National Appliance Energy Conservation Act

NEEA or "the Alliance" – Northwest Energy Efficiency Alliance

NGCC – Natural Gas Combined Cycle power plant

NPPC or "the Council" – Northwest Power Planning Council,

NWEC or "the Coalition" – NW Energy Coalition

RNP - Renewable Northwest Project

RTF – Regional Technical Forum of the Northwest Power Planning Council, a group of efficiency experts established in 1999 to develop standards to verify and evaluate conservation savings. http://www.nwcouncil.org/energy/rtf/background.htm

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EXECUTIVE SUMMARY

Analytic Approach

This report assesses the efficiency and renewable resources that could be tapped to meet Pacific Northwest electricity needs over the next two decades. The last regional assessment of this type was compiled for the Northwest Power Planning Council's 4th Power Plan in 1994-96 ("the 4th Plan"). Since then, the landscape of technologies, markets, and policy options has shifted, while growing concerns about electricity price volatility, energy security, and global climate change have increased the value of investments in efficiency and renewable resources.

With the benefit of recent analyses by the Council's Regional Technical Forum (RTF), the Northwest Energy Efficiency Alliance, national energy laboratories, and renewable resource mapping studies, we have prepared an up-to-date assessment of efficiency and renewable resources. This report can provide a benchmark for the Council's upcoming 5th Power Plan and a guidepost for establishing clean energy policies. We undertook a "bottom-up" measure-by-measure analysis, examining the costs, benefits, and market potential of over 30 individual efficiency and combined heat and power (CHP) measures, and three principal renewable resources (wind, biomass and geothermal). To arrive at our estimates, we combined several methods and sources. We began with the 4th plan, its analysis of potentials, and its medium forecast for future electricity requirements by end-use. We then incorporated key changes in market conditions as of 2001-2002, such as higher avoided costs, new efficiency standards, and more up-to-date costs for wind and other technologies. We also applied constraints on the resource that can be reasonably achieved and/or utilized.

Efficiency, Fuel Switching and Combined Heat and Power

We find that efficiency, fuel switching, and CHP measures could reduce grid electricity demands by 12% in 2010 and 24% in 2020, as shown in Table ES-1. The latter amounts to a reduction of nearly 6283 aMW. Of this 3542 aMW are pure electric efficiency investments, 73 aMW are saved by solar water heaters, and 2741 aMW are reduced by residential gas water heaters and commercial and industrial cogeneration units.[1]

Table ES-1. Efficiency, fuel switch, and CHP measures - reductions by sector (aMW)

	2010		2020	
Sector	**aMW**	**% savings**	**aMW**	**% savings**
Residential	568	7%	1618	18%
Commercial	1088	19%	2260	36%
Industrial	1079	13%	2365	24%
Other	33	4%	39	4%
Total Demand Reduction	**2768**	12%	**6283**	24%

[1] If the added gas use were used in grid-based natural gas combined cycle units, they would deliver 1746 aMW, so the "net" savings of these investments (in lieu of the grid-based units using the same gas), is 4538 aMW (6283 -1746 aMW).

The overall package of investments analyzed here could provide the Northwest with cumulative discounted savings of $2.8 billion, as illustrated in Table ES-2. Monetizing the benefits of avoided pollutant emissions could nearly double the social benefits to $5.5 billion overall. In the early years, annual economic benefits are limited ($1 million in 2010), because of the continuing investment in new equipment purchases, particularly for solar, condensing gas, and heat pump water heaters. Once the purchases end, the savings begin to accrue. Annual benefits jump to almost $500 million per year in 2020.

Table ES-2. Regional Economic Savings (million $2001)

	Annual Benefits		Cumulative NPV Benefits		
Sector	**2010**	**2020**	**to 2020**	**to 2050**	**to 2050 (w/externalities)**
Residential	($171)	$81	($938)	$131	$1,446
Commercial	$75	$172	$530	$1,423	$2,190
Industrial	$94	$227	$812	$1,189	$1,847
Other	$2	$2	($2)	$14	$43
Total	**$1**	**$482**	**$402**	**$2,755**	**$5,528**

Renewable Resources

Three renewable resources – wind, biomass, and geothermal – could conceivably provide up to 35 percent of the region's electricity needs, as shown in Table ES-3. Renewable generation costs span a range from as low as 1 cent per kWh for cofiring of low-cost residues to around 7 cents for higher cost geothermal locations. Wind cost numbers are shown with and without the 1.7 cent production tax credit (levelized cost at 1.3 cents/kWh).

Table ES-3. Summary of renewable resource results (assuming 2010 costs)

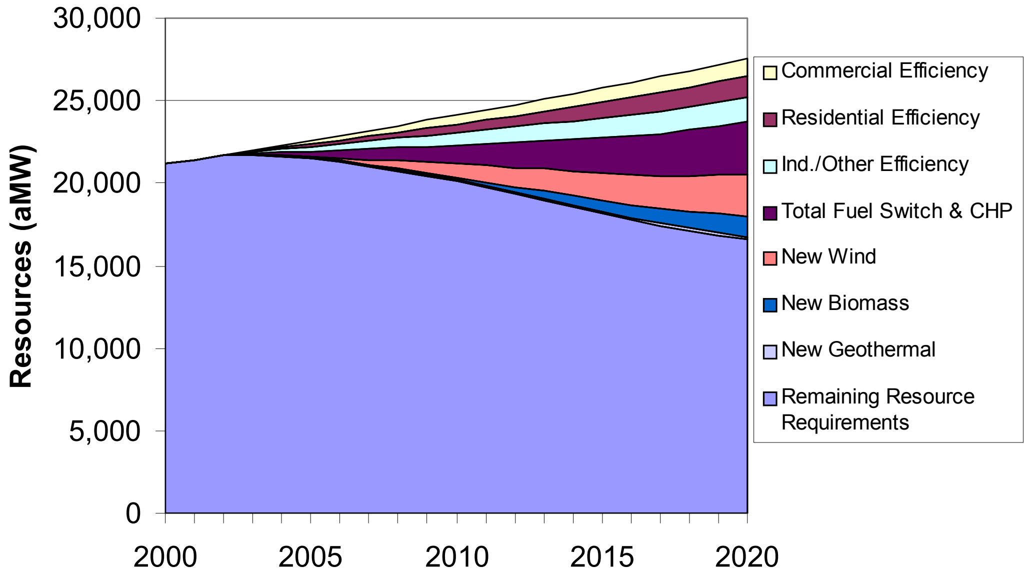
	Total Potential		Generation Cost (cents per kWh)	
	aMW	**Percent of Regional Demand**	**Range**	**Weighted Average**
Wind	6433	23%	2.6 – 6.1	3.7 (5.1 w/o PTC)
Biomass	2880	10%	1.1 - 6.0	4.4
Geothermal	641	2%	5.0 - 7.0	5.8

These results suggest that significant increases in the contribution of renewable resources -- especially wind, since large-scale increases in biomass generation still depend on technology improvements -- should be possible without major electricity price increases. Such a conclusion ultimately depends on the course that electricity markets take in the years to come. If market prices remain at levels in the 3 cent range, then extensive investment in renewables may increase electric bills. If market prices rise or spike again as they did in the 2000-2001 season, these renewable energy investments might yield strong economic benefits. In face of this uncertainty, renewable resources can provide an important hedge against volatile electricity markets. In either case, they provide major air pollution and climate change benefits, stimulate job creation, and by reducing gas and other fuel purchases, stem the flow of funds away from the region.

A Vision of the Future

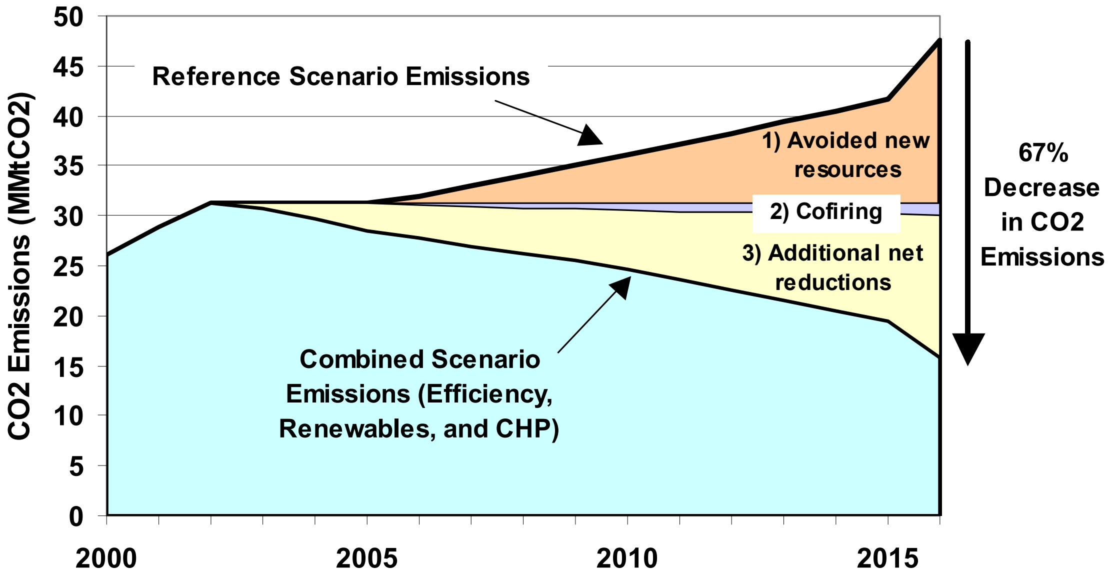
We can construct an illustrative scenario that combines the efficiency, CHP, and fuel switching potentials identified in this study with an assumption that 20 percent of remaining 2020 regional resource requirements can be met with renewables. Figure ES-1 shows that such a scenario could reduce total resource requirements by over 40 percent from levels currently projected for 2020.

Figure ES-1. A Combined Resource Scenario



The remaining resource needs, roughly 16,500 aMW, is only slightly more than the region's current hydro production in an average rainfall year. Such a scenario would mean that over 6000 aMW of the region's currently existing generating resources could be used for sales to other regions or decommissioned, depending on the nature of the resource. This scenario leads to major reductions in carbon dioxide emissions, as shown in Figure ES-2.

Figure ES-2. Regional CO2 emissions from electricity generation under combined resource scenario



The combined efficiency, renewables, and CHP and fuel switching scenario provides sufficient resources to: 1) avoid any new gas resources, saving 16 MMt in CO2 emissions by 2020; 2) offset over 1.3 million metric tons of CO2 by 2020 by displacing coal use by cofiring biomass; and 3) enable existing resources to operate less or avoid new plant construction in other regions, saving another 15 MMT in CO2 emissions by 2020[2]. Together, this suggests that with aggressive pursuit of efficiency and renewables, CO2 emissions in 2020 can be reduced by 66%, relative to business-as-usual growth, or by 50% relative to today's levels.

Conclusions

There may be far greater economically viable efficiency and renewable resources than other regional studies have shown, and more importantly, than are currently being pursued. The economic and environmental benefits of policies that promote these resources could be very large, in the billions of dollars (at least on the efficiency side) and in the tens of millions of tons of CO2 and other pollutants avoided.

The actual potentials might even be considerably higher than shown here given the many potentially attractive options – low-impact hydro development, distributed solar PV applications, improved building design, and others – that were not included in the analysis. The limited scope of this study precluded the additional data collection and modeling analysis that might help answer some of these unknowns.

[2] We also assumed here that high-efficiency gas units would be avoided. If existing gas or coal plants were displaced, then the savings would be considerably higher. If existing hydropower were displaced then the savings would be lower.

1. INTRODUCTION

This report assesses the efficiency and renewable resources that could be tapped to meet Pacific Northwest electricity needs over the next two decades. The last regional assessment of this type was compiled for the Northwest Power Planning Council's 4th Power Plan ("the 4th Plan"). That analysis was undertaken in the 1994-1996 period, and some of the data used is now well over a decade old. Since then, the landscape of technologies, markets, and policy options has shifted, while growing concerns about electricity price volatility, energy security, and global climate change have increased the value of investments in efficiency and renewable resources.

For over two decades, energy institutions in the Northwest, such as the Power Planning Council ("the Council"), the Northwest Energy Efficiency Alliance ("the Alliance"), the NW Energy Coalition ("the Coalition"), and individual utilities have been nationally recognized as innovators and leaders in energy efficiency. Even though it represents only 4% of the US electricity market, the Northwest has shown it can influence national energy policy, providing benefits not just for the region but also for the country as a whole. An example is the Alliance's WashWise program, whose success set the stage for new national efficiency standards for clothes washers.

But while Northwest leadership has been potent at times, investments in energy efficiency declined throughout much of the 1990s. Cheap electricity prices and the deregulation of electricity markets combined to stifle continued progress in capturing efficiency gains that promise long-run economic benefits. Uncertain transmission policies and limited policy support have left important renewable energy opportunities untapped. With the benefit of recent analyses by the Council's Regional Technical Forum (RTF), the Alliance, national energy laboratories, and wind resource mapping experts, an up-to-date assessment of efficiency and renewable resources provides a benchmark for the Council's upcoming 5th Power Plan and a guidepost for establishing clean energy policies.

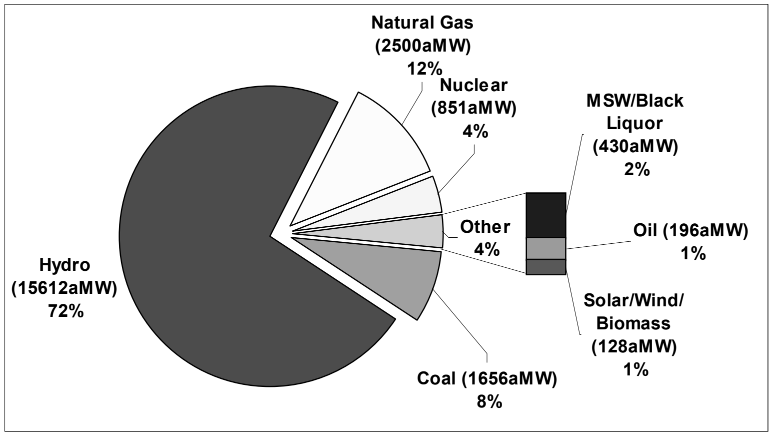
1.1 Context: Electricity and the Northwest

Blessed with abundant hydropower, the Pacific Northwest[3] has historically produced the nation's lowest-cost electricity, a key factor in the region's economic development for much of the 20th century. Now that the hydro resource has been fully tapped and electricity markets have become more geographically integrated, this situation has fundamentally changed. As demonstrated by the price spikes of 2000 and 2001, the region's electricity bill is now intimately linked, not only to local rainfall patterns, but also to the dynamics of electricity and natural gas markets throughout the West. The once-surplus hydro resource can no longer shield the Northwest from the higher and more volatile prices faced by other regions. In addition, the region is considering removal and modification of some dams that have significant impacts on salmon populations.

[3] The Pacific Northwest, for the purposes of this report, corresponds to the region defined by the Pacific Northwest Electric Power Planning and Conservation Act. This regional definition, which is also used by the Council, corresponds roughly to the US portion of the Columbia River water basin, including Washington, nearly the entire states of Idaho and Oregon, Montana west of the Continental Divide, as well as some small rural areas in Wyoming, Nevada, California, and Utah, which we do not explicitly account for in our quantitative analysis.

Figure 1-1 illustrates the current mix of generating resources in the region. In an average water year, regional hydro resources can provide about three-quarters of regional electricity requirements, approximately 16,000 of 22,000 average megawatts (aMW) (NPPC, 2001c; NPPC, 2002). If load continues to grow at the 1.6% per year pace seen during the 1980s and 1990s, the hydro resource will correspond to less than 50% of regional supply sometime in the next 20-30 years. Meanwhile, natural gas appears likely to continue its rapid growth as a regional power source. In the early 1990s, natural gas accounted for only 3% of regional generation. By 2003, it is expected that about 5400 aMW of new gas-fired capacity will have come on line (NPPC, 2002).[4] If the dominance of natural gas continues, in spite of recent price instabilities, it could account for over 30% of the region's electricity supply within the next two decades.[5]

Figure 1-1. Electricity generation resources located within the Pacific Northwest, 2001



(Source: NPPC, 2001c)

Another potential source of increased generation is coal. Currently, the only two major coal plants located within the region are the Centralia plant in Western Washington and the Boardman facility in Northeastern Oregon, totaling 1656 aMW or 8% of current supply. However, Pacific Northwest utilities own another 2000 aMW of coal generation in eastern Montana, Wyoming, and Nevada that serve Northwest consumers but are not included in Figure 1-1 above. New coal generation could be transmitted from mine-mouth facilities in coal-rich Mountain states, or even from proposed new coal plants within the region.

With the recent completion of the 263 MW (89 aMW) windfarm at Stateline (not shown in Figure 1-1), non-hydro renewable electricity generation recently climbed to over 200 aMW, nearly 1% of regional electricity needs. Much of the remaining renewable generation is from mill residues and landfill gas. Another 430 aMW are generated from black liquor residues at paper and pulp mills and from incineration of municipal solid waste.[6]

Based on our adapted Council forecast described below, regional electricity generation requirements would increase by about 6500 aMW between 2000 to 2020. Under a business-as-usual scenario, it would appear likely that much of this additional generation would come from natural gas, or perhaps from coal. However, heavy reliance on natural gas will continue to

[4] The Council recently cited a figure of 6700 MW (NPPC, 2002), which is equal to 5400 aMW assuming an average capacity factor of 80%.

[5] Assuming that new plants are built only to serve growing Northwest loads. If additional generation is built to serve loads to the south, the fraction could be considerably higher. Conversely, if the West relies more on coal from Mountain states, the number could be lower.

[6] We use the Coalition's convention of considering black liquor and solid waste resources as distinct from renewables.

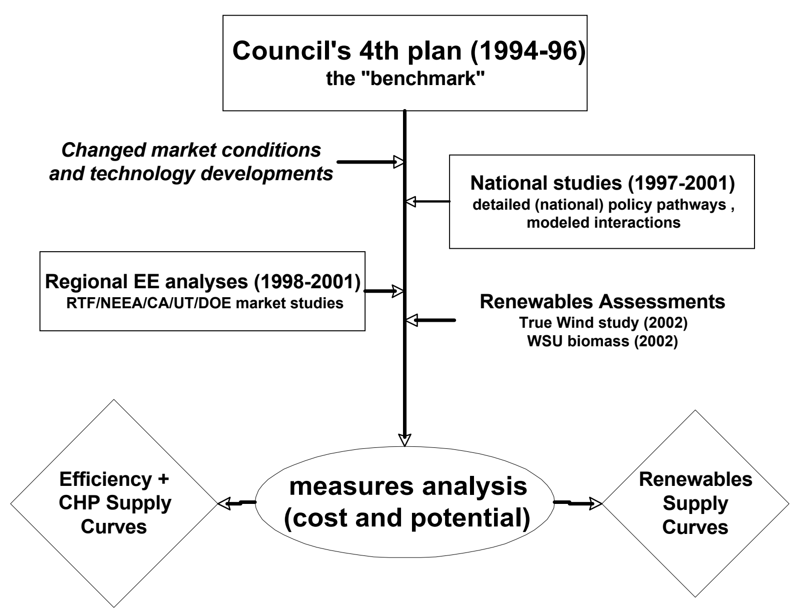
expose the region to significant price volatility, and coal and natural gas present a host of environmental costs from extraction impacts to high greenhouse gas emissions.

The Council's 4th Plan analysis suggested that efficiency could provide an average of 1535 aMW at the then-current cost-effectiveness threshold (about 3c/kWh) and up to 2300 aMW at higher prices projected in 2001[7]. It also found about 2700 aMW of renewable resources available at cost ranging from 2.0 cents per kWh (for low cost small hydro) to 6 cents per kWh (forest thinning residues, higher cost wind and geothermal).[8] But conditions have changed considerably since the 4th Plan analysis was conducted in 1996. Price outlooks for electricity and natural gas are different. More detailed renewable resource assessments are available, with costs for wind and other renewables better understood, and in some cases declining. Furthermore, there are some options on which the 4th Plan did not focus, such as end-use fuel switching to natural gas and efficiency improvements in industrial processes. In light of these changes, this study aims to shed new light on the contribution efficiency and renewable resources can make to energy security, environmental quality, and the regional economy over the next two decades.

1.2 Approach

To arrive at our estimates, we combined several methods and sources. As illustrated in Figure 1-2, we began with the 4th plan, its analysis of potentials, and its medium forecast for future electricity requirements by end-use. We then incorporated key changes in market conditions as of 2001-2002, such as higher avoided costs, new efficiency standards, and more up-to-date costs for wind and other technologies. We consulted national studies, such as US National Laboratories' *Clean Energy Futures* study (EERE, 2001) and others (e.g., Nadel et al, 1998; Kubo et al, 2001; Bernow et al, 1999; Bernow et al, 2001; USDOE/EIA, 2002). We then turned to the wealth of regional energy efficiency and market baseline studies (e.g. Alliance reports), cost-benefit analyses of individual technologies (e.g. RTF spreadsheets), and other recent studies done in the Western US (e.g. those done for the Western Regional Air Partnership). To

Figure 1-2. Schematic of Study Approach



[7] The widely cited 1535 aMW estimate is a mean value across various load forecasts. For the medium load forecast (used here), the cost-effective conservation was 1780 aMW.

[8] Table 5-8 of the 4th Plan shows 700 aMW of wind available for 4.1 to 6.4 c/kWh, around 1000 aMW of geothermal energy for 4.8 to 6.0 c/kWh, 800 aMW of biomass resources for 3.1 to 6.1 c/kWh, and 170 aMW of new small hydro power for 2.0 to 4.7 c/kWh.

develop our renewables analysis, we relied on new wind and biomass resource potential studies (described below) and consulted leading regional experts.

We then undertook a "bottom-up" measure-by-measure analysis, examining the costs, benefits, and market potential of over 30 individual efficiency and combined heat and power (CHP) measures, and four principal renewable resources (wind, biomass, geothermal, and solar).

Key elements of our approach include:

- **Using common assumptions and projections,** to the extent possible reflect those already developed by the Regional Technical Forum (RTF), the Council, or the Alliance. Key assumptions including the discount rate (4.75%), future avoided costs, and external costs for greenhouse gas (GHG) emissions and local pollutants[9] are shown in Appendix A. Instead of the RTF's standard avoided cost projections completed in February 2000 with levelized avoided costs of under 3c/kWh (2003-2020), we used their January 2001 sensitivity analysis which results in levelized avoided costs of 3.6c/kWh that appear closer to current estimates.[10] We used the Council's 4th Plan medium forecast of end-use demands, with adjustments to account for recent growth patterns, new efficiency standards, and extrapolation an additional 5 years to 2020 (see Section 2.1).
- **Collecting current data** on the costs and performance of energy-efficiency measures and renewable resources and technologies. Many of our estimates draw directly from the work of the Regional Technical Forum and the Northwest Energy-Efficiency Alliance. Others are taken from DOE studies, technology studies by the American Council for an Energy Efficient Economy and others, and estimates provided by state agencies, as well as local vendors.
- **Soliciting input from energy-efficiency and renewable experts in the region.** This process helped to define which technologies\measures are most likely to have significant impacts in the Northwest. In some cases, this meant scrapping outdated regional or national analyses, and adopting lower estimates than used in other studies (e.g. geothermal).
- **Defining options to consider.** We compiled a comprehensive list of demand-side measures (see Table 2-2) by consulting recent RTF, Alliance, and other studies (e.g. EERE, 2001; Nadel et al, 1998; Kubo et al, 2001; WRAP, 2001[11]; Nichols and Von Hippel, 2001). Although not considered as part of the Council's conservation mandate, we include fuel switching to natural gas for water heating, where the overall system efficiency can be significantly enhanced. Based on guidance from the Coalition, we

[9] The RTF has adopted a value of $15/tCO2, which assumes an avoided resource of natural gas combined cycle units at 0.4 tCO2/MWh, results in a cost of 0.6c/kWh. The RTF avoided cost forecast used here reflects a tax on CO2 emissions, which increases gradually to $20/tCO2 by 2015. Therefore, to avoid double counting, we reduced the value of the CO2 external cost adder from 0.6c/kWh to 0.4c/kWh. For local air pollutants, we used a value of 0.6c/kWh, based on NGCC emission rates and a review of externality values and trading prices for various pollutants, with calculations shown in Appendix A. For direct gas use in water heating and CHP measures, the combined external cost comes to $1.70/MMBtu.

[10] For example, during Puget Sound Energy's current rate case, PSE submitted estimated 5-year average avoided costs of 3.4c/kWh (plus additional capacity charges).

[11] A forthcoming study for the Western Regional Air Partnership's Air Pollution Prevention Forum (WRAP/AP2F) estimates the costs and benefits of electricity energy efficiency and combined heat and power programs for three regions within the US West, as inputs to modeling options for reducing pollutant emissions from electricity generation in the West.

focused on the renewable resources described in Table 1-1. Due to data and resource constraints, several potentially promising options -- low-impact hydro development, distributed solar PV and small scale wind applications, improved building design, and fuel switching to gas for space heating – were not evaluated.

- **Evaluating the cost-effectiveness and market potential of each option.** For efficiency options, we conducted individual measure assessments, utilizing methods similar to those used by the Council, Alliance, and Regional Technology Forum.[12] We include added costs associated with the intermittence of wind generation.
- **Applying constraints on the resource that can be reasonably utilized.** In many instances, it is practically difficult to induce all consumers to purchase, or all providers to deliver, improved efficiency technologies. For this reason, we apply achievable technology penetration rates of 30 to 75 percent, depending on technology characteristics and market niche. Similarly for renewable resource options, not all of the technically available cost-effective resource can or, arguably should, be developed. For wind generation, we limit the amount of land that could be developed owing to aesthetic concerns, land use and other constraints. For biomass, we restrict use of most residues to a fraction of the available resource, particularly where significant residue extraction might pose ecological concerns or logistical constraints, as in logging and agriculture.

[12] Based on projected equipment sales and end-use demands, we simulated the increasing penetration of improved technologies, including measure-specific program administration costs (typically 10-15% of measure costs), O&M costs and savings, applying end-use-specific RTF avoided cost projections, accounting for bulk and local system transmission and distribution benefits, and considering external benefits costs where relevant, in an discounted present value calculation running out to 2050. Even though we consider efficiency investments only through 2020, energy savings continue up to 30 years longer, depending on measure lifetimes. We accounted for end-use interactions, such as increased heating/decreased cooling loads associated with the reduced energy losses from more efficient lights and appliances, where estimates are readily available.

Table 1-1. Renewable resources considered in this study

Resource	Resources considered or excluded
Wind	• Parks and elevations above 1800 meters (6,000 ft.) excluded. • Only windier areas included (Class 4-7). • Land available for wind development limited to no more than 1% of land area in a given state, and no more than 25% of any given class. • Shaping and added transmission costs included.
Biomass	• Landfill gas capture and generation. • Increased use of mill, agricultural, logging, forest, and poplar plantation residues at existing power plants, including co-firing at regional coal plants. (near-term) • Accelerated development of biomass gasification, combined-cycle technology for residue use. (2010 and beyond) • Residue availability limited by ecological and logistical constraints. • Animal wastes and biogas not considered due to limited data and total potential resource.
Geothermal	• Development potential limited by location of many resources near protected or sensitive areas (e.g. parks, monuments, and wilderness areas). • Small (binary) as well as larger-scale considered. • Ground-source heat pumps not included due to limited time and data.
Solar	• Solar water heating included. • Though already competitive in localized applications (remote or distribution constrained areas), solar PV technology potentials not quantified, due largely to data/time limitations.
Hydro	• Not included in this analysis. • 4th Plan suggests up to 170aMW of potentially cost-competitive small hydro, however, determining how much meets low-impact criteria[13] is beyond scope of this study.

[13] See www.lowimpacthydro.org.

2. DEMAND-SIDE OPPORTUNITIES

2.1 Introduction

Reflecting extensive review of energy efficiency technologies and practices across all sectors, the Council's 4th Plan analysis stands as the current benchmark for regional energy conservation analysis. It projected that, under the Council's medium demand forecast for the year 2015, 1780 aMW, or 7% of regional demand (24,430 aMW), could be met through cost-effective efficiency investments. When power prices climbed in 2001, rendering more efficiency options economic at 4th Plan prices, the analysis suggested that 2300 aMW would be available[14].

Though the 4th Plan conservation analysis is now 5-10 years old[15], it is still widely used. Indeed, the Council pointed to its 4th Plan calculations when it recently called for a 300 aMW "conservation power plant" to be implemented over the next three years (NPPC, 2001c). While the Council's Regional Technical Forum has continued to update the analysis of efficiency options in light of evolving technologies and prices, it has focused exclusively on cost-effectiveness and not on how much efficiency measures could now contribute to meeting growing demand for energy services.

Because they reflect the collective input of many of the region's key energy experts and stakeholders, the 4th Plan and RTF analyses provide the framework for our calculations here. As noted in Section 1, we adopt Council/RTF assumptions for discount rates and avoided costs, among other parameters. However our analysis differs in a few key respects:

- Relative to the 4th Plan, we account for newer National Appliance Energy Conservation Act (NAECA) standards for water heaters, washing machines, refrigerators and freezers. Together, these standards should reduce future regional demand by about 400 aMW (in 2015). They also achieve much of the energy savings previously included for these end-uses in the 4th Plan conservation assessment. As a result, the remaining new conservation potential is reduced by a similar amount: the original 1780 aMW savings estimate drops to around 1400 aMW and the savings at higher prices from 2300 aMW to around 1900 aMW. Additional reductions of up to about 100aMW will likely result when Congress settles on new NAECA standards for air conditioners and heat pumps.
- Recent studies confirm a dramatic reduction in the use of electric space heat in new construction during the 1990s, which should both reduce future space heating electricity loads as well as the market for electric efficiency improvements in new buildings. About 15 percent of recent single-family and 70 percent of recent multi-family new construction installed electric space heating (heat pump, forced air, or baseboard). These figures compare with the 4th Plan's projected use of electricity for space heating in 39 percent of new single-family unit and 94 percent of new multi-family units. These changes suggest that the 4th Plan conservation savings estimates should be lowered by about 100 aMW.
- We adjusted the Council's 4th Plan medium demand forecast as shown in Table 2-1. The first five items reflect reductions in projected demand due to the developments described above. We also compared forecast performance against actual demands from 1995-1999,

[14] Assuming avoided power costs of 4 to 5, instead of 3 cents per kWh.
[15] Though dated 1998, the 4th Plan analysis was conducted largely during the 1994-96 period, based on data and studies that in some cases date back to the 1980s.

and adjusted the projections to reflect faster-than-expected growth in residential and commercial loads, and slower growth in non-DSI industrial loads.[16] We did not speculate on the long-term outlook for DSIs, and simply adopted the 4th Plan projected loads for the purpose of efficiency analysis; prospects are unlikely that loads will return to these levels.

Table 2-1. Principal changes to load projections (relative to 4th Plan medium scenario in 2015)[17]

Factor	Change to 4th Plan Forecast in 2015 (aMW)
Fewer Electrically Heated Homes	-692
New Refrigerator Standards	-161
New Freezer Standards	-51
New Water Heater Standards	-104
New Clothes Washer Standards	-109
Faster-than-predicted Residential Growth	+1053
Faster-than-predicted Commercial Growth	+195
DSI/Primary Metals	No change
Slower-than-predicted growth in non-DSI Industries	-390
Net Change	**-54**

- The Council typically assumes that 85 percent of the economic potential of an efficiency measure can be achieved. We have taken a slightly more conservative approach, assuming 30-75 percent achievability for many options.
- We updated several technology assessments and cost estimates relative to the 4th Plan. For instance newer studies show increased savings are available in motor systems, commercial lighting, and CHP (OnSite Sycom, 2001; Xenergy, 2000; Easton and Xenergy, 1999). We also included some end-uses and markets not extensively evaluated in 4th Plan, such as plug loads (standby losses from VCRs, phones, and other devices), aluminum production, and internet data centers, and include some high-efficiency technologies, such as heat pump and condensing gas water heaters, that are currently on the brink of economic competitiveness.

Efficiency measures considered are listed in Table 2-2 by sector and end-use, along with historical and projected demands in order to suggest where significant potential for savings may lie. For most measures, we conducted a bottom-up measure analysis, based on data and assumptions described in the remainder of this section. For some, as indicated by asterisk, we simply used results from the 4th Plan. For others, as shown in italics, available data and

[16] See Hollen (2001) for a more detailed comparison of the forecast to actual demand. Among the other dynamics that have arisen since the forecast was prepared are: fewer manufactured homes than projected, larger homes (more ft2 to heat and light), and higher DSI demands until the power crunch of 2000-2001. Note we have not attempted to adjust the forecast to fully reflect the impacts of the current recession, since the ultimate duration and impacts are still unclear. Some downward adjustment of both the near-term forecast and projected efficiency potential would likely be appropriate. However, viewed over the entire 20-year period analyzed here, the current recession may only have a minor impact. Due to highly uncertain future outlooks, we made no attempt to adjust the 4th Plan's forecast for the primary metals subsector, which encompasses all of the aluminum DSI loads.

[17] Recently adopted Idaho and revised Washington State energy codes should also reduce demand, but expected savings have not been estimated.

resources precluded their evaluation, or they were too small in total remaining potential (e.g. LED exit signs) to warrant further analysis. The absence of several potentially valuable measures – further HVAC and building shell improvements, better-than-NAECA-standard appliances (e.g. clothes washers, refrigerators, electric resistance water heaters), industrial sector-specific process improvements (e.g. silicon chip manufacturing), and advanced, integrated design and technologies (e.g. ground source heat pumps and evaporative cooling) for new buildings – suggests that the actual efficiency potential could be considerably higher than we estimate in this study.

Box 2-1. Indicators of Efficiency Measure Costs and Benefits

In the text and tables below, we use the following indicators of efficiency measure cost and potential:

- **Cost of saved energy (c/kWh):** The cost of saved energy (CSE) for each measure and initiative (group of related measures) is calculated as the cumulative discounted costs (minus any benefits such as reduced O&M costs) divided by the cumulative discounted electricity savings, yielding a cents per kWh result that can be directly compared with the costs of new electricity supply delivered to consumers. CSE results do not account for any external cost benefits.
- **Electricity savings (aMW):** For comparison, we report electric energy savings in average MW (aMW) for the years 2010 and 2020, though computed through 2050. An average MW is equal to 8760 MWh, equivalent to the output of a 1 MW power plant operating for all hours of the year.
- **Benefit/cost ratio:** Benefit/cost (B/C) ratios are calculated as the cumulative discounted measure benefits (avoided wholesale electricity costs, avoided transmission and distribution costs, and incremental O&M benefits if any) divided by the cumulative discounted measure costs (equipment and other direct costs, administrative costs, incremental O&M costs, and natural gas costs for fuel switching and CHP measures). We present B/C ratios with and without the externality benefits of avoiding greenhouse gas and local air pollutant emissions.
- **Annual Savings ($):** We present "snapshots" of the effects of each measure in 2010 and 2020. For some cost-effective measures with significant upfront costs in later years (e.g. continued penetration of new higher first cost technologies), the result may be negative savings (net costs), meaning that it will take longer for the overall measure to yield net economic benefits, even though individual investments may be paid back more quickly. These figures are not discounted. For comparison, all economic figures are given in 2001 dollars.
- **Cumulative NPV Saving ($):** Cumulative net present value savings represent the sum of discounted annual benefits (minus costs) from 2002 through 2050, and are the most comprehensive indicator of economic benefits.

Table 2-2. End-use demands and efficiency measures

Sector/End-use	**Demand (aMW)**		**Measures Considered** (* = 4th Plan results used) (*italics* = *not included in our analysis*)
	1994 estimated	**2020 projected**	
Residential	**6,443**	**8,867**	
Space Heat	2,249	2,347	Duct/heating service/repair, furnace fan efficiency, super-efficient windows*, weatherization retrofits*, code upgrade*, building beyond code levels*, improved manufactured homes*, *switch to gas, higher efficiency heat pumps*
Cooling	45	62	*Higher efficiency units*
Lighting	322	441	Fluorescent torchieres, Indoor and outdoor CFL fixtures, CFL bulbs
Water Heating	1,559	1,753	Add-on and integral heat pumps, high-efficiency (condensing) gas, solar, *higher efficiency clothes washers and electric water heaters*
Refrigerator/Freezer	844	571	Extra appliance retirement, *Advanced standards*
Other	1,424	3,694	Plug loads/standby losses
Commercial	**4,491**	**6,342**	
Heating, Venting, and Air Conditioning (HVAC) systems	1,338 (heat) 355 (cool) 629 (vent)	1,524 412 1,000	New building commissioning*, existing building retrocommissioning**, improved building design, new/ upgraded codes, ground source heat pumps, switch to gas, high efficiency AC, evaporative cooling systems, high-efficiency fans*
Lighting	1,419	1,979	High-efficiency fluorescents, emerging technologies and practices, *exit signs*
Refrigeration	296	432	Several refrigeration technologies
Water Heating	103	206	*Switch to gas*
Other	350	787	Generic O&M, internet data centers, washing machines, *Cross-cutting programs**
Industrial	**6,674**	**9,779**	
Motors and motor systems			Premium motors, improved motor system (pumps, fans, compressors, etc.)
Aluminum			Efficient cell design
Other industries and end-uses			Non-motor savings, generic O&M, high-efficiency transformers, *on-site delivery, delivery through alternate channels*
Other	**901**	**900**	
Public	179	181	Streetlighting/traffic lights
Irrigation	722	719	Hardware, scheduling, and education*
Total Demand	**18,509**	**25,887**	

2.2 Residential Sector

At present, two end-uses, space heat and water heat, are responsible for over half of residential electricity use and about 20 percent of total electricity sales in the Northwest. At the same time, we project that electric space and water heat loads are unlikely to grow substantially over the next 20 years, due largely to a significant shift to natural gas heating systems in new construction and new standards for water heaters and clothes washers. These developments, according to our analysis, could reduce projected loads by 1000 aMW by 2020 (the sum of the top five entries in Table 2-2).

Despite these trends, from 1995 and 1999 residential demand actually grew faster than the 4th Plan projected. In the absence of detailed end-use surveys, the reasons for this growth remain unclear. It is conceivable, for instance, that declining energy prices and rising affluence during the 1990s led to larger homes, with increasing heating and lighting overcoming efficiency improvements and fuel switching from electricity to gas. It is also possible that televisions, computers, and other smaller consumer electronics, along with other miscellaneous end-uses, grew quite rapidly in the 1990s. Though this "other" category, often called "plug load" accounts for only 12 percent of current residential electricity, and it is the fastest growing aspect of residential energy use (EERE, 2001).

In the subsections below, we describe the key residential end-uses and the efficiency measures we evaluated. We note some of the indicators of measure cost and potential here (see Box2-1), and report them more fully in Appendix A. As noted previously, our analysis is far from comprehensive. Though savings exist for these other end-uses, we assume national standards for clothes washers, refrigerators/freezers, and space cooling will capture much of the savings. In addition, the technology improvement potential for clothes driers and stoves is minimal.

2.2.1 Space Heating

Largely because of the region's historically low electricity prices, about 50-60 percent of Pacific Northwest homes are heated with electricity, compared with only 30 percent of all US homes.[18] However, this fraction now appears to be declining quite rapidly. In the 1990s, favorable economics and aggressive marketing by gas utilities led many homes – about 20,000 per year by gas utility estimates -- to switch from electric to gas heat in the 1990s (NPPC, 2001a). Recent surveys indicate that natural gas is now the standard in much of the region's new single-family construction, particularly in areas with adequate gas distribution capacity (Ecotope, 2001a; Ecotope, 2001b). Natural gas commands 90 percent or more of the single-family construction market in Idaho, Montana, and Oregon (Ecotope, 2001a).[19] In Washington, the fraction of gas heat in recent construction has been slightly lower (80%), owing in part to heat pump installations, which went into about 15 percent of new homes, concentrated in the Spokane, Tri-Cities, and Seattle suburbs. Even though 90 percent of Oregon multi-family construction is still electric heat (mostly zonal resistance), gas systems are making serious inroads in the Washington market, and now account for over half of the new multi-family buildings.

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[18] US Bureau of the Census, QT-04. Profile of Selected Housing Characteristics: 2000, www.census.gov. Estimated electric space heat fraction depends on data source and calculation method. The US Census has reported about a 50% share in both 1990 and 2000, while the NPPC estimated 58% for 1994.

[19] This figure includes a small amount of propane.

As a result of these changes, the Council's 4th Plan space heat forecast, which assumed 62 percent of Northwest homes would be electrically heated in 2015 would now appear to be quite high. Assuming that current trends continue, as indicated in surveys done for the Alliance for single- and multi-family construction, less than 50 percent of homes will be electrically heated by 2015, suggesting that space heating loads might turn out to be 20 percent lower (or about 600 aMW) lower than projected.[20] Although newer electric single-family homes have gotten somewhat larger (relative to the forecast), providing more square feet to heat, any increase in electric load would be tempered by newer and stricter building codes as well as a shift to smaller multi-family units in the overall mix of electricity space heated homes.

As a consequence, the efficiency savings potentials in new electrically heated homes has likely diminished substantially, simply because there will be fewer space heating kWh to avoid. Nonetheless, significant opportunities for improving efficiency in electrically heated homes still remain, in heating technologies (furnaces, furnace fans), building envelopes (e.g. insulation, weatherization, and windows), and in fuel choice (e.g. greater use of natural gas, especially in multi-family homes). Savings of another 20-25 percent might be achievable by providing incentives at the design stage, which could result in buildings that require far less energy to heat or cool.[21]

- **System and Duct Service and Repair**: Many existing heating systems can be made significantly more efficient by applying a package of system and duct repair measures, including tune-ups for heat-pump condenser and evaporator units, cleaning, sealing and insulating duct work, or re-routing duct work to make the flow of heat from the furnace to living areas more efficient. Based on an estimate that 42 percent of forced air and heat pump systems are accessible and in need of repair, and an assumed 65 percent success rate in reaching these homes, we estimate 56 aMW of savings are possible by 2020.[22] These measures are relatively cost-effective (benefit/cost ratio of about 2, cost of saved energy of 2.6 cents per kWh), and provide added benefits such as the removal of accumulated dust and spores from the heating system.
- **Furnace and Heat Pump Fans**: The fans that move conditioned air from heat pumps and furnaces to living spaces typically consume an average of 800-1000 kWh per year. More efficient fans using less than 300 kWh per year could be mass-produced for an additional $100 per unit (Kubo *et al*, 2001). Assuming the furnace and heat pumps market can be transformed over the next five years to deliver improved fans, the savings could be significant: 55 aMW by 2010 and 147 aMW by 2020, at a cost of 1.2 cents per kWh saved and a benefit-cost ratio of 3.5. Since furnace fans often come as integral components of heating systems, a long-term effort to work with manufacturers will be needed to achieve these savings. National standards may ultimately be the best approach for implementing this measure, and the Pacific Northwest could work with other regions in leading the way, as with residential clothes washers.

[20] Note this estimate does not even account for the 100-200,000 homes that may have converted to natural gas since 1990 or any future conversions. If 150,000 natural gas conversions have occurred, and were not accounted for in the 4th Plan forecast, then space heat forecast would be reduced by at least another 5% (or 150aMW), perhaps more given the likelihood that those switching fuels were those with higher than average heating bills.
[21] Dave Baylon, Ecotope, personal communication.
[22] Cost and savings data for applications of these measures in different types of installations in the Northwest were adapted from RTF analysis by Tom Eckman. See "PTCS.XLS" (RTF, 2001).

- **Super-Efficient Windows**: Building codes in most states of the Pacific Northwest already call for very high-quality windows, but there is considerable potential for upgrading glazing in existing buildings, and in some applications there may be potential for installing window systems whose performance exceed code levels. Super-efficient windows employ a combination of reflective coatings, several layers of glass, well-insulated windowsills, and a between-pane filling of an inert gas such as argon to improve their thermal performance. Given the complexity of evaluating improvements to building shells, rather than conduct a new analysis, we adapted the 4th Plan's assessment of potential energy savings for "Super Windows in Residential Housing", which compares the efficiency of windows with U (thermal flux resistance) values of 0.25 or less with windows meeting current code levels of 0.4 (NPPC, 1996a; Oregon Office of Energy, 2002). We reduced the available potential by approximately 50 percent to reflect fewer expected new electrically heated housing units. The result is approximately 40 aMW of savings by 2020 and a benefit/cost ratio of 1.3, and cost of 3.3 cents per kWh saved.
- **Weatherization Retrofits**: The thermal performance of a dwelling—the degree to which a heated house stays warm and (less frequently in the Northwest) a cooled house stays cool, is a function of many factors, including how well insulated the house is, the integrity of its windows and doors, whether it has been well-sealed to control the incursion of outside air, its overall design, its orientation relative to sun and wind, and its proximity to nearby vegetation. Of these factors, the first three are usually addressed by measures installed during a weatherization retrofit of an existing dwelling. Often the greatest gains from these retrofits are to be had in older homes that have relatively inefficient heating systems, such as baseboard heat. As with other building shell measures, we used the 4th Plan assessment, which found 27 aMW of savings potential to 2015 (NPPC, 1996a). Using recent cost information, the benefit/cost ratio for these improvements comes to 1.7, with a cost of saved energy of 1.9 cents per kWh.
- **Better-than-Code Building Envelopes for New Homes**: Although Washington and Oregon already have state (and sometime local) residential building codes that mandate quite high building performance, there are opportunities to exceed code levels. There are also opportunities to ensure that more buildings are actually built to code, through improved code enforcement, and to extend strong building codes to other states. We drew from the 4th Plan analysis for this measure, scaling down to 12 aMW of savings by 2020 due to the reduction in the number of new electrically heated homes since the NPPC analysis (NPPC, 1996a). Based on NPPC cost data, these measures are extremely cost-effective, yielding a cost of 0.5 cents per kWh saved and benefit/cost ratio over 9. This low cost derives from a combination of the low cost of the measures included in this package (which in turn result from the ease of installation of better insulation at the time of first construction) and very long measure lifetime.
- **Improving Thermal Integrity of Manufactured Homes**: The manufactured homes industry, working together with federal and state energy agencies and utilities (through utility programs), made great strides in improving the energy efficiency of new manufactured housing during the past two decades. The 4th Plan includes in its residential program "bundle" (NPPC, 1996a) an estimate of the benefits of improving the thermal envelope (through measures such as improved insulation, windows and doors) of

new manufactured housing beyond the 1994 standards set by the federal Department of Housing and Urban Development. Applying a 49 percent reduction in savings to 4th Plan estimates to reflect lower electric heating penetration in new manufactured housing, we estimate potential savings from this program of 29 aMW by 2010 and 48 aMW by 2020, at an estimated levelized cost of 2.6 cents/kWh.

There are additional energy-efficiency-related activities that can assist in increasing the penetration of weatherization activities and in promoting the construction of high-efficiency homes. One key activity of this type is the training and certification of weatherization contractors and installers, as well as builders, in the implementation of building envelope measures. Though the ultimate impact of these types of support activities are difficult to quantify, training and certification programs should proceed in tandem with the promotion of residential building energy-efficiency measures in order to assure success of building envelope improvement initiatives.

2.2.2 Lighting

For virtually the entire twentieth century, incandescent lamps dominated the US residential lighting market. These lamps are inexpensive, but they have relatively low lighting *efficacy* (the efficiency with which electricity is converted into light), and burn out relatively quickly, with a bulb lifetime on the order of 1000 operating hours. Over the last decade or so, compact fluorescent light bulbs (CFLs) designed for use in incandescent fixtures – and lamps and fixtures specifically designed to use CFL technology – have been making inroads in the U.S. market. CFLs use roughly one-quarter of the electricity to produce the same amount of light as incandescent bulbs, and last up to 10 times longer. The marketing of CFL lighting has been assisted by utility-based and other incentive or "buy-down" and bulk purchase programs[23], and has resulted in very strong sales of CFL bulbs in the Northwest over the last year or so. The following measures build on this momentum, focusing on CFL torchieres, indoor and outdoor fixtures designed for CFL use, and additional CFL bulb use in existing fixtures.

- **CFL Torchieres**: The "torchiere" style of tall floor lamp gained tremendous popularity in recent years as inexpensive units have become widely available. Most units use bright, but inefficient, halogen bulbs, while some use incandescent bulbs. Their high electricity use and the fire hazards[24] created by high temperature halogen units have prompted the development of the CFL torchiere. The CFL torchiere produces the same light output as the halogen and incandescent units, using 20-30 percent of the electricity and eliminating an important fire risk. With proper incentives, we assume that CFL torchieres could capture 70 percent of the torchiere market by about 2008, resulting in savings of 15 aMW by 2010 and 45 aMW by 2020 at a cost of about 2.8 cents per kWh saved and a benefit/cost ratio of 1.2.
- **Indoor CFL Fixtures**: CFLs work best when used in fixtures specifically designed for them. Based on assumptions about the market for specific types of indoor fixtures in the

[23] In a buy-down program, an organization offers manufacturers incentives, including, for example, a guaranteed minimum purchase quantity, to make products (in this case, CFLs) available at a lower-than-prevailing price. In a "bulk purchase" program, an agency (a utility or non-profit organization, for example) purchases a large quantity of CFLs at a discounted price, and then (typically) sells the bulbs to consumers at or near the discounted cost, which is usually much lower than the prevailing retail price of the units.

[24] More than 400 fires have been attributed to halogen torchieres (Kubo et al, 2001).

Northwest, we estimated that 50 percent of the fixtures purchases by 2008 could be CFL fixtures.[25] Assuming an average usage of 1.5 hours per fixture per day, we estimate savings from indoor CFL fixtures in the Northwest of about 30 aMW of electricity by 2010 and 97 aMW by 2020, at a cost of about 3.1 cents per kWh saved and a benefit/cost ratio of 1.2.

- **Outdoor CFL Fixtures**: Using CFLs in outdoor fixtures presents an attractive way to save both money and electricity, as long-lived CFL bulbs are used for many hours per day when installed for outdoor security lighting. In addition, as many outdoor incandescent bulbs designed for outdoor use are both expensive and short-lived, there are significant operation and maintenance savings from using outdoor CFL-based fixtures. We assumed that outdoor bulbs would be used five hours per day, and that CFL-based outdoor fixtures could account for 50 percent of the market for outdoor fixtures by 2008 with an aggressive marketing/incentive effort. We estimate that the result or such an initiative would be savings of 12 aMW by 2010 and 40 aMW by 2020. Due to the labor and bulb savings resulting from use of long-lived CFL outdoor fixtures, there is actually a net benefit to using them, equal to about 5.3 cents per kWh saved and a benefit/cost ratio of 5.3.
- **CFL Bulbs**: Not surprisingly, many consumers find it easier to change a light bulb within an existing fixture than to replace the entire fixture. We assumed that by 2008 about 2.8 percent of all Northwest households buy 4 CFL bulbs annually (instead of incandescent bulbs) as the result of an aggressive CFL marketing initiative. Given that many households have already installed CFLs in the most heavily used fixtures, we assumed new initiatives would result in replacing incandescent bulbs that operate fewer hours (1.5 per day on average). Still, the economics are quite favorable. We estimate that 14 aMW of electricity could be saved by 2010, and 37 aMW by 2020, at a cost of about 0.6 cents per kWh saved (benefit/cost ratio of 6.4).

2.2.3 Water Heating

Accounting for approximately one fourth of electricity sold to Northwest homes, water heating is a key source of potential efficiency savings. Electric resistance water heaters, installed in about 80 percent of Northwest homes, use a heating element to heat water in an insulated tank. New national standards for water heaters will reduce their energy requirements by about 5 percent, approaching the maximum realistic efficiency of resistance water heaters. Gas water heaters are the other water heating technology widely used in the region. They are increasingly installed in new construction alongside gas-fired space heating systems. Standard gas water heaters consisting of a gas burner, typically vented through a pipe up the middle of the tank, are typically cost-effective compared with electric water heat, but are not particularly efficient.

Several water heating technologies can substantially reduce electricity needs, including electric heat-pump water heaters, high-efficiency gas-fired water heaters, solar water heaters, and devices that capture residual heat from household wastewater. Equally important are measures to reduce the demand for hot water. For instance, efficient clothes washers can reduce household hot water requirements by over 10 percent, and efficient dishwashers by over 2 percent. Coming

[25] Fixture cost and performance data for indoor and outdoor fixtures, as well as market estimates for these fixtures, were based largely on NEEA (1999).

standards for clothes washers will achieve most of these savings over the next 20 years.[26] We thus concentrate our analysis on three principal options that offer significant potential for future savings: heat pump, high-efficiency gas, and solar water heaters. All three options are more expensive than most of the other efficiency options in this study, but are important to consider because of the magnitude of savings, and the potential for large-scale implementation to significantly reduce costs and improve performance.

- **Heat-Pump Water Heaters**: Heat-pump water heaters extract heat from their surroundings and transfer it to water in much the same way that the heat-pump furnaces produce space heat. Heat-pump water heaters can be two to three times as efficient as electric resistance water heaters (with "energy factors", or "EF", in the range of 2.0 to 2.4, as opposed to 0.86 to 0.91 for resistance water heaters), but they are far more complex, with a number of moving parts to maintain (as opposed to essentially none for resistance water heaters). Heat pump water heater technology has been improving in recent years, yielding improvements in efficiency and reliability as well as cost reductions. Aggressive efforts are needed to both improve technology reliability and develop the market supply chain that can properly sell, install and maintain these devices. While heat pumps are relatively complex water heating technologies, they offer the potential for cutting electricity use for water heating by 50 percent or more, and thus deserve closer consideration.

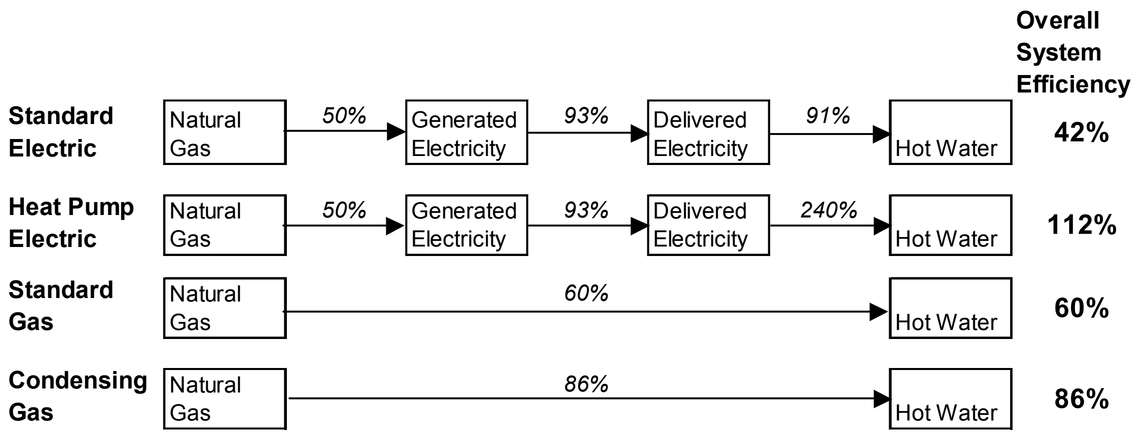
  We include two heat pump measures in our analysis. The first is an "add-on" type heat pump, designed for use with an existing water tank (for example, an existing electric resistance water heater). The second is a heat pump water heater with an integral tank of a type that is in the final stages of commercialization. We assume that the add-on heat pump water heaters are implemented starting in 2002, reaching 15 percent of the market for electric water heaters by 2010, with their share of the market declining to zero by 2020. Integral heat pump water heaters are assumed to start at 5 percent of the market in 2005, increasing to 40 percent of the market by 2020. These two types of units, taken together, are estimated to provide electricity savings of 124 aMW by 2010, and 456 aMW by 2020, at costs ranging from 2.7 (integral HP) to 4.8 (add-on HP) cents per kWh. Their benefit/cost ratios are 1.5 and 0.9, respectively. If environmental benefits are considered, the ratios rise to 1.8 and 1.1, respectively.

- **Gas-Fired Water Heaters**: A typical gas-fired water heater has an overall efficiency or energy factor (EF) of about 0.54 to 0.62, meaning that a considerable amount of the energy in the combustion gases is lost "up the stack" or in tank heat losses to the surrounding environment (often a basement or garage). A standard gas water heater is a cost-effective replacement for an electric resistance water heater in applications where gas is available and the costs of connecting a water heater to a gas line are not large. As shown in Figure 2-1, the standard gas water heater has an approximately 60 percent efficiency compared with a new efficient electric heater, which has a system efficiency of about 42 percent when the energy losses from electricity generation (by a high-efficiency NGCC unit), transmission, and distribution are also considered. While these units offer

[26] Our water heater savings estimates account for reduced water heating loads due to NAECA clothes washer and water heater standards.

overall energy savings, we focus instead on high-efficiency, "condensing" gas-fired water heaters that offer twice the overall savings, though at considerably higher first cost.

Figure 2-1. Comparative system efficiency of alternative water heating methods



There are two types of condensing gas water heaters, a typical tank unit and an instantaneous or tankless unit. The tank-type units typically include a helical coil of stainless steel tubing inside the water tank to capture much of the energy in the combustion gases that is lost through the vent in a standard gas water heater.[27] These units have EF values of 0.86 or more. We have assumed that tank-type condensing water heaters could take 15 percent of the electric water heater market by 2010, yielding *gross* electricity savings of 322 aMW by 2020 at an average cost of about 5.5 cents per kWh saved.[28] If the same gas used by these water heaters were instead use to generate electricity in new high-efficiency power plants, it would produce 162 aMW of gas-fired electricity. Therefore, the *net* electricity savings of using gas in water heaters instead of power plants comes to 160 aMW.[29] At current unit prices, condensing gas water heaters are not yet cost-effective, with benefit-cost ratios of 0.73 without, and 0.80 with consideration of external benefits. Standard gas water heaters could yield 40 percent of the savings and considerably lower cost, given that today a 60 percent efficiency gas heater costs only about $400, compared with a condensing system for which we assume a cost of $2000. However, given their currently limited market niche, wide-scale adoption of condensing water heater technology could well result in lower prices over time.

- **Solar Water Heaters**: Despite the relatively cloudy Northwest climate, solar water heaters can provide 60-70 percent of a household's hot water needs. Solar water heaters consist, generally, of one or more flat metal panels located on the roof (or another nearby,

[27] The Oregon Office of Energy website offers a list of both instantaneous and tank-type high-efficiency gas water heaters that qualify for the Oregon Residential Energy Tax Credit. www.energy.state.or.us/re/tax/appheat.html
[28] Tankless heater units were not considered in this analysis because of their high cost. Though the high-end water heater market may increase use of tankless water heater units.
[29] For example, a program to install 2000 natural gas water heaters might use 35 MMbtu of gas annually and avoid 1 aMW of electric water heating on a *gross* basis. However, this 35 MMbtu of gas could be used in a new combined cycle gas turbine plant to generate about 0.55 aMW of electricity. Therefore, the water heating measure produces a *net* 0.45 aMW more electricity (in savings) than if the same gas were used in power plant.

non-shaded location) in a glass-covered box. Tubing, through which either water or a solution of water and an antifreeze flows, are built into the panels, and this tubing is plumbed to a water heater tank. Factors that have kept solar water heating from achieving a significant market share in many areas (including even areas with much better solar resources than the Northwest) have been the high first cost of the solar units (in part a function of low sales volumes), and the lack of standard methods of solar water heater certification and installation. We assume that efforts to overcome these barriers could result in 5 percent penetration of solar water heaters by 2010, resulting in savings of 23 aMW by 2010, and 73 aMW by 2020, but at a relatively high cost: 13 cents/kWh saved. Mass production of solar water heaters, coupled with the development of tools and training to standardize and streamline water heater installation, could considerably reduce the cost of this technology below our assumptions, which are based on current installation costs of about $4000.[30]

We have not included either higher-efficiency electric resistance water heaters or heat recovery from wastewater in our analysis to date. Electric resistance with higher EF ratings than those meeting new (2004) standards may become available, but the net gain in efficiency is likely to be quite small (though the net cost may be modest as well). Wastewater heat recovery is a promising technology that works by using a heat exchanger to pre-heat water entering a water heater (electric or gas) using wastewater—water exiting a shower or sink, for example—as a source of heat. Savings of 10 to 40 or more percent of hot water heating energy may be possible using this technology, depending on how water is used in the home and how the unit is installed,[31] As more field trials are conducted with this technology, more will be known about its cost-effectiveness and suitability for Northwest applications.

2.2.4 Refrigeration

The per-unit consumption of electricity by new household refrigerators increased markedly starting around the 1950s, reaching very high levels in the 1970s as the appliance industry sought to provide units that were large inside, small outside, and inexpensive to build. Since the 1970s, and particularly in the last 10 years, the efficiency of household refrigerators and freezers has improved dramatically. Although refrigerators are available that have a range of different unit energy consumption ratings within each model type and size class, the new, relatively stringent federal standards recently in force means that the potential energy savings are rather modest.[32] As a consequence, we have only examined the potential savings from refrigeration retirement, as indicated below.

- **Second Refrigerator Retirement**: It has been estimated that 10 to 15 percent of households keep second (or even third) refrigerators plugged in and operating, generally for the convenience of occasionally storing a few items. These often lightly used, and usually older vintage (and thus less-efficient) appliances are a source of substantial electricity demand. Based on our analysis, a brief (two-year) initiative aimed at inducing

[30] RTF analysis and Christopher Dymond, Oregon Office of Energy, personal communication.
[31] See, for example, Federal Energy Management Program (2001), *Heat Recovery from Wastewater Using a Gravity-Film Heat Exchanger*. Publication DOE/EE-0247, produced by Oak Ridge National Laboratory, for the U.S. Department of Energy, May, 2001. Available on www.eren.doe.gov/femp.
[32] Limited-production, super-efficient refrigerators are available in some size classes, but these units generally carry a substantial cost premium relative to mass-produced models.

consumers to give up their second (or third) refrigerators in exchange for cash (or a utility bill credit) and free refrigerator recycling/disposal service could save 26 aMW within 2 to 3 years, at a cost of about 1.8 cents/kWh saved. Because we have assumed that second refrigerators have only a limited remaining life (6 years) at the time of their retirement, and because we have assumed an initiative of only limited duration, savings do not persist to 2010. Initiatives to avoid the accumulation of new, older, second refrigerators over time, would yield lasting savings.

2.2.5 Other Electricity Use

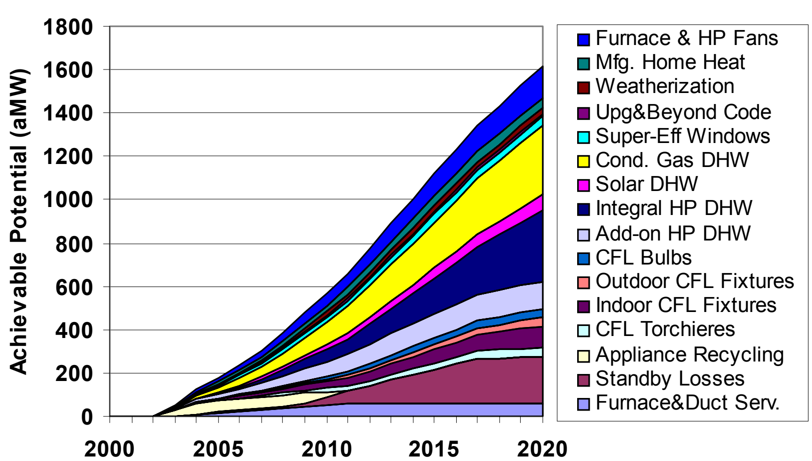
In recent years, the proliferation of "other" devices plugged into American homes – VCRs, larger televisions, chargers for cordless devices, computers, other home electronics – has accounted for the fastest growing segment of residential demand, as noted above. A key measure for reducing the electricity consumption of these devices is to reduce their "standby losses", as indicated below.

- **Standby Loss Reduction in Home Electronics**: Even when turned off, many household electronic devices consume small amounts of electricity. While insignificant on an individual device basis, the total energy consumed by standby equipment adds up to about 5 percent of current residential electricity use, due to the multitude of devices and their steady power drain (Kubo et al, 2001). The EPA *Energy Star* program already includes an initiative to encourage the reduction in average standby consumption from 4.4 to 1 watt per device, a drop of over 75 percent. We assumed an initiative could achieve a 10% increase in the number of electronic devices that meet the 1-watt target (in addition to the estimated 50 percent that already meet the target) through 2009. In 2010, we assumed that maximum standby losses of 1 watt would become the standard for electronic devices. Such an initiative could save 39 aMW by 2010 and 218 aMW by 2020, at a cost of 1.4 cents per kWh saved and a benefit/cost ratio of 2.4.

2.2.6 Residential Sector Cost and Savings Summary

The measures described above, when combined, yield over 500 aMW of net grid savings by 2010 and 1600 aMW by 2020, equal to 7 percent and 18 percent, respectively, of projected residential demands. The growth in time of savings by measure is shown in Figure 2-2. Water heating measures yield the greatest energy savings over time, followed by standby loss reductions. However, the relatively expensive water heating measures considered here result in rather significant upfront costs as illustrated in Figure 2-3.

Figure 2-2. Residential efficiency and fuel switch savings to 2020



This chart, and similar ones that follow, show the net costs (or savings) attributable to each measure in a given year, and bear some explanation. In the early years, a few measures yield immediate net economic benefits (bars above the $0 axis), such as appliance recycling and outdoor CFL fixtures. Most measures, however, have net costs for several years, showing below the $0 axis. This outcome is a function of the longevity of the efficiency measures. Because we assume that improved technologies slowly penetrate each market, new equipment purchases – such as light bulbs, water heaters, and windows – continue for many years until maximum saturation levels are achieved. When the annual energy and other savings from *past* equipment investments is greater than the cost of *new* equipment purchases, then the measure yield net benefits showing above the $0 axis. (Note that for the individual investment, the consumer may see net benefits somewhat sooner.) Figure 2-3 shows that for all residential measures through 2015, net cost measures – dominated by the costs of water heater purchases – exceed the benefits from other measures (those above the $0 axis). Once all equipment purchases are completed (2020, for the purposes of this assessment), there are annual savings of $480 million a year in avoided electricity generation, transmission, and distribution. These savings decline over time as the equipment purchases near the end their useful lives.

Figure 2-3. Net annual benefits, residential measures

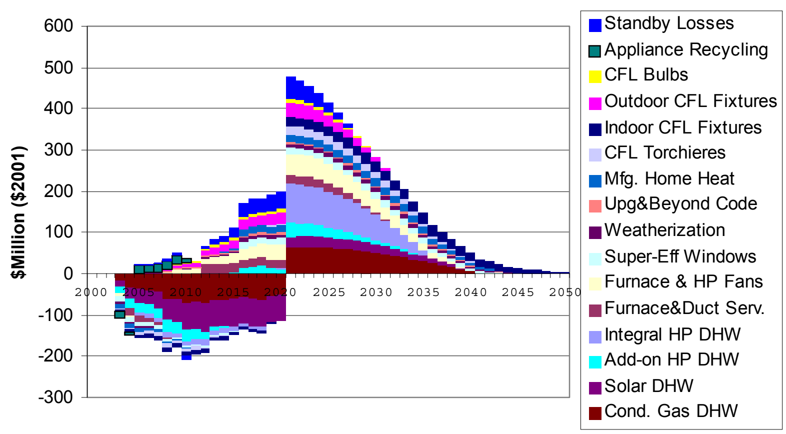
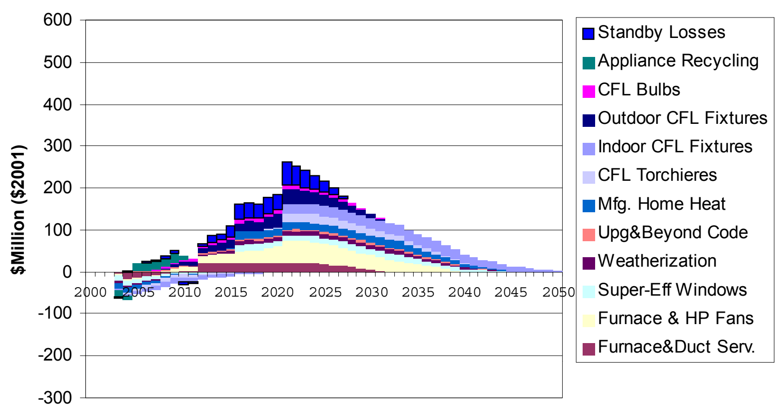


Figure 2-4 shows the effect of removing the water heating measures. Net annual savings are achieved much sooner in 2008, but the overall magnitude of the overall energy cost savings is reduced considerably, peaking at about $260 million per year in 2021.

A key cost indicator is cumulative lifetime NPV benefit, which amounts to $1.1 billion without the water heating measures, and $130 million with them. These savings correspond to about $25 to $200 per household. If societal benefits of avoided pollutant emissions are included in the calculation, the benefits are $1.7 billion without and $1.4 with the water heating measures. In other words, aggressive efforts to capture water heating savings can be combined with other residential measures and still achieve an overall regional economic benefit, and a very significant one when environmental benefits are

Figure 2-4. Net annual benefits, residential measures excluding water heating



considered. However, if maximum economic benefits are sought, a package of less ambitious water heating measures (specifically standard in place of condensing gas and less aggressive implementation of solar and heat pump water heaters), should be pursued.

2.3 Commercial Sector

The commercial sector – spanning office buildings, retail stores, schools, hospitals, and other establishments – is the region's fastest growing, averaging 3 percent annual growth throughout the past two decades, nearly twice the growth rate in overall regional electricity consumption. Office and retail buildings account for almost half of the region's 5000 aMW commercial loads. Half of this electricity is used to heat, cool, and ventilate commercial buildings, and another 30 percent to light them. Other significant commercial end-uses, in order of importance are miscellaneous uses, refrigeration, and water heating.

In many businesses and institutions, electricity costs constitute a relatively small share of overall costs of doing business, and, partly as a consequence, considerable potential remains for improving the efficiency of electricity use in commercial buildings. Improving commercial lighting efficiency is a frequent target of utility DSM programs, but considerable potential for improving commercial energy efficiency exists in heating, cooling, ventilation, and refrigeration as well, with additional potential in water heating. The Council's 4^{th} Plan estimated energy efficiency potential in commercial lighting of approximately 63 aMW out of a total commercial lighting demand of over 1800 aMW by 2015. A number of more recent sources suggest that potential energy efficiency in this end-use, not to mention the sector as a whole, could be much greater. The subsections below present the measures we have investigated in each end-use, and describe our estimates of the achievable potential electricity savings in the Pacific Northwest from these commercial measures.

2.3.1 Space conditioning, HVAC systems, and building thermal integrity

As in the residential sector, relative to the nation as a whole, electricity is used as a heating fuel by an unusually large fraction of the businesses and institutions in the Northwest. As of 1994, over three-quarters of the office building floorspace, and nearly 57 percent of floorspace in all buildings, were heated primarily using electricity (NPPC, 1998). Although these fractions are forecast to decline somewhat over time as gas is used more frequently for space heat, the electrically heated fraction of commercial floorspace will clearly remain very significant.

Although the cooling of commercial buildings consumes less of the overall commercial electricity budget in the Pacific Northwest than in many areas of the country, cooling, and particularly cooling and ventilation combined, consume a much larger share of sectoral demand than space cooling consumes in the residential sector in the Northwest. Commercial buildings have significant internal heat loads (for example, from lights and office equipment), and typically require cooling for more of the year than residential buildings.

Since they account for over half of commercial building electricity use, heating, ventilation, and air conditioning (HVAC) systems are natural targets for efficiency improvement, along with the building designs and operations that dictate how much space conditioning is needed. However, as with residential buildings, the analysis of building space conditioning options is complicated by the interactions between many design and operation options: windows, insulation, building orientation, heating and cooling equipment, and the fans, ducts, and pipes that deliver conditioned air. Given study limitations, we identified the following potentially promising options, but were unable to examine them in detail:

Heating:

- Heating and duct system servicing and repair.
- Highest-efficiency electric heat pumps: Heat pump units are available with efficiency ratings that exceed the ratings of standard units by up to 20 percent (Xenergy, 2001) at modest incremental cost.
- Accelerated switching to gas-fired furnaces: In some cases, gas-fired heaters and boilers are less expensive (and more efficient) than electric ones of equivalent capacity (ADL, 1998).

Cooling:

- Higher-than-standard efficiency "package" air conditioning (AC) units and centrifugal chillers: Work for the Western Regional Air Partnership (see above) suggest that using higher-than-standard efficiency "package" AC and centrifugal chiller units may provide significant cost-effective savings.
- Evaporative cooling technologies: Evaporative cooling technologies use the latent heat of vaporization of water to cool air. One of the most promising configurations, indirect-direct evaporative cooling (IDDEC) can substantially reduce electricity requirements relative to conventional cooling systems (Scofield and Dunnavant, 1999) and operate well in the relatively low humidity conditions that prevail during Northwest summers.
- Cooling tower improvements: Used for large commercial AC systems, cooling towers can be improved through a combination of fan and drive/control system improvements (Xenergy, 2001).
- Increased use of ambient air cooling: Perhaps the most cost-effective and universally applicable means of reducing cooling electricity requirements in the Northwest is to take advantage of the relatively dry Northwest summer climate by using outside air whenever possible to cool buildings.

Ventilation:

- Improved ventilation fans and air handling systems: As shown with industrial motor systems (below) and residential furnace and heat pump fans (above), improved fan designs can provide significant, cost-effective savings.

Design and Construction:

- Improved building design: The best opportunity to improve building efficiency is at the design stage when features like building orientation, shading, daylighting, roof coatings, and other features can be included.
- Code upgrade and enforcement: Despite the relatively stringent building codes now in place in many Northwest jurisdictions, there is potential for additional electricity savings

through further tightening building codes as well as through improved enforcement of existing energy codes.

We did adapt two measures from the 4th Plan—"commissioning" and "retrocommissioning"—that can capture some of the savings offered by the types of measures described above, and which consider the benefits of general improvements in building operation and maintenance (see below). Clearly, however, more thorough and up-to-date analysis is called for if all major cost-effective efficiency investments are to be identified. The Northwest Energy Efficiency Alliance and the Council are conducting a commercial buildings market efficiency potential assessment for release in 2003.

- **Commissioning of Commercial Buildings**: "Commissioning" is defined in 4th Plan documentation as "a systematic process, starting at the design phase and following through start-up and operation, of ensuring that all of the energy-consuming systems in the building work together as intended and can be maintained to continue to do so" (NPPC, 1996b). As such, it includes a combination of design assistance and review, training of the installers and operators of the energy-using systems installed in buildings, and follow-up analysis to make sure that the building operates and is operated as intended. Based on 4th Plan results, we estimate that commissioning of new commercial buildings could save 58 aMW by 2010 and 95 aMW by 2020, at an average levelized cost of 1.2 cents/kWh.
- **Retrocommissioning**: "Retrocommissioning" denotes a process of commissioning in existing buildings. As such, as defined in 4th Plan materials (NPPC, 1996b), retrocommissioning is "a process of thoroughly identifying the current needs for services within a building, assessing the functionality and appropriateness of the equipment now serving the building, devising and implementing a systematic plan for repairing, rejuvenating or replacing the existing systems, and finally creating operations and maintenance practices to assure continued functionality of the systems". Starting with program results estimates from the 4th Plan, we calculate potential savings of 16 aMW by 2010, 26 aMW by 2020, and an average levelized cost of 1.6 cents/kWh.

2.3.2 Lighting

Commercial lighting improvements are an important part of virtually any energy efficiency portfolio. Commercial lighting improvements can run the range from using more efficient bulbs (compact fluorescent versus incandescent, or just using higher-efficiency fluorescent bulbs) and ballasts for fluorescent fixtures, to improving fixtures themselves, using lighting controls that shut off lights in unoccupied rooms or adjust lighting levels for the amount of incoming daylight, and other enhancements. Lighting improvements often result in a reduction in air conditioning/ventilation use as well, as the less energy is used in lighting, the less heat must ultimately be removed from the building (Sezgen and Koomey, 1998). During the heating months, of course, lighting efficiency gains may results in additional heat needs, but these are often modest when compared with cooling savings, particularly in the larger buildings where major lighting efficiency improvement opportunities exist.

In order to simulate the impacts of a commercial lighting initiative, we have estimated the savings potential of two sets of measures: the replacement of standard fluorescent bulbs and ballasts with higher-efficiency bulbs and ballasts, and a package of advanced lighting measures.

- **Fluorescent Bulbs and Ballasts**: Replacing standard bulbs and ballasts in the four-foot fluorescent fixtures that are most common in office and other applications with high-efficiency bulbs and ballasts produces significant savings. [33] Assuming that this measure is used to address about 32.5 percent of total lighting energy use by 2020[34], we estimate an achievable potential savings of 72 aMW by 2010 and 146 aMW by 2020, at a cost of about 1.2 cents per kWh saved.
- **Advanced Lighting Measures**: Based on the results of a study prepared for a consortium of state, federal, and business organizations, we estimated the impacts of the application of a package of "emerging" lighting measures (Nadel et al, 1998). These measures, ranging from use of daylighting to lighting controls to the use of advanced bulbs and fixtures, offer average energy savings over standard practice of more than 50 percent. Assuming, as with the more standard fluorescent lighting measure, that this package of technologies is applied to 32.5 percent of forecast lighting energy use by 2020, we estimate savings of 209 aMW by 2010, and 422 aMW by 2020. These savings are achieved at an average cost of 2.6 cents per kWh.

By way of comparison, the sum of the savings from these measures by 2010, as estimated above, is similar in magnitude to the savings estimated for a group of "Economic/Moderate Potential" measures evaluated by Xenergy, Inc. for the Alliance (Xenergy, 2000). The study by Xenergy and other groups estimated savings of 232 aMW in existing and 41 aMW in new commercial buildings.

2.3.3 Refrigeration

Commercial sector refrigeration ranges from large refrigerators not much different from residential units to cold cases in grocery stores to walk-in or building-sized cold storage rooms or freezers to beverage vending machines. Commercial refrigeration, unlike residential, has not been subject to national standards. Options for improving the energy efficiency of refrigeration systems in the commercial sector include improving door seals, compressors, insulation, and controls. We separately modeled measures having payback times of less than two years ("lower-cost measures") and those offering paybacks of between two and five years.[35] According to DOE research, the lower cost measures, alone, could reduce refrigeration energy use by from 45-55 percent.[36] Assuming that the two measures jointly address 75 percent of refrigeration electricity demand by 2020, and that lower-cost measures address 70 percent of the total penetration by both measures, we estimate that lower-cost refrigeration efficiency improvement measures could save 29 aMW by 2010, and 57 aMW by 2020 at an average cost of

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[33] In this case, we assumed as standard practice 34 W, four-foot fluorescent tubes with "Energy Efficient" ballasts would be replaced by "T-8" bulbs with electronic ballasts, yielding energy savings of over 20 percent. In applying this current energy efficiency improvement over 2002 to 2020, we are implicitly assuming that as the standard technology improves, even better higher-efficiency technologies will become available, at costs similar to today's costs per unit of energy saved.

[34] We assumed that the two commercial lighting measures combined could address a combined 65% of lighting energy demand by 2015. Each measure was assumed to address half of the total, and to be phased in at 2% in the first program year (2002), and 4.5%/yr in the program years thereafter.

[35] Estimates for refrigeration measures are derived from Arthur D. Little (1996).

[36] As cited in Kubo et al, 2001.

0.9 cents per kWh, while "higher-cost" measures could save 16 aMW by 2010 and 31 aMW by 2020 at an average cost of 1.7 cents per kWh.

2.3.4 General Operations and Maintenance

Unless well operated and maintained, building equipment rarely performs as advertised. This unsurprising observation applies equally to the efficient technologies discussed here and less efficient ones that they may (or may not) replace. Pacific Energy Associates reviewed the literature on O&M savings and concluded that, in the commercial sector, good O&M program design save 14 percent of building energy, at 2 cents per kWh (Gordon and Miller, 1996). If other efficiency “hardware” measures are introduced, such as the improved lighting and refrigeration technologies described above, the amount of available O&M savings is reduced. However, Gordon and Miller note that even where other efficiency options are tapped, improved O&M practices should save 3 percent of commercial energy.[37]

There have been a number of building O&M programs around the country, including audits and training of building operators, some within the Northwest. However, Gordon and Miller estimate that only 20 percent of commercial buildings have captured these potential O&M savings. We assume that a concerted, ambitious effort to transform building maintenance practices through out the Northwest could reach 60 percent of the remaining commercial buildings by 2010, saving nearly 1.5 percent of commercial electricity use (80% x 60% x 3%). Total savings come to 75 aMW in 2010, and grow to 79 aMW in 2020, counting new commercial building loads, at 2.4 cents per kWh saved.

2.3.5 Miscellaneous Measures

This category accounts for 8.5 percent of total sectoral demand by 2000, should rise to about 11 percent of commercial demand by 2015 (NPPC, 1998). As such, the rate of growth in forecast electricity use in this "end-use" is higher than for any other end-use in the sector. Miscellaneous end uses including the important category of office electronics (including "data centers" or "server farms", copiers, computers, monitors, and printers), laundry machines, and other devices. We have investigated two specific measures within the miscellaneous category: high-efficiency transformers for commercial applications, and high-efficiency clothes washers for commercial laundries, and have also prepared, based on a recent national study, an estimate for potential energy efficiency improvements from data centers.

- **Transformers**: In larger commercial buildings, transformers are used to "step down" high-voltage power from the electrical grid to usable lower voltages. Transformer losses are not substantial, but as each kWh of electricity used in a building typically must pass through a transformer, even a small reduction in losses improves the energy-efficiency of the entire building. We estimate that upgrading commercial-sized transformers to a "TP-1" standard could save approximately 5 aMW by 2020, if 30 percent of commercial consumers purchasing transformers choose these higher-than-standard-efficiency units (ORNL, 1997). These savings are achieved at a cost of approximately 1.3 cents per kWh saved.

[37] Gordon and Miller (1996) cite a technical potential study done for BC Hydro. One might argue that the reduced savings would lead to higher costs per kWh saved. On the other hand, adding O&M components to an already major conservation program may have a much lower incremental cost (e.g. benefiting from common site visits, etc.).

- **Clothes Washers**: Upgrades in commercial clothes washers, as with residential washers, can yield significant energy savings in water heating and clothes drying, as well in the washer itself. Analysis suggests that 35 percent energy savings are possible at a modest incremental cost (ACEEE, 2001). Assuming incentives in 2003 leading to national standards by 2007[38], we estimate 10 aMW of savings by 2020 are possible at a cost of 3.0 cents per kWh saved.

- **Internet Data Centers**: As of 2000, data centers – facilities hosting banks of computer servers, often referred to as "internet hotels" – accounted for an estimated 0.15 to 0.2 percent of national electricity demand (Beck, 2001). Assuming the Northwest were representative of the national average, data centers would have consumed approximately 27 aMW in 2000. According to a recent report, it may be possible to improve the energy efficiency of data centers by up to 52 percent through a combination of measures such as improved processor efficiency, improvements in the electronics of server accessories, lighting improvements, and data center HVAC system upgrades (Beck, 2001). Data centers are projected to be an extremely fast-growing element of the commercial sector. Though estimates of growth in the use of data centers made in previous years may be overstated (one study projected growth from 9.5 to 25 million square feet nationally in the 2000 to 2003 period), given the recent slowdown in the world, national, and regional economies, we make the rough estimate that baseline electricity use by data centers will grow at an average rate of approximately 12 percent annually though 2010, and then 7 percent annually through 2020. At this rate of growth, a package of data center energy efficiency measures like those suggested by Beck (2001)–including improvements in server component efficiency, improvements in chiller and air conditioning systems, air handling system improvements, and balance-of-system improvements–would yield savings of about 40 aMW in the Pacific Northwest by 2010, and 79 aMW by 2020[39]. Though there are still no studies on which to base cost estimates, anecdotal evidence suggests that efficiency improvements are likely to be quite cost-effective.[40]

[38] E.g. California recently approved new standards for commercial clothes washer standards.

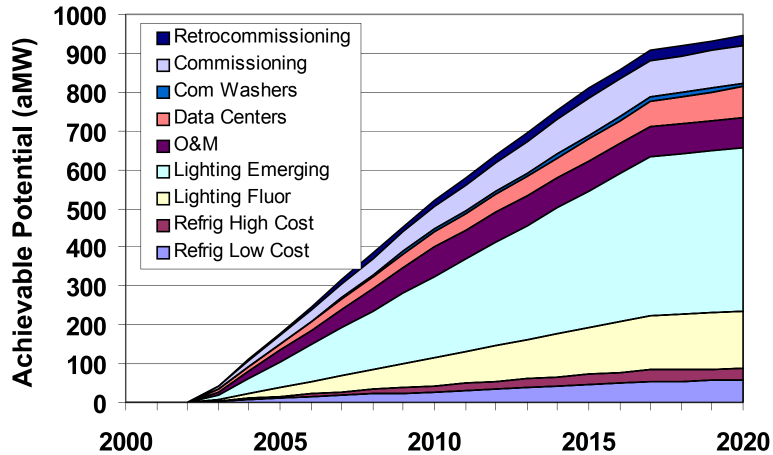
[39] This calculation assumes that all data center baseline energy consumption plus growth is reduced by 52 percent in 2010 and 2020. At the rates of growth indicated, without any change in energy efficiency, data centers in the Pacific Northwest would consume about 165 aMW by 2020.

[40] Lower wattage computer equipment and greater use of ambient air cooling should enable significant downsizing of HVAC and power-supply systems, which may more than pay for any incremental costs of efficiency gains. Effective implementation will need to address the current high mobility of data centers, as they may readily move to other commercial sites depending on utility costs and other factors, providing a disincentive for site-specific investment. For the purposes of overall benefit-cost analysis and plotting the efficiency options on the cost curve, we assume costs will equal benefits on a net present value basis.

2.3.6 Commercial Sector Cost and Savings Summary

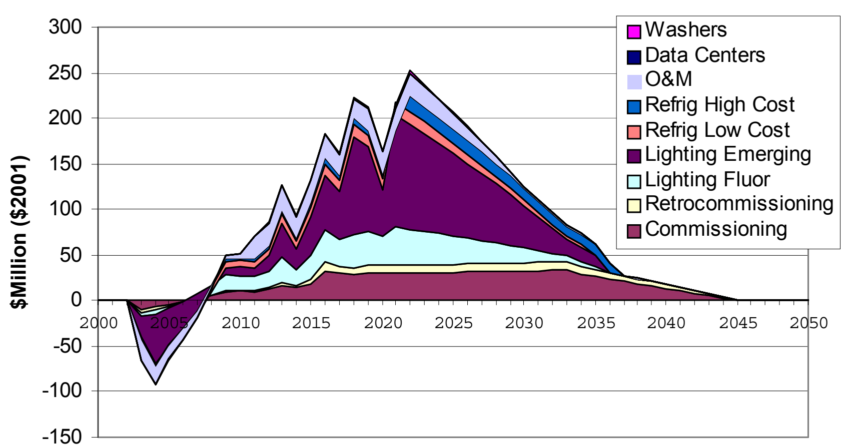
The above commercial measures result in approximately 524 aMW of savings by 2010 and 945 aMW by 2020, as illustrated in Figure 2-5. These measures, if implemented, stand to reduce commercial electricity use by 9 percent in 2010 and 15 percent in 2020. Over half of these savings come from commercial lighting improvements. And due to the study limitations noted above, calculated savings in heating, cooling, and ventilation amount to only 10 percent of the total savings, despite comprising over half of commercial demand. Further investigation of the commercial HVAC and building shell opportunities, such as those listed above, could reveal far greater cost-effective savings.

Figure 2-5. Commercial efficiency savings to 2020



Even with the limited scope of this commercial analysis, the overall cost savings from these measures is quite significant. Absent the large amount of high cost measures like the water heating ones considered for the residential sector, the commercial sector begins to see net savings accrue much earlier. As illustrated in Figure 2-6, the package of commercial efficiency investments turns a profit in 2007, within 4 years of first program start-ups in 2003. Annual savings rise to $52 million per year in 2010, peak at over $166 million per year before declining as new efficiency investments cease. The cumulative lifetime NPV benefit is $1.2 billion without and $1.8 billion with the inclusion of external cost benefits.

Figure 2-6. Net annual benefits, commercial sector measures



2.4 Industrial and Other Sectors

The industrial sector is the single largest consumer of electricity in the Northwest, accounting for 7874 aMW or 38 percent of regional demand in 1999. Of this, 3000 aMW was consumed by the direct service industries (DSI) in 1999, largely by the aluminum plants with BPA contracts that have cut most production since the 2000-2001 wholesale electricity price hikes. For the purpose of analyzing efficiency potential at aluminum facilities, we use the Council's 4th Plan DSI forecast (approximately 2100 aMW throughout the period). However, it appears increasingly unlikely that the aluminum production will return to this level. Other industrial subsectors with significant electricity consumption in the Northwest include pulp and paper, electrical, chemicals, machinery, food processing, lumber, and rubber.

National studies have shown that over half of industrial electricity consumption is used to drive motors. Lighting, refrigeration, and space conditioning account for a much smaller fraction of electricity consumption than in the commercial sector. Industrial process-specific electricity uses, such as silicon chip processing or melting of metals, account for much of the remainder of industrial electricity demand. We sought to address as many of industrial options as possible, but this industrial sector is plagued by very limited data, often due to proprietary concerns. Our analysis looked at the following six measures:

- **Motors Efficiency Improvements**: Industrial motors efficiency can be improved in several ways: by replacing failed motors with premium (highest efficiency) instead of standard models, by substituting premium motors where motors would otherwise be rewound, and by downsizing motors to appropriate capacity for the systems they power. These types of improvements typically save only 1-4 percent of motor electricity requirements, but when applied across the large number of industrial motors, the savings can be considerable. Drawing from a motors study done for the Northwest Energy Efficiency Alliance (Easton and Xenergy, 1999), we estimated potential electricity savings from each of these three efficiency improvements. Assuming that a motors initiative could reach 65 percent of motor electricity demand within 8 years, the estimated electricity savings would be 126 aMW by 2010 and 148 aMW by 2020.[41] The average cost of these improvements is 1.4 cents per kWh saved.
- **Motor System Improvements**: Even greater savings of motor electricity use can be achieved by modifying the design and operation of systems that motors drive: air compressors, pumps and valves, fans, and other systems (e.g. conveyors). Drawing from the Alliance study (Easton and Xenergy, 1999) and other sources[42], we evaluated the potential savings for improving each of these four types of motor systems, which can range from 5 percent for fans to nearly 20 percent for pumps and air compressors. Motor systems typically have longer lifetimes than motors, so achieving these savings will take somewhat longer, given the slower stock turnover. Assuming a 15-year average lifetime for motor systems, motor systems measures that reach 65 percent of motor electricity use would yield 209 aMW in savings by 2010 and 422 aMW by 2020, at an average cost of 1.3 cents per kWh.[43]
- **Industrial Transformers**: As in the commercial sector, we estimated the potential savings from replacing failed transformers in the industrial sector with high-efficiency "TP-1" compliant transformers instead of new standard units. Based on an initiative that

[41] The bulk of the savings come from replacing standard with premium motors.
[42] PacifiCorp reports and other Xenergy studies.
[43] 35 percent of the motors demand is estimated to be addressed by pump system measures, 39 percent by "other" system measures, and the remainder by fan and air compressor measures.

captures roughly 30 percent of the industrial transformer market each year, we estimate potential savings at 2 aMW in 2010 and 5 aMW by 2020, at a cost of about 1.3 cents per kWh.

- **Aluminum Production Process Improvements**: Primary aluminum production – as opposed to secondary production from recycled aluminum feedstocks -- is a very energy-intensive process that involves reducing bauxite ores to molten aluminum metal. Electricity is a major component of aluminum production costs, and indeed cheap electricity is what historically brought this industry to the Pacific Northwest. In the wake of the recent power price spikes, lower worldwide aluminum prices, and subsequent plant shutdowns, the future of the aluminum industry in the Northwest is more uncertain. However, if the aluminum industry does return to fuller operation, arguably these operations should be upgraded to take advantage of modern, cost-effective aluminum production methods. Inducing the aluminum companies to invest the necessary capital improvements in their Northwest plants rather than in other regions or countries where electricity and other production costs are lower will be a challenge.

  One of the key options for reducing electricity consumption per unit of aluminum produced is to retrofit aluminum production cells for higher electrolytic efficiency and lower heat loss. If aluminum production returns to levels similar to those forecast by the Council in their 4th Plan, and an average of 3 percent of aluminum production capacity is retrofitted each year, cell retrofits could save 90 aMW by 2010, and 210 aMW by 2020. Considerable reductions in O&M costs accompany these cell retrofits, so that they actually yield net benefits of 0.6 cents per kWh saved. Other technological advances are possible, such as advanced forming and near net-shape casting, which are designed to save energy by producing aluminum in shapes that are close to their final form, can provide considerable O&M and thermal energy (typically gas energy) savings, though typically small electricity savings.

- **Other Industrial Savings:** Literature, case studies and experts all suggest that considerable low-cost electricity savings can be found in industry-specific process and other non-motor improvements. However, relevant data on process improvements (e.g. silicon chip manufacturing) is often proprietary and hard to obtain, and the heterogeneous nature of manufacturing processes makes generalized estimates difficult. For similar reasons, the 4th Plan analysis was weak in this area. The recent Seattle City Light (SCL) efficiency potentials analysis is perhaps the only study in the region that has looked in a fairly detailed manner at other industrial savings.[44] This analysis found that achievable efficiency savings could exceed 25 percent of industrial demand, approximately half due to motor and motor systems measures akin to those described above. Excluding these, we took the remaining lighting, refrigeration, HVAC, and other options identified and extrapolated them, weighting sub-sectoral results to reflect the Northwest region's, rather than Seattle's, industrial profile. The resulting savings amount to 256 aMW in 2010 and 515 aMW in 2020. The cost of these measures averages about 2.0 cents per kWh. Especially given their potential size and low cost, a closer examination of these "other industrial" potential savings is called for.

[44] 2000 Seattle City Light Conservation Supply Curves, Industrial Sector, unpublished results and powerpoint presentation. Jeff Harris, personal communication.

- **Industrial Operations and Maintenance.** As with commercial buildings, improving the operations and maintenance of industrial facilities can save considerable electricity. Gordon and Miller (1996) conservatively estimated savings of 6 percent at 3 cents/kWh for industrial facilities. Using the same approach described above for commercial buildings, we estimate that O&M programs (audits, training, etc.) could save 31 aMW by 2010 and 35 aMW by 2020 for 3.5 cents per kWh.[45]

2.4.1 Other Measures

We also looked at two other measures that fall outside the main three sectors:

- **Irrigation Hardware, Scheduling, and Education**: Irrigation accounts for about 3 percent of electricity requirements in the Northwest. A number of irrigation measures can reduce electricity requirements, including improvements in hardware (improved pump efficiency, use of low pressure irrigation on center pivot systems, and redesign and modification of fittings and main lines so as to reduce friction losses), institution of systematic irrigation "scheduling" (management of the timing and amount of water applications throughout the growing season so as to reduce water use without reducing yields), and education in order to provide training and timely information to irrigators to enable them to reduce water and energy use (NPPC, 1996c). Analysis prepared for the 4th Plan suggests that these measures could save 29 aMW at a cost of 3.9 cents per kWh.[46]
- **LED Traffic Signals**: Light emitting diodes (LED) have been widely used in electronics for years, are now starting to find new lighting applications. As with LED exit signs (which we assume are already entering the market), long-lasting LED traffic signals, though they cost more per bulb than incandescent signals, dramatically reduce energy use (by 90%) as well as O&M costs. Although LED traffic signals do not produce the same amount of overall light as incandescent signals, the focused points of bright light produced by LEDs make them easy for the eye to pick out, and thus ideal for traffic lights and other signage. Based on a major study by Nadel et al (1998), we estimate that about 4 aMW could be saved with an LED traffic light initiative by 2010, and 10 aMW by 2020 assuming 60-80% of signals become LED.[47] The average cost of these savings is estimated at about 2.7 cents per kWh, but does not adequately reflect O&M savings. With O&M savings included, the net cost of this measure is strongly negative, even before consideration of energy savings.

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[45] We reduced the savings potential to 1.3% to account for interactions with motor and other hardware savings, using the same ratio between total potential (14%) and non-overlapping (3%) savings.

[46] The Alliance has initiated a program that has already captured some of these savings.

[47] This does not count savings for the one-half of (less expensive) red traffic signals already being switched to LED units.

2.4.2 Industrial/Other Sector Cost and Savings Summary

Together, the eight industrial and other measures yield 747 aMW of savings by 2010 and 1374 aMW by 2020, 11 percent of projected 2010 industrial and other electricity use and 14 percent of 2020 use. As illustrated in Figure 2-7, most of the savings come from the motor measures (43% of 2020 industrial savings), the roughly estimated "other end-use" savings (39%), and aluminum process improvements (16%). This package of measures could yield net economic savings as soon as 2006, as shown in Figure 2-8. Total cost savings come to $136 million in 2010 and $280 million in 2020, with cumulative lifetime savings of $1.4 billion.[48]

Figure 2-7. Industrial and other efficiency savings to 2020

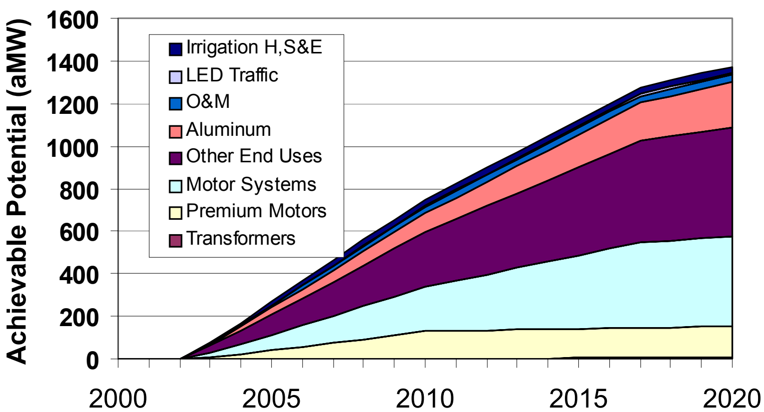
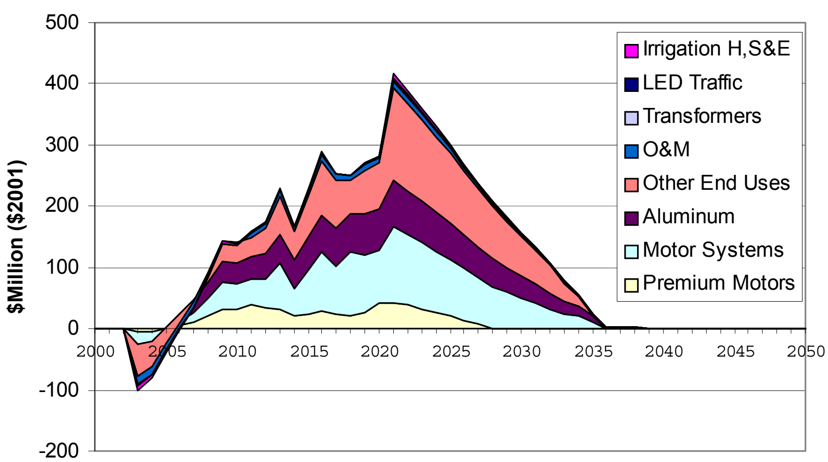


Figure 2-8. Industrial and other efficiency measure costs



2.5 Combined Heat and Power

From half to two-thirds of the energy used for fuel-based electricity generation is typically lost as waste heat. Combined heat and power (CHP) systems effectively capture this waste heat and supply it to a facility's process or building heat requirements, and can thereby approximately double the overall efficiency of fuel use to 80 percent or so. CHP systems can be as large as standard power plants, as is often the case for large industries and district heating systems, or small enough for small buildings and restaurants. They are typically optimized for either electricity generation or for heat delivery, depending on the heat demands of the particular

[48] If aluminum industry load is lower than the 2000 aMW assumed by the Council, then the savings would be reduced accordingly.

facility. CHP is a well-established technology, particularly in larger industries, and is in place in much of the region's refineries and paper and pulpmills. However, they are less ubiquitous in small industries and commercial establishments.

We investigated several types of natural gas-fired CHP systems in several size classes:

- **Internal Combustion Engines**: Internal combustion (IC) engines have been used in stationary power generation applications for a century or more, and are a very mature technology. Heat from gas-fired water-cooled IC engines can be captured from the engine's coolant system via a radiator, and used to heat or pre-heat air or water to help provide space or water heat. We incorporated three sizes of IC units into our commercial and industrial sector CHP estimates: 100 kW, 800 kW, and 3000 kW.
- **Combustion Turbines**: Conventional combustion turbines (CT) are a newer, but still quite mature, electric generation option, having been in wide use for decades. Here heat can be captured from the hot exhaust gases of the turbine via a heat exchange unit, and used for space or water heat, or (more likely) for process heat in industrial plants. We incorporated 10 and 40 MW combustion turbines into the industrial sector CHP initiative that we evaluated.
- **"Micro" Turbines**: Micro-turbines (MT) are self-contained CHP devices that are new on the market. These units, the size of a large household refrigerator (in the 30 kW size) produce heat and electricity using a high-speed but very reliable miniature turbine coupled to a generator. These units, recently commercialized, will be available in size classes other than 30 kW soon, but only the 30 kW units are included in our analysis.
- **Fuel Cells**: The first commercial fuel cells, rated at about 200 kW, are on the market now, and several highly promising designs are in the testing phase. Fuel cells produce power at very high efficiencies, with more power to heat produced than other technologies. Due to their current high cost, we have not included fuel cells in the initiatives evaluated here, but recommend that attention be paid to the development of this promising technology.
- **Steam-cycle CHP:** CHP using standard steam turbines is also available in several possible configurations, and is fairly widely used in the Northwest with natural gas and other fuels, notably including wood waste and related wastes (including "black liquor") from the lumber and pulp and paper industries. The addition of steam-cycle CHP capacity in the Northwest was not included in this analysis because combustion turbines are a less expensive technology, though such additions are possible and may be desirable options for some specific industry applications.

To develop our CHP estimates, we relied heavily on a recent U.S. Department of Energy study (Onsite Sycom, 2000). Our key input assumptions and results by sector are as follows:

- **Commercial CHP**: Our estimates of potential CHP in the commercial sector included 30 kW MT units, 100 kW IC units, and 800 kW IC units, with some of the units displacing grid electricity and heat from electric resistance boilers or water heaters, and other units displacing grid electricity and heat from gas-fired boilers or water heaters. CHP units were assumed to run 8000 hours per year in order to amortize capital cost over as much output as possible. We assumed that approximately 30 percent of the total estimated CHP potential (net of existing units) in the commercial sector could be tapped by 2020. As a result, commercial CHP could displace the need for 565 aMW in grid electricity requirements by 2010 and 1315 aMW by 2020. When the amount of electricity that could be generated using this gas in new power plants is deducted, the overall net electricity savings come to 207 aMW by 2010 and 462 aMW by 2020. The cost of electricity generated by these units is estimated to be 3.2 cents/kWh, with an overall benefit/cost ratio of 1.08.

- **Industrial CHP**: For the industrial sector, our estimate included 800 and 3000 kW IC units, and 10 and 40 MW CT units. All co-generated heat from these units was assumed to displace gas-fired boilers or process heating equipment. As in the commercial sector we assumed that about 30 percent of remaining CHP potential could be captured by 2020. We estimate that 365 aMW of grid electricity generation can be avoided by the use of CHP in the industrial sector by 2010, and 1031 aMW by 2020. Deducting the electricity this gas could generate at new combined cycle plants, the net savings come to 107 aMW by 2010 and 301 aMW by 2020. The average estimated cost of industrial sector CHP is 3.7 cents/kWh displaced. With a benefit/cost ratio of 0.92 (0.94 with externalities included[49]), electricity prices may need to be slightly higher (or gas prices lower) for the full package of industrial CHP to be cost-effective.

2.6 Summary of Findings

Table 2-3 and Table 2-4 show the total results of the sectoral analyses. They indicate that, together, the efficiency, fuel switching, and CHP measures examined here could reduce grid electricity demands by 12% in 2010 and 24% in 2020. The latter amounts to a reduction of nearly 6283 aMW. Of this 3542 aMW are pure electric efficiency investments, 73 aMW are saved by solar water heaters, and 2741 aMW are reduced by residential gas water heaters and commercial and industrial cogeneration units. If the added gas use were used in grid-based natural gas combined cycle units, they would deliver 1746 aMW, so the "net" savings of these investments (in lieu of the grid-based units using the same gas), is 4538 aMW (6283 -1746 aMW). See Appendix Table 7 for more details.

Table 2-3. Efficiency, fuel switch, and CHP measures - reductions by sector (aMW)

	2010		2020	
Sector	**aMW**	**% savings**	**aMW**	**% savings**
Residential	568	7%	1618	18%
Commercial	1088	19%	2260	36%
Industrial	1079	13%	2365	24%
Other	33	4%	39	4%
Total Demand Reduction	**2768**	12%	**6283**	24%

[49] Since the CHP units produce net electricity with less gas than a new combined cycle plant, CO_2 emissions are reduced. However, net nitrogen oxide emissions could be higher, and possibly problematic if the units are located in urban areas with pre-existing NO_x pollution problems. In those locations, low-NO_x technologies should be promoted.

Despite the high-cost water heating measures, the overall package of investments analyzed here could provide the Northwest with cumulative discounted savings of $2.8 billion, as shown in Table 2-4. Annual benefits are only modest ($1 million) by 2010, largely because of the continuing investment in new equipment purchases, particularly for high cost solar, condensing gas, and heat pump water heaters. Should these technologies decline significantly in cost, as might be expected with greatly increase production and competition, the savings could be much higher overall. The monetized benefits of avoided pollutant emissions ($2.6 billion) nearly double the social benefits to $5.5 billion overall.

Table 2-4. Regional Economic Savings (million $2001)

Sector	Annual Benefits		Cumulative NPV Benefits		
	2010	2020	to 2020	to 2050	to 2050 (w/externalities)
Residential	($171)	$81	($938)	$131	$1,446
Commercial	$75	$172	$530	$1,423	$2,190
Industrial	$94	$227	$812	$1,189	$1,847
Other	$2	$2	($2)	$14	$43
Total	**$1**	**$482**	**$402**	**$2,755**	**$5,528**

3. RENEWABLE RESOURCE OPTIONS

Our analysis of renewable electricity supply options includes wind, biomass, and geothermal resources, which are likely to be the most abundant, cost-competitive resources for large-scale grid applications in the region during the timeframe of this analysis.[50] As with our efficiency analysis, the Council's 4th Plan provides the starting point. The key elements of our renewables analysis include:

- use of a recently released comprehensive wind resource assessment for the region, and current data on wind turbine costs, performance, and system integration (shaping and transmission), to develop a cost curve (in cents per kWh delivered) for ramping up wind generation to 10-20 percent of regional load by 2020.
- updated figures on the regional availability of landfill gas and biomass residue opportunities for co-firing of biomass at the region's coal plants, and the potential for cost-effective and efficient uses of biomass through accelerated development of biomass gasification combined cycle technologies.
- updated estimates of developable geothermal resources in the region.

The solar photovoltaic (PV) industry is growing rapidly, and there are many market niches in which this technology is already making inroads. Examples include off-grid supply and on-grid distributed applications where costly distribution system upgrades are required.[51] Even though costs should continue to drop from their current levels of 25-50 cents per kWh, larger grid-scale solar PV systems are unlikely to produce electricity competitive with the other resources considered here within the next two decades.[52] For this reason, we have not considered solar PV electricity in our analysis. Nonetheless, there are strong reasons to promote solar electricity within the region: 1) niche markets can be more fully developed through pricing strategies that reflect the true value of solar PV generation (e.g. hot sunny days are often when demand is highest in the West); 2) strong distributed markets (e.g. rooftop systems) could help drive down costs; and, 3) where there are strong solar and related manufacturing industries, increased solar development could bring jobs and economic benefits. Furthermore, beyond the 2020 time horizon of this study, solar technologies could be central to the development of an indigenous sustainable electricity system.

Due to resource constraints, this study did not evaluate the potential for other distributed renewable generation technologies such as small wind turbines or fuel cells using biomass fuels or hydrogen generated by wind or solar sources. Distributed renewables can relieve distribution and transmission system congestion, improve power quality, and reduce peak power demands on the system. These technologies deserve more in-depth evaluation.

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[50] We did not analyze the potential for additional hydro development, given the limited amount of remaining resource and the difficulty in assessing impacts on fish, habitat, recreation, and other environmental services without site-specific analysis.
[51] Though the resource is strongest in less-populated areas, such as Southeast Oregon and Southwest Idaho, the solar resource is still sufficient for distributed applications throughout the Northwest.
[52] Under some projections grid-scale PV electricity costs might drop to 15-20 cents per kWh by 2020 (ELPC, 2001).

3.1 Wind

Wind energy is the fastest growing source of electricity in the world today. In recent years, installed wind capacity has grown 25-30 percent annually. With 3500 MW added in 2000, the world total is now close to 17,000 MW, a number equal to almost half the electricity generating capacity in the Northwest.[53] Wind technology has emerged from the demonstrations and boom-bust cycles of 1980s to become a robust and competitive force in many electricity markets, most often spurred on by supportive policies such as the European feed-in laws (guaranteeing a near-retail electricity price to generators) and renewable portfolio standards here in the US. European countries, most notably Denmark and Germany, have become leaders in wind power development, with wind expected to provide 18 percent of Danish electricity this year, and 21 percent by 2003.[54]

The US continues to lag behind in wind development, but recent initiatives promise continued growth. As a result of RPS policies, Texas will likely see 2000 MW of new wind this decade, and other states like Minnesota are seeing several hundred MW under development and more planned. With a strong resource and recent upsurge in activity, including startup of the 263 MW Stateline project on the Oregon/Washington border, the Northwest is establishing itself as a major region for wind power development.

Today, wind generates less than half a percent of the region's electricity, but there is considerable promise for far more. Acall for proposals by BPA in 2001 generated over 2500 MW of bids from wind developers at near market prices. Wind technologies continue to improve, with performance improving, costs dropping, and concerns about excessive noise and avian mortality fading.[55] The potential for both large utility-scale and smaller distributed applications has stirred strong interest among utilities, developers, and rural landowners throughout in the Northwest. At the same time, because of the often long-distances between good wind resources and major load centers, and congestion and under-investment in the transmission system, wind development faces some challenges as well.

To help inform both communities and developers, Northwest Sustainable Energy and Economic Development (NWSEED) recently commissioned a detailed wind resource assessment for the four states by TrueWind Solutions, using their MesoMap modeling system.[56] We worked with TrueWind to convert wind resource measurements into aggregate state-level resource data, and then applied resource constraints, current estimates of wind technology prices and performance, and the added costs of transmission and backup power required for this intermittent, lower availability resource.

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[53] http://www.awea.org/utilityscale.html
[54] http://www.windpower.dk/news/
[55] National Wind Coordinating Council as cited in ELPC, 2001. Modern blade design produces far less noise than its predecessors. The move to tubular towers avoids the lattice and other structures that invitie birds of prey to perch. Proper siting is also important in minimizing avian and other wildlife impacts.
[56] The MesoMap system provides validated method for simulating complex meteorological phenomena – e.g. mountain/valley winds, low-level nighttime jets, temperature inversions, surface roughness effects, flow separations in steep terrain, and channeling through mountain passes -- not adequately represented in standard wind flow models, and of particular importance in the Northwest. See Michael Brower, Bruce Bailey, and John Zack, "Applications and Validations of the MesoMap Wind Mapping System in Different Climatic Regimes", Proceedings of Windpower 2001, American Wind Energy Association (2001).

As with other wind resource estimates in the past, the TrueWind analysis reveals more overall wind resource than is likely to be developed within the coming two decades. A widely cited Pacific Northwest National Laboratory study found 133,000 aMW available in the Northwest.[57] The TrueWind figures indicate a total potential of 76,000 aMW.[58] Three factors limit achieving this full potential. First, the unpredictability of the wind resource means that until new means of storing wind electricity are brought to the market (e.g. compressed air, conversion to hydrogen), wind resources may incur cost penalties once it supplies more than 20 percent of the region's electricity. At the same time, the region's extensive storage hydro facilities, depending on how much operational flexibility remains, might enable a higher fraction of wind to be supported in the Northwest, especially compared with other regions.[59] Second, some good wind sites may pose concerns related to aesthetics, cultural and environmental impacts, competing land uses, or preservation of undeveloped lands. Third, as noted above, many of the region's best wind resources are located in areas far from major electricity demands and limited in existing transmission capacity.

To address these constraints, we excluded some land types altogether, such as local, state and national parks, lands above 1800m (6000 ft.) in elevation (due to limited site accessibility), water bodies[60], and lands over 20 miles from a transmission line.[61] We then considered only wind sites categorized as Class 4 and above, even though much more abundant Class 3 sites could be developed, especially close to load centers. Finally, we restricted to 25 percent the wind potential within each class that would be developed.[62] This further restriction reflects the fact that some sites may be inaccessible due to local concerns or competing land uses, as noted above.[63]

The result of applying these assumptions to the TrueWind wind resource analysis is illustrated in Table 3-1. Sixteen percent (162,613 km^2) of the total land area was excluded on the basis of high elevation, park status, or water bodies. The figures show the region holds over 72,000 km^2 of Class 4 or windier land, over 80 percent of this in Montana. Developing 25 percent of windy land in Idaho, Oregon, and Washington, and only 0.5 percent in Montana, our assumptions yield a total of 4,299 km^2 (1,660 mi^2) of developable wind sites. This is equivalent to 0.4 percent of land area in the 4-state region, and no more than 0.7 percent in any state (Washington). Typically less than 5 percent of this land would actually be occupied by wind turbines, electrical equipment, and access roads. Existing land uses, such as farming or ranching could continue on the remaining 95 percent (Elliott and Schwartz, 1993). Installation of wind turbines on this land

[57] Elliott et al. (1991) as cited by Renewable Northwest Project (RNP).
[58] This estimate assumes that all sites Class 3 and above are developed (with park and elevation exclusions noted below).
[59] There are differences of opinion on how much the region's hydro resource can be used to shape or absorb fluctuations in wind output due to the need to maintain adequate flow regimes for salmon,.
[60] The region's rugged and deep-water coastline is not particularly suitable for offshore wind development.
[61] In general, 20 miles was measured from 115 and 230kV lines, and in some instances, 69kV lines as well. Existence of transmission right-of-way is likely to be more important than the size of a line, since it will generally be easier and more desirable to upgrade a line than to site and clear a new transmission corridor.
[62] Most wind development today is occurring in class 5-7 sites, but the economics of class 4 sites are often comparable. Many Class 3 sites may be attractive as well, especially if suitably located, e.g. near demand centers.
[63] These figures are more restrictive than those used in a widely-cited Pacific Northwest National Laboratory study, which employed detailed, though equally judgment-based, exclusion assumptions by land use type (Elliott and Schwarz, 1993). That study found that 65 percent of the total windy land area (Class 4 or above) in the US would be accessible to development under a moderate land use scenario with full environmental exclusions. See http://www.nationalwind.org/pubs/wes/wes09.htm.

would yield 6000-7000 aMW of wind generation. Significantly more wind development, particularly in Montana, is certainly plausible, however, transmission is a significant constraint.

Table 3-1. Land areas considered for wind analysis (km^2)

	Idaho	Montana	Oregon	Washington	Region
Total land area	214,325	376,990	248,648	172,448	1,012,411
Excluded land (parks, water, or > 1800m)	72,709	61,255	15,575	13,073	162,613
Of the non-excluded land, area considered:					
Class 4	655	50,553	2,734	3,271	57,213
Class 5	151	8,311	705	1,021	10,188
Class 6	69	3,351	312	539	4,271
Class 7	12	529	56	130	728
Total Class 4-7	888	62,744	3,808	4,961	72,400
Class 4-7 land included in cost curve below	222	1,885	952	1,240	4,299
Percent of total land area	0.1%	0.5%	0.4%	0.7%	0.4%

To calculate the cost of wind power generation at these sites, we applied the assumptions shown in Table 3-2. We assumed estimated capital and O&M costs (ELPC, 2001) for construction in 2010, the midpoint of our analysis period.[64] We looked at costs both with and without federal production tax credit, which has been instrumental in wind growth in the US and was recently extended through the end of fiscal 2003. The production tax credit provides a benefit of 1.7 cents per kWh for 10 years, which amounts to 1.3 cents per kWh on a real levelized basis.

Table 3-2. Key technical assumptions for wind analysis (for installations in 2010)

Parameter	Value	Units/Notes
Average size	100	MW
Land requirements	0.2	Km2/MW (nominal)
Installed capacity Cost	$900	Per kW
Operation and Maintenance Cost	0.5	cents per kWh
Avg. Capacity Factor (Class 4)	30.9%	result of wind assessment, includes losses and
Avg. Capacity Factor (Class 7)	37.6%	varies by location
Local Transmission	$135,000	$/mile
Cost of Transmission Substation	$1.5	Million $/per windfarm
Value of federal production tax credit	1.3	Cents/kWh (levelized value)

Because of their intermittency, wind plants may incur extra costs to provide power with reliability value similar to that of a traditional, dispatchable thermal power plant. There is

[64] Costs for current construction might be slightly higher, but given that early activity will be concentrated at the best wind sites, which increases the performance (capacity factor), costs may be similar. Unlike some renewables cost studies, capacity factor in our analysis is not an assumption, but rather a result, based on the wind characteristics of each location. This provides some improved precision and accounts for much of detail seen in the wind cost curve below.

presently no simple way to determine the added cost of backup generation and transmission[65]. One can calculate the cost of building backup capacity and beefed up transmission, which comes to about 0.8 cents per kWh for 10% penetration of wind generation in a given system. [66] An alternative approach to estimating the intermittency and transmission costs is to look at how these costs are being assessed in contracts in today's regional generation market. Utilities typically like to buy a "shaped" wind product, i.e. wind generation that is made to resemble the performance characteristics of a conventional thermal generation facility as closely as possible. If strictly interpreted, this approach can imply contracting, along with the wind generation, for hydro or thermal facilities that operate only as backup capacity when the wind does not blow – a potentially expensive proposition and one that is often unnecessary since excess generating capacity is often available across the system. In addition to backup capacity, shaping/ancillary charges include the costs of bulk transmission and other miscellaneous items.[67] Shaping/ancillary charges have been getting lower as utilities get used to buying wind electricity, and analysis have shown that earlier estimates were excessive. These charges are currently about 0.8 cents per kWh in the Northwest, a value we adopt in this study. [68]

[65] Wind resources must also compete with other resources for access to transmission capacity. Due to their lower capacity factors , they may be more costly to transmit on a per kWh basis. However, these and other transmission costs are still poorly understood, the subject of ongoing research and debate by the Utility Wind Interest Group, BPA, and other utilities. For a good general discussion of the issues, see http://www.nationalwind.org/pubs/wes/wes09.htm.

[66] Based on research conducted by the National Renewable Energy Laboratory (Milligan, M. Measuring Wind Plant Capacity Value, http://www.nrel.gov/wind/windsta1.html) one can assume that at low penetrations, wind plants have the reliability value of a conventional thermal plant times the wind plant's capacity factor (30-40%). This reliability value then declines to zero as wind reaches 10 percent penetration of the grid system. In other words a 50 MW wind farm that operates at 30% capacity factor, has the reliability value of about 15 MW of a standard, dispatchable power plant. As wind supplies more of the electricity in a region, the incremental capacity value of each new wind development declines, as wind resources tend to be spatially correlated (low wind periods will tend to have more of an impact) and the need to back up the wind with other capacity increases. On the other hand wind development across many different sites in the region can provide some temporal diversity benefits (ELPC, 2001). The result is a backup cost of about 0.7 cents per kWh at 10 percent wind penetration. This figure represents the cost of building a new gas single-cycle combustion turbine as backup (1 MW CT for every 1 MW wind), plus some incremental fuel costs. Bulk transmission costs come to about 0.1 cents per kWh, assuming an average cost of $75/kW to upgrade existing transmission corridors (ELPC, 2001).

[67] Such as reactive voltage control and other modest cost items.

[68] Deb Malin, Bonneville Power Administration, personal communication.

Figure 3-1. Wind Resource Cost and Potential (with and without Production Tax Credit)

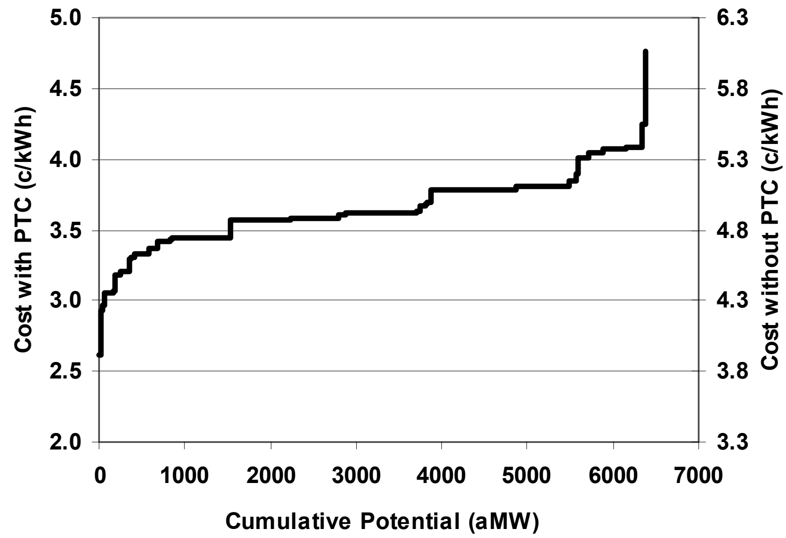

Figure 3-1 shows how wind cost varies with the extent of development (in aMW), and with and without the production tax credit (left vs. right axes). The results in costs ranging from about 3-4 cents per kWh with the tax credit and 4.3-5.3 cents per kWh without. It shows that up to 2500 aMW, or about 10 percent of 2010 regional generation requirements, could be available at average costs of under 3.5 cents per kWh with the production tax credit and under 5 cents per kWh without. Together the approaches suggest that wind could supply 20 percent of the region's power (5600 of 28,000 aMW by 2020) at an average cost in the range of about 3.6 cents per kWh.[69]

Table 3-3 shows that, of the 6437 aMW wind potential illustrated in the cost curve, over half is located in Washington and Oregon, and 40 percent comes from Montana. Compared to what is shown here, more wind development closer to loads in Washington and Oregon is certainly possible, especially if there is greater use of distributed wind generation and more abundant Class 3 sites.

Table 3-3. Wind potentials, by state and power class (aMW)

	Power Class				
State	**4**	**5**	**6**	**7**	**Total**
ID	212	58	28	6	**303**
MT	2090	412	181	30	**2714**
OR	1016	292	144	30	**1482**
WA	1235	418	228	56	**1938**
Total	**4553**	**1180**	**582**	**122**	**6433**

3.2 Biomass

Biomass energy is already used widely in the Northwest. Pulp and paper mills produce considerable amounts of process steam and over 100 aMW of electricity from wood residues, and another 400 aMW from black liquor residues (spent pulping waste). Solid waste landfills capture and burn methane to generate electricity in Goldendale, Spokane, Eugene, and elsewhere

[69] As wind penetration rises, shaping charges could rise, but wind costs could also fall. A cost of $660/kW and a 7% improvement in wind turbine capacity factor are possible by 2020, which would reduce wind generation costs by as much as 1 cent per kWh (ELPC, 2001).

in the region, currently amounting to another 20 aMW. However, the potential resource is far greater, not just from landfill and milling, but from the region's agriculture and logging activities, which all produce vast quantities of residues. In addition, poplar plantations are a growing source of pulpwood, producing significant amounts of bark and other combustible waste products often near regional load centers or existing power plants, not to mention a potential energy crop itself. Expanding the use of these resources for electricity production could provide substantial economic as well as environmental benefits, the latter assuming that biomass energy use does not stimulate expanded logging activity. Studies show that biomass facilities create jobs because of the labor-intensiveness of agriculture and forest products (relative to other energy resource) industries, and bring money to rural areas where the fuels are produced.[70]

As a first step in our biomass assessment, we commissioned an updated biomass resource analysis to develop estimates of cost and availability of different residue types by state.[71] This analysis considered residues from mill operations, logging, agriculture, and forest health[72] activities[73]. We then constrained the use of logging, agricultural, and forest health residues given potential environmental concerns (maintenance of soil structures, limiting road use in forests, etc.). Cost estimates, which are shown in Appendices A and C, also include transportation to move resources from fields and forests to central power generation sites, a potentially significant component of the overall costs. We then adapted USEPA data to assess landfill methane that could be economically captured and combusted for electricity.[74]

Biomass-to-electricity options can be divided into those with near-term and longer-term potential. The most promising near-term options for increasing biomass use are additional landfill gas generation and the use of available residues in existing power plants. The latter approach avoids the high cost of building new power plants specifically for burning biomass. The cost of power plants sized and suitable for burning biomass feedstocks, which are typically uneven in size and moisture content, can be significantly higher than those designed to burn other fuels, particularly oil and gas. Thus we looked at the following near-term opportunities:

- **Co-firing.** Biomass is now being burned in numerous coal plants across the US, in various boiler types including those in use here in the Northwest. Biomass co-firing offers major economic and environmental advantages. Since every BTU of biomass burned displaces nearly a BTU of coal, the attendant emissions benefits can be significant, not only for CO_2, but for sulfur and nitrogen oxides as well. The costs of adding the necessary storage, drying, and processing facilities at the coal plant are far lower than the costs of building a new biomass power plant. In addition, the efficiency of

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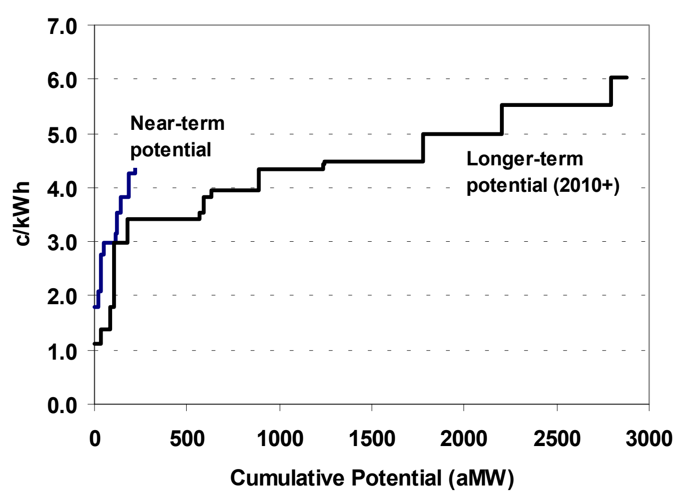
[70] See Union of Concerned Scientists et al (1993) as cited in ELPC (2001).
[71] This analysis was conducted by Jim Kerstetter of Washington State University's Energy Program and is described in more detail in Appendix C
[72] See Sampson et al, 2001 for a discussion of issues related to "forest health" activities and biomass energy production, which are aimed at overcoming the impacts of decades of fire suppression in forests. "Treatment to return forests to a more fire-tolerant condition involves removing excess fuels and introducing prescribed fire when conditions allow low-intensity burns." Fuel extraction would need to be limited to areas where roads already exist, and land use plans are unaffected (e.g. potential future wilderness areas, etc.) in order to address environmental concerns. As a result, the estimated forest health resource considered here is a fraction (40%) of the potential estimated in the resource assessment (Appendix C).
[73] Dedicated energy crops are generally higher-cost resources than residues. They could become an important resource for transportation fuels in the near-term and electric generation power in a few decades.
[74] Personal communication, Brian Guzzone, USEPA Methane Outreach Branch.

large coal plants is far superior to that of the typical smaller boilers in which biomass is often burned. We looked specifically at the opportunity to cofire biomass at the two major coal plants located with the PNW, Centralia (WA) and Boardman (OR). Experience with existing co-firing facilities suggests costs on the order of $50 (for cyclone boilers) to $200 (for pulverized coal boilers) per kW of biomass capacity, and $10/kW-year for additional O&M costs (Tillman et al, 1998; Plasynski et al, 1999). For this analysis, we assumed that a combination of resources would be delivered to the coal plants, including unused mill, forest health, agricultural residues, and waste materials from nearby poplar plantations (in the case of the Boardman coal plant). Assuming a 10 percent cofire rate and accounting for the heat rate (efficiency) penalties for substituting biomass for coal, the total amount of biomass capacity at the two coal plants comes to about 160 aMW. Cofiring could provide electricity at from 1 to 4 cents per kWh, depending on the biomass resource used.

- **Recommissioning older boilers.** Scattered about the region, there is about 40 aMW of older steam turbines that are currently not in operation, but might be recommissioned given suitable incentives. We assumed that residues could be burned in some of these plants as a near-term measure to develop biomass supply market, in anticipation of improved biomass generation technologies, generating electricity at a cost of 4 to 5 cents per kWh.
- **Landfill capture and generation.** Based on recent data from the USEPA Methane Outreach Office, we compile a list of the major landfill sites in the Northwest (See Appendix A). To generate electricity at a landfill, two principal investments are required: a methane collection system and generator, typically a simple reciprocating engine. For health and safety and local air pollution control reasons, larger landfills are already required by the federal Clean Air Act to install methane collection and flaring systems. Thus larger landfills can be set up as electricity generators for about $1300 per kW, while at smaller landfills the cost is closer to $1900 per kW. As shown in Appendix A, the region's planned and potential landfill gas generation sums to 97 aMW, and can produce electricity at costs ranging from 3.0 to 4.4 cents per kWh.

The commercialization of biomass gasification combined cycle (BGCC) technology could greatly expand the level of economically viable biomass energy use in the Northwest. Still under development and testing, BGCC technology promises high efficiencies, low emissions, as well as significantly lower capital costs for biomass generation. USDOE (2001) projects that by 2010, larger (100 MW) BGCC units could cost $1300 per kW with an efficiency of 38 percent. The cost of generating electricity from these units would be only about 2.6 cents per kWh

Figure 3-2. Cost Curve for Regional Biomass Electricity Options



plus the cost of the delivered biomass feedstock. When the costs of various regional residues are considered, the cost of BGCC generation comes to 3.4 to 6.0 c/kWh for up to approximately 2300 aMW of regional generation. Our detailed cost analysis, by state, residue type, and cost of delivery, is shown in Appendix B.

BGCC technology is especially promising for pulp and paper mills, where 400 aMW is already generated from black liquor wastes. Black liquor is typically burned in far less efficient boiler systems, and upgrading to gasification combined cycle technology could nearly double electricity output from the same feedstock amounts, while significantly reducing local air pollutant emissions. Assuming an incremental cost of upgrading existing black liquor boilers of $1000 per kW, we estimate that 349 aMW of additional generation could be obtained at a levelized cost of 4.3 cents per kWh.[75]

Table 3-4. Longer-term biomass resources by state and type (aMW)

Resource Type	Idaho	Montana	Oregon	Washington	Total
Agricultural Residues	337	0	105	1018	**1460**
Poplar Residues	0	0	213	218	**431**
Forest Residues	96	0	86	76	**258**
Logging Residues	36	3	21	26	**86**
Unused Mill Residues	34	11	80	74	**200**
Landfill Gas	2	0	36	59	**97**
Black liquor (more efficient use)	86	7	76	180	**349**
Total	**590**	**22**	**617**	**1652**	**2880**

Figure 3-2 charts the total near-term and longer-term biomass resource against our cost estimates. It shows that on a near-term basis cofiring, landfill gas, and use of existing boilers could yield nearly 230 aMW at costs ranging from 2 to 4.4 cents per kWh.. The longer-term development and commercialization of BGCC technology could increase the biomass potential nearly ten-fold to 2880 aMW at costs ranging from about 1 to 6 cents per kWh. Table 3-4 shows that nearly half of this new generation could come from agricultural residues.

3.3 Geothermal

With its recent volcanic activity and abundant hot springs, the Northwest would seem an ideal location for geothermal power development. Geothermal energy is used today for district heating systems in Boise and Klamath Falls, and by ground source heat pumps in several of the region's residential and commercial buildings. But large-scale geothermal electricity production, though the technology is well established and provides nearly 3000 aMW across the US, has yet to make a foothold here in the Pacific Northwest.

[75] Though we discuss more efficient use of black liquor here in the biomass section, the Coalition and RNP do not consider it to be a renewable resource, given its toxicity. This analysis does not increase the use of black liquor, it only changes the technology that is used for electricity generation to more efficient gasification combined cycle units.

At costs of 5 cents per kWh and higher, geothermal electricity has had trouble competing in this low-cost electricity region. Furthermore, geothermal development can present land use and siting challenges, since many of the potential resources are located in scenic, environmentally, or culturally sensitive areas, such as Mount Baker (WA) or the Alvord Desert (OR). Exploratory drilling for geothermal resources -- essential for determining whether resources suggested in geological models actually exist, and with sufficient volume and pressure to generate cost-effective electricity – has been limited over the past two decades.

Due to the large uncertainties and the lack of recent resource assessments, our analysis of geothermal resources was more limited in scope and depth than for biomass and wind resources. To assemble a simple potential assessment, we consulted existing studies and regional geothermal experts.[76] The 4th Plan analysis suggested that 340 to 3300 aMW of geothermal resources could be developed in the region at cost of 6 cents per kWh or less. According to data recently assembled by USDOE national modeling efforts (USDOE/EIA, 2002), about 1500-2000 aMW of resources are available for under 6 cents per kWh or so. However, these estimates rely on older studies, and in the case of USDOE include resources (such as Alvord Desert) that are not as likely to be exploited due to siting concerns.

Figure 3-3. Regional geothermal costs and potential

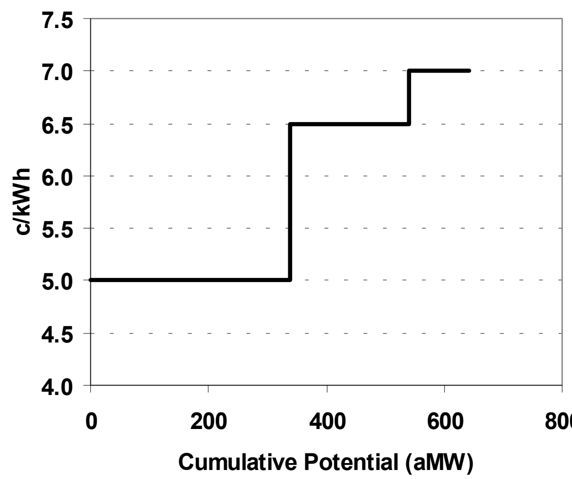


Figure 3-3 shows our more limited, and likely quite conservative, estimates of the available resource. It includes the larger resources where exploratory drilling or preliminary development (Medicine Lake highlands[77]) has suggested viable geothermal heat sources. Also included are about 100aMW at small lower-temperature sites, using binary-cycle plants.[78] The total potential shown here is 641 aMW with costs ranging from 5 to 7 cents per kWh.

3.4 Summary of Renewables Results

Three renewable resources – wind, biomass, and geothermal – could conceivably provide up to 35 percent of the region's electricity needs, as shown in Table 3-5. High penetration levels, especially for wind, may be difficult to reach given resource intermittency and transmission requirements. However, it is useful to bear in mind that Denmark plans to deliver 21 percent of its electricity requirements with wind in 2003. Ambitious targets for wind, the Danes and Germans have shown, are achievable.

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[76] These included Dave McClain, independent consultant, Gordon Bloomquist, WSU Energy Program and the database assembled for the USDOE's National Energy Modeling System, which is based on the last comprehensive USGS assessment done in 1979 (Circular 790) and expert opinion.
[77] In far northern California, it is within the BPA service region.
[78] Binary cycle plants are somewhat more costly, although unlike standard dry and flash steam plants can use moderately hot geothermal water, by transferring heat to a secondary fluid with a much lower boiling point than water.

Neglecting the production tax credit, renewable generation costs span a range from as low as 1 cent per kWh for cofiring of low-cost residues to around 7 cents (and above) for higher cost wind and geothermal locations (assuming technology costs projected for 2010, roughly the midpoint of this analysis). The production tax credit significantly increases the competitiveness of these resources, dropping their effective costs by as much as 1.3 cents per kWh. At present, renewable resources must compete against other resources costing about 3 to 4 cents per kWh (assuming the RTF long-run avoided cost forecast), and about 4 to 5 cents per kWh if external costs are considered.

Table 3-5. Summary of renewable resource results (assuming 2010 costs)

	Total Potential		Generation Cost (cents per kWh)	
	aMW	**Percent of Regional Demand**	**Range**	**Weighted Average**
Wind	6433	23%	2.6 – 6.1	3.7 (5.1 w/o PTC)
Biomass	2880	10%	1.1 - 6.0	4.4
Geothermal	641	2%	5.0 - 7.0	5.8

These results suggest that significant increases in the contribution of renewable resources -- especially wind, since large-scale increases in biomass generation still depend on technology improvements (BGCC) -- should be possible without major electricity price increases. Such a conclusion ultimately depends on the course that electricity markets take in the years to come. If market prices remain low, at levels in the 2 to 3 cent range, then extensive investment in renewables may increase electric bills. If market prices rise again, then these renewable energy investments might yield strong economic benefits. In face of this uncertainty, local, renewable resources can provide an important hedge against volatile electricity markets.[79] In either case, they can provide major air pollution and climate change benefits, stimulate job creation, and by reducing gas and other fuel purchases, stem the flow of funds away from the region.

[79] A new study from the Lawrence Berkeley National Laboratory quantifies the fuel price hedge value of wind power to be about 0.5 cents/kWh. This is how much more natural gas fired power plants have had to pay to guarantee a predictable price for ten year contracts. http://eetd.lbl.gov/ea/EMS/EMS_pubs.html#RE

4. RESULTS AND CONCLUSIONS

As the preceding sections have shown, the Pacific Northwest possesses substantial efficiency, renewable, and CHP resources that can be tapped to meet the region's electricity requirements. New renewable resources could provide a significant fraction of the region's electricity, while energy efficiency promises major regional economic benefits. In this section, we briefly look at what a combined efficiency/renewables resource scenario might look like.

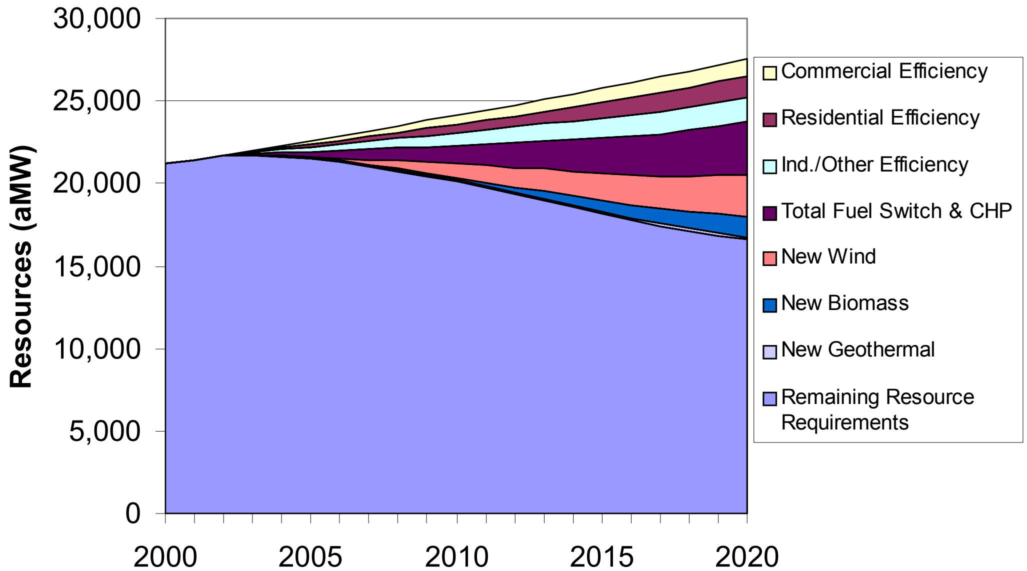
4.1 A Combined Resource Scenario

Studies show that ambitious strategies to increase the penetration of efficiency, renewable, and CHP technologies can yield significant benefits for greenhouse gas and local air pollutant emissions, resource diversity, economic growth, and jobs (EERE, 2000; Bailie et al, 2001; ELPC, 2001). While this resource assessment does not include policy or macroeconomic analysis, we can construct an illustrative scenario that builds on the potentials identified in the previous sections. Specifically, we assume that:

- the full efficiency, CHP, and fuel switching potentials identified in Section 2 can be achieved through appropriate policies and programs. Together, these measures reduce resource requirements by over 25% by 2020, and yield an overall cumulative economic benefit of $400 million by 2020 and over $5 billion by 2050, based on simple cost-benefit analysis.
- 20 percent of remaining 2020 regional resource requirements can be met with renewables. Such a target has been widely discussed. It was closely considered in the recent Senate energy bill, and has been recommended by the Western Regional Air Partnership. To achieve this target, we assume that 50 percent of the biomass and geothermal potentials described in Section 3 would be tapped, and that the remainder of the target would be met by wind resources.

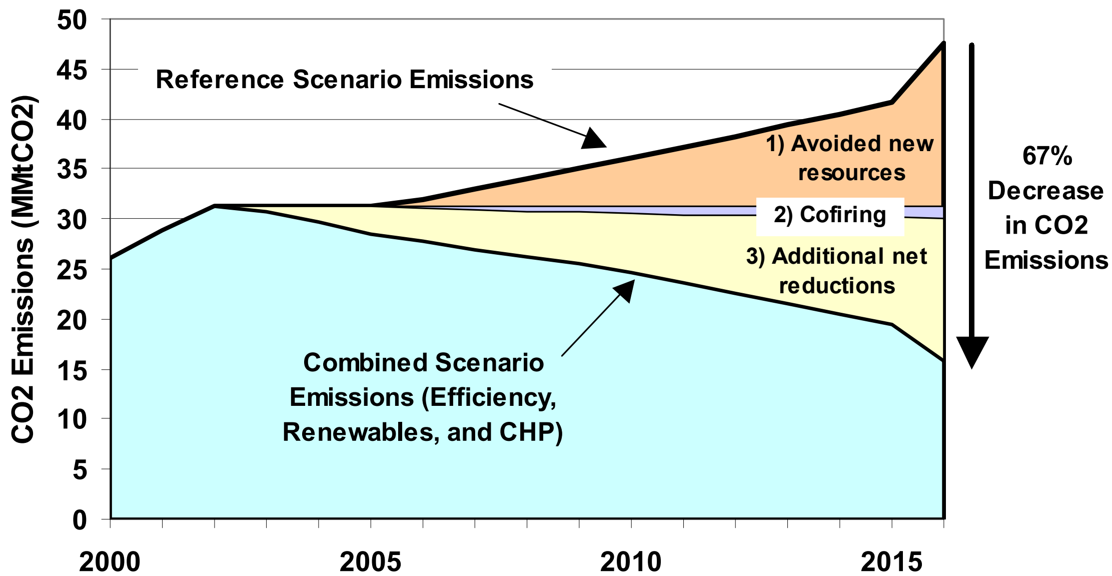
The results of these assumptions are illustrated in Figure 4-1. Over 40 percent of total resource requirements are met with efficiency and renewables. The remaining resource needs, roughly 16,500 aMW, is only slightly more than the region's current hydro production in an average rainfall year. Such a scenario would mean that over 6000 aMW of the region's currently existing generating resources could be used for sales to other regions or decommissioned, depending on the nature of the resource.

Figure 4-1. A Combined Resource Scenario



In the first few years of the scenario (through 2010), wind is in the predominant renewable resource, coming in at about 180 aMW (500 MW nominal) per year from 2006-2010, only slightly faster than wind capacity grew in the late 1990s in Denmark, a country smaller in population and electricity use that the Pacific Northwest. Biomass resources ramp up slowly at first (20aMW/year) until markets and technologies mature in the 2010-2020 period, with a more rapid growth pace of slightly over 100 aMW/year. This scenario leads to major reductions in carbon dioxide emissions, as shown in Figure 4-2.

Figure 4-2. Regional CO2 emissions from electricity generation under combined resource scenario



The calculation of CO2 emissions for the Pacific Northwest region requires some simplifying assumptions. To calculate emissions for a reference, or business-as-usual, scenario, we only accounted for emissions from power plants within the NPPC region.[80] We then assumed that all electricity requirements beyond the capability of existing resources would be supplied by new high-efficiency natural gas combined cycle units.[81] These assumptions lead to reference scenario CO2 emissions of about 32 million metric tons (MMt) of CO2 emissions in 2002 (with the completion of new gas plants in 2001 and 2002). Emissions stay constant through 2006 until loads begin to exceed current regional resources and new gas plants are built. Under these conditions, regional electricity emissions would rise to 47 million metric tons by 2020.

The combined efficiency, renewables, and CHP and fuel switching scenario provides sufficient resources to: 1) avoid any new gas resources, saving 16 MMt in CO2 emissions by 2020; 2) offset over 1.3 million metric tons of CO2 by 2020 by displacing coal use by cofiring biomass; and 3) enable existing resources to operate less or avoid new plant construction in other regions, saving another 14 MMt in CO2 emissions by 2020[82]. Together, this suggests that with aggressive pursuit of efficiency and renewables, CO2 emissions in 2020 can be reduced by 67%, relative to business-as-usual growth, or by 50% relative to today's levels.

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[80] Even though some Northwest utilities may supply electricity from coal or natural gas plants in adjacent areas, some also sell hydropower to other regions.
[81] This assumption may significantly understate reference emissions if coal plants are developed, as some have proposed.
[82] We also assumed here that high-efficiency gas units would be avoided. If existing gas or coal plants were displaced, then the savings would be considerably higher. If existing hydropower were displaced then the savings would be lower.

4.2 Key Findings and Conclusions

The principal finding of this analysis is that there may be far greater economically viable efficiency and renewable resources than other regional studies have shown, and more importantly, than are currently being pursued. The economic and environmental benefits of policies that promote these resources could be very large, in the billions of dollars (at least on the efficiency side) and in the tens of millions of tons of CO2 and other pollutants avoided.

The actual potentials might even be considerably higher than shown here given the many potentially attractive options -- low-impact hydro development, distributed small wind and solar PV applications, improved building design, and others – that were not included in the analysis. On the other hand, the potential resource might be lower, particularly from cost-effectiveness perspective, given that large reductions in demand could conceivably depress electricity prices and undermine the market for higher-cost measures and renewable energy investments. This limited scope of this study precluded the additional data collection and modeling analysis that might help answer some of these unknowns.

Our findings suggest that regional entities:

- Support regular and more thorough analysis of regional efficiency and renewable potentials. They appear large and capable of offering significant economic and environmental benefits to the region. Policy makers need to be aware of these when shaping laws, regulations, and plans.
- Undertake more detailed modeling of the electricity market, economic, and employment impacts that would result from an ambitious efficiency and renewables scenario. This type of analysis would capture economic relationships and feedback effects that cannot be deduced from the cost-benefit analysis.
- Conduct the surveys and modeling needed to better understand regional demand trends. Existing forecasts do not appear to adequately reflect recent shifts away from electric heat in new construction, new NAECA standards, and other trends.

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APPENDIX A. KEY TECHNICAL ASSUMPTIONS

Appendix Table 1. General Parameters

Common Parameters		
Earliest Start Date for Efficiency Programs	2003	
Cost Reference Yr	2001	
Real Discount Rate	4.75%	Drawn from RTF analysis spreadsheets
Bulk Power T&D Loss Factor	2.5%	Drawn from RTF analysis spreadsheets
Local Power T&D Loss Factor	5.0%	Drawn from RTF analysis spreadsheets

Cost-Benefit Parameters		
Bulk Power T&D Credit ($/kw-yr)	3.00	Drawn from RTF analysis spreadsheets
Local Power T&D Credit ($/kw-yr)	20.00	Drawn from RTF analysis spreadsheets
CO2 Externalities Credit ($/Mwh)	4.0	From RTF analysis spreadsheets, value of $6/MWh based on CO2 @ $15/tCO2, reduced to $4/MWh due to C tax embedded in avoided cost estimates.
Non-CO2 externalities ($/MWh)	6.0	Based on Tellus analysis for NGCC facility running at 7000 BTU/kWh (see below)
Direct Gas Use Externality ($/MMBtu)	1.7	Based on above externalities, assuming above heat rates and similar emissions per BTU

Financing (supply-side)		
Composite Fixed Charge Factor	11.0%	Based on finance rate and amortization period below.
Adjustment to 4th Plan returns	-1.8%	Estimate drop in cost of capital/expected returns since mid/late 90s
Composite Finance Rate (real)	7.0%	Based on parameters below
Return on Equity (real)	13.05%	Adapted from current Council assumptions (Jeff King, 11/15/01), based on 4th Plan
Return on Debt (real)	4.45%	Adapted from current Council assumptions (Jeff King, 11/15/01), based on 4th Plan
Equity Fraction	30%	Current Council assumptions (Jeff King, 11/15/01), based on 4th Plan
Debt Fraction	70%	Current Council assumptions (Jeff King, 11/15/01), based on 4th Plan
Amortization Period (years)	15	Current Council assumptions (Jeff King, 11/15/01), based on 4th Plan

Appendix Table 2. Avoided cost estimates used in this study ($2000)

	Electricity for selected load profiles (c/kWh)			Natural Gas ($/MMBtu)
Year	System Load Shape	Residential Domestic Water Heating	Commercial Lighting - New	Utility price ($/MMBtu)
2003	3.5	3.4	3.3	$3.38
2004	3.8	3.7	3.6	$3.63
2005	4.1	4.0	3.9	$4.00
2006	3.9	3.8	3.8	$3.63
2007	4.0	3.9	3.8	$3.48
2008	4.2	4.1	4.1	$3.90
2009	4.5	4.4	4.3	$4.16
2010	4.0	3.8	3.8	$3.90
2011	3.4	3.3	3.3	$3.64
2012	3.4	3.3	3.2	$3.85
2013	3.6	3.5	3.6	$4.06
2014	3.0	2.9	2.8	$3.90
2015	3.3	3.1	3.1	$3.74
2016	3.5	3.2	3.4	$3.94
2017	3.1	2.9	2.9	$3.94
2018	2.9	2.7	2.7	$3.87
2019	3.1	2.9	3.0	$3.91
2020	3.1	2.9	3.0	$3.95
Levelized cost (2003-2020)	3.6	3.5	3.5	$3.80

Electricity costs are from RTF's January 15, 2001 sensitivity analysis. Natural Gas prices at the Henry Hub from Jeff King, NPPC, are the values used for developing the avoided electricity cost estimates shown here.

Appendix Table 3. Non-CO2 External Cost Estimate (for Natural Gas CC plant at 7000 BTU/kWh)

		Carbon Monoxide CO	Nitrogen Oxides NOx	Particulates PM-10	Volatile Organics VOC	Total
Plant emissions (1)	(lb/MWh)	0.574	2.24	0.269	0.0147	
Externality (low est.)(2)	($/ton)	700	4100	1700	1100	
Externality (high est.)(2)	($/ton)	1200	5700	3000	1500	
Externality (mean)	($/ton)	950	4900	2350	1300	
External Cost of New Generation	c/kWh	0.03	0.55	0.03	0.00	**0.61**

Notes:
1. Electric supply corresponds to an NGCC operating at 7000 Btu/kWh; Sources, EPA FIRE database
2. Externality values are based on ranges found in State externality proceedings, adjusted to 1999$

Appendix Table 4. Biomass Technology Assumptions

	Year Available	Heat Rate (Btu/kWh)	Plant Size (MW)	Capital ($/kW)	Fixed O&M ($/kW-yr)	Var O&M ($/MWh)	Lifetime	Cap Factor	Cofire Heat Rate Penalty	Coal Plant HR (BTU/kWh)	*Source:*
Existing Facility	2000	17,000		$100	$99.0	$2.3	30	80%			
Stoker-Fired Steam	2000	14,390	25	$2,600	$99.0	$2.3	30	80%			*NPPC, 1998*
New Direct Fire Steam	2005	13,000		$1,510			30	80%			*USDOE/EIA, 2001*
Biomass gasification CC	2005	10,000	75	$1,939	$44.5	$5.0	30	80%			*USDOE/EIA, 2001*
Biomass gasification CC	2010	8,911	100	$1,300	$44.5	$5.0	30	80%			*USDOE/EIA, 2001*
Biomass gasification CC	2020	8,911	110	$1,137	$44.5	$5.0	30	80%			*USDOE/EIA, 2001*
Cofiring* Cyclone	2000	11,550		$50	$2.5		30	80%	5%	11,000	*ELPC, 2001*
Cofiring* PC	2000	11,550		$200	$10.0		30	80%	5%	11,000	*ELPC, 2001*
Black Liquor Cogeneration	2000	4,500	25	$620		$14.0	30	80%			*NPPC, 1998*

Appendix Table 5. Biomass Analysis Assumptions

Biomass Analysis Assumptions (except existing resources used at mills)

Key Parameters			**Resources/Exploitable Fractions**		
Composite Finance Rate	**7%**	from NWEC Master Inputs	Ag Field Residue	40%	AG
Woody material content	**17.0**	Mbtu/dry ton	Energy Crops	100%	EC
Ag material content	**15.0**	Mbtu/dry ton	Forest Health	40%	FH
Fixed charge factor	**11%**	at 15 year amort period	Logging Residue	20%	LR
Use lifetime as amort period?	**Y**	if not "Y" use above	Mill Residue	100%	MR

Key Assumptions

Existing plants/cofiring

The aggregation of residues to sufficient quantity for new boilers/plants, or to get residues to idle capacity, may entail trans cost above those assumed by Kerstetter.

Cofiring applications at Centralia (mill/forestry residues, transitioning to energy crops) and Boardman (energy crops/hybrid poplar)

	MW nom	CF	aMW	Cap (MW	Max cofire	Suitable resources	
Boardman cofiring max biomass cap (OR/WA)	56	80%	45	560	10%	EC	capacities and CFs from NPPC project database
Centralia cofiring max biomass cap (WA)	146	80%	117	1,460	10%	EC, MR	capacities and CFs from NPPC project database
Assumed available idle boiler capacity (OR)	53	80%	42			MR	NPPC database shows 58 MWn idle wood waste facilities (53 OR/5 WA)
Assumed available idle boiler capacity (WA)	5	80%	4			MR	$10 per bdt added transport and $100/kW start-up costs assumed
Other suitable cofiring/fuel switch sites	-	80%	-	-	10%	EC, MR	
Totals:			**208**				

Appendix Table 6

Landfill Gas Analysis (based on data from USEPA)

Finance Rate	7%
CF assumed	90%

NSPS Regulated?	Landfill Name	Location	LFGTE System Type	Current Project Status	Potential (MW)	Included?	MW	CF (%)	Average Energy (MWa)	Action Date	Capital Cost ($/kW)	O&M ($/kW-yr)	c/kWh (2001$)
EXISTING													
YES	Coffin Butte LF	Corvalis,OR	Reciprocating Engine	Operational	2.4	yes	2.4	90%	2.2	1996			
YES	Short Mountain LF	Eugene,OR	Reciprocating Engine	Operational	3.2	yes	3.2	90%	2.9	1992			
YES	Hidden Valley LF	Puyallup,WA	Reciprocating Engine	Operational	1.9	yes	1.9	90%	1.7	1999			
YES	Northside LF	Spokane,WA	Reciprocating Engine	Operational	0.9	yes	0.9	90%	0.8	1999			
YES	Roosevelt Regional LF	Goldendale,WA	Reciprocating Engine	Operational	10.5	yes	10.5	90%	9.5	1999			
YES	Tacoma LF	Tacoma,WA	Reciprocating Engine	Operational	1.9	yes	1.9	90%	1.7	1998			
Subtotal Existing							**20.8**		**18.7**				
POTENTIAL/PLANNED													
YES	Columbia Ridge LF	Arlington,OR	Unknown	Potential	23.9	yes	23.9	90%	21.5		$1,309	$143	2.99
YES	Finley Buttes LF	Boardman,OR	Unknown	Potential	6.0	yes	6.0	90%	5.4		$1,309	$143	2.99
YES	Riverbend Sanitary Landfill	McMinnville,OR	Reciprocating Engine	Potential	6.7	yes	6.7	90%	6.0		$1,309	$143	2.99
YES	Cedar Hills LF	Maple Valley,WA	Unknown	Potential	25.0	yes	25.0	90%	22.5		$1,309	$143	2.99
YES	Roosevelt Regional LF	Goldendale,WA	Reciprocating Engine	Planned	11.7	yes	11.7	90%	10.5		$1,309	$143	2.99
NO	Fort Hall Mine Landfill	Pocatello,ID	Unknown	Unknown	1.8	yes	1.8	90%	1.6		$1,909	$216	4.44
NO	Klamath Falls LF	Bonanza,OR	Unknown	Low Interest	0.3	no	0.0	90%	0.0		$1,909	$216	4.44
NO	Knott Pit LF	Bend,OR	Unknown	Planned	0.6	yes	0.6	90%	0.6		$1,909	$216	4.44
NO	Northern Wasco County LF	The Dalles,OR	Unknown	Low Interest	1.4	yes	1.4	90%	1.3		$1,909	$216	4.44
NO	Roseburg LF	Roseburg,OR	Unknown	Potential	1.8	yes	1.8	90%	1.6		$1,909	$216	4.44
NO	Cathcart LF	Snohomish,WA	Reciprocating Engine	Planned	2.9	yes	2.9	90%	2.6		$1,909	$216	4.44
NO	Cheyne Road LF	Yakima,WA	Unknown	Low Interest	1.1	no	0.0	90%	0.0		$1,909	$216	4.44
NO	Greater Wenatchee LF	,WA	Unknown	Low Interest	1.8	no	0.0	90%	0.0		$1,909	$216	4.44
NO	Kent Highlands LF	Kent,WA	Reciprocating Engine	Potential	25.0	yes	25.0	90%	22.5		$1,595	$166	3.53
NO	Leichner LF	Vancouver,WA	Unknown	Unknown	1.0	yes	1.0	90%	0.9		$1,909	$216	4.44
NO	Terrace Heights LF	Yakima,WA	Unknown	Low Interest	3.4	no	0.0	90%	0.0		$1,909	$216	4.44
Subtotal Potential/Planned							**107.9**		**97.1**				
GRAND TOTAL							**128.7**		**115.8**				

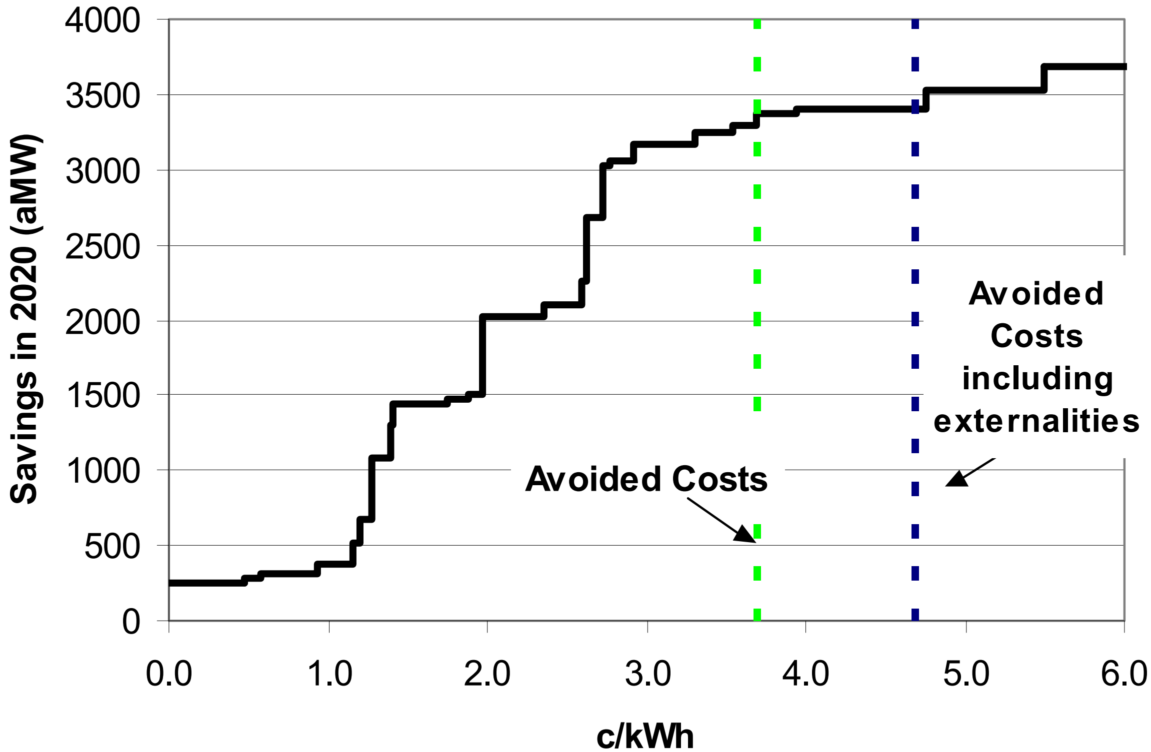
APPENDIX B: DETAILED RESULTS

Appendix Table 7

Aggregated Results by "Measure"

7/6/02	Results									
Measure	Cost of Saved Energy (c/kWh)	Savings by 2010 (aMW)	Savings by 2020 (aMW)	Benefit/ Cost Ratio	Benefit/ Cost Ratio (w/ext costs)	2010 Savings (million$)	2020 Savings (million$)	Cum Savings (million$ NPV by 2020)	Lifetime Cum Savings (million$ NPV)	Lifetime Cum Social Savings (million$ NPV)
Residential										
Furnace&Duct Serv.	2.6	49	56	1.80	2.19	$1	$21	$46	$96	$141
Furnace & HP Fans	1.2	55	147	3.53	4.36	$11	$39	$119	$288	$383
Super-Eff Windows	3.3	25	40	1.31	1.61	($4)	$14	($29)	$38	$75
Weatherization	1.9	17	27	2.28	2.81	$1	$9	$16	$61	$86
Upg&Beyond Code	0.5	8	12	9.14	11.26	$3	$4	$23	$44	$55
Mfg. Home Heat	2.6	29	48	1.66	2.05	($1)	$17	($3)	$76	$120
CFL Torchieres	2.8	15	45	1.21	1.43	($7)	$3	($47)	$27	$56
Indoor CFL Fixtures	3.1	30	97	1.23	1.55	($11)	($1)	($77)	$52	$128
Outdoor CFL Fixtures	-5.3	12	40	5.33	5.81	$8	$30	$105	$181	$201
CFL Bulbs	0.6	14	37	6.39	8.12	$4	$10	$41	$61	$81
Add-on HP DHW	4.8	68	125	0.86	1.07	($29)	$9	($131)	($124)	$25
Integral HP DHW	2.7	56	331	1.45	1.82	($12)	$4	($86)	$62	$364
Appliance Recycling	1.8	26	0	2.30	2.86	$9	$0	$53	$53	$75
Standby Losses	1.4	39	218	2.38	3.19	($8)	$38	$99	$172	$275
Residential Subtotal		***443***	***1223***			***-$36***	***$196***	***$129***	***$1,086***	***$2,066***
Commercial										
Commissioning	1.2	58	95	3.33	4.18	$10	$30	$99	$242	$330
Retrocommissioning	1.6	16	26	2.49	3.11	$2	$8	$18	$58	$82
Lighting Fluor	1.2	72	146	3.53	4.48	$15	$32	$152	$249	$343
Lighting Emerging	2.6	209	422	1.58	1.99	$10	$50	$88	$373	$643
Refrig Low Cost	0.9	29	57	4.20	5.37	$7	$13	$64	$101	$138
Refrig High Cost	1.7	16	31	2.22	2.85	$2	$5	$20	$61	$92
O&M	2.4	75	79	1.72	2.15	$4	$24	$61	$110	$174
Data Centers	*3.7*	40	79							
Washers	3.0	7	10	1.36	1.69	$1	$1	$3	$7	$14
Commercial Subtotal		***522***	***945***			***$52***	***$164***	***$504***	***$1,201***	***$1,816***
Industrial										
Premium Motors	1.4	126	148	2.74	3.45	$31	$42	$193	$253	$357
Motor Systems	1.3	209	422	2.97	3.76	$41	$87	$390	$0	$0
Aluminum	-0.6	90	210	8.03	9.72	$35	$68	$339	$532	$660
Other End Uses	2.0	256	515	1.87	2.37	$33	$74	$226	$589	$924
O&M	3.5	31	35	1.12	1.40	($4)	$9	($12)	$12	$40
Transformers	1.3	2	5	2.95	3.71	$0	$1	$2	$12	$16
Industrial Subtotal		***714***	***1335***			***$136***	***$280***	***$1,137***	***$1,397***	***$1,996***
Other										
LED Traffic	2.7	4	10	1.41	1.77	($0)	$1	($1)	$7	$13
Irrigation H,S&E	3.9	29	29	1.07	1.33	$2	$1	($2)	$7	$30
Other Subtotal		***33***	***39***			***$2***	***$2***	***-$2***	***$14***	***$43***
Total Efficiency (1)		**1713**	**3542**			**$154**	**$643**	**$1,769**	**$3,698**	**$5,921**
Fuel Switching and Direct Renewables										
Solar DHW	13.2	23	73	0.30	0.38	($65)	($63)	($525)	($475)	($388)
Cond. Gas DHW	5.5	101	322	0.73	0.80	($70)	($52)	($542)	($481)	($231)
CHP										
Commercial CHP	3.2	565	1315	1.08	1.13	$24	$8	$26	$221	$375
Industrial CHP	3.8	365	1031	0.92	0.94	($42)	($53)	($325)	($209)	($149)
Total Fuel Switch + CHP (2)		**1055**	**2741**			**($153)**	**($160)**	**($1,367)**	**($943)**	**($393)**
Total Demand Reduction (1+2)		**2768**	**6283**			**$1**	**$482**	**$402**	**$2,755**	**$5,528**
Equivalent Electricity Generation from Natural Gas used for CHP and water heating (3)		**666**	**1746**							
"Net" Savings (1+2-3)		**2103**	**4538**							

Appendix Figure 1. Efficiency Cost Curve (not including CHP)



Appendix Table 8

A Combined Efficiency/Renewables Scenario

Renewables Assumptions

Renewables target 2010	6% of projected load (after other measures)		
Renewables target 2020	20% "" ""		
Biomass	Introduce all of near-term biomass potential by 2010 (linear ramp up 2005-2010)		
	Ramp up to	50%	of long-term potential from 2010-2020 (all resources under 5c/kWh + 1.2c/kWh levelized prod tax credit)
Geothermal	Ramp up to	50%	of long-term potential by 2020 (all resources under 5c/kWh + 1.2c/kWh levelized prod tax credit)
Wind	Fills in remainder of RPS target		
Startup-year	2004 allows 1 year lead-time for construction		

Efficiency and Renewable Resources (aMW) by Year

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Projected Res Requirements	**21,345**	**21,626**	**21,912**	**22,201**	**22,494**	**22,790**	**23,091**	**23,396**	**23,704**	**24,017**	**24,334**	**24,655**	**24,980**	**25,310**	**25,644**	**25,982**	**26,325**	**26,672**	**27,024**	**27,380**	**27,742**
Total Efficiency, of which:	**0**	**0**	**0**	**177**	**417**	**640**	**867**	**1,105**	**1,351**	**1,598**	**1,844**	**2,057**	**2,294**	**2,532**	**2,771**	**3,012**	**3,234**	**3,459**	**3,575**	**3,693**	**3,812**
Residential Efficiency	0	0	0	51	115	160	209	267	334	406	477	549	644	739	834	932	1,021	1,111	1,178	1,247	1,317
Commercial Efficiency	0	0	0	46	120	193	266	340	414	488	562	623	685	747	810	872	924	977	990	1,003	1,017
Ind./Other Efficiency	0	0	0	80	182	287	392	498	603	704	804	885	966	1,046	1,127	1,209	1,290	1,371	1,407	1,443	1,479
Total Fuel Switch & CHP	**0**	**0**	**0**	**67**	**208**	**337**	**465**	**629**	**772**	**911**	**1,100**	**1,280**	**1,510**	**1,694**	**1,924**	**2,120**	**2,354**	**2,543**	**2,780**	**2,982**	**3,223**
Fuel Switch + Solar DHW (gross)	0	0	0	5	16	29	43	60	82	106	134	161	190	219	246	275	305	334	364	395	425
New CHP (incl. black liquor, gross)	0	0	0	62	192	309	421	570	690	804	966	1,119	1,320	1,475	1,678	1,844	2,049	2,208	2,416	2,588	2,798
Net Resource Requirements	**21,345**	**21,626**	**21,912**	**21,956**	**21,869**	**21,813**	**21,760**	**21,662**	**21,581**	**21,509**	**21,390**	**21,317**	**21,176**	**21,084**	**20,949**	**20,850**	**20,736**	**20,671**	**20,669**	**20,706**	**20,706**
Total Non-Hydro Renewables, of which	**128**	**218**	**218**	**218**	**262**	**327**	**435**	**650**	**863**	**1,075**	**1,283**	**1,577**	**1,863**	**2,151**	**2,430**	**2,711**	**2,986**	**3,266**	**3,555**	**3,851**	**4,141**
Renewables Target (%)	0%	0%	0%	0%	0%	2%	2%	3%	4%	5%	6%	7%	9%	10%	12%	13%	14%	16%	17%	19%	20%
Existing Renewables*	128	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218
New Wind	0	0	0	0	0	46	125	311	495	679	858	1,031	1,197	1,364	1,523	1,683	1,838	1,998	2,166	2,342	2,512
New Biomass	0	0	0	0	0	19	38	57	77	96	115	225	336	447	557	668	778	889	1,000	1,110	1,221
New Geothermal	0	0	0	0	45	45	54	64	74	84	93	103	113	123	132	142	152	162	171	181	191
Remaining Resource Requirements	**21,216**	**21,409**	**21,694**	**21,739**	**21,606**	**21,486**	**21,324**	**21,012**	**20,718**	**20,433**	**20,106**	**19,740**	**19,312**	**18,933**	**18,519**	**18,140**	**17,750**	**17,405**	**17,114**	**16,854**	**16,565**

All figures shown in terms of resource requirements. As a result:

All Demand-side resources are multiplied by 1.076 to reflect Average T&D losses = 7.6%

CHP assumes only half of the avoided T&D benefit, since some electricity is sold back to grid, and some large consumers connect to lower-loss high-voltage lines

Appendix Table 9

Regional CO2 Emission Calculations

		Emissions based on	2000	2001	2002	2003	2004	2005	2010	2015	2020
Reference Scenario											
Projected Resource Requirements	**(aMW)**		**21,345**	21,626	21,912	22,201	22,494	**22,790**	**24,334**	**25,982**	**27,742**
Existing Regional Resources (additions through 2002)	(aMW)		21,376	22,171	22,911	22,911	22,911	22,911	22,911	22,911	22,911
New Resource Requirements (after 2003)	(aMW)					0	0	0	1,423	3,071	4,831
CO2 Emissions	**MMtCO2**		**26.1**	28.9	31.3	31.3	31.3	**31.3**	**36.1**	**41.6**	**47.5**
From Existing/Under Const Resources (to 2002)	MMtCO2	existing plant types	26.1	28.9	31.3	31.3	31.3	31.3	31.3	31.3	31.3
New Resources (2003 on)	MMtCO2	marginal NGCC				0.0	0.0	0.0	4.8	10.3	16.2
Combined Scenario											
Projected Resource Requirements	**(aMW)**		**21,345**	21,626	21,912	21,956	21,869	**21,813**	**21,390**	**20,850**	**20,706**
Existing Regional Resources (additions through 2002)	(aMW)		21,376	22,171	22,911	22,911	22,911	22,911	22,911	22,911	22,911
New Resource Requirements (after 2003)	(aMW)					0	0	0	0	0	0
New Renewable Resources (after 2003)	(aMW)					0	45	110	1,066	2,493	3,924
Additional Resource Savings	*(aMW)*					*244*	*670*	*1,087*	*2,587*	*4,554*	*6,129*
Regional CO2 Emissions	**MMtCO2**		**26.1**	28.9	31.3	30.7	29.6	**28.5**	**24.6**	**19.5**	**15.8**
From Existing/Under Const Resources (to 2002)	MMtCO2	existing plant types	26.1	28.9	31.3	31.3	31.3	31.3	31.3	31.3	31.3
New Resources (2003 on)	MMtCO2	marginal NGCC				0.0	0.0	0.0	0.0	0.0	0.0
Reductions from cofiring at existing facilities	MMtCO2	centralia/boardman				0.0	0.0	-0.1	-0.8	-1.1	-1.3
Natural gas applications (fuel switch and CHP)	MMtCO2	direct use of NG				0.2	0.6	0.9	2.4	4.1	5.8
Additional CO2 Savings (at marginal emission rate)	MMtCO2	marginal NGCC				-0.8	-2.2	-3.6	-8.3	-14.8	-20.0

Notes:

Assumed Marginal Emission Rate for all new resources (or resource savings) 3348 tCO2/aMW

Avoided generation all assumed to be from NG Combined Cycle per below, except cofiring which avoids an average of Centralia and Boardman rates

Emission rates	tCO2/aMW	tCO2/MWh	lbCO2 /MWh	000 Short Ton CO2	GWh (1999)	lbCO2/MMBtu
NWPower Pool (US) avg	3435	0.39	864			
Standard Combined Cycle Natural Gas	3348	0.38	842			
EPA Marginal Analysis (NEMS region)	4776	0.55	1202			
Coal (Centralia)	8734	1.00	2198	9511	8656	207.9
Coal (Boardman)	8689	0.99	2186	4042	3698	
Coal (Centr/Board Avg)	8721	1.00	2194	13553	12354	

Appendix Table 10 Biomass Resource Analysis Results (included in cost curve)

	Application	State	Resource Type	Bin Average $/dry ton	Transport Adder ($/bdt)	Total $//Mbtu	Est Resource bdt/yr	% of resource nearby	Capital ($/kW)	Fixed O&M ($/kW-yr)	Var O&M ($/MWh)	Lifetime	Cap Factor	Heat Rate (Btu/kWh)	Gen Cost ($/MWh)	Total (aMW)	Exploitable (aMW)
NEAR-TERM	Boardman cofire	Oregon	Energy Crops (2000)	$25		$1.5	75,000	80%	$200	$10	$0	30	0.8	11550	**$21**	10	**10**
RESOURCES	Boardman cofire	Oregon	Ag Field Residue	$35		$2.1	201,559	20%	$200	$10	$0	30	0.8	11550	**$28**	6	**2**
	Boardman cofire	WA	Ag Field Residue	$35		$2.1	4,211,677	5%	$200	$10	$0	30	0.8	11550	**$28**	31	**12**
	Centralia cofire	WA	Energy Crops (2000)	$25		$1.5	75,000	25%	$50	$3	$0	30	0.8	11550	**$18**	3	**3**
	Centralia cofire	WA	Unused Mill Residue	$15	$10	$1.5	246,500	50%	$50	$3	$0	30	0.8	11550	**$18**	21	**21**
	Centralia cofire	WA	Logging Residue	$45		$2.6	71,531	50%	$50	$3	$0	30	0.8	11550	**$32**	6	**1**
	Centralia cofire	WA	Logging Residue	$55		$3.2	597,580	50%	$50	$3	$0	30	0.8	11550	**$38**	50	**10**
	Centralia cofire	WA	Forest Health	$45		$2.6	105,327	50%	$50	$3	$0	30	0.8	11550	**$32**	9	**4**
	Centralia cofire	WA	Forest Health	$55		$3.2	879,917	50%	$50	$3	$0	30	0.8	11550	**$38**	74	**30**
	Idle Capacity	Oregon	Unused Mill Residue	$15	$10	$1.5	369,500	80%	$100	$99	$2	30	0.8	17000	**$43**	34	**34**
	Idle Capacity	WA	Unused Mill Residue	$15	$10	$1.5	246,500	20%	$100	$99	$2	30	0.8	17000	**$43**	6	**6**
LONGER-	Boardman cofire	Oregon	Energy Crops (2020)	$15		$0.9	1,050,000	30%	$200	$10	$0	30	0.8	11550	**$14**	53	**53**
TERM	Centralia cofire	WA	Energy Crops (2020)	$15		$0.9	1,050,000	20%	$50	$3	$0	30	0.8	11550	**$11**	35	**35**
RESOURCES	Centralia cofire	WA	Unused Mill Residue	$15	$10	$1.5	246,500	50%	$50	$3	$0	30	0.8	11550	**$18**	21	**21**
	Centralia cofire	WA	Logging Residue	$45		$2.6	71,531	50%	$50	$3	$0	30	0.8	11550	**$32**	6	**1**
	Centralia cofire	WA	Logging Residue	$55		$3.2	597,580	50%	$50	$3	$0	30	0.8	11550	**$38**	50	**10**
	Centralia cofire	WA	Forest Health	$45		$2.6	105,327	50%	$50	$3	$0	30	0.8	11550	**$32**	9	**4**
	Centralia cofire	WA	Forest Health	$55		$3.2	879,917	50%	$50	$3	$0	30	0.8	11550	**$38**	74	**30**
	New BGCC	WA	Energy Crops (2020)	$15		$0.9	1,050,000	80%	$1,300	$45	$5	30	0.8	8911	**$34**	183	**183**
	New BGCC	Oregon	Energy Crops (2020)	$15		$0.9	1,050,000	70%	$1,300	$45	$5	30	0.8	8911	**$34**	160	**160**
	New BGCC	Oregon	Unused Mill Residue	$15	$10	$1.5	369,500	100%	$1,300	$45	$5	30	0.8	8911	**$39**	80	**80**
	New BGCC	WA	Unused Mill Residue	$15	$10	$1.5	246,500	100%	$1,300	$45	$5	30	0.8	8911	**$39**	54	**54**
	New BGCC	Idaho	Unused Mill Residue	$15		$0.9	154,500	100%	$1,300	$45	$5	30	0.8	8911	**$34**	34	**34**
	New BGCC	Montana	Unused Mill Residue	$15		$0.9	51,000	100%	$1,300	$45	$5	30	0.8	8911	**$34**	11	**11**
	New BGCC	Idaho	Ag Field Residue	$25		$1.5	1,630,369	100%	$1,300	$45	$5	30	0.8	8911	**$39**	313	**125**
	New BGCC	Idaho	Ag Field Residue	$35		$2.1	2,750,004	100%	$1,300	$45	$5	30	0.8	8911	**$45**	528	**211**
	New BGCC	Oregon	Ag Field Residue	$35		$2.1	201,559	80%	$1,300	$45	$5	30	0.8	8911	**$45**	31	**12**
	New BGCC	WA	Ag Field Residue	$35		$2.1	4,211,677	95%	$1,300	$45	$5	30	0.8	8911	**$45**	769	**308**
	New BGCC	Oregon	Ag Field Residue	$45		$2.6	582,325	100%	$1,300	$45	$5	30	0.8	8911	**$50**	112	**45**
	New BGCC	WA	Ag Field Residue	$45		$2.6	4,587,162	100%	$1,300	$45	$5	30	0.8	8911	**$50**	881	**353**
	New BGCC	Oregon	Ag Field Residue	$55		$3.2	620,486	100%	$1,300	$45	$5	30	0.8	8911	**$55**	119	**48**
	New BGCC	WA	Ag Field Residue	$55		$3.2	4,658,589	100%	$1,300	$45	$5	30	0.8	8911	**$55**	895	**358**
	New BGCC	Oregon	Forest Health	$45		$2.6	187,503	100%	$1,300	$45	$5	30	0.8	8911	**$50**	41	**16**
	New BGCC	WA	Forest Health	$45		$2.6	105,327	50%	$1,300	$45	$5	30	0.8	8911	**$50**	11	**5**
	New BGCC	Idaho	Forest Health	$55		$3.2	352,303	100%	$1,300	$45	$5	30	0.8	8911	**$55**	77	**31**
	New BGCC	Oregon	Forest Health	$55		$3.2	796,803	100%	$1,300	$45	$5	30	0.8	8911	**$55**	174	**69**
	New BGCC	WA	Forest Health	$55		$3.2	879,917	50%	$1,300	$45	$5	30	0.8	8911	**$55**	96	**38**
	New BGCC	Idaho	Forest Health	$65		$3.8	747,335	100%	$1,300	$45	$5	30	0.8	8911	**$60**	163	**65**
	New BGCC	Oregon	Logging Residue	$45		$2.6	90,134	100%	$1,300	$45	$5	30	0.8	8911	**$50**	20	**4**
	New BGCC	WA	Logging Residue	$45		$2.6	71,531	50%	$1,300	$45	$5	30	0.8	8911	**$50**	8	**2**
	New BGCC	Idaho	Logging Residue	$55		$3.2	266,769	100%	$1,300	$45	$5	30	0.8	8911	**$55**	58	**12**
	New BGCC	Montana	Logging Residue	$55		$3.2	77,884	100%	$1,300	$45	$5	30	0.8	8911	**$55**	17	**3**
	New BGCC	Oregon	Logging Residue	$55		$3.2	383,028	100%	$1,300	$45	$5	30	0.8	8911	**$55**	83	**17**
	New BGCC	WA	Logging Residue	$55		$3.2	597,580	50%	$1,300	$45	$5	30	0.8	8911	**$55**	65	**13**
	New BGCC	Idaho	Logging Residue	$65		$3.8	565,908	100%	$1,300	$45	$5	30	0.8	8911	**$60**	123	**25**

APPENDIX C: NOTES ON BIOMASS RESOURCE ESTIMATES

The following notes describe the sources and assumptions underlying the biomass resource analysis, as conducted by Jim Kerstetter, WSU:

- **Logging Residues:** We draw upon a recent, thorough assessment of woody residues available subsequent to commercial logging operations in the Northwest that could be collected and transported to a central conversion site (Kerstetter and Lyons, 2001). Commodification and increased use of these materials could provide economic benefits in rural, logging communities without increasing timber harvests. At the same time, it could conceivably place greater pressure on forested lands, and raise ecological concerns due to increased machinery use and removal of organic material. Therefore, we limited potential logging residues to a maximum of 10% of the available resource, a resource amount that was already calculated conservatively assuming practices that would leave residues on the land for ecological maintenance. In any case, logging residues are relatively expensive resource – the cost of recovering the residues and transporting them to assumed regional conversion sites range from $50-70/dry ton – that are unlikely to be profitable absent subsidies or advances in biomass conversion technologies. The data are cumulative values in dry tons per year, e.g. for Idaho there are 266,769 tons available at a cost of $50-59/ton and 565,908 tons at a cost of $60-69. Future volumes are assumed to be the similar to those currently available. The harvest data show that the decline in harvest over the past two decades has stabilized and is now only showing the normal annual variations.

- **Agricultural Residues:** Agricultural residues represent wheat straw, the dominant agricultural residue in the region, are based on the same extensive analysis as logging residues (Kerstetter and Lyons, 2001) The quantity assumed available for removal is computed by assuming that 3,000 pounds of residue must be left on the land for erosion control. The costs of recovery were based on the cost of collecting bailing and transporting the residue to a conversion facility. The volumes are cumulative for the different cost categories and represent the average cost for the quantity shown. The volume of residue is not assumed to change between current values and 2010.

- **Energy Crops:** We did not assume that dedicated energy crops would be grown in the region. Rather, we did assume that 30% of the materials grown for pulp will be used for energy. There are currently 100,000 acres of hybrid poplars grown in the region[83] and we assume the acres are equally divided between WA and OR. We further assume that the biomass yield is 5 dry tons/acre-year. The 75,000 tons shown as currently available in each state is the 100,000acres x 5ton/acre-yr x 0.5 in WA x 0.3tons energy crop/ton total biomass = 75,000 tons energy crop/year-state. The projection for 2010 uses the data from Alig, et al who estimated the quantity of hybrid poplar that would be grown in the region by 2020.[84] They assumed 7 million tons/yr would be harvested. We again assumed equal distribution in WA and OR and 30% for energy. The cost of recovery was assumed

[83] Johnson, Jon D. and Gorden Ekuan, *WSU Poplar Research Program*, http://www.puyallup.wsu.edu/poplar/
[84] Alig, Ralph and Darius Adams, Bruce McCarl and Peter Ince, "Economic Potential of Short Rotation Woody Crops on Agricultural Land for Pulp Fiber Production in the United States" *Forest Products Journal*, Vol 50 (5) 67-74, May-00

to be $20-29/ton, which represents typical costs for chipping and transporting the material.

- **Black Liquor:** The wood pulping process creates a residue called black liquor that contains woody material that cannot be used for pulp and the chemicals used to process the wood into pulp. A chemical recovery boiler is used to recover and recycle the chemicals and also burn the woody material. Steam is generated in the boilers and used in the pulping process and for the generation of electricity using a steam turbine. Not all pulp mills use the steam for electricity generation. We used the data from Weyerhauser to estimate the current potential for increased electrical production from existing black liquor combustion.[85]

- **Mill Residues:** Mill residues are those materials resulting from the production of lumber and plywood from the timber that is harvested. Most of the residues are already being used for fiber byproducts or as process energy at the mills. The remaining material is classified as miscellaneous byproducts and not used. We assumed that 50% of the miscellaneous byproducts and all the material not used could go to electrical generation. The U.S. Forest Service computes the quantity of mill residues by state.[86] Their numbers are similar to those derived by Kerstetter[87] using a different methodology. The 2020 volumes are assumed to be the same as the current values for the same reason used to project logging residues. The harvest levels and lumber production levels seem to have reached a steady state. The costs are given in the $10-19/dry ton range. This basically represents the cost of transportation. They are in line with the Summer 2000 prices for hog fuel reported by Wood Resources International.[88]

- **Forest Health Resources:** This is the most difficult resource to estimate. We first assumed that no material would come from National Forests because of the institutional barriers faced by a Federal agency. The gross amount of material was for selected counties in each state and based on the acres of timberland. Timberland acreage was from U.S. Forest Service.[89] We assumed 10 tons/acre could be removed. The percentage of materials available at less than $60/ton was derived from the recovery costs for logging residues. For example, 26% of logging residues were available at a cost of $60/ton or less so 26% of the forest health volume would be available. Similar numbers for ID, WA, and OR, are 32%, 40%, and 40% respectively. We also assumed that the material will be removed over fifteen years. The cumulative cost was then allocated between cost ranges in the same proportion as the logging residue results. These estimates do not account for the fact that for economies of scale larger plants would be desired which entails longer shipping distances. This is a trade off and cannot be determined by this study.

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[85] Weyerhaeuser Corporation, private communication, 1994
[86] U.S. Forest Service, http://srsfia.usfs.msstate.edu/
[87] Kerstetter, James D. *Northwest Power Planning Council Biomass Briefing Paper*, Washington State Energy Office, Olympia WA, Olympia, WA, 1994
[88] Wood Resources International Ltd. *North American Wood Fiber Market Update September 2000*, Bothell, WA, 2000
[89] U.S. Forest Service, http://fia.fs.fed.us/dbrs_setup.htm under Mapmaker