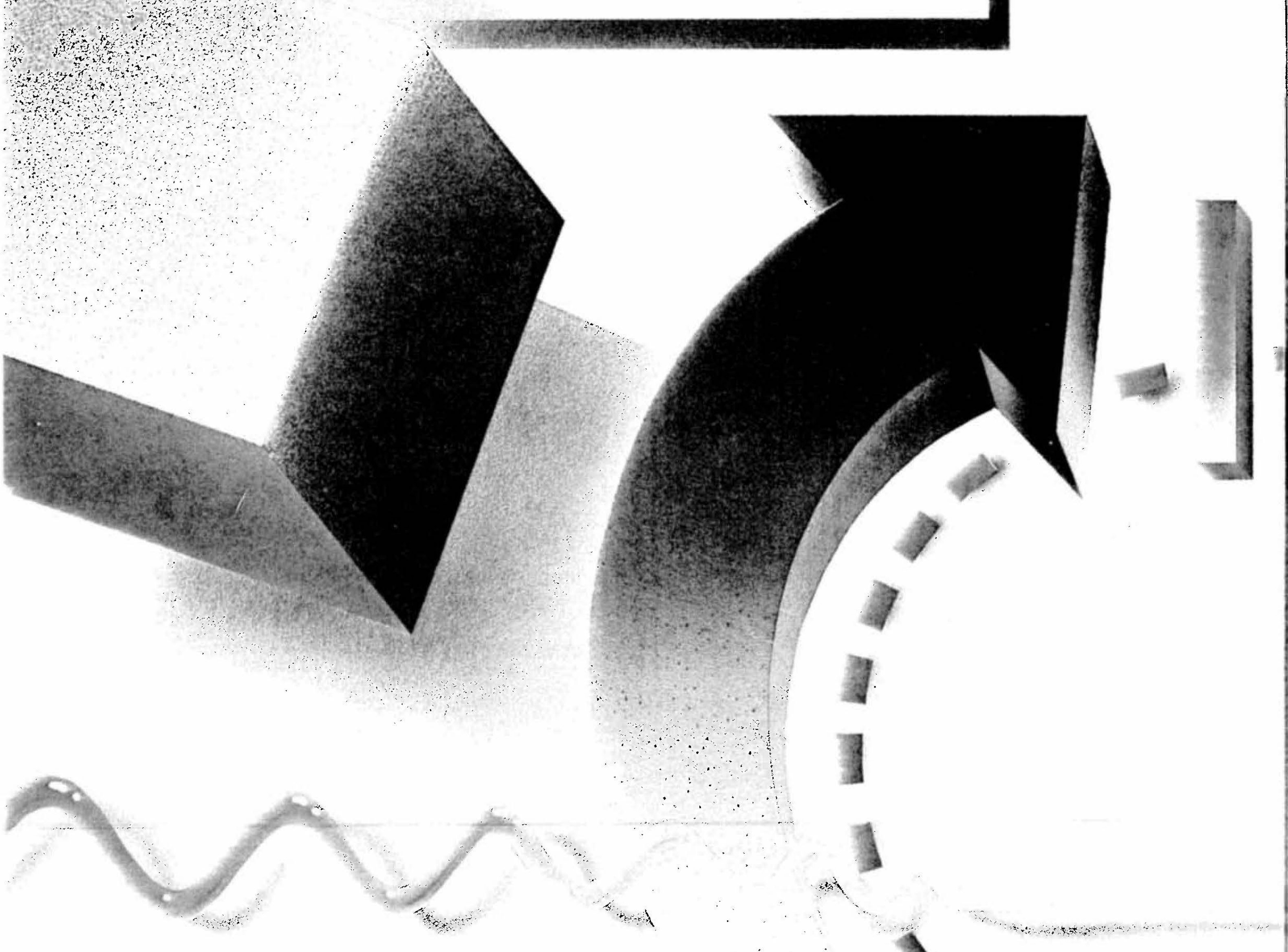
1991 NORTHWEST CONSERVATION and ELECTRIC POWER PLAN
VOLUME II—PART I



NORTHWEST POWER PLANNING COUNCIL

91–05

TABLE OF CONTENTS

Part I

Part II

Chapter 8
Generating Resources 443

Chapter 14
Resource Cost–Effectiveness 929

Chapter 15
Risk Assessment and Decision Analysis 939

Glossary 955

LIST OF ILLUSTRATIONS

LIST OF TABLES

CHAPTER 1

RECOMMENDED ACTIVITIES FOR IMPLEMENTATION OF THE POWER PLAN

Introduction

For the first time in its 10-year history, the Northwest Power Planning Council has written a power plan that calls for a major push to acquire new resources. Volume I of this 1991 Northwest Conservation and Electric Power Plan narrates, in broad terms, what it will take to deliver the electricity needed by the four Northwest states over the next 20 years. The activities outlined in this first chapter of Volume II provide more detail. Because new supplies of electricity are needed now, actions in this plan, or actions that can meet the Council's objectives equally well, should be started immediately.

The plan's first objective identifies and calls for rapid acquisition of 2,300 megawatts[1] of low-cost conservation, hydropower and cogenerated electricity. Typically, generating resources costing less than 7.5 cents per kilowatt-hour and conservation measures at less than 11 cents per kilowatt-hour are considered cost-effective in this plan. (For more discussion on these cost cut-offs, see Chapters 7, 8, 9 and 14 in this volume.) This chapter proposes ways to obtain each resource. Chapter 11 in this volume explains the acquisition principles that should govern all resource development.

The plan's second objective calls for measures to shorten the time it takes to develop resources, so that projects can be brought into production when their power is needed. Actions pertinent to this objective also are listed in this chapter, arranged primarily by resource.

Third, the plan calls for research, demonstration and development of resources about which there remain significant questions, particularly about how they will operate in the Pacific Northwest. This chapter incorporates confirmation activities for geothermal, solar, wind and ocean energy sources. The plan's third objective also includes the need to determine whether two unfinished nuclear power plants in Washington should be preserved, completed or terminated.

Finally, the plan sets a fourth objective, which addresses the need to look at regulatory and other changes that can facilitate the achievement of the first three objectives. Most of the activities relating to this objective are included in this chapter under "Supporting Activities."

These actions should not be read as sequential, rather, they all are critical now. Nor are the actions described here meant to restrict other activities. On the contrary, while the Council worked hard to assemble a set of activities that, if carried out aggressively, could meet the objectives in this plan, additional or replacement activities that also meet those objectives are encouraged.

The Council's work does not stop with production of this plan. Our next task is, if anything, even greater. As noted in Volume I, we expect this decade to be a challenging one. It will take the concerted efforts of every Northwesterner to capture all the energy savings and other low-cost resources needed to protect this region's economy and its environment. The Council intends to lead that effort.

Conservation

It will not be easy to save more than 1,500 megawatts of electricity by the year 2000. New conservation programs will need to be designed to capture savings in areas not yet tapped. This may include targeting manufacturers (see manufactured housing and efficient appliances, below) or enlisting energy service companies or other organizations to help deliver the conservation resource. State and local governments will be needed to pass energy-conscious building codes, recycling plans and solar access legislation, as well as help finance conservation efforts.

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1. Throughout this plan, "megawatts" refer to average megawatts. An average megawatt is the amount of energy produced by one megawatt of capacity operating over a period of one year, or 8,760 megawatt-hours of energy. This is equivalent to 8.76 gigawatt-hours.

Existing conservation programs will need to be stepped up and improved, where necessary, so that all regionally cost-effective conservation can be acquired. Energy saving programs need to be evaluated to be certain the conservation resource is being acquired in the best possible way. And emerging technological advances in conservation need to be tested so their potential for the Northwest can be assessed.

The Council has determined that incremental conservation measures costing up to 11 cents per kilowatt-hour are cost-effective and should be acquired as soon as possible. This is because conservation as a resource has several advantages that are not captured in the 7.5 cents per kilowatt-hour avoided cost figure for generating resources. Electricity that is generated requires transmission and distribution lines, and energy is lost on its way to customers. Conservation has neither the added expense of transmission lines nor the line loss en route. Energy savings also have fewer environmental impacts than any of the generating resources included in this plan. Furthermore, many conservation programs closely track growth and decline in the economy.

Failure to purchase these environmentally sound and economical resources now could force acquisition of more costly and more environmentally damaging resources later. If only cheaper measures are installed, and higher cost measures are postponed, it will cost more and be much more difficult to return to the site to install additional measures. See Volume II, Chapter 14 for further discussion.

Activities designed to garner conservation resources for the region are divided into three general sections: 1) conservation acquisition,[2] 2) evaluation and verification of savings, and 3) resource assessment.

Targeted New Programs

The Council has noted that large amounts of conservation are available from specific sectors or industries where the decision-making process is fairly centralized. For example, about 130 megawatts could be saved by working directly with the 18 principle manufacturers of factory-built housing in the Northwest to add all regionally cost-effective efficiency measures in homes constructed in this industry. Approaching the relatively few manufacturers is much simpler than approaching thousands of purchasers of manufactured homes, or even the hundreds of retailers of such houses.

The Council has identified nine examples where targeted acquisition programs could be the most effective means of securing substantial amounts of energy savings. The Bonneville Power Administration and the utilities should begin developing and operating innovative programs designed to secure savings in the following areas:

Conservation 1: Operate conservation programs for large commercial and industrial customers.

Bonneville and the utilities should design and implement programs to secure energy savings from large commercial and/or industrial enterprises. Retail chains and franchises, or corporations with divisions spread throughout the region can contribute substantial amounts of energy savings with comparatively little administrative effort because decisions are made centrally. An efficiency change in one facility can be easily replicated at other facilities.

Conservation 2: Operate conservation programs for manufactured housing.

Bonneville and the utilities should develop and implement programs to garner energy savings in manufactured housing. As noted, nearly all the manufactured housing in the Northwest is constructed by about 18 companies located in the region. A program targeting these manufacturers would be easier to administer than a program that works only with housing consumers. By contracting directly with these manufacturers, it is more likely that the region will attain significant energy savings in this market.

Conservation 3: Operate conservation programs for electrical appliances and equipment.

Bonneville and the utilities should design and implement programs that influence manufacturers to produce appliances that are more efficient than applicable codes and encourage consumers to purchase these appliances. The best way to implement this action may be to create large, unified markets for appliances meeting certain efficiency levels. This can be accomplished through such items as rebates or other financial incentives that would apply throughout a utility's service territory. This approach will be most successful if coordinated with utilities in California and other western states outside the region.

The Council specifically endorses the "Golden Carrot" initiative devised by the Natural Resources Defense Council, Bonneville, the Pacific Gas and Electric Company and others. In the Golden Carrot initiative, utilities contribute to a fund that will be used to spur mass production of super-efficient appliances that exceed federal standards by substantial margins.

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2. Certain conservation activities reduce energy losses in the transmission and distribution system or improve the efficiency of electricity production. Energy savings from these activities accrue directly to the utility. Power sales are not affected. These activities are marked with an asterisk throughout this chapter.

Conservation 4:
Operate conservation programs for institutional facilities.

Bonneville and the utilities should work with school districts, and state and local governments, including state energy offices, to achieve energy savings in buildings used by these agencies. Recent experience suggests that this may be the only way to achieve significant penetration in this sector. In addition, because of state and local bond issuing abilities, efforts in this sector may be accomplished through shared financing.

Conservation 5:
Operate conservation programs for federal buildings and facilities.

Bonneville and utilities should pursue conservation efforts in federal buildings and facilities. Mechanisms need to be developed for utilities to secure conservation, following federal regulations regarding procurements. Tacoma City Light is in final negotiations with Fort Lewis on a plan to improve the efficiency of the fort. The experience gained in this negotiation should be used in other federal facilities in the Northwest.

Conservation 6:
Improve the efficiency of the transmission and distribution system.

Bonneville and the utilities should acquire all cost–effective energy from all transmission and distribution systems. Savings in the transmission and distribution of electricity are extremely attractive because they are generally low cost, have no lost revenue component, may save both energy and capacity, and have few, if any, environmental impacts.

Conservation 7:
Improve the efficiency of existing hydropower projects.*

Bonneville, hydropower operators and the utilities should secure cost–effective efficiency improvements at existing hydropower projects. Additional low–cost energy can be derived from efficiency improvements at many existing hydropower facilities. The Council has called for 110 megawatts of new energy from hydropower efficiency improvements. Hydropower project owners and operators should periodically assess efficiency potential and include cost–effective measures in their acquisition plans. Efforts to capture this resource at federal hydropower projects should be intensified.

The Council will work with interested parties to determine how improvements at hydropower facilities can be most efficiently acquired. Among other options, this effort should examine possible legislative actions and the development of efficiency improvement measures by third–party developers.

Conservation 8:
Secure energy savings through conservation voltage regulation.*

Northwest utilities should secure cost–effective energy savings through conservation voltage regulation. Low–cost energy savings can be secured with properly applied conservation voltage regulation. In this plan, the Council estimates that 100 megawatts of energy savings can be obtained from conservation voltage regulation. All utilities should examine the applicability of conservation voltage regulation to their distribution systems and implement it to the extent that it delivers cost–effective savings of electricity. Bonneville should assist its customer utilities in this endeavor.

Conservation 9:
Improve the efficiency of existing thermal projects.*

Bonneville and the utilities should secure cost–effective efficiency improvements in existing thermal projects. Additional low–cost energy can be derived from efficiency improvements at many existing thermal power plants. The Council estimates that 58 megawatts of new energy can be obtained from thermal power plant efficiency improvements. Thermal project owners and operators should periodically assess thermal efficiency improvement potential and include cost–effective measures in their acquisition plans.

Traditional Conservation Programs

While new conservation programs are being developed, it is important to maintain existing ones. Northwest governments, power suppliers and citizens have already created mechanisms to secure regionally cost–effective energy savings, but the pace of conservation acquisition must be accelerated and certain programs need design modifications to make them operate as effectively as possible. Long–term, stable and aggressive conservation programs are essential to this endeavor.

The following activities suggest improvements to some programs, expansions to others and several new programs to be implemented by Bonneville and the utilities.

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* See footnote 2 on page 2.

Conservation 10: Incorporate additional end uses in residential weatherization.

Bonneville and the utilities should expand residential weatherization programs to acquire conservation in all appropriate end uses during normal weatherization efforts. The key reason for a comprehensive program is to minimize administrative costs by capturing as much cost-effective conservation as possible during a single visit. This is a "one-stop shopping" approach to acquiring conservation resources in existing residences. In addition to traditional building-shell measures, financial assistance should be offered for cost-effective energy-efficient lighting, energy saving water appliances such as low-flow showerheads, as well as other water heater energy saving measures as appropriate (e.g., thermal traps, tank wraps and bottom boards). When appropriate, other appliances, such as efficient refrigerators and freezers, also should be encouraged by the program.

Conservation 11: Incorporate all regionally cost-effective measures in new residences.[3]

Bonneville and the utilities should modify current financial and technical assistance marketing programs in new residences (e.g., Super Good Cents or Comfort Plus) to include all regionally cost-effective measures in electric space heating, water heating and appliances.

The goal of this program is to secure all savings that would be achieved if all new electrically heated residences included all regionally cost-effective space heating, water heating and appliance energy savings. There are regionally cost-effective space heating conservation measures that are not captured by current programs, such as Super Good Cents and Comfort Plus. These measures need to be introduced to the building community and given support to increase their penetration. In addition, there are regionally cost-effective conservation opportunities in other end uses, such as water heating, lights, refrigerators and freezers, which could be secured when the building is constructed.

Current programs need to be changed into full-spectrum conservation programs. The proposed programs should continue to demonstrate the feasibility of improving energy efficiency. The programs should be continued as long as they remain regionally cost-effective.

Financial assistance is an essential element of these programs. In addition to the financial assistance offered by Bonneville under this program, the servicing utility may find it necessary to make higher acquisition payments to consumers to encourage greater market penetration. An alternative approach for securing high penetration rates without significant utility financing is to ensure that lenders incorporate the value of the reduced electric bills in their mortgage calculations so homebuyers can finance the efficiency measures (see Conservation 15).

Conservation 12: Include efficient electric appliances in non-electrically heated houses.

Design and implement programs or methods to acquire conservation from electric appliances in new and existing houses that are not heated with electricity. Recommended revisions to residential weatherization and new housing programs only reach those houses with electricity as their primary heating source. It is important to achieve cost-effective electrical appliance savings in houses that are not heated with electricity. Some of these efforts will need to dovetail with acquisitions targeted at manufacturers (see Conservation 3).

Conservation 13: Secure all regionally cost-effective savings in commercial buildings.

Bonneville and the utilities should modify programs to secure all regionally cost-effective savings in new and existing commercial buildings. Bonneville's Energy Smart Design program, for example, should be modified to target all regionally cost-effective savings in new and existing commercial buildings. Even new commercial buildings built to recently revised energy codes leave out some cost-effective measures. Both technical and financial assistance will be essential to spur conservation investments in new and existing commercial buildings.

Conservation 14: Develop energy code adoption program for commercial sector.

Bonneville and the utilities should develop an energy code adoption program, including technical and financial assistance, for the commercial sector. The Council's model conservation standards were designed to be adopted into state and local building codes to incorporate at least those savings that minimize buildings' life-cycle costs for construction and operation. Utilities should offer financial assistance to reimburse builders for incremental costs that are beyond those required to meet enhanced energy codes and that are at or below the regionally cost-effective level.

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3. These programs ensure compliance with the model conservation standards for utility conservation programs for new commercial buildings (see Volume II, Chapter 12).

Conservation 15: Expand the lender and appraiser program.

Bonneville should continue and expand the lender and appraiser program so credit is given in mortgage calculations for energy efficiency in new and existing houses, and commercial buildings, if appropriate. Conservation can be encouraged if lenders recognize that more money will be available to the purchaser to meet mortgage payments if the building being purchased is energy-efficient. Great strides already have been made in securing such lender policies in new housing. Utilities should continue to work in cooperation with Bonneville, the Council, state energy offices and lending institutions.

Conservation 16: Expand education and vocational training in conservation.

Continue and expand education, and professional and vocational training for all parties who will be involved during regionwide conservation acquisition programs. Bonneville, in cooperation with the utilities, state energy offices, the Council and other interested parties should sponsor an assessment of training needs and form an advisory committee to develop a strategy to improve the qualifications of professionals and paraprofessionals delivering energy-efficiency services. Education and training efforts should focus initially on the commercial and industrial sectors.

This long-term effort is crucial to the success of conservation acquisition. The strategy should at least address each of the following areas: 1) continuing education for professionals currently working in the field; 2) training for allied tradespeople serving businesses and industry; 3) outreach and education for managers on the importance of employing building operators who have the necessary qualifications and certifications; 4) academic training through four-year college and community college degree programs that will help address the long-term shortage of qualified personnel; 5) near-term strategies to alleviate the immediate need for qualified personnel through a mixture of academic and experiential training; 6) establishing "nodes of expertise" to support implementation of regional programs to market and monitor major energy saving opportunities, such as those relating to motors, compressors, HVAC equipment and controls.

The region already has a start with certain types of educational activities through such facilities as the Lighting Design Lab in Seattle, Portland General Electric's Energy Resource Center in Tualatin, Oregon, the Electric Ideas Clearinghouse operated by the Washington State Energy Office, and the Energy Analysis and Diagnostic Center at Oregon State University. Such information and training programs should continue to be supported. In addition, efforts should be expanded to develop education programs in lighting technologies, such as those initiated by the California Energy Commission.

Conservation 17: Support enforcement of energy codes.

Bonneville, the utilities and the region's public utility commissions should work together to design aggressive programs to ensure adequate enforcement of all energy codes aimed at saving electricity. Programs should include education, technical support and financial assistance, where necessary. Programs should be continued as long as they remain cost-effective. Conservation codes must be enforced to achieve energy savings and to make conservation a reliable resource. Inspections of completed structures should be improved to be sure the resource is actually acquired. Local building inspection offices with heavy work loads often focus on issues of health and safety as higher priorities than energy codes. All parties must work together to ensure energy code enforcement, even if this means an active role for the utilities in inspecting new buildings. The commissions should provide appropriate rate treatment for enforcement actions and programs operated by regulated utilities.

Federal, State and Local Government Conservation Acquisition

Governmental actions will be crucial to securing conservation. As discussed in the Action Plan in Volume I, federal, state and local actions are needed to adopt efficient energy codes and standards that apply to all end uses of electricity. Many governmental agencies have tools at their disposal that are not available to utilities. For example, state regulatory authorities could play a key role by adopting policies that will remove the regulatory barriers to conservation acquisition. The following activities should be pursued by federal, state and local governments to help secure conservation.

Conservation 18: Develop policies to reward conservation acquisition.

Utility regulatory authorities should establish policies that reward aggressive conservation acquisition. Currently, utility profits are tied to kilowatt-hour sales. Because conservation reduces kilowatt-hour sales, profits are reduced. Unless this condition is changed, utilities have a disincentive to conserve energy. A partial solution is to decouple profits from kilowatt-hour sales. Additional conservation acquisition could be fostered by providing positive reinforcement. Utilities that successfully acquire large amounts of conservation should be rewarded, possibly through allowances of higher profits. The Council intends to work with regulators and utilities in solving this problem.

Conservation 19: Form partnerships to secure energy savings.

Bonneville and the utilities should form partnerships with local governments to develop aggressive programs at the community level that will market and capture all cost-effective conservation. Concentrated activity at the community level, using the expertise of local government associations, can augment virtually all conservation efforts. Local governments provide an important leadership role in carrying out a wide variety of economic and energy program activities.

Conservation 20: Establish state and local building codes, solar ordinances, recycling efforts, etc.

State and local governments should help implement this power plan through such activities as the adoption and enforcement of energy-efficient codes, passive-solar ordinances, and the encouragement of recycling, which results in energy efficiency. Actions state and local governments have already taken in adopting energy-efficient building codes have been pivotal to the success of conservation over the last few years. Similar strong actions need to be taken in other areas as well, such as solar access ordinances and recycling. Solar access ordinances save energy and lower the cost of conservation because they preserve the opportunity to replace some uses of electricity with direct applications of sunlight. Recycling can result in the use of less energy to produce products and can extend the availability of natural resources. Other actions may include exploring financing mechanisms, such as issuing state bonds, to secure conservation in state and local government buildings, or investigating new methods to acquire funds for the hiring and training of building inspectors, who are crucial to ensuring the efficiency of new and remodeled buildings.

Conservation 21: Set user fees based on efficiency.

Utilities and utility regulatory authorities should consider adopting fees based on the efficiency of the end use of electricity, in order to encourage consumer adoption of all regionally cost-effective conservation. In areas or end uses where codes do not include all regionally cost-effective measures or are pre-empted by federal law from doing so, user fees can be a successful way to encourage efficiency and place the cost of inefficiency on the appropriate person. An inefficient house, for example, would be more expensive to hook up to electric service than an efficient house. If fees are based on the efficiency of the home, a homeowner has the choice of participating in a utility model conservation standards program or paying the user fee. The user fee should reflect the cost to the power system of serving an inefficient load. Charges should be developed for all appropriate sectors and end uses.

Conservation 22: Implement rate treatment for conservation expenditures.

Utility regulatory authorities should provide appropriate rate treatment for conservation assessment, development and acquisition. It is important that utilities be able to recover legitimate costs of developing the conservation resource. This includes the assessment of the conservation resource, research and development of promising conservation, as well as direct acquisition, including code enforcement assistance. The Council intends to work closely with utilities and regulators to achieve this objective.

Conservation 23: Encourage conservation actions of permitting, zoning and planning agencies.

Building permitting, zoning and planning agencies should foster the development of more efficient buildings with the help of Bonneville and the utilities. These agencies are aware of proposed buildings very early in the design process. This early stage is the best time to lay the groundwork for incorporating energy conservation measures, especially for new commercial buildings. In addition, these agencies have significant leverage with developers. Building permitting agencies deal with building developers all the time and understand the types of incentives that motivate developers.

Conservation 24: Establish local, state and federal health protection criteria for conservation resources.

Responsible local, state and federal health and environmental agencies should establish adequate conservation-related health protection criteria that the Council and the region can rely on in conservation resource decisions. The Council and the region's utilities have tried to maintain or improve the environment when taking conservation actions. This has been most obvious in connection with indoor air quality. However, it would be better if decisions in this area could be made by appropriate health and environmental agencies, instead of the utility system. These agencies need to take the lead in setting standards and criteria that the utility system can follow to ensure public health and safety.

Conservation 25: Institute utility and government conservation competitions.

Associations of utilities, and state and local governments should consider competitions among their members to help develop a team spirit regarding energy conservation acquisition. These competitions could be modeled after the Super

Good Cents annual award banquets. Recognition should be given to outstanding performers.

Evaluation, Verification, Implementation

Conservation 26: Monitor and evaluate conservation efforts.

Bonneville and the utilities should monitor and evaluate conservation efforts to verify the cost-effectiveness of the resource, improve future conservation acquisition efforts and help guide decisions on further acquisition. The data and results of the evaluations and monitoring must be made widely available. Monitoring and evaluation are crucial, but they should be accomplished in a manner that will not compromise the acquisition of cost-effective resources. Evaluation should be used to modify conservation programs, not to penalize past activities that were based on the best information available at the time. Efforts should focus on those conservation resources whose performance is relatively unknown.

Impact evaluations are necessary to determine how much conservation is acquired at what cost and how much of the resource remains to be acquired. Failure to monitor and measure performance carefully could result in a resource that is undervalued, overly expensive or not performing as anticipated. Process evaluations, which examine and critique the effectiveness of acquisition programs, also are needed.

Conservation 27: Pool resources and data.

Bonneville and the utilities should accomplish savings verification, evaluation and monitoring activities using pooled resources and data. For example, regional cost data for commercial energy conservation measures may serve as the basis for analyzing the programs of several utilities.

Conservation 28: Share information on acquisition plans.

To facilitate the acquisition of conservation resources, the Council, Bonneville and the region's utilities need to exchange information on the utilities' conservation acquisition plans. (See also Supporting Activities 1.) These plans should include budgets, time lines, staffing levels, proposed method of acquisition (including payment levels), targeted market sectors and expected penetration rates for conservation acquisition. In addition, the plans should review estimates of the amount and cost of conservation already acquired. This activity is needed to inform planners on the status of conservation acquisition, the anticipated schedule for further acquisition and the remaining conservation potential. Where appropriate, individual utilities may wish to develop these plans jointly with other utilities and/or with the assistance of Bonneville and utility associations.

Conservation 29: Centralize data base on technical aspects of conservation.

Bonneville needs to take the lead in organizing technical information on performance of conservation and end-use data in a uniform format so that information collected by all parties in the region can reside in a centralized location and be accessible to all parties for analysis. Learning from experience is an essential piece of securing the conservation resource. Unless information on the technical performance of conservation is collected and analysis is conducted to help us understand where to improve future efforts, we will not be successful at acquiring all conservation in a cost-effective manner. This action is intended to be a joint effort by all parties in the region to consolidate data and make it widely available for analysis. Bonneville should take the lead in organizing the effort. It would include the End-Use Load and Conservation Assessment Program data.

Conservation 30: Centralize data base on conservation programs.

Bonneville, in cooperation with utilities, should develop a data base on the successes and problems associated with implementation of conservation programs. Perhaps the largest barrier blocking acquisition of conservation is the question of how to successfully implement energy-efficiency programs. For example, what are the critical elements of program design? What will be needed in terms of people resources per megawatt saved? What kind of skills should those people have?

The answers to these and other critical implementation questions already exist, but they are dispersed across the region and the nation. These answers need to be gathered and the information compiled and shared across the region, so conservation planners and implementors can learn from the successes and mistakes of others. This data base would be similar to the North American Electric Reliability Council's 1983 Generating Availability Data System. It will help speed successful and efficient acquisition.

Conservation 31: Meet annually to share conservation experiences.

The Council, in cooperation with Bonneville and the utilities, will coordinate at least annual meetings to facilitate the sharing of information on the successes and problems of the conservation acquisition efforts. These meetings will use, among other resources, the data base on key implementation issues to be developed by Bonneville and the utilities, described above. The goal of these meetings is to share information among utilities and others on the features of programs that are working well and those that are not.

Resource Assessment

While acquiring conservation resources that already are known to be cost-effective, the region needs to continue research and demonstration of newer technologies and emerging conservation measures. These measures could supply significant savings if they prove feasible. Ongoing efforts to define the cost and size of the conservation resource in all sectors, and increase conservation cost-effectiveness and availability, need to continue. All utilities in the region should cooperate in this work.

The region also needs to continue investigating conservation markets and marketing strategies. These efforts are important for improving methods of acquiring the conservation resource.

Conservation 32: Research, develop and demonstrate new conservation technologies.

The Council, Bonneville, Northwest utilities and other interested parties should cooperate on research, development and demonstration activities aimed at proving new conservation technologies. The Council will convene a committee of interested parties to help identify and coordinate specific actions for cooperative research, development and demonstration. (See Supporting Activities 6.) These activities are needed to help realize the large conservation potential identified for acquisition in this plan, and to help discern and remove barriers to further conservation. At a minimum, the activities should include a continuation of the Residential Construction Demonstration Program and initiation of similar programs in the commercial and industrial sectors. Additionally, the committee should look at promising conservation resources and design actions to make them viable options in the near future.

Conservation 33: Assess and acquire cost-effective on-site renewable resources.

Assess the cost-effectiveness of on-site applications of renewables on a site-specific basis as individual applications become evident and acquire those that are cost-effective. Because on-site renewables need to be assessed on an individual, site-specific basis, there can be no general statement whether or not to acquire them. However, as individual applications are judged to be cost-effective, they should be acquired.

Conservation 34: Monitor conservation voltage regulation.

Bonneville and the utilities should monitor the cost and performance of conservation voltage regulation as applied to Northwest distribution systems and secure energy savings where appropriate. It is likely that conservation voltage regulation can save significant amounts of electricity at low cost. Several Northwest utilities have initiated efforts to secure this resource. These efforts should be replicated as models for other distribution feeders and systems. The results of ongoing efforts to implement conservation voltage regulation should be made available to interested utilities. Periodic seminars and technical documents detailing successes and failures in implementing conservation voltage regulation would be effective ways to transfer the technical and cost information needed to implement conservation voltage regulation.

Conservation 35: Reassess hydropower efficiency improvements.

Owners and operators of existing regional hydropower projects, working with Bonneville and the Council, should reassess the potential for hydropower efficiency improvements. The last regional assessment of hydropower efficiency improvements occurred during preparation of the 1986 Power Plan. At that time, only turbine runner and governor improvements were considered to be available resources because of uncertainties regarding the cost and performance of other promising measures. Since that review, several owners and operators of existing hydropower projects have undertaken these and additional efforts to capture cost-effective efficiency improvements. It is now clear that additional low-cost energy can be derived from efficiency improvements to many existing hydropower facilities, but the size and reliability of that resource and its cost still need to be confirmed.

Conservation 36: Assess thermal plant efficiency improvements.

Owners and operators of existing regional thermal power plants, working with Bonneville and the Council, should assess the potential for energy savings from thermal plant efficiency improvements. Several owners and operators of existing thermal power plants have identified potential efficiency improvements to these resources, and have included this resource potential in their least-cost plans. Additional potential energy savings are thought to exist. Many improvements to existing thermal power plants appear to be cost-effective within the next several years, and the Council has included this resource in its plan for acquisition.

Hydropower

An estimated 410 megawatts of firm energy can be obtained by development of new hydropower projects and additions to existing projects. This energy, which excludes new energy from efficiency upgrades to existing hydropower plants (discussed as a conservation resource), would cost from 2.4 to 13.4 cents per kilowatt-hour. Further discussion of new regional hydropower potential is provided in Volume II, Chapter 8.

Environmental impacts pose the greatest constraint to the development of new hydropower projects. Hydropower projects may cause biological, aesthetic, recreational and socioeconomic impacts that may be difficult to mitigate. Compliance with the Council's protected areas policies and other conditions of development set forth in this power plan and the Columbia River Basin Fish and Wildlife Program should help minimize the environmental impact of new hydropower development. Upgrades, expansions and improvements to the efficiency of existing projects generally pose few environmental problems. Some hydropower upgrades may even mitigate existing project impacts.

Hydropower 1: Acquire low–cost hydropower.

Bonneville and the utilities should immediately begin the process of acquiring hydropower at the most cost–effective and environmentally sound sites in the Northwest. The Council estimates that about 150 megawatts of new, low–cost hydropower could be acquired by the year 2000. These new projects must comply with the protected area requirements of the Columbia River Basin Fish and Wildlife Program and with the conditions for hydropower development detailed in Volume II, Chapter 11 of this plan.

Hydropower 2: Option an additional 100 megawatts of low–cost hydropower.

Bonneville and the utilities should begin siting, licensing and designing 100 megawatts of hydropower projects that are somewhat more expensive than those called for in Hydropower 1. The Council is not recommending completion of these projects at this time. Instead, through the options process, resource development can be divided into several decision steps.

The first steps are the least costly and most time consuming—siting, licensing and designing the projects. These steps can and should be taken now. Decisions to complete the projects, a more costly process than the earlier steps, can then be made as load–growth monitoring points up the need for these resources.

Electricity from these projects may not be needed by the year 2000, but the projects could still be cost–effective to complete if loads grow rapidly. If load growth does not increase quickly, these projects could be held for up to four years under current Federal Energy Regulatory Commission regulations. All of these projects must comply with both the Council's protected areas requirements and the conditions for hydropower development detailed in Volume II, Chapter 11 of this plan.

Hydropower 3: Maintain all hydropower data bases.

Bonneville, in cooperation with the Council and the U.S. Army Corps of Engineers, should continue to maintain the Pacific Northwest Hydropower Data Base and Analysis System, the Rivers Information Systems in each state, System Planning Data, the River Reach File (both tabular and graphic components) and the Anadromous Fish Study. An agreement should be established among participants regarding long–term funding of this effort.

Hydropower 4: Assess ability to operate power system to serve the needs of salmon better.

The Council will explore innovative ways to plan for and operate the region's entire power system so that it best serves the needs of salmon. The Council believes that the region's power system can be better adapted to the salmon's life cycle, and is committed to exploring the right balance between a cost–effective power supply and the survival of marginal salmon stocks. In the course of amending the Council's Columbia River Basin Fish and Wildlife Program in 1991 and 1992, the Council will explore these issues. The Council will also continue to work with Bonneville, the Corps of Engineers, the Fish Passage Center and others, to monitor the effects on fish and wildlife of changes in river operations.

Hydropower 5: Determine environmental impacts of the hydropower system and incorporate costs into operational, and fish and wildlife decisions.

Bonneville should determine the environmental impacts of the hydropower system and incorporate those costs into operational, and fish and wildlife decisions. Bonneville is currently in the process of quantifying the environmental costs of new resources. The Council believes that this effort should be expanded to include the environmental costs of operating the existing hydropower system.

Biomass

Biomass fuels are defined as any organic matter that is available on a renewable basis. This material includes: forest residues, wood product mill residues, agricultural field residues, waste products from animals and food processing, agricultural and forest crops grown for fuel and municipal solid wastes (i.e., garbage collected from residences, commercial buildings and industrial firms). The heat content, moisture levels and other physical characteristics of biomass resources differ widely.

The total production of electricity from biomass could be as high as 2,700 megawatts, but competing uses, collection costs and seasonal variations in supply result in a much lower estimate of availability. Activities aimed at a better understanding of these issues could increase the amount of power derived from biomass-fired resources.

In this plan, the Council estimates that about 600 megawatts of cost-effective generation fueled by biomass will be available. This estimate includes about 480 megawatts that will be produced in cogenerating facilities (see cogeneration, below), about 90 megawatts of stand-alone biomass-fired plants and about 30 megawatts of electricity from plants fired with municipal solid waste. An in-depth discussion of biomass fuel availability and prospects for using these fuels for electric power production is included in Volume II, Chapter 8.

Biomass 1: Acquire cost-effective biomass resources.

Bonneville and the utilities should acquire, as needed, all cost-effective and environmentally sound new, biomass-fueled resources. The Council has identified 650 total megawatts of low-cost cogenerated resources,including biomass-fueled ones, that could be needed in the region by the year 2000 (see "Cogeneration" below). Because of the economics of cogeneration, most new, biomass-fueled electricity is likely to come from cogeneration plants. (Stand-alone biomass-fueled plants are more expensive than biomass-fueled cogeneration facilities.) All biomass resources must comply with the acquisition principles detailed in Volume II, Chapter 11, as well as with the siting, design, construction and operating criteria being developed by the Council in conjunction with state siting agencies and other interested parties in the Northwest (see Supporting Activity 15).

Biomass 2: Participate in Pacific Northwest and Alaska Bioenergy Program.

Bonneville should continue to participate in the Pacific Northwest and Alaska Bioenergy Program and to look for additional opportunities to take part in nationally funded ventures of this sort. The region has benefitted from participation in this program and can benefit from other programs like it. In general, coordinating the region's activities with those in other parts of the country and world is an effective way to increase our understanding of the potential of all resources.

Biomass 3: Develop confirmation plan for biomass.

The Council's Research Development and Demonstration Advisory Committee should develop a schedule of activities like those developed for other promising renewable resources to foster the orderly development of biomass resources. As indicated, the potential for biomass appears to be much greater than the amounts included in this plan. A detailed plan to address and resolve the issues surrounding competing uses of biomass, biomass collection and storage procedures, and biomass conversion technologies could identify ways to make more of this resource available.

Cogeneration

Since 1978, cogeneration (the simultaneous production of heat and electricity) has been specifically encouraged by the Public Utility Regulatory Policies Act (PURPA), various tax provisions, and fuel use restrictions in the Powerplant and Industrial Fuel Use Act. PURPA requires utilities to purchase electricity from qualifying cogeneration facilities at the utility's avoided cost for new generating capacity and to provide back-up electricity and supplemental power to cogenerators at fair rates. The relevant portions of the Fuel Use Act and the tax provisions have been repealed or weakened recently, but PURPA remains in effect. These conditions have fostered the development of standardized, reliable and inexpensive cogeneration systems of different sizes. This, along with the decline of natural gas prices, has made cogeneration economically attractive in a much wider range of applications.

Recent estimates show that more than 40,000 megawatts of cogeneration capacity currently exist in the United States. According to recent data collected by the Bonneville Power Administration, there is approximately 900 megawatts of existing cogeneration capacity in the Pacific Northwest. This capacity is concentrated (85 percent) in the pulp, paper, lumber and other wood products industries.

Future cogeneration potential in large industrial applications is often a question of economics, rather than technology. The region's industries hold a fairly substantial potential for cogeneration, but low electricity rates and ample, reliable supplies of electricity have discouraged cogeneration development here.

The integration of cogeneration into the electric utility system requires some changes in the way utilities typically have done business. In the past decade, PURPA provided the stimulus to address these changes. Further encouragement for cogenerators, as well as for other independent power producers, is coming from changes in the utility regulatory environment, as discussed in the Council's staff briefing paper 89-31, "The Changing Utility Environment."

The Council estimates that more than 1,700 megawatts of cost-effective power will be available from natural gas-fired cogeneration plants. An additional 480 megawatts of cost-effective power is available from biomass-fired cogeneration plants. An in-depth discussion of regional cogeneration potential is provided in Volume II, Chapter 8.

Cogeneration 1: Acquire low-cost cogeneration.

Bonneville and the utilities should acquire, as needed, all cost-effective and environmentally sound cogeneration resources available in the region. The Council estimates that approximately 650 megawatts of cost-effective cogeneration could be needed by the turn of this century. Cogeneration projects that match their electricity output with industrial heat requirements (known as thermally matched projects) will maximize the efficient use of natural gas or biomass and thus have minimum impacts on the environment. For this reason, the Council prefers such systems over non-thermally matched ones. All new cogeneration resources should meet the acquisition principles described in Volume II, Chapter 11, as well as the siting, design, construction and operation criteria for cogeneration being developed by the Council in conjunction with state siting agencies and other interested parties in the Northwest (see Supporting Activity 15).

Cogeneration 2: Option 750 megawatts of cogeneration resources.

Bonneville and the utilities should seek developers and work with them to secure the necessary approvals and contracts to enable the rapid installation of cogeneration equipment sufficient to produce 750 megawatts of energy in regional industrial facilities, as need and opportunities arise. This is in addition to the resources acquired in Cogeneration 1.

Cogeneration facilities have shorter lead times than some other resources. However, installation of cogeneration facilities is often contingent upon expansion or rehabilitation of "host" facilities. If utilities could negotiate agreements with potential resource developers in advance of need, development and installation of cogeneration equipment could be expedited.

As described in activity Cogeneration 1, the Council prefers thermally matched cogeneration projects. Cogeneration projects optioned in response to this activity also should conform to the acquisition principles described in Volume II, Chapter 11 of this plan, as well as the siting, design, construction and operation criteria for cogeneration being developed by the Council (Supporting Activity 15).

Cogeneration 3: Refine estimates of cogeneration potential.

Bonneville, working with the Council, the utilities and other interested parties, should continue to refine estimates of regional cogeneration potential. Because of the important role that cogeneration is expected to play in the region's future power system, it is important that good estimates of regional cogeneration potential be available.

Hydropower Firming

The Northwest hydropower system produces on average about 4,100 megawatts of nonfirm energy per year, mostly between January and July. This nonfirm energy serves the top (interruptible) quartile of the Bonneville Power Administration's direct service industry load and displaces the output of thermal plants in the Northwest and in the Southwest.

Northwest nonfirm energy, in conjunction with a back-up resource, could be used to meet firm loads in the Northwest. This combination resource has been described as "firming nonfirm" or "nonfirm strategies." Although the Council's analysis of firming has focused on the use of natural gas-fired simple- and combined-cycle power plants as the back-up resources, there are other possible alternatives, including purchased power, interruptible contracts and contracts for use of energy from out-of-region thermal plants.[4]

The Council, when exploring the use of this nonfirm energy to meet regional firm loads, considers the water budget[5] and other hydropower operational requirements to improve the survival of fish and wildlife as firm constraints on hydropower system operation. The Council expects the flows called for in the Columbia River Basin Fish and Wildlife Program or future amendments to the program, including flows established in response to threatened or endangered species listings, to continue to be firm constraints on system operation. Future fish flow requirements may convert additional firm hydro energy to nonfirm energy. If so, this additional nonfirm may increase the amount, on average, that turbines can be displaced, and thus increase the relative cost-effectiveness of the various firming strategies.

Hydropower Firming 1: Option up to 1,500 megawatts of cost-effective hydrofirming resources.

Bonneville and the utilities should secure options to develop approximately 1,500 megawatts of resources to back up nonfirm hydropower. The purpose of this activity is to prepare for the timely development of resources to back up additional nonfirm hydropower, if needed; to confirm the feasibility of alternatives for backing up nonfirm hydropower; and to improve understanding of the potential of

4. These alternatives are not precisely equivalent to resources built in the region, especially gas-fired units, which can be converted to burn coal-gas. Although they could provide the same firming benefits, they will not necessarily provide the hedge against high natural gas prices that the coal gasification option would. This difference should be considered when resources to firm nonfirm hydropower are being acquired.

5. The water budget is an increase in flows between dams on the Columbia and Snake rivers to improve survival of juvenile salmon migrating downstream.

the hydrofirming resource. This effort should consider extraregional transactions and increased interruptible loads as possible alternatives to combustion turbine firming strategies. (See footnote number 4.) One approach to identifying alternative strategies would be to issue a request for proposals specifically targeted at backing up nonfirm hydropower.

Before acquiring any hydrofirming resources, Bonneville and the utilities should evaluate the effects of these resources on hydropower system operating constraints. Hydrofirming resources should comply with the acquisition principles described in Volume II, Chapter 11, as well as applicable siting, design, construction and operation criteria for generating resources developed by the Council as described in Supporting Activity 15.

A significant component of the effort to back up additional nonfirm hydropower likely will be natural gas-fired combustion turbines. Securing options on these plants should include the identification and licensing of transmission corridors for connecting plants to the regional grid. Fuel supplies should be identified and plans prepared for the development of needed fuel transportation facilities. Power plant feasibility studies and preliminary engineering should be completed for the selected sites, focusing on technologies featuring high-efficiency, low emissions, short lead time and modular development.

Because most alternatives for backing up nonfirm hydropower will likely require irregular and occasionally very significant revenue requirements to cover the operating costs of the back-up resource, the options for backing up nonfirm hydropower should include procedures to smooth out these possible fluctuations in revenue requirements.

Because of the uncertainty of the future cost and availability of natural gas, and the possible need for coal-fired resources to meet high load growth or to offset resource uncertainties, the region should be prepared to develop coal-fired power plants, if necessary.

At this time, the Council believes that this capability can best be secured by planning for the use of gas-fired combined-cycle power plants that could be retrofitted with coal gasifiers. At least two-thirds of any gas-fired resources optioned to back up nonfirm hydropower should be located at sites suitable for conversion to coal gasification. By the time coal-fired power plants are needed, however, some other technology, such as pressurized fluidized bed combustion, might be preferable to gasification.

To achieve the needed capability, the Council recommends that sites selected for the development of combustion turbines also should have the necessary land, fuel transportation access and permits to allow for possible future conversion to coal gasification. Factors that should be considered in selecting these sites include:

- Proximity to transmission services.
- Proximity to load centers.
- Proximity to natural gas supplies.
- Proximity to transportation systems suitable for delivering coal.
- Existing thermal power plant sites that would minimize conversion of additional land to generating plant use.
- Availability of existing generating plants or other facilities from which emission offsets could be obtained.

Among candidate sites are the Creston, Boardman and Centralia power plant sites.

Washington Water Power has available a licensed site for future construction of coal-fired generating units located four miles southeast of Creston, Washington. Land options, licensing permits and a state Site Certification Agreement are being maintained by the company, in order to keep this site available for future resource needs. The company worked with the Washington Energy Facility Site Evaluation Council to extend the Site Certification Agreement for five years. The company has received extensions to the Prevention of Significant Deterioration Permit for Creston. To accommodate Creston's Air Contaminant Permit, Washington Water Power will provide new "Best Available Control Technology" analyses to be approved by the Site Evaluation Council at the time a decision is made to construct the project. The license for Creston could be amended to accommodate new technologies, such as coal gasification or fluidized bed designs. This would position Creston to be a more environmentally acceptable energy resource within the region.

Because the Creston site appears to face the fewest constraints for the development of new central station generating plants, the Council recommends that the Creston licenses be maintained for the development of coal-fired power plants to ensure regional flexibility in planning for the future. Additional studies will be needed to determine whether the site is capable of being used for gas-fired combined-cycle combustion turbine power plants that can be converted to coal gasification.

The Centralia site is located in western Washington near the city of Centralia. A two-unit coal-fired power plant is located at this site. This plant has historically relied on coal from adjacent mines, but recently has also been burning coal shipped in by rail. A natural gas pipeline runs near the site. Because of this site's proximity to the Puget Sound area, it is attractive for helping to mitigate problems with voltage stability. The Centralia site could potentially accommodate additional gas or coal-fired generation. Because of possible airshed constraints, emissions from additional facilities may have to be closely controlled. Offsets may be available from the existing units at this site.

The Boardman site is located in eastern Oregon near the intersection of two major gas pipelines. The site originally was planned for several power plants, one of which, a coal-fired power plant, was built. Licenses for additional plants are in effect, but are nearing expiration. The Boardman site could potentially accommodate additional gas or coal-fired generating plants. Offsets may be available from the existing plant at this site.

Hydropower Firming 2: Develop data on central station thermal generation.

Bonneville, the utilities and the Council, in cooperation with other interested parties, should continue to develop and maintain information concerning the cost and performance of central station thermal generating technologies. Because of the important role of central station generating technologies in this plan, it is important that reliable information be available concerning the cost and performance of these technologies, and the price and availability of their fuels.

This effort should include continuation of Bonneville's Comparative Electric Generating Study, or equivalent technology assessments. Consideration should be given to cooperative ventures with the Electric Power Research Institute (EPRI), wherein EPRI technology assessments are broadened to include cases applicable to the Pacific Northwest.

Priority should be given to monitoring and assessment of advanced generating technologies using natural gas or coal. These include coal gasification combined-cycle power plants, pressurized fluidized bed coal-fired power plants, advanced combustion turbine designs (including steam-injected, intercooled and humid-air turbines), and fuel cell power plants. These assessments should include sensitivity studies considering 1) alternative Pacific Northwest sites, 2) environmental controls representing best available technology, and 3) alternative fuels available to Pacific Northwest plants.

Technology assessments should be consistent with the guidelines established for the Bonneville Comparative Electric Generating Study.

Nuclear

In the Northwest, two nuclear units of conventional design—Washington Public Power Supply System nuclear projects 1 and 3 (WNP-1 and WNP-3)—are partially completed and are being preserved. Together, these units could produce about 1,680 average megawatts of energy. Additional discussion of the cost and availability of WNP-1 and WNP-3, the issues associated with preservation, completion and operation of these plants, and the status of advanced design efforts are provided in Volume II, Chapter 8.

Nuclear 1: Determine whether WNP-1 and WNP-3 should be preserved, completed or terminated.

Bonneville and the Supply System should undertake the work necessary to determine whether the issues associated with WNP-1 and WNP-3 are resolvable in order for the region to make a fully informed judgment in the next power plan whether 1) to continue preserving the plants, 2) to construct either or both plants if needed, or 3) to terminate them.

The Council is not calling for the start of construction of either of the Washington Public Power Supply System's unfinished nuclear projects (WNP-1 or WNP-3). Nor is it calling for a change in the preservation status of these plants.

WNP-1 is located at Hanford, Washington, and is 65 percent complete. WNP-3 is at Satsop, Washington, and is 76 percent complete. Bonneville and its customers are spending approximately $11 million[6] per year to preserve these two plants.

The Council maintains that it is time to determine whether continued preservation of these plants is a prudent insurance policy. That is, in the event that generating resources of this magnitude are needed, would it be possible to complete construction and cost-effectively operate these plants? If not, they should be terminated.

There are issues that would have to be resolved before these plants either could be completed or terminated. For example, in many of the future scenarios analyzed in this plan, the utilities most likely to need the plants are not the public utilities that own them. There are a number of questions about how power from the plants could be transferred to utilities that may need it.

There also is controversy about the agreements that control the financing, budgeting and management of these projects. Other issues include public opposition to nuclear power, compliance with the National Environmental Policy Act, the Washington Initiative 394 settlement requiring cost-effectiveness studies prior to resuming construction, and licensing by the U.S. Nuclear Regulatory Commission.

Other issues would have to be resolved if the plants were terminated. For example, the legal agreements that control these projects offer very little guidance about how a decision to terminate would be made, or what would happen to the assets if the plants were terminated. There are questions regarding the effect of termination on the outstanding bonds issued for these projects. There are also unresolved issues about the extent and cost of restoring the construction sites. For example, what are the site restoration requirements upon termination? What are the costs associated with site restoration? How different are the site restoration and decommissioning costs, if the plants are terminated now versus after they have been operated? When does site restoration have to begin and when does it have to be completed? Could the sites be used for other energy resources?

Bonneville and the Supply System should undertake the work necessary to determine whether these issues are resolvable in order for the Council and the region to make a fully informed judgment in the next power plan whether

6. This figure does not include property taxes on the portion of WNP-3 owned by investor-owned utilities because the assessed value on that portion is under dispute.

1) to continue preserving the plants, 2) to construct either or both of the plants if needed, or 3) to terminate them. Before any significant step is taken that would alter the current status, whether to commence site construction (or financing for such construction) or to terminate, the Council must find that the proposed action is consistent with the plan.

Bonneville and the Supply System should report to the Council by 1994 on how outstanding issues related to preservation, construction and termination, can be resolved.

Geothermal

(Note: Activities to confirm the cost, viability and availability of geothermal resources were proposed by the Council's Research, Development and Demonstration Advisory Committee. A more complete discussion of the committee's analysis is contained in Appendix 1–A at the end of this chapter.)

The regional geothermal potential may exceed 4,600 megawatts, at costs ranging from 9.5 to 10.5 cents per kilowatt-hour. Some of this potential could be obtained by development of basin and range geothermal resources, such as those that have been developed in California, Nevada and Utah. Because this type of resource has been demonstrated elsewhere, the Council considers 350 megawatts of geothermal energy from Northwest basin and range areas available for the resource portfolio of the 1991 Power Plan.

The bulk of the regional geothermal potential would be from the Cascade geologic province. But the feasibility of developing Cascade geothermal resources has not been demonstrated. For this reason, the principal focus of these activities is to resolve uncertainties associated with development of the geothermal resources of the Cascades. The recommended schedule for the activities is shown in Figure 1–1.

Geothermal 1: Compile and circulate data on geothermal plant operating experience.

Bonneville and the region's utilities should compile and circulate reliable data on geothermal power plant operating experience and geothermal resources to the power planning community and others. This data will enable better estimates of the cost and performance characteristics of geothermal power plants. This task parallels similar technology monitoring tasks recommended for Solar 1, Wind 1 and Ocean 1.

This action will involve creation and maintenance of a data base containing geothermal resource and power plant data for active North American sites. Data should include operating experience, as well as available construction, cost, engineering, financing, power sales and regulatory

Geothermal Agenda

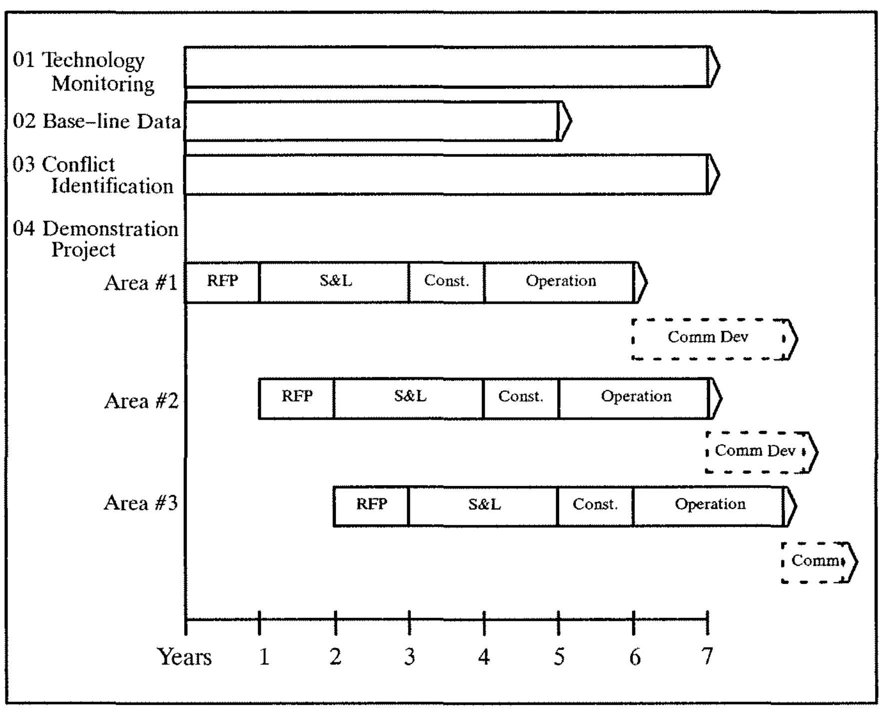


Figure 1–1
Geothermal Confirmation Agenda

information. This work will build on the four-state geothermal inventory and assessment conducted earlier by Bonneville.[7]

The estimated cost is about $25,000 for the first year and about $15,000 per year to maintain.

Geothermal 2: Document and circulate data on geothermal resource areas.

Bonneville and the region's utilities should document the pre-development environmental characteristics of geothermal resource areas. This documentation will assist in identifying key environmental issues and to facilitate the National Environmental Policy Act (NEPA) process and other environmental assessment work. Present federal regulations require geothermal developers to collect one year of base-line environmental data before beginning power plant construction. Federal agencies are required to complete a NEPA process prior to issuing permits for site development or to purchasing or wheeling the output of a geothermal project.

More reliable estimates of the environmental impacts of geothermal power plants can be made if longer term data are available. Moreover, the existence of base line data prior to plant design and permitting is expected to shorten the lead time for development by reducing the time required to complete NEPA and other environmental assessment work required for licenses and permits for site exploration and development. The region's most promising geothermal resource areas are sufficiently well-defined that data acceptable for the NEPA process can be obtained. Base-line studies also may help avoid duplication of efforts by multiple developers operating within a single resource area and may facilitate the assessment of cumulative impacts of geothermal development.

This action will involve documentation of pre-development environmental conditions for promising geothermal resource areas. Information to be collected may include data on air quality, climatology, geology, geochemistry, geophysics, hydrology, water quality, flora, fauna and cultural features. Work should proceed to the development of needed NEPA assessment documents. One approach might be to develop a general environmental impact statement for each resource area. Subsequent environmental impact statements for specific developments within the resource area could be "tiered off" the basic environmental impact statement, reducing the lead time required for completion of environmental assessments.

This work initially should be accomplished at the resource areas where the demonstration projects (Geothermal 4) will be located. If successful, and if additional geothermal resources are needed and can be acquired on a regionally cost-effective basis, this work should be extended to other geothermal resource areas. Two to three years typically will be required to collect and analyze data and to complete a general environmental impact statement for a resource area.

This action is expected to cost about $50,000 per year, per resource area.

Geothermal 3: Facilitate resolution of environmental conflicts.

Bonneville and the region's utilities should identify and facilitate resolution of potential environmental and land use conflicts at promising geothermal resource areas. Most promising geothermal resource areas in the Northwest are located near national parks, wilderness areas and other lands of high environmental quality, sensitivity and recreational value. Poorly conceived geothermal development near these areas may lead to land-use and environmental conflicts, inhibiting geothermal development not only at these sites, but at others, too. Geothermal exploration near Crater Lake, Newberry Caldera and the Alvord Desert already is controversial.

It is clear that development of certain geothermal resource areas must be limited because of land-use and environmental sensitivities. Advance identification of the potential for conflict and the development of possible remedial actions should reduce conflict, litigation and delay when development is proposed. This would reduce resource lead times and minimize expenditures on projects that are not acceptable for environmental or land use reasons.

This action seeks to identify key environmental and land use issues, and to initiate resolution of potential conflicts through land use and environmental management procedures. These might include comprehensive land use plans, zoning, site development and performance standards and state siting council regulations. This action will require the mutual efforts of state and local governments, resource management agencies, geothermal developers, environmental organizations, land owners and other interested and affected organizations and citizens.

This action will draw upon the inventories of natural and cultural values assembled in action Geothermal 2. An assessment of the likely effects of geothermal exploration and development, including transmission line and access road construction, should follow. The compatibility of geothermal development with site conditions then should be assessed. Public participation should be sought in order to establish the value of the natural and cultural features (including geothermal potential) of the resource area. The action should conclude with the identification of possible mitigation measures. These might include siting and performance standards, comprehensive land-use plans and other means.

7. Bonneville Power Administration. *Evaluation and Ranking of Geothermal Resources for Electrical Generation and Electrical Offset in Idaho, Montana, Oregon and Washington.* 1985.

Bonneville is supporting activities intended to accomplish these objectives at geothermal resource areas in the Deschutes National Forest. This work initially should take place at the geothermal resource areas where demonstration projects will be located. If successful, and if additional geothermal resources are needed and can be acquired on a regionally cost-effective basis, this work should be extended to other geothermal resource areas.

This action is expected to cost $50,000 to $100,000 per year for each resource area. Several years might be required to complete this work at each resource area.

Geothermal 4: Initiate geothermal demonstration projects.

Bonneville and the region's utilities should demonstrate the feasibility of electric power generation using Northwest geothermal resources. Each major geothermal resource area of the Cascades is thought to have the potential to generate several hundred megawatts of energy or more. But each area is thought to have somewhat unique characteristics, and none is understood well enough to predict with confidence the feasibility or costs of development. Nor is it fully understood what technology and environmental control measures may be required to develop the resource in a regionally cost-effective and environmentally acceptable manner.

A series of geothermal demonstration projects located at promising resource areas can produce many important benefits. A demonstration project can confirm the cost and feasibility of generating electric power with geothermal energy in a particular area. Demonstration projects also can accelerate the refinement of geothermal technology to suit specific resource characteristics, identify and test environmental mitigation measures, provide a basis to judge environmental and land-use concerns, and reduce investment risk and cost of commercial-scale development that might follow. A demonstration project also can be used as a vehicle to confirm the presence of additional resource potential. All this can provide improved planning certainty and shorten the lead time for commercial-scale development.

The elements of this demonstration program should include exploration at multiple resource areas, demonstration of generating plant operation and confirmation of additional resources for future development. Demonstration of innovative technology, while not discouraged, should be secondary to successful plant operation. The focus of the program should be Cascades-type geothermal resources, though other types of resources should not be ruled out.

Bonneville has indicated a willingness to join regional utilities to purchase up to 10 average megawatts of output from each of three geothermal projects.[8] Right of first refusal on up to 100 megawatts of additional development on each property would be required. An output power sales contract would be used, so payments would be made only as power was delivered. Following completion of the three demonstration projects called for here, the success of this approach will be assessed by the Council. If successful, and if additional geothermal resources are needed and can be acquired on a regionally cost-effective basis, the Council may consider extending this approach to other geothermal resource areas.

Action to secure at least one demonstration project should begin immediately. Action to secure demonstration projects at two additional areas should follow at no less than one-year intervals. It is expected that at least four years will be required from preparation of a request for proposals to an operating demonstration project (see Figure 1-1).

Energy costs of a demonstration plant may range from 6 cents to 8 cents per kilowatt-hour, and possibly higher. These costs will likely be higher than the marginal cost of new resources during the early years of operating the demonstration plant. But the premium will decline as the marginal cost of new resources increases over time. Bonneville has agreed to contribute to a demonstration project if other utilities are willing to join in the financing. Costs could be recovered over the operating life of the demonstration plant.

Solar

(Note: Activities to confirm the cost, viability and availability of solar resources were proposed by the Council's Research, Development and Demonstration Advisory Committee. A more complete discussion of the committee's analysis is contained in Appendix 1-A at the end of this chapter.)

The Council's Research, Development and Demonstration Advisory Committee maintains that solar photovoltaics offer good potential for future application in the Northwest. But because of high costs, the deployment of these and other solar technologies will follow that of geothermal and wind resources in the Northwest, except for certain remote applications of photovoltaics that currently are cost-effective. Accordingly, the committee placed somewhat less emphasis on solar compared to geothermal and wind. Nevertheless, the recommended solar actions are expected to form the foundation for a broader solar confirmation effort as the costs of solar technologies decline and feasible applications broaden.

The committee's solar recommendations include collection of long-term solar insolation data to support deployment of solar-electric technologies when these become cost-effective, monitoring of solar-electric technology development and a feasibility study of possible Northwest applications of solar photovoltaics. A follow-on contingent action would address constraints to deployment

8. The individual project size could exceed 10 average megawatts, with Bonneville taking up to 10 megawatts of output. This would provide flexibility to capture the potential cost savings from larger-scale projects.

of photovoltaic technologies. The Council, in considering these recommendations, added additional activities, consisting of a program to seek out and acquire all regionally cost-effective applications of solar photovoltaics, and a series of activities that could lead to a photovoltaic demonstration plant in the region. The sequence of these actions is illustrated in Figure 1-2.

Solar 1:
Assemble improved Northwest solar insolation data.

Bonneville and the region's utilities should assemble insolation data, including finer spatial resolution, information on both global and direct-beam radiation, and longer-term records, to support the design and analysis of solar applications, provide better understanding of the future contribution of solar-electric power, and help identify sites for future solar-electric installations.

This action will involve re-establishing a comprehensive regional solar insolation monitoring system, insolation data collection and data reduction. The monitoring system should consist of about 10 monitoring stations at locations suitable for creating improved regionwide maps of solar insolation. Each station should collect insolation and other data required to assess the performance of various types of solar-electric and direct-use applications, including global, fixed-beam and tracking-beam radiation measurements.

The monitoring system should be designed to operate for a period of at least 15 years in order to gain a good understanding of interannual variation and possible long-term trends. This effort should build upon current and earlier insolation monitoring efforts. These include the networks maintained by the Eugene Water and Electric Board, the irrigation scheduling network operated by the Washington State Energy Office, and the earlier insolation monitoring program sponsored by Bonneville (see Volume II, Chapter 8).

This action should be implemented immediately to minimize gaps in solar data records. Data should be collected, reduced and reported on a continuing basis.

This action is estimated to cost about $20,000 for setting up each new monitoring station and about $50,000 to $100,000 annually for station maintenance data collection, reduction and reporting.

Solar 2:
Collect information on solar-electric technology and its applications.

Bonneville, the region's utilities, the Council and others should collect reliable information on solar-electric technology and its application to the power planning community and others. This action will help identify promising Northwest applications of solar-electric technologies and assist in making better estimates of the cost and performance

Solar Agenda

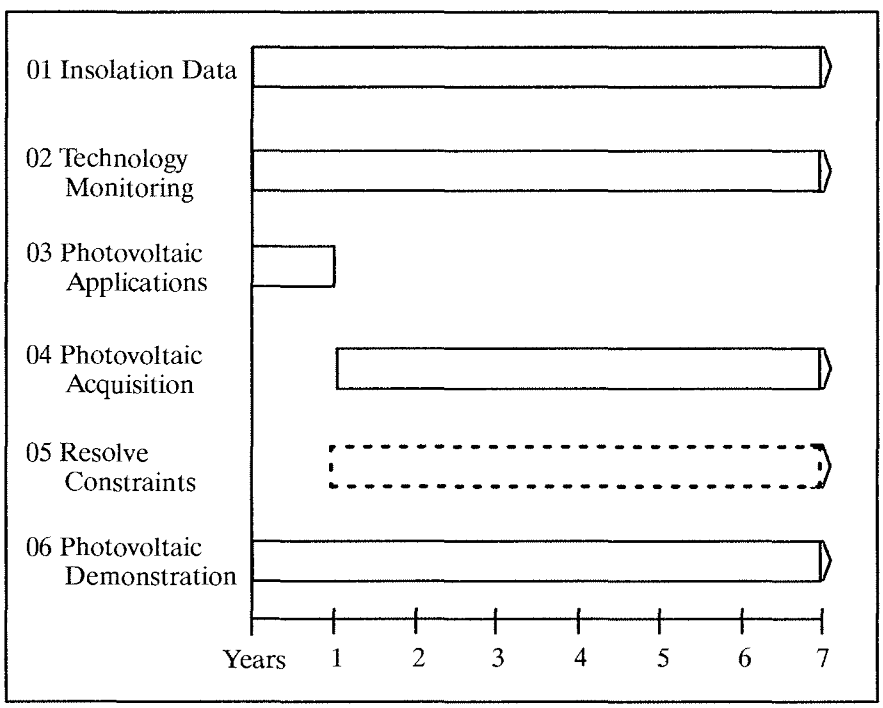


Figure 1-2
Solar Confirmation Agenda

characteristics of solar technologies. Compilation should commence immediately and continue on an ongoing basis.

This action will involve creation and maintenance of a data base of solar photovoltaic and solar-thermal technology. Data should include operating experience as well as available construction, cost, engineering, financing, power sales and regulatory information. This work should incorporate information assembled in activity Solar 2. To the extent feasible, this effort should rely upon data assembled by organizations, such as the Electric Power Research Institute (EPRI) and the Solar Energy Research Institute (SERI). The estimated cost is about $25,000 per year.

Solar 3: Identify promising photovoltaic technologies for the Northwest.

Bonneville and the region's utilities, working with the Council, should identify promising applications of photovoltaic technologies in the Pacific Northwest and key constraints to these applications. It is important to gain an understanding of potential solar photovoltaic applications in the Pacific Northwest because of good prospects for cost reductions and a wide diversity of potential applications. This will allow the region to focus on the technologies and applications showing the greatest promise for this region.

This action will include a review of promising photovoltaic applications in the Northwest. The review should include central-station generation, on-site applications, currently available photovoltaic technologies, promising technologies that could become available in the next several years, applications that could be retrofit at existing sites and new construction. The study should identify and describe possible applications and assess their technical feasibility, cost and likely timing. Key constraints to these applications should be identified and possible means of overcoming these constraints should be proposed. The results of this study will provide information needed for acquisition of cost-effective photovoltaic applications (Solar 5).

This work should begin immediately. It will take about one year and will cost about $75,000.

Solar 4: Resolve constraints to Northwest applications of photovoltaics.

Bonneville, the utilities and others should resolve constraints to promising regional applications of photovoltaic technology. The need for and timing of this task will depend on the findings of the assessment of regional applications of solar photovoltaic technology in Solar 3. This effort will involve resolving constraints identified in action Solar 3.

Solar 5: Acquire cost-effective applications of photovoltaics.[9]

Bonneville, the utilities and others should improve understanding of the cost and performance of photovoltaic technology in the Northwest, strengthen the market for photovoltaic devices and facilitate expansion of cost-effective applications of photovoltaics in the Northwest.

Although the cost of electricity from central-station photovoltaic plants is still much greater than from other resources, there are specialized applications for which photovoltaic power sources may be regionally cost-effective. These applications generally are characterized by their remote location and low power demand—characteristics that increase the per-unit energy cost of providing electrical service. Typical cost-effective applications of photovoltaic technology include communication relay stations, maritime navigation aids, railroad signals, aircraft warning beacons, pipeline cathodic protection, remote household service and remote irrigation pumping.

As efficiencies increase and costs decline, new markets will open to photovoltaic devices. In the United States, this market is expected to include household loads requiring power line extensions of one to two miles. Further efficiency improvements and cost reductions eventually may open up the central-station bulk power market.

There has apparently been considerable penetration of the remote power market by photovoltaics in certain sectors. Although the cost of grid extension and average retail power costs routinely are considered by those considering photovoltaic systems, it is unlikely that the marginal cost of new resource alternatives normally is incorporated in this decision-making process. This action item should foster a greater awareness of cost-effective photovoltaic opportunities.

This action will involve the design, testing and implementation of programs for acquiring cost-effective photovoltaic devices. These programs should include methods of assessing the cost-effectiveness of photovoltaic devices compared to conventional grid service. The marginal cost of new grid-service resources should be considered in these assessments. Other factors that might be included in these programs include design and financial assistance, standard photovoltaic equipment packages (including back-up power sources, where necessary) and equipment servicing. These programs should be made available regionwide, although priority might be given to areas where solar resources and local load characteristics favor photovoltaic applications.

9. This and the following activity were added by the Council after considering other comments and reviewing the Research, Development and Demonstration Advisory Committee's recommendations.

This action should follow the photovoltaic feasibility study Solar 3. That study will identify potentially cost-effective photovoltaic applications, thereby providing a basis for designing acquisition policies and procedures needed for this action.

Because this activity would secure only cost-effective photovoltaic applications, it should be accomplished at no net cost to the power system.

Solar 6: Begin activities leading to a Northwest photovoltaic demonstration.

The Council, Bonneville and others should begin a phased process that could lead to a regional solar photovoltaic demonstration facility. The cost of electricity from solar photovoltaic devices, though currently not competitive with other central-station power plants, continues to decline. It is important that questions regarding the cost and performance of this technology at suitable Northwest sites be resolved. Issues that can be resolved through development of a demonstration facility include: 1) demonstration of the performance of leading solar photovoltaic technologies in a representative Northwest solar resource area; 2) improving the understanding of central-station solar-photovoltaic power quality issues; 3) improving solar resource data at the selected demonstration site; 4) identification and possible resolution of central station solar photovoltaic siting issues; and 5) improved understanding of interactions (including possible beneficial synergisms) with other resources.

This process would begin with Council membership in PVUSA (Photovoltaics: Utility Scale Applications). PVUSA is a national program for testing and comparing emerging photovoltaic technologies. It was initiated by Pacific Gas and Electric Company, in California, and is jointly supported by the U.S. Department of Energy, the Electric Power Research Institute (EPRI), the California Energy Commission and other utilities and state agencies. Under way for nearly four years, PVUSA sponsors small-scale (20-kilowatt) demonstrations of emerging solar photovoltaic technologies, as well as larger (200 to 400 kilowatt) demonstrations of promising technologies.

Bonneville and other members of the Electric Power Research Institute (EPRI) have access to PVUSA information through EPRI. Two levels of more active participation in PVUSA are available. Technical review committee membership is available for $25,000 per year. This level of membership provides information on photovoltaic technologies and demonstration project findings. Steering Committee membership is available for $50,000 per year. This level of membership enables the participant to be involved in decisions regarding the nature and location of demonstration projects. Steering committee membership could lead to demonstration project cost-sharing.

The Council will participate in PVUSA at the technical review committee level for a year or two, and see activity Solar 3 through to its completion. This first phase could be followed by steering committee membership in PVUSA. A decision can be made at that time to complete site selection and conceptual design of a photovoltaic demonstration facility to be located in the Northwest. It is likely that the region could do this in partnership with federal and other agencies, and out-of-region utilities through PVUSA.

Wind

(Note: Activities to confirm the cost, viability and availability of wind resources were proposed by the Council's Research, Development and Demonstration Advisory Committee. A more complete discussion of the committee's analysis is contained in Appendix 1-A at the end of this chapter.)

The regional wind power potential is estimated to be nearly 19,000 megawatts of turbine capacity. This could supply approximately 4,500 average megawatts of energy at costs ranging from 9.5 to 21 cents per kilowatt-hour. But nearly 85 percent of this potential lies along the eastern slopes of the Rocky Mountains in Montana. Successful development of this resource requires resolution of transmission constraints, institutional questions and the ability of wind turbines to operate reliably in the often-harsh weather of central Montana.

Although it is believed that contemporary wind turbines can operate reliably at milder climate sites in the western part of the region, uncertainties remain regarding Northwest wind resource potential. Chief among these are the spatial extent, wind turbulence and shear characteristics of promising resource areas, and site-specific technical, environmental and institutional constraints to development.

Considering these constraints to development, the Council concluded that 600 megawatts of electricity could be obtained by development of wind resources over the 20-year planning period of this power plan. Because of limited wind resource data, harsh environmental conditions and the general remoteness of the Rocky Mountain Front wind resource areas, the Council currently considers very little of the potential of these areas to be available for the 1991 Power Plan's resource portfolio. Wind-generated electricity considered for the portfolio is expected to be available at costs ranging from 9.5 to 16.8 cents per kilowatt-hour. Further reductions in the cost of wind-generated electricity are expected. The Council also concluded that the potential exists for more extensive development of the Northwest wind resource, particularly along the eastern front of the Rocky Mountains in Montana.

The wind power confirmation agenda has two principal components. One is to prepare for commercial development of wind resources in the western part of the region. The Committee believes that this can be accomplished by improved characterization of wind resource areas holding the greatest promise for development, and the identification and resolution of key issues affecting development.

The second component is to confirm the feasibility of developing the Montana wind resource. This will require an assessment of transmission requirements. If it is found feasible to transmit significant amounts of power from these areas to the regional grid, this effort should continue with improved wind resource area characterization, identification and resolution of key issues affecting development, and the development and demonstration of wind turbine generators with year-round dependability under Montana climatic conditions. The level of investment in each of these activities should be proportional to the likely extent of a potentially cost-effective resource.

Continuing elements of the wind power confirmation agenda are maintenance of a regional long-term wind monitoring network and monitoring of wind technology development.

The Council, in considering the committee's recommendations, added an activity: Development of a commercial-scale wind demonstration project. Benefits of this project include confirmation of estimated wind project costs and performance, experience integrating wind farm electrical output with the grid, better understanding of the physical and environmental consequences of wind farm construction and testing of wind farm siting and licensing procedures.

A schedule for these activities is shown in Figure 1-3.

Wind 1: Monitor long-term variation in Northwest wind resources.

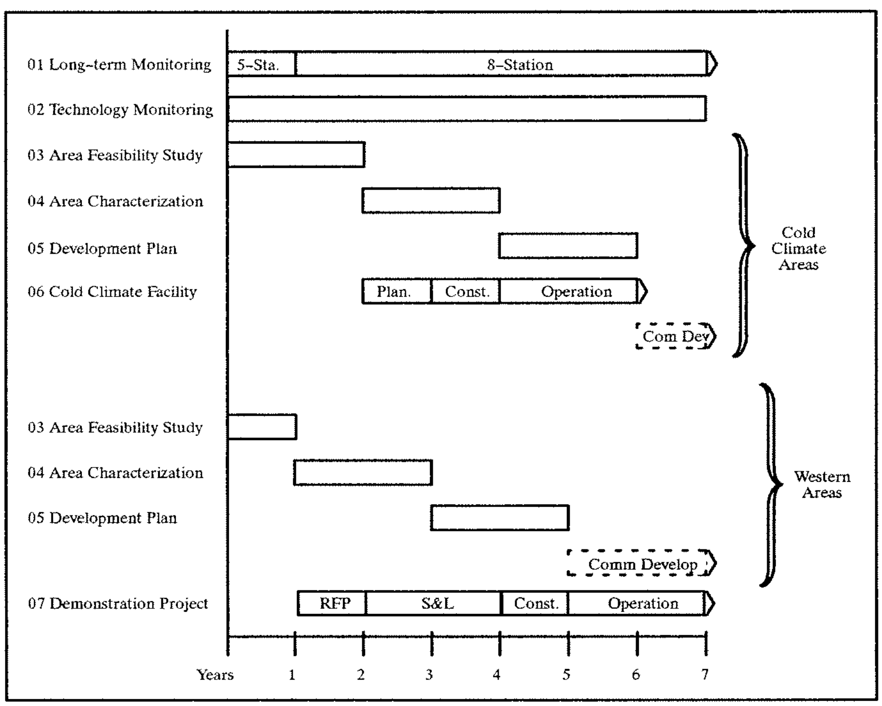
Bonneville, the utilities and others should monitor long-term (interannual) variation in regional wind resources. Wind resources are subject to variations over periods of many years that can only be understood through long-term measurements. Knowledge about interannual variation will reduce project risk, enhance the quality of energy production estimates and facilitate resolution of questions regarding interaction of large-scale wind power development with the regional electric power system.

This action will involve maintaining the five existing long-term wind monitoring stations. Three new long-term stations should be considered for addition to the regional network once a wind resource area development feasibility study (Wind 3) is completed. Wind statistics from these stations should be compiled on an ongoing basis. The three new stations should be sited in areas that would contribute to the complete coverage of the Northwest's promising wind resources.

In 1988, there were 10 long-term wind monitoring stations in operation in the region. These stations were sited to serve as the long-term base-line measurements against which other shorter-term measurements could be compared. As originally designed, this program was to last five years. By the end of 1989, five of the original 10 stations had been dismantled, having served their five years.

Wind Agenda

Figure 1-3
Wind Confirmation Agenda



But it is now known that five years is not sufficient to capture the full range of interannual variation. Additional stations may be dismantled if the goals of this program are not revised to support continued long-term monitoring of wind resources.

This work should begin immediately and continue on an ongoing basis. The five existing stations should continue to operate, and analysis of their measurements should be enhanced. Establishment of the three new sites would be conditioned on the findings of action Wind 3.

The cost of maintaining the current network of five stations is about $60,000 per year. An expanded network of eight stations is estimated to cost about $100,000 per year.

Wind 2: Provide reliable information on wind power technology and resources.

Bonneville, the Council and others should provide reliable information on wind power technology and wind resource development to the power planning community and others. This information should include improved estimates of the cost and performance characteristics of wind power development.

This action would involve creation and maintenance of a wind power data base. Information to be collected would include operating experience as well as construction, cost, engineering, financing, power sales and regulatory information. This task should seek out information regarding wind power development in California and elsewhere, and improvements in wind power technology. To the extent feasible, this effort should rely on data assembled by organizations, such as the Electric Power Research Institute (EPRI), the Solar Energy Research Institute (SERI) and Sandia National Laboratory.

The estimated cost of this ongoing activity is about $25,000 per year.

Wind 3: Identify promising wind resource areas in the Northwest.

Bonneville and the utilities should identify wind resource areas having the greatest promise for development by eliminating areas with "fatal flaws." This review will allow better definition of the institutional, environmental and technical feasibility of developing the Northwest's best wind resource areas. It will guide subsequent actions including spatial, turbulence and shear measurements (Wind 4), preparation of wind resource area development plans (Wind 5) and a cold-climate turbine test facility (Wind 6).

Wind 3 will consist of an evaluation of the feasibility of developing each of the promising wind resource areas identified in the Bonneville wind energy assessment program, plus other promising wind resource areas, such as those identified by the Montana Department of Natural Resources and Conservation. Two tasks, a screening followed by a site ranking, are suggested. Priority in the screening should be given to technical, environmental and institutional "showstoppers." Resource areas for which development appears to be feasible would then be ranked, considering factors such as cost-effectiveness, expected energy production, available and potential transmission capacity, environmental impacts, and seasonality (including possible synergistic effects of areas having different seasonal energy production profiles).

An important component of this action is assessment of transmission interconnection requirements for large-scale development of Rocky Mountain Front wind resources.

This action should begin immediately. It is estimated it will take one year to complete this work for areas in the western part of the region. Two years may be required to complete this study for Montana areas because of the greater complexity of the transmission interconnection assessment.

The cost of this action is estimated to be about $550,000, including $250,000 for the analysis of transmission interconnection of Rocky Mountain Front wind resource areas.

Wind 4: Obtain better wind data at promising Northwest sites.

Bonneville, the utilities and others should obtain better information about the quantity and quality of wind resources at resource areas showing the greatest promise for development. The wind resource areas for which this action should be implemented will be identified in action Wind 3. This action is expected to define developable land area more completely, and thereby allow better estimates to be made of the energy potential and boundaries of prospective wind resource developments. The results will establish a better empirical foundation for estimating the quantity and quality of the Northwest's wind resources, reducing the uncertainty currently associated with this resource. This action will provide supporting data for preparation of wind resource area development plans (Wind 5) and ultimately for commercial wind power development. The information developed by this action should reduce development risk and may reduce site development lead time by one to two years. Finally, this action should provide better information about the boundaries of the resource areas for agencies and others responsible for permits and siting standards.

This action will measure the spatial extent, shear and turbulence characteristics of the Northwest's most promising wind resource areas, as identified in action Wind 3. This work will expand the wind resource information collected in the Bonneville regional wind resource assessment. The objective is to collect data that would allow better estimates of the potential productivity of wind resource areas, and to provide a data base sufficient to allow a wind resource developer to begin siting studies immediately. However, it is not intended that this work address specific wind sites. That task is machine-specific and best accomplished by the resource developer.

The energy production potential of a wind resource area is directly related to the size of the area. The boundaries are sensitive to the relation between the wind and the topography. These factors determine how many wind turbines can be installed. Though the Bonneville regional wind power assessment includes estimates of the spatial extent of promising wind resource areas, these estimates are based on very limited information—a single meteorological tower in most cases. The spatial extent of these areas was estimated by inspection of topographic maps and indicators, such as flagged vegetation.

An understanding of wind shear and turbulence is a prerequisite to developing a wind resource area. Small errors in site assessment can lead to large errors in estimating wind farm energy production. Rolling terrain is problematic due to spatial variations in the wind caused by topography. The extrapolation of wind data from the heights measured to the height of the prospective turbines is done with wind shear factors. An understanding of wind shear (the increase in wind speed with height) is therefore important. Excessively turbulent winds will result in poor wind turbine performance, high maintenance costs and equipment failure.

This task should initially focus on the most promising wind resource areas identified in Wind 3. If successful, and if wind resources are needed and can be acquired on a regionally cost-effective basis, this work should be extended to other wind resource areas. A minimum of a year of data collection is needed to assess the spatial extent at each wind resource area. Measurements of shear and turbulence would be done simultaneously. The complete assessment package, including analysis and reporting, is estimated to require two years for a typical area of moderate size. The number of areas to be assessed depends on the outcome of the area feasibility study (Wind 3). Several areas could be done at once. If Wind 3 suggests that large-scale development of the Rocky Mountain Front is feasible, a substantial portion of this effort should be focused on that resource.

The cost of this action will depend on the number of wind resource areas to be assessed and the size of the areas. The committee's Wind Resource Advisory Panel estimated that spatial, shear and turbulence studies could be completed at 15 wind resource areas, including the very large Blackfoot area on the eastern slope of the Rocky Mountains, for a minimum cost of $550,000.

Wind 5: Resolve major uncertainties at promising Northwest sites.

Bonneville and the region's utilities should resolve major technical, environmental and institutional uncertainties at important wind resource areas. Area development plans can help achieve best resource use with minimum environmental impact, and can reduce planning uncertainty, site development lead times and project investment risk. This work also can contribute to cost savings and improved performance for later commercial-scale development. This action will be accomplished by identifying and resolving technical, environmental and institutional development issues associated with specific wind resource areas, as also recommended for geothermal resource areas (Geothermal 3). The need for this action and its scope will be determined by the findings of the area feasibility study (Wind 3) and the spatial, shear and turbulence studies (Wind 4).

This action should initially include preparation of wind resource development plans for two areas. If activities Wind 3 and Wind 4 conclude that large-scale development of the Rocky Mountain Front is feasible, at least one development plan should be for a Rocky Mountain Front resource area. These plans should focus on the technical, environmental and institutional site development issues identified in the Wind 3 feasibility study. Specific wind project designs would not be included in these plans. That level of design is best left to project developers. Instead, the area development plans would address the overall technical, environmental and institutional constraints to development. One objective, for example, would be to establish local siting and licensing procedures. Also, in cooperation with the local utility, existing model wind farm interconnection requirements could be adapted to the requirements of the area. An important component of the development plans would be preparation of grid interconnection plans.

This work should begin after completion of Wind 3, initially focussing on the most promising wind resource areas identified in Wind 3. Completion of this action for any wind resource area will require completion of the assessment of spatial extent called for in Wind 4. If successful, and if wind resources are needed and can be acquired on a regionally cost-effective basis, this work should be extended to other wind resource areas. Plans for a typical wind resource area could be completed in one year. Plans for a Rocky Mountain Front area might require two years because of the greater complexity of constraints facing wind power development in this area.

The cost of a typical wind resource area development plan is estimated to be $200,000.

Wind 6: Demonstrate wind turbines in a cold climate.

Bonneville and the utilities should develop and demonstrate wind turbines capable of reliable year-round operation in the environment of the Rocky Mountain Front. Development of this facility would proceed if large-scale development of the wind resources of the Rocky Mountain Front were found to be feasible (Wind 3). This action should occur in parallel with actions Wind 4 and Wind 5. Successful completion of these actions should open the way for large-scale commercial development of the wind resources of Montana's Rocky Mountain Front, when needed and regionally cost-effective.

Most wind turbine generator operating experience has been in California. Though wintertime sub-freezing conditions are experienced at some of California's wind resource areas, the environment of these areas is not as challenging as the wintertime high wind and sub-zero cold conditions characteristic of the Rocky Mountain Front wind resource areas. Moreover, adverse climatic conditions occur in Montana when wind resource potential and regional electrical loads are at their greatest. In contrast, freezing conditions occur in California during slack load periods.

Large-scale deployment of wind turbines in Rocky Mountain Front wind resource areas will require the development and testing of turbines capable of sustained, reliable operation in the environment of these areas. In particular, the challenges of extreme cold, very strong winds and restricted maintenance opportunities need to be addressed. Turbine manufacturers argue, however, that existing state-of-the-art machines can be modified to operate reliably under these conditions.

This action would involve creation of a cold-climate wind turbine pilot facility. This facility should be located at a site having wind and climate conditions representative of the better wind resource areas of the Rocky Mountain Front. The facility should be stocked with several wind turbine designs, adapted for cold-climate conditions. The site and machines should be provided with instrumentation to support testing. The site should be conveniently located to centers of activity to ensure adequate maintenance and monitoring. The principal objectives of the pilot facility should be to refine and test wind turbine technology for cold-climate conditions, to develop operation and maintenance procedures suitable for cold-climate conditions and to prepare better estimates of the capital and operating costs of turbines located in cold-climate areas.

Planning for the cold-climate test facility should commence if action Wind 3 indicates development of a large-scale Rocky Mountain resource is feasible. Planning and construction of the facility is estimated to require about four years. At least two years of pilot facility operation is desirable prior to commercial-scale deployment of turbines on the Rocky Mountain Front.

The overall construction cost of a cold-climate wind turbine pilot facility including about five 100- to 300-kilowatt machines is estimated to be \$1 million to \$2 million. Annual operating costs, including basic data logging, are estimated to be about \$250,000, exclusive of the costs of specific experiments. For example, a comprehensive structural measurement program operated by the Solar Energy Research institute on two turbines at San Gorgonio in California cost \$600,000, not including data reduction and analysis costs. Because of interest elsewhere in developing cold-climate wind turbine capability, there appears to be a good chance of securing joint participation in this facility. Opportunities for cost-sharing with the U.S. Department of Energy, turbine manufacturers, and other states, Canada, other countries, regions and utilities having cold-climate wind resources should be explored.

Wind 7: Demonstrate a state-of-the-art wind project in the Northwest.[10]

Bonneville and the region's utilities should demonstrate a state-of-the-art commercial-scale wind farm demonstration project of about 30 megawatts capacity. This is expected to confirm the cost and performance of wind power plants under Northwest conditions, provide experience in integrating the output of a commercial-scale wind farm with the regional power system, improve understanding of the physical and environmental consequences of wind power development, and test wind power siting and licensing procedures. This project also will provide a test area for research and will refine wind farm operational and maintenance procedures for Northwest conditions.

The knowledge gained from this project should lead to greater local confidence in wind power technology, more competition among developers, shorter lead times and improved performance from subsequently developed commercial wind farms. The cost and performance information from this project is expected to reduce resource planning uncertainty.

The work would involve the development of a commercial demonstration wind farm of about 30 megawatts capacity. A project of this size, sited in a good wind resource area, should produce from 6 to 11 average megawatts of energy. A site that represents the better Northwest wind resource areas should be chosen for the demonstration project. The project should employ commercial-grade turbines of proven reliability. A 30-megawatt array would be of sufficient size to allow economies of scale in its development and operation and, therefore, demonstrate representative energy costs. This size also should be sufficient to test system integration equipment and procedures.

The power purchase price offered to developers for this project should be capped by the estimated cost of the geothermal demonstration projects (Geothermal 4) or expected marginal resource costs, whichever is greater. An output power sales contract should be used to provide incentive to the developer and to minimize risk to the region. The contract should allow for research to be performed at the site and should make detailed operational data available.

The total cost of the project to the regional power system might range to \$4 million to \$7 million per year, depending on wind farm performance and cost. Funding to support specific research would be additional. The premium over then-current marginal resource costs would

10. This activity was added by the Council after considering other comments and reviewing the Research, Development and Demonstration Advisory Committee's recommendations.

depend on marginal resource costs at the time that the project operates. At currently estimated avoided cost for the mid-1990s, there would be no premium. The region would break even.

A power purchase offer for this project should be extended as soon as the likely cost of the geothermal demonstration projects can be established. The offer should remain outstanding until accepted. Siting, licensing and development of the project would require about three years.

Ocean

(Note: Activities to confirm the cost, viability and availability of ocean resources were proposed by the Council's Research, Development and Demonstration Advisory Committee. A more complete discussion of the committee's analysis is contained in Appendix 1-A at the end of this chapter.)

The Council has concluded that ocean power technologies eventually may provide several hundred average megawatts of energy to the Pacific Northwest. The most promising of Northwest oceanic energy resources appears to be ocean wave energy. But ocean power technologies are at an early stage of development. Much additional technological research, development and demonstration must occur before ocean power resources can be considered sufficiently reliable and regionally cost-effective for inclusion in the Council's plan. Moreover, there will be significant environmental constraints to large-scale deployment of wave and other ocean energy devices.

The Council requested that its Research, Development and Demonstration Advisory Committee prepare recommendations for furthering the development of ocean energy resources. In view of the early state of development of ocean energy technologies and the apparently limited applications of these technologies in the Pacific Northwest, the committee recommended that resource confirmation efforts for the next several years be focused on other resources thought to be available in greater quantity and at lower cost. Accordingly, ocean energy action is limited to periodic review of technological development.

Ocean 1:
Monitor development of promising ocean power technologies.

Bonneville, the Council, the region's utilities and others should monitor information concerning the development of promising ocean power technologies to allow the region to identify the need for possible future actions, such as resource assessment and demonstration projects. This action would involve periodic assessments of the status of ocean power technologies, emphasizing the technologies with greatest promise to the Northwest. The Council's assessment suggests that wave-energy devices have the greatest potential in the Pacific Northwest. Biomass conversion, salinity gradient and ocean current turbines may offer some potential in the long term. Tidal-hydroelectric and ocean thermal conversion devices appear to offer little potential in the Northwest because of resource limitations.

The cost of this action is estimated to be about $10,000 to $15,000. The committee recommends that the next review of ocean power technology be conducted in conjunction with the next general revision of the Northwest Power Plan. One approach to this review would be to encourage Electric Power Research Institute to produce periodic updates of its 1987 assessment of state-of-the-art ocean energy technologies.[11]

Supporting Activities

There are a number of more general activities that support those listed in earlier sections of this chapter. These activities are not associated with any specific resource, but are needed to support resource assessment, development or the acquisition of all resources.

Supporting Activities 1:
Convene regional meetings on resource planning and acquisition.

The region's utilities, Bonneville, the Council and other interested parties should meet on a periodic basis to evaluate success toward coordinated planning and acquisition of resources. These meetings will help each utility identify specific actions to take in developing and implementing their least-cost resource plans. The meetings will also serve as the basis for reviewing progress toward a least-cost electrical system.

Supporting Activities 2:
Complete and test resource acquisition process.

Bonneville should complete and test the resource acquisition processes now being developed. The effort should determine whether environmental impact statements are needed at the time Bonneville acquires an option or when a decision is made to move into construction, or both. These determinations will be most important if it is anticipated that an option will be held for a long time.

Supporting Activities 3:
Identify out-of-region resources.

Bonneville and the utilities should identify any potential resources from outside the region that are more cost-effective and environmentally acceptable than the resources included in the Council's plan. The Council supports additional power exchanges with and purchases from out-of-region utilities.

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11. Electric Power Research Institute (EPRI). *Ocean Energy Technologies: The State of the Art, AP-4921.* Prepared by the Massachusetts Institute of Technology, Cambridge, Massachusetts. 1986.

These transactions should be consistent with the Act and the Council's plan, and should be at least as cost-effective as the resources included in the plan. An ongoing understanding of these opportunities, shared with other regional decision-makers, can help to minimize uncertainty about the availability of resources to meet load growth. Sources to serve regional load include those in Alberta, British Columbia, California, Utah and the Southwest.

Supporting Activities 4: Account for natural gas in power planning.

The Council will continue to improve its ability to take account of natural gas in its power planning. The Council recognizes that natural gas plays a vital role in power planning, both because it is used to produce electricity, and because, in many instances, gas and electricity are close substitutes. The Council will initiate the formation of a gas policy group, including gas distribution companies, pipeline suppliers and other interested entities to determine how best to integrate natural gas planning into regional power planning.

Supporting Activities 5: Share funding of research, development and demonstration activities.

Bonneville and the utilities should jointly sponsor research, development and demonstration activities because the whole region ultimately benefits from a more diverse mix of viable resources. An agreement should be established among participants regarding the proper balance for long-term funding of this effort. Joint development is equitable, efficient and in the best interest of both ratepayers and utilities. Costs per ratepayer will be lower and benefits per ratepayer would be higher with coordinated activities.

Supporting Activities 6: Coordinate research, development and demonstration.

The Council will act as regional coordinator for research, development and demonstration of conservation, geothermal, wind, biomass and solar resources. In this role, the Council will designate projects within the region for research and development funding, including funding from the U.S. Department of Energy, the state energy departments and the Bonneville Power Administration.

Supporting Activities 7: Provide rate treatment for research, development and demonstration activities.

Regulatory commissions should provide rate treatment encouraging prudent research, development and demonstration activities. Research, development and demonstration of promising technologies could provide alternative resources that may significantly decrease the costs and/or environmental impacts of the current selection of resources. The Council will work with state legislatures, regulatory commissions, utilities and others to promote this recommendation.

Supporting Activities 8: Remove barriers to conservation from Bonneville's average system cost methodology.

Bonneville should remove barriers to the development of cost-effective conservation in its average system cost methodology. In some cases, the current average system cost methodology penalizes utilities for acting consistently with the plan. For example, the methodology does not allow conservation support costs, such as audits and advertising, to be counted as part of exchangeable costs, although Bonneville incurs such costs for its own programs. Bonneville should do what is necessary to revise the methodology so that all investments to secure regionally cost-effective conservation are allowed. Bonneville should continue to judge whether proposed dollar levels are appropriate, as it does with its own programs.

Supporting Activities 9: Review transmission constraints, costs, upgrades and environmental hazards.

The Council will review transmission constraints, transmission and distribution costs, alternative transmission upgrades, and potential environmental hazards associated with reliable delivery of electric power from present and potential sources of generation to the region's load centers. This review will focus on transmission issues that may affect implementation of the power plan. The Council will review: 1) transmission constraints within the region and on interregional interties; 2) the added value of resources that are located near electrical load centers or areas where transmission is constrained; and 3) the transmission costs associated with new resources, especially those that are a long distance from the existing power grid. Based on this review, the Council will work to remove transmission barriers supporting cost-effective intertie expansions.

Supporting Activities 10: Account for environmental uncertainties.

The Council will continue to develop a more complete reflection of environmental uncertainties in its planning. To date, the Council has used its judgment to account for costs incurred by society that are not covered in the costs of electricity (these costs are sometimes referred to as external costs). The Council will work with environmental experts to improve this process, to seek ways to mitigate or avoid externalities, and to select the best mix of resources to meet the plan's multiple objectives. This effort will focus on Council strategies and policies to minimize damage to the environment.

Supporting Activities 11: Quantify environmental costs.

The Council will work with regulatory commissions, siting agencies, Bonneville, utilities, and other interested or affected parties to evaluate alternative approaches and to identify appropriate methodologies for incorporating quantified estimates of unmitigated environmental pollutants into its planning. As with most commodities, when a price is too low, the commodity is used too much and economic efficiency suffers. Unfortunately, the price charged to emit unmitigated pollutants to the environment is zero, and it has been virtually impossible to develop accurate estimates of all external costs. This is why the Council has relied on its judgment. However, the Council will continue to look for ways to develop and enhance methodologies for quantifying and incorporating environmental externalities into its planning.

Supporting Activities 12: Convene regional renewable resource forum.

The Council, in cooperation with Bonneville, the utilities and other regional parties will develop a regional renewable resource forum. This effort should provide information regarding current technologies and the status of plans for resource exploration and development in the Pacific Northwest. This information should be provided to utilities, developers, state and federal agencies, local governments, the environmental community and the interested public. Better information regarding these resources should promote public and utility understanding and acceptance, facilitate resolution of environmental and other concerns, and encourage environmental and land-use regulations that enable quality resource development when needed. An objective of this effort is to provide current information to utilities developing requests for resources to allow fair consideration of renewable resources in the acquisition process.

Supporting Activities 13: Develop multilevel priority firm rate.

Bonneville and its customers should consider a multilevel priority firm rate as an alternative to the billing credits policy. The billing credits policy provides for payment to a utility for energy saved or generated up to the difference between Bonneville's avoided cost and the priority firm rate. Implementation of this policy should help to ensure that regionally cost-effective investments in conservation and resources are made.

If, for any reason, by the 1993 rate case, billing credits and other Bonneville acquisition programs are not as effective at securing cost-effective conservation as anticipated, the Council recommends that Bonneville and its customers investigate and implement wholesale rate designs consistent with the goal of giving individual wholesale customers price signals based on avoided costs. A multitiered wholesale rate, with the last tier set at avoided costs, could be an appropriate alternative. In this case, utilities that acquire conservation or build new generation will reduce their bills from Bonneville by the same amount as if they had been paid a billing credit.

Supporting Activities 14: Allow recovery of costs of optioning.

Utility regulatory authorities should provide appropriate rate treatment for expenses incurred by utilities optioning resources. It is important that utilities be able to recover legitimate costs of developing resources. These costs include pre-construction expenditures on resources being held as options against future load growth. The Council's analysis shows that this is in the best interest of utilities' ratepayers. If utilities must wait for plants to be constructed, and found to be used and useful before they can begin to recover their costs, they will be reluctant to invest in the optioning of resources. The Council will work with state legislatures, regulatory commissions, utilities and others to promote this recommendation.

Supporting Activities 15: Establish criteria for siting resources.

The Council, with the assistance of its advisory committees, will work with state siting authorities, and other interested and affected parties throughout the region to develop criteria for the siting, licensing, construction and operation of resources in the Council's resource portfolio. In this effort, it is not the intent of the Council to usurp the authority of any agency currently charged with responsibilities in these areas. Rather, the Council wishes to work with these agencies to develop criteria that will enable the region to meet future load growth most efficiently, while maintaining public support and protecting the environment from uncontrolled development. The Council's concern is focussed mainly on resources that may not come under the auspices of siting agencies in the four Northwest states. Establishing acquisition criteria can help all concerned, including potential developers of the resource, by focussing resource development in areas where it is most likely to be successful.

Supporting Activities 16: Pursue conservation at the federal level.

The Council, Bonneville and the utilities should aggressively pursue conservation at the federal level, especially in codes and standards-setting processes, such as those provided by the Department of Housing and Urban Development (HUD) for manufactured housing and by the U.S. Department of Energy (DOE) for appliances. This action is important because federal standards often preempt state or regional action. Some types of conservation standards can only be

0achieved if the federal government takes action. The region's interests in energy efficiency need to be represented during federal proceedings.

Supporting Activities 17: Gain a better understanding of resource interactions.

The Council, Bonneville and the region's utilities should work together to explore the interactions among existing resources and those that might be added to the region's power system. Many potential resources, renewables in particular, have benefits that go beyond the sum of their individual contributions, when all interactions are accounted for. For example, solar power delivers most of its energy in the summer and early fall, hydropower in the spring and summer, and wind in the late fall and winter. All of these resources are intermittent to a greater or lesser degree. However, the reliability of each might be enhanced by using the three resources together. There already may be enough diversity among existing or planned resources to easily accommodate additional intermittent resources. This activity should be pursued aggressively to better understand the cost-effectiveness of wind and solar resources and the best approach to their development and operation.

Supporting Activities 18: Address capacity concerns.

Bonneville, utilities, regulatory commissioners and other interested parties should address potential capacity concerns in their future power plans. Although the Northwest has enough capacity to meet daily peak loads easily, some utilities in specific areas could face problems in the future similar to the capacity problems that exist today around Puget Sound. The capacity-related benefits of conservation and load management, which reduce both line losses and the need for capacity reserves, should be carefully examined and given appropriate credit in utilities' acquisition plans.

Supporting Activities 19: Identify rapid-replacement resources.

Bonneville, the region's utilities, and other resource developers should immediately begin to identify 500 to 1,000 megawatts of resources that could be brought online quickly, in the event of a sudden loss of existing resources. Among the many sources of uncertainty this plan must address are the continued availability of existing resources at their current output levels. For example, proposals to alter flows in the Columbia and Snake rivers to assist the downstream migration of salmon could cost the region some hydropower. The effect of losing existing resources would be mitigated somewhat if the region had resources that could be called on quickly to produce power. A few good candidate resources for this role have been identified, but utilities are urged to look for others.

The most obvious resources to serve this role may be existing combustion turbines. Puget Sound Power and Light Company owns nearly 700 megawatts of combustion turbine capacity that could supply about 500 megawatts of electricity, all situated in the Puget Sound area. The turbines could be used as stand-alone resources or, more likely, in combination with the hydropower system's nonfirm power to provide a firm resource. Because of their location, they would also be able to help alleviate transmission limitations in the Puget Sound area. Contractual, economic, institutional or technical issues that prevent the use of the turbines in this way should be resolved.

Bonneville and the region's utilities should also expand their requests for new resources. Through bidding proposals, utilities are helping to identify a large variety of independently developed resources. Some of these resources could be brought into production quickly. Future requests for bids for new resources should target these short lead time resources.

Finally, Bonneville and the utilities need to evaluate those rapid-response opportunities beyond the Pacific Northwest's boundaries. Large amounts of generating capability exist outside the region. It is conceivable that, through seasonal exchanges or energy purchase contracts, the region could rapidly replace a substantial amount of energy. The terms and conditions of necessary contracts need to be understood to make this resource a reality.

The Council recommends that these efforts begin immediately and have a target completion date of the summer of 1992.

If sufficient rapid-response resources cannot be identified, it may be necessary to seek increased interruptible loads and develop curtailment strategies until resources with longer lead times can be added.

APPENDIX 1-A

CONFIRMATION OF RENEWABLE RESOURCES

Introduction

The Council has developed coordinated actions intended to foster the efficient development of geothermal, solar, wind and ocean generating resources. Analyses by the Council and others suggest that these resources have the potential to provide a substantial, cost–effective and environmentally sound contribution to the power generating needs of the region. The recommended actions should reduce uncertainty regarding these resources, and thereby improve planning decisions concerning these and other resources. These actions should lower costs and increase reliability and environmental acceptability of these resources and the ability to develop them in a timely manner when they are needed. These actions form an important component of the research and development element of the power plan, as required by the Northwest Power Act.

The Council, in its 1986 Power Plan, called for the formation of a Research, Development and Demonstration Advisory Committee pursuant to the provisions of the Act. The Council charged this committee with delivering recommendations to resolve uncertainties affecting resource planning and to improve the cost–effectiveness and environmental acceptability of promising resources.

The Research, Development and Demonstration Advisory Committee convened in March 1989. Over the next year, the committee assembled technical advisory panels for geothermal, solar and wind resources. Recommendations of these technical advisory panels and subsequent deliberations of the advisory committee led to the actions described earlier for geothermal, solar and wind resources. The action for ocean energy technologies was developed by the committee in response to the Council request in September 1989 to prepare recommendations for ocean energy resources. The Council, in deliberating the recommendations of the committee, added the actions involving a wind demonstration project and solar photovoltaic acquisition.

Each action recommended by the committee is supported by at least a majority of the committee members. Many of the recommendations are unanimously supported. Members of the Research, Development and Demonstration Advisory Committee are listed in Table 1–A–2, and members of the technical advisory panels, which worked with the committee, are listed in Table 1–A–3 (see pages 34 and 35).

Criteria for Actions

The recommended actions meet three principle criteria. First, these actions are believed to have a high probability of achieving the objectives of improving planning certainty; fostering resource cost–effectiveness, reliability and environmental acceptability; and improving the ability to develop these resources in a timely manner when needed.

Second, these actions generally are limited to those addressing needs and circumstances unique to the Pacific Northwest. Organizations, such as the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (DOE) are positioned to address resource issues of general interest nationwide. But these organizations typically do not address unique regional problems. Moreover, the U.S. Department of Energy emphasizes basic research, whereas an important need of this region is to prepare for the commercial development of these resources. The Northwest must be prepared to support resolution of problems unique to the Northwest.

Finally, these actions should commence within five years. The Council's power plan will be revised by then, and this resource confirmation agenda can be reassessed at that time or before. Because many of the actions are conditional upon prerequisite actions, and because the need or feasibility of developing these resources may change through time, the agenda will be reviewed annually by the committee.

Benefits of the Recommended Actions

The benefit of these actions lies in the expectation that they will prepare for development and improve the regional cost-effectiveness of resources generally thought to possess desirable characteristics and to be present in abundance in the Northwest. Equally important, information resulting from these actions is expected to lead to better decisions with respect to these resources and their alternatives. Demonstration projects will allow the region to gain experience with resources that have received little exposure here. Specifically, the principal reasons for these actions are the following:

■ Better Resource Planning Decisions

An important element of the Council's power planning strategy is the management of uncertainty. But an equally important planning strategy is the reduction of that uncertainty. Information gleaned from these actions will lead to improved planning decisions through the reduction of uncertainties regarding geothermal, ocean, solar and wind resources. These decisions affect not only these resources, but resources that might have to be developed in their place. Foremost among the resource planning benefits of these actions will be confirmation of the feasibility of developing geothermal resources in the Cascade Mountains and wind resources of the Rocky Mountain Front.

■ Reduced Time to Develop

Many of the actions are expected to reduce the time required to bring these resources into service when they are needed. The geothermal demonstration projects, for example, will promote resolution of siting, technical and environmental issues at their respective sites. They will help reduce the time required to site, license and construct commercial plants. Council studies indicate that reduction in the time to bring resources into service is valuable. For example, completing resource exploration activities for 300 megawatts of geothermal energy, and thereby reducing development lead time by three years, is estimated to have a net present value of $80 million.

■ Reduced Environmental Impacts

Some of the actions are expected to reduce environmental impacts through better siting and improved environmental mitigation.

■ Reduced Cost

Some of the actions may lead to reduced resource development costs. For example, wind turbulence and shear data will provide better understanding of wind resource characteristics, thereby improving the siting of wind farms. Improved siting should result in higher capacity factors, lower power production costs and improved reliability. Cost reductions, though directly accruing to project developers, should pass through to ratepayers as more favorable power-purchase costs.

■ Improved Performance

Some of the actions will facilitate improvements in power plant technical performance. For example, the cold-climate wind turbine pilot project is intended to lead to turbine design refinements enabling reliable operation in the severe climate of the Rocky Mountain Front. Like cost reductions, benefits of improved performance, though directly accruing to the resource developer, should pass through to ratepayers as reduced power costs and greater reliability.

Priority and Timing

Certain actions should be implemented immediately. These are indicated in the descriptions and schedules. Current rapid load growth suggests that subsequent actions be implemented promptly as shown in the schedules, providing that the need for these actions is sustained by findings of preliminary actions. However, it is important that these schedules be periodically reassessed in light of improved resource information, changing technology and electrical load growth. Experience has shown that attempts to develop resources "before their time" may adversely affect the credibility of the resource.

Cost

Preliminary cost estimates are included in the descriptions of the actions. Precise cost estimates; however, will be possible only when a detailed statement of work for each action is completed. And, for some actions, a detailed statement of work can only be prepared upon completion of prerequisite actions. That is because the information obtained from the prerequisite actions defines the scope, design, or even the need for following actions. Preparation of detailed statements of work is best left to those responsible for implementation of each activity. Thus, the cost estimates provided earlier should be viewed as approximations to be refined as the confirmation agendas are implemented.

The most expensive actions will be the demonstration projects. Because these will be operational generating plants, they will be costly. And because the demonstration projects may be completed in advance of the resource being regionally cost-effective, a premium over the then-current value of energy may be required to cover the costs and risks associated with first-time development. But, because these projects likely would be developed using output contracts,[1] ratepayers will pay only for successful projects, and then only when the projects enter service. Because a successful demonstration project will produce energy, the true cost of the demonstration projects will not be the full cost of the power purchase contracts, but the net of the payments for energy, less the then-current value of energy from new resources. The premium paid for a demonstration project constructed in advance of need should decline as loads grow and avoided costs for new resources rise. The net costs of these projects ultimately are expected to be captured through the reduced cost of subsequent resource development, including the resource options secured as a direct result of the demonstration projects.

The estimated annual cost for the recommended package of actions is shown in Table 1-A-1. The estimated annual cost of the first four years of the recommended program (the period prior to the first demonstration project coming into service) is estimated at $1 million to $1.6 million. We expect that these costs will be shared by all utilities in the region. However, to gain a sense of the magnitude of the costs, we estimate that they would increase Bonneville's preference rates about one-tenth of one percent if all costs were borne by Bonneville and incorporated into Bonneville's preferred rates. Rate impacts would increase once the recommended demonstration projects come into service, but even then, they are estimated to be about 0.5 percent.[2]

Principles Governing Resource Confirmation Activities

The Research, Development and Demonstration Advisory Committee identified several principles to guide activities intended to determine the cost and availability of resources available for future development. These are:

1. Focus on resolution of region-specific problems. Whereas some problems associated with the development of new resources are being addressed elsewhere, other problems are specific to the Northwest. One example of a problem unique to the Northwest is the feasibility of generating electricity from geothermal resources of the Cascades. Emphasis should be given to addressing regional problems because it is less likely that national organizations or organizations operating outside the region will support work on these problems. The principal responsibility for addressing region-specific problems lies with the region.

2. Minimize construction of actual generating projects prior to these being cost-effective. Some resources, such as geothermal from the Northwest's Cascades, can only be tested by completing development of a generating project. But project development requires engineering and construction—typically a risky and expensive process. In most cases, other means of resolving uncertainties associated with new resources can and should be pursued. Resources should only be developed when other, less risky and expensive approaches appear ineffective or not feasible for resolving questions about the resources.

3. The costs and risks of resource confirmation activities should be spread, to the extent feasible, among those who will benefit. Ratepayers regionwide will benefit from confirmation of less expensive, more reliable and less environmentally damaging resources. Resource developers will benefit from the availability of expanded business opportunities. No scheme for perfectly equitable allocation of these benefits is achievable. However, reasonable allocation of resource confirmation costs and risks can be promoted by ad hoc partnerships involving Bonneville, investor-owned utilities, consumer-owned utilities, developers and the states.

4. Activities should be designed to achieve multiple goals and widespread benefits. For example, this plan proposes the development of several geothermal demonstration projects. As proposed, these projects would help determine the feasibility of generating electricity using Cascade Range geothermal resources in several resource areas. But the projects would also test and refine generating technologies, provide experience with environmental mitigation methods for Cascade resources, and prove geothermal resources for further commercial development.

5. Priority should be given to resources promising low or declining costs, abundant quantity, modest environmental effects and favorable development characteristics, including short lead time and modularity.

6. Distinction should be drawn between activities to foster the development of resources in general and those that are primarily associated with the development of specific projects. The former are more justifiably supported by the region as part of a resource confirmation program, whereas the latter more rightfully are the responsibility of a project developer. For example, assessing the spatial extent, general turbulence and shear characteristics of a wind resource area is largely a regional responsibility, whereas studies leading to placement of individual wind turbines is a responsibility of the developer.

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1. An output power sales contract is one in which the purchaser pays for the energy production of a project at an agreed-upon rate. Payments commence upon delivery of energy.

2. Based on the estimated net costs of demonstration projects (total cost less energy value).

This principal is not intended to discourage the acquisition of options for the development of cost-effective resources. Many of the siting, licensing and design activities comprising the acquisition of resource options are project-specific. Although undertaken by a resource developer, these activities must be supported by the region through compensation to the developer.

Table 1-A-1
Estimated Annual Costs for Recommended Actions[a]
(thousands)

	Year						
	1	2	3	4	5	6	7
Geothermal 1 Technical Monitoring	25	15	15	15	15	15	15
Geothermal 2 Base-Line Data[b]	50	100	150	100	50	—	—
Geothermal 3 Conflict Identification[b]	150	150	150	100	75	75	75
Geothermal 4 Demonstrations[b]	60	60	60	60	6,200[c] / 1,900[d]	12,300[c] / 3,700[d]	18,400[c] / 5,500[d]
Solar 1 Resource Data[e]	125	125	75	75	75	75	75
Solar 2 Applications	75	—	—	—	—	—	—
Solar 3 Technical Monitoring	—	25	25	25	25	25	25
Solar 4 Resolve Constraints	—	f	f	f	f	f	f
Solar 5 Photovoltaic Acquisition	0[g]	0[g]	0[g]	0[g]	0[g]	0[g]	0[g]
Solar 6 Photovoltaic Demonstration	25	25	h	h	h	h	h
Wind 1 Resource Data	100	100	100	100	100	100	100
Wind 2 Technical Monitoring	25	25	25	25	25	25	25
Wind 3 Area Feasibility	275	275	—	—	—	—	—
Wind 4 Area Characterization[i]	—	110	110	110	110	110	—
Wind 5 Development Plans[j]	—	100	100	k	k	k	k
Wind 6 Cold Pilot	—	100	500	900	250[l]	250[l]	250[l]
Wind 7 Demonstration	—	50	50	50	50	5,500[c] / 1,800[d]	5,500[c] / 1,800[d]
Ocean 1 Technical Review	—	—	—	15	—	—	—
Supporting Activity RD&D Forum	50	50	50	50	50	50	50
Total (Gross)	960	1,310	1,410	1,625	7,025	18,525	24,515
Total (Net)	960	1,310	1,410	1,625	2,725	6,225	7,915

a Constant 1990 dollars.

b Assuming three resource areas staged at approximately annual intervals.

c Gross costs of successful projects.

d Net costs of successful projects assuming new resource costs of 5 cents per kilowatt-hour.

e The costs shown assumed that five additional stations are established over the initial two-year period.

f The scope of Solar 4 will be established by findings of Solar 3.

Table 1-A-1 (cont.)
Estimated Annual Costs for Recommended Actions[a]
(thousands)

[g] Because this resource only would be acquired when cost-effective, there would be no net "R&D" cost. Additional costs could be incurred, if any special assessments of equipment performance were undertaken.

[h] The $25,000 per year is for membership in PVUSA. The costs of a solar photovoltaic demonstration project will depend upon the nature of the project.

[i] Assuming 15 wind resource areas.

[j] Assuming two wind resource areas.

[k] Continue for other wind resource areas, if successful.

[l] Special experiments may increase the annual operating cost.

Implementation Issues

The Research, Demonstration and Development Advisory Committee concluded that mechanisms exist to accomplish the recommended actions. But the committee also concluded that significant impediments remain to implementation of resource confirmation activities in the Northwest.

One problem is the sharing of costs and benefits. Most of the proposed actions are expected to benefit ratepayers regionwide, yet no mechanism exists to spread the costs of these actions equitably among the region's ratepayers. In previous power plans, the Council tended to look to Bonneville as the principal source of funding to support regional resource research, development and demonstration. Through its power sales agreements and the exchange program, Bonneville, more than any other single entity in the region, has the ability to spread resource confirmation costs to those who potentially benefit. But it is clear that Bonneville will not be the sole entity acquiring new resources. Therefore, in the interest of equity, it is important to seek resource confirmation funding mechanisms that more broadly spread the costs of resource confirmation among those who potentially benefit.

One approach is for a lead utility to enter into joint contracts with other utilities for support of specific activities. Bonneville has proposed this approach for the geothermal demonstration program. But even joint contracting will spread costs imperfectly among the potentially benefitting ratepayers (unless all utilities participate, which is unlikely). Furthermore, soliciting joint participation is difficult and time consuming.

A second impediment is the limited ability of investor-owned utilities to recover costs associated with research, development and demonstration activities. Investor-owned utility expenditures either can be expensed or rolled into the utility's rate base. Expensed costs are immediately recovered through rates, but the utility earns no return on these expenditures. A utility may receive a return on expenditures incorporated into its rate base, but most states require the product of these expenditures to be "used and useful." Many of the recommended actions are not expected to result directly in a project meeting the conventional test of "used and useful." Oregon, for example, though allowing research, development and demonstration expenditures to be expensed, does not permit these expenditures to be rate-based.

The Council has called for resolution of both of the issues described above. Resolution of these impediments and implementation of the renewable resource confirmation agendas will require the concerted efforts of the Council, Bonneville, regional utilities, state public utility commissions, resource developers and others.

Table 1–A–2
Research, Development and Demonstration Advisory Committee Members

Name	Organization
K.C. Golden	Northwest Conservation Act Coalition
Paul Cartwright	Montana Department of Natural Resources and Conservation
Clyde Doctor	Pacific Power and Light Company
John Frewing	Portland General Electric Company
Michael Gluckman	Electric Power Research Institute
Jan Hamrin	Independent Energy Producers Association
Roy Hemmingway	Independent consultant
Walter Myers	Bonneville Power Administration
Scott Spettel	Eugene Water and Electric Board
Nancy Rockwell	Oregon Department of Energy
Yacov Shamash	Washington State University
Robert Stokes	Solar Energy Research Institute
Brian Thomas	Puget Sound Power and Light Company
Dick Watson	Washington State Energy Office

Table 1-A-3
Resource Technical Advisory Panel Members

Name	Organization
Geothermal Advisory Panel	
Gordon Bloomquist	Washington State Energy Office
George Darr	Bonneville Power Administration
Robert Edminston	Anadarko
Robert Fujimoto	U.S. Forest Service
Fred Hirsch	Oregon Chapter, Sierra Club
Gary Lavering	California Energy Company
Paul Lienau	Oregon Institute of Technology
Alex Sifford	Oregon Department of Energy
Mike Wright	University of Utah
Solar Advisory Panel	
Nick Butler	Bonneville Power Administration
David Carlson	Solarex
Lynn Coles	Solar Energy Research Institute
Robert D'Aiello	Solarex
Ed DeMeo	Electric Power Research Institute
Dennis Horgan	Luz International, Limited
David McDaniel	University of Oregon
Dave Robinson	Pacific Power and Light Company
Wind Advisory Panel	
Don Bain	Oregon Department of Energy
Bob Baker	Oregon State University
Mike Batham	California Energy Commission
Hap Boyd	U.S. Windpower
Nick Butler	Bonneville Power Administration
Dave Dysinger	Montana Department of Natural Resources and Conservation
Robert Lynette	Lynette and Associates
Robert Thresher	Solar Energy Research Institute

CHAPTER 2

BACKGROUND AND HISTORY OF THE NORTHWEST POWER SYSTEM

Introduction

For well over half a century, electrical power has been a cornerstone of the Pacific Northwest economy. Thanks to the nation's most productive hydropower system, abundant, low–cost electricity has made the Northwest attractive to business and industry, despite the fact that the region is a long way from major markets.

Electricity has lighted and powered the farms of the region and turned deserts and sparse grasslands into highly productive cropland. Aluminum smelting, pulp and paper production, and industrial chemical manufacturing have all benefited from abundant and cheap electrical supplies. Sales of electricity have provided the revenues that made the damming of the Northwest's rivers possible, thus multiplying economic growth through increased navigation, irrigation and flood control.

Now, however, products from other regions are competing strongly with the region's products. As a result, maintaining low–cost electricity is more vital than ever to the Northwest economy. The goal of the 1991 Northwest Power Plan is to preserve and enhance this valuable asset by identifying the steps that need to be taken to ensure the lowest cost electrical energy future for the Pacific Northwest.

This new age poses major new challenges for the region.

All new sources of power are much more expensive than the region's existing electric power system. Conservation costs about double Bonneville's current wholesale power costs, and new generating plants cost four times as much. As a result, electricity prices will go up as the region adds new resources.

The region's industries have divergent needs. The Northwest's traditional industries—pulp and paper, wood products, chemicals, agriculture, transportation equipment and metals—represent the backbone of the region's economy. These industries employ more than 400,000 people and produce much of the economic activity in the region. These basic industries rely on low–cost power to remain competitive with other parts of the country and the world. New industries, such as high technology and consumer services, are not as dependent on low–cost power because power costs represent a smaller portion of their overall operation costs. Nevertheless, as these new industries grow, new resources will be needed. The dilemma is that new additions to the power system will raise electricity costs and thereby threaten the traditional industries.

New energy resources can also affect the Northwest's environment. The region's citizens have a strong interest in stewardship for our land, water, air, fish and wildlife.

The challenge for the future is to meet the energy service needs of the Northwest at the lowest possible cost to our economy and our environment.

The Last 50 Years: A History of Northwest Electrical Power Development

The Hydropower Era

Today's electric energy choices reflect a reversal from yesterday's economics of power. For years, the region had been blessed with low–cost electricity from the seemingly inexhaustible Columbia River system. The rapid economic growth of the region created a steady demand for more and more power. Because of economies of scale and growing sales of electricity to pay the costs, each new dam actually brought the cost of electricity down.

From 1940 to 1979, the wholesale rate for Bonneville Power Administration public utility customers dropped, when adjusted for inflation, from 2.7 cents to 0.6 cents per kilowatt–hour (see Figure 2–1). The region's huge hydropower system on the Columbia River, built when inflation and interest rates were low, provided the nation's cheapest electricity. From farm to factory, the region prospered during this hydropower era. With the cost of power dropping, "living better electrically" became the axiom of the times. Power planning in the 1950s and 1960s involved minimal risk of being wrong. If the supply of electricity exceeded demand, demand was certain to catch up soon. The far greater risk, or so it was perceived at the time, was to underbuild, to have demand for electricity exceed the supply.

By 1960, the region's power system had grown to 6,000 megawatts of average energy. Figure 2-2 shows both the growth in electric load and the additions to the Northwest power system. During the 1960s and 1970s, electric load growth averaged 5.2 percent per year. The region added 10,000 megawatts of new resources during this period.

The Hydro-Thermal Power Program

During the 1960s, it became obvious that hydropower alone could not supply all the Northwest's growing electrical needs. For one thing, the region was running out of new river sites that could be developed. The Hydro-Thermal Power Program was conceived in the late 1960s as an answer to this problem. As the name suggests, it was an effort to mesh new thermal resources with the existing hydropower system. A major goal of this program was to allow construction of large generating plants, while preserving the basic roles of Bonneville and its customers. Bonneville would supply energy peaking needs, and utilities would build large base-load[1] generating resources.

Rapid growth was projected to continue for years ahead; and the Hydro-Thermal Power Program was based on the energy economics of the day. Nuclear reactors and coal-fired plants are designed to run with a constant output of electricity throughout the year. The hydropower system, on the other hand, could follow the hour-to-hour demand for electricity in the region.

By law, Bonneville could not construct or own generating plants. Therefore, public utilities would finance, construct and operate the new base-load plants, and Bonneville would acquire their output by crediting the owner utilities for the cost of those plants when it billed the utilities. The arrangement was called net billing. An adverse Internal Revenue Service ruling and high costs ended the original Hydro-Thermal Power Program in 1973.

The second phase of the program followed, with the region's utilities taking power from their own shares of the generating plants, while Bonneville provided transmission and "shaping" of the generation to fit power loads. Washington Public Power Supply System nuclear plants 4 and 5 were the principal products of this phase. Bonneville's participation in this phase effectively ended in 1975 with adverse court decisions, which required the agency to prepare lengthy environmental impact statements on its role.

Few had anticipated the cost of the thermal era transition. The cost of new coal or nuclear plants escalated by billions of dollars with power from these plants costing many times more than power from the existing Northwest dams.

As the cost of the new thermal plants increased, so did the value of the hydropower system. Although its output varies with annual rainfall and snowpack conditions, during high-water years there is enough low-cost hydropower to allow other, more expensive resources to be shut down, thus saving ratepayers some of the cost of running thermal plants. Given today's cost of building and operating any new plant, economics point toward getting maximum use out of the hydropower system while planning new resources that complement that system.

Congress Addresses the Region's Problems

By 1977, the forces that were leading to the Northwest Power Act of 1980 were becoming clear. Regional utility planners were frustrated with a plethora of increasingly difficult problems. These led regional decision-makers to look to Congress for a comprehensive solution to a set of linked problems.

First, hold-ups in siting and licensing and delays in plant construction had become commonplace. Utilities began projecting they would be unable to meet the region's power needs in the early 1980s. Deficits of more than 3,000 megawatts were projected by the mid-1980s in the event of low-water years. A mechanism was needed to speed new resources into the system.

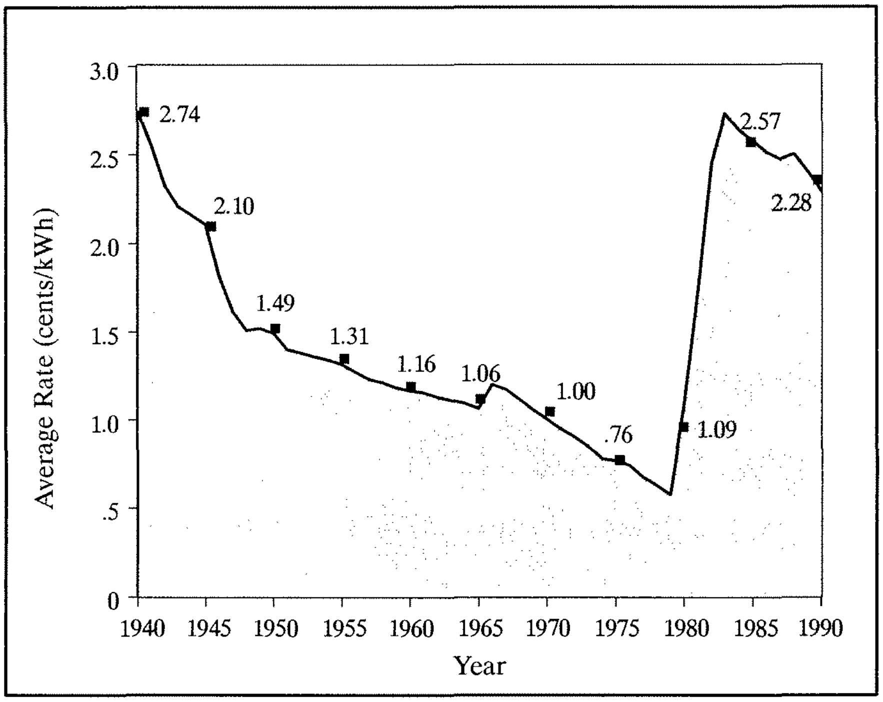
Second, while Bonneville and several utilities were promoting construction of large thermal plants, a number of critics were arguing that the region's power needs could be met by conservation programs at substantially less cost. State siting agencies began to consider conservation as an alternative to thermal plants. However, at the time, conservation was a new and unfamiliar resource to most utilities.

Third, utilities were having problems financing new generating resources. With the end of federal dam construction and the limiting of net billing, Bonneville could no longer acquire additional resources to meet new loads. Investor-owned utilities, which traditionally had relied on surplus Bonneville power to meet their growing loads, found in 1973 that they were cut off from firm contracts for cheap federal hydropower by the "preference clause" of the Bonneville Project Act, which granted public utilities first access to federal hydropower. The investor-owned utilities then began turning to expensive thermal generation, a step that was reflected in their rates by the mid-1970s. Many of the region's public utilities are small, serving only one county or a sparsely populated rural area. But even the larger investor-owned utilities were limited in their ability to move into the thermal age. It was not unusual for an investor-owned utility to have half its assets tied up in construction of generating plants that could not bring in revenue until they were declared "used and useful" by the state regulatory commission.

1. Base-load resources run continuously except for maintenance and forced outages.

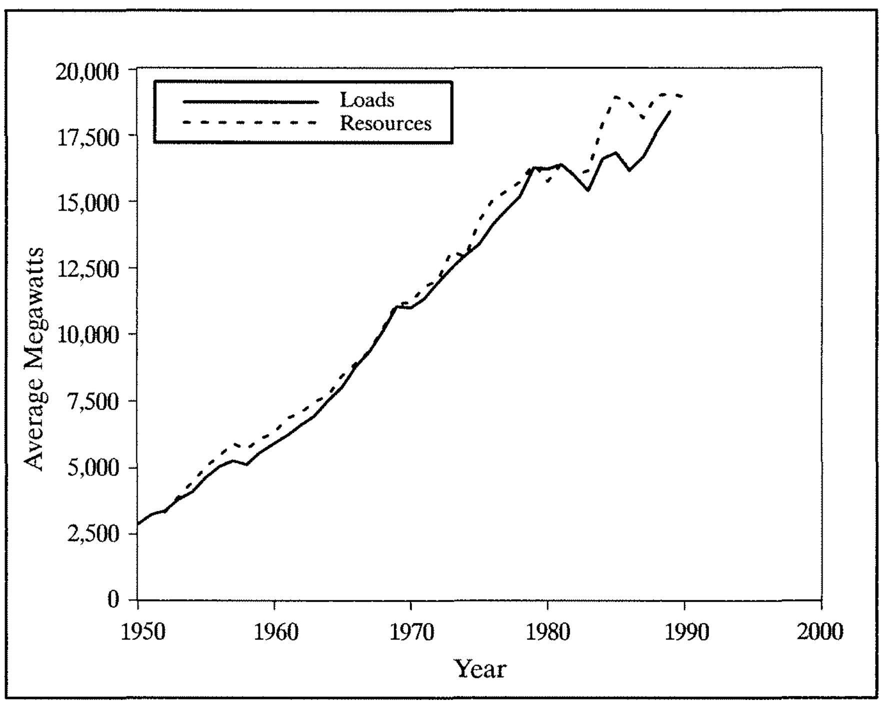
Bonneville Power Rates

Figure 2-1
Bonneville Power Administration Preference Rate—1940–1990 (All Figures in 1990 Dollars, Adjusted for Inflation)



Loads and Resources

Figure 2-2
Firm Electricity Loads and Resources



Fourth, by 1977, investor-owned utility rates, which historically had been comparable to public utility rates, skyrocketed to two or three times those of public utilities. Growing pressure to correct this rate disparity prompted the state of Oregon to enact the Domestic and Rural Power Authority, which was to lay claim as a publicly owned utility to federal hydropower for the benefit of all the state's citizens.

Fifth, with limited power supplies and growing customer loads, Bonneville foresaw a day when it would no longer be able to meet all the power needs of its public utility customers. On July 1, 1976, it issued a Notice of Insufficiency informing its customers that after seven years it could no longer meet all their needs. Bonneville then began a lengthy proceeding to develop a formula to allocate its available power supplies. This effort was expected to be extremely difficult and controversial.

Sixth, the direct service industries' contracts were to expire in the 1980s. The power supplied to these industries would have to be sold to the public utilities under the preference clause. If they were to survive in the Northwest, these industries needed an assured source of power. Some of these plants are old, but Figure 2-3 shows that approximately 60 percent of the region's aluminum capacity was built after 1965.

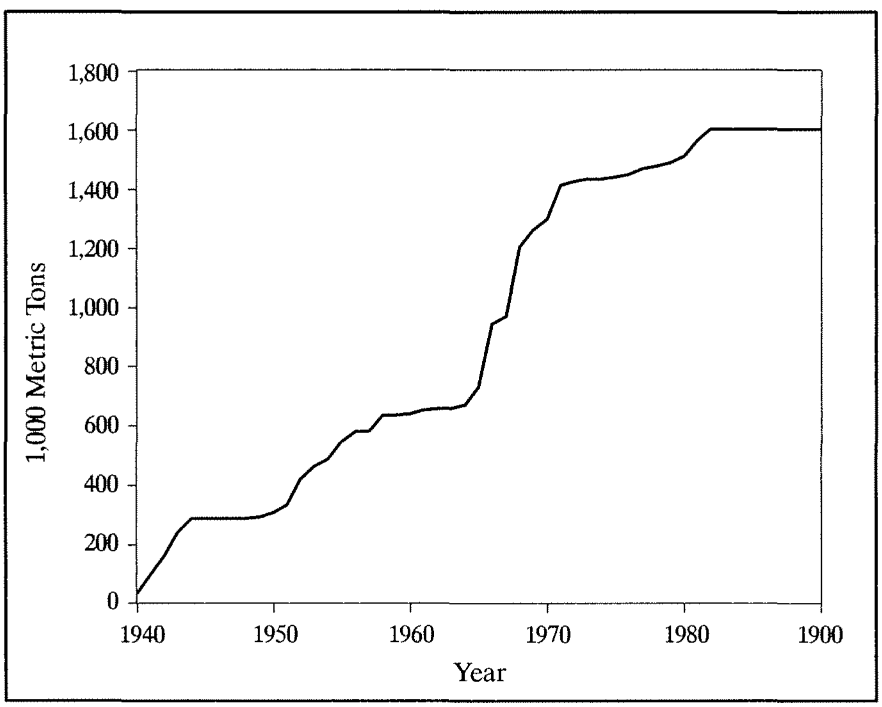
And finally, concerns over the decline of the famed Columbia River salmon and steelhead runs were drawing regional attention. Since the first dams went up in the 1930s, the annual salmon catch had declined 70 percent. While hydroelectric development was not the only cause for the decline, there was widespread agreement that the dams had been a major factor and that remedial measures were needed. Getting a coordinated response was a problem. The river and its tributaries flowed through all the Northwest states and a number of jurisdictions, including Indian tribal lands.

The Northwest Power Act Ushers in a New Power Era

By 1980, it was clear that not only was a comprehensive solution needed for the region's electrical power problems, but a mechanism for addressing that part of the fish and wildlife problem resulting from the power system was needed as well. That comprehensive solution was found in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act, Public Law 96-501) passed by the 96th Congress in December 1980.

Aluminum Capacity

Figure 2-3
Growth in Regional Aluminum Capacity



Among other things, the Act gave Bonneville an expanded role, allowing it to acquire resources, including the development of conservation programs, and to help restore fish and wildlife. The Act also created a public process for future electrical power planning by allowing the creation of a state-appointed Northwest Power Planning Council. The Council was charged with planning for future electrical energy demand and resources, including conservation, to be developed to meet the region's needs. It also gave the Council the authority to plan the actions and investments to be undertaken to rescue the fish and wildlife resources, particularly salmon and steelhead, affected by the Columbia River power system dams.

Bonneville received broad new authorities. In return, the Northwest states, whose ratepayers fund Bonneville, received an increased role in directing their own energy future through the Council. All of the Council's business and decision making are conducted in public, and the Council maintains a broad public information and involvement program to stimulate public participation.

Bonneville's expanded role allowed it to acquire new power supplies through a mechanism by which Bonneville would acquire the power generated by a power plant and pledge to pay the costs of building and operating it. This "guaranteed purchase" was intended to give financially strapped utilities better access to financial markets to get funds for new conservation programs and thermal plants, and was designed to spread the financial risks of developing new resources across the region.

With the ability to acquire new resources, Bonneville could execute new contracts as well as continue to supply the non-generating utilities and the growing needs of all other utilities. The Act also authorized Bonneville to sign residential "exchange" contracts with utilities, allowing them to buy power to serve their residential and agricultural customers at the same rate that Bonneville charges public utilities. In turn, the generating utilities would sell Bonneville power at their own average system cost. This exchange gives residential and small farm customers of utilities participating in the exchange access to the Northwest's cheap hydropower and has saved these customers approximately $1.7 billion since the passage of the Act.

The Act also authorized Bonneville to enter into new long-term contracts with the direct service industries. These industries gave up existing contracts, most of which were scheduled to expire in the 1980s, for higher-priced contracts of 20 years' duration. The direct service industries also agreed to absorb a large portion of the costs to Bonneville for the exchange program described above.

Finally, the Act also set up a system of "rate pools" to assist Bonneville in determining what the various classes of customers would pay for power.

The Northwest Power Planning Council

In the past, dams had been built and transmission lines constructed with relatively little public participation. However, new coal and nuclear plants were seen as affecting both the economy and environment of the Northwest. Electricity rates had begun to climb dramatically in many parts of the region prior to the Act, and the impacts of the dams and thermal generating plants on the environment had become matters of intense public controversy. The public at large, as well as state and local governments, needed and demanded a voice to express their interest in energy issues.

Public opinion on electrical energy issues had become so strong that future power development seemed stymied. To propose a new generating unit in the atmosphere of the late 1970s was to subject a utility to what appeared to be an endless process before public bodies and a largely uncertain outcome. The lack of consensus was counterproductive to planning. While energy plants were being stalemated, the conservation programs that would be necessary if the plants were not built were not being undertaken, either. The need for regional consensus building was a primary impetus for the formation of the Northwest Power Planning Council.

The creation of the Council took place in the framework of an interstate agreement under the "compacts clause" of the U.S. Constitution. The principal duties of the Council under the Act are to: 1) develop a 20-year regional power plan (the plan) to ensure the Northwest an adequate, efficient and reliable electrical power supply at the lowest cost; 2) develop a fish and wildlife program (the program) to "protect, mitigate and enhance" the fish and wildlife affected by hydroelectric development in the Columbia River Basin; and 3) provide for broad public participation in these processes.

According to the Act, Bonneville implements actions consistent with both the plan and the program. The Act requires Bonneville to seek the Council's approval for any resource acquisition over 50 megawatts and five years in duration. If the Council finds that any proposed resource acquisition is not consistent with its power plan, Bonneville must secure congressional approval before acquiring the resource. In addition, Bonneville, the Corps of Engineers, the Bureau of Reclamation and the Federal Energy Regulatory Commission must take the Council's Fish and Wildlife Program into account "at each relevant stage of decision-making to the fullest extent practicable."

1980–1985: A Changing Power Picture

Even as the Council worked to develop its first plan, the Northwest electrical power picture had already begun to change dramatically. Much of the impetus for the Act had been the projection of large deficits in power supply. Because many utility planners in the 1970s assumed they could predict the most likely future, the result was a single energy forecast for the region that led to the start of construction of 17 coal plants and 10 nuclear plants. In 1980, there were predictions of blackouts and severe regional shortages.

But between 1981 and 1983, it became apparent to the Council that the mid-1980s would not be characterized by deficits but by an expensive surplus of uncertain duration. This signaled the emergence of a new and different set of problems.

Uncertainties inherent in forecasts of energy needs had led the region to build large expensive generating plants that were not needed, at least not on their schedules for completion. The high electricity rates resulting from these expensive new plants were leading to consumer unrest and even some shutdown of industrial processes in the region. Figure 2-1 also shows that Bonneville's wholesale rates increased by 500 percent between 1980 and 1983, primarily as a result of the cost of the Washington Public Power Supply System plants.

Other factors also cast a new cloud on the regional power picture. The region entered its deepest economic recession since the depression of the 1930s. At the same time, due to low world aluminum prices, a significant portion of the aluminum production capacity in the Northwest shut down, temporarily exacerbating power surpluses. Other traditionally reliable, large industrial power loads, such as the wood products industry, also dropped off. As a result, electric load during this period actually declined. Bonneville and the region's utilities suddenly found themselves with more power than they could sell.

The Northwest Power Plan: Planning for Flexibility

In April 1983, the Council adopted its first 20-year power plan. That plan spelled out a new kind of planning strategy and set significant new directions for the Pacific Northwest.

The plan addressed the surplus of electricity in the region and focused on preventing lost opportunities to the region. Lost-opportunity resources are cost-effective resources that, if not secured, could be lost forever to the region. The primary example is incorporating energy-efficient features into new buildings when they are constructed. Many of these measures cannot be installed later, and the building will consume energy long after the surplus is over.

The plan called for few new resources to be acquired. Instead, it emphasized the need to develop the capability to deliver energy conservation in the commercial, industrial, governmental and agricultural sectors. The plan also called for continued capability in the residential sector with an emphasis on programs to reach low income and renter households.

In accordance with the statutory priorities established in the Act, the plan relied primarily on conservation. Improving energy-efficiency costs considerably less than building new thermal resources.

Like the 1983 plan, the 1986 plan emphasized lost-opportunity conservation and called for no near-term development of new resources except those that are cost-effective and could be lost to the region if they are not secured. In addition, that plan emphasized the following priorities: a stronger regional role for Bonneville; development of conservation on a regional basis; strategies to make better use of the hydropower system; building conservation capability in all sectors; demonstration of the cost-effectiveness of renewable resources so they are available before the region has to build new thermal generating resources; development of an acquisition process to secure resource options and to demonstrate the purchase of conservation and generating resources so they can be available when needed; equitable allocation of costs for two unfinished nuclear plants and removal of problems that would block their completion when and if they were needed; and study of electrical power sales and purchases between regions. These efforts were designed to prepare the region to meet future electric energy needs.

Key to most of the priorities in the 1986 plan was cooperation among power organizations, both public and investor-owned.

1985-1990: The Region Prepares for the Future

Since the Council adopted its 1986 plan, the region's economy has boomed and electric load growth has averaged about 3.5 percent. In 1986, the regional surplus was approximately 2,500 megawatts. Today, the region has just enough firm resources to meet its current energy needs. The region is facing major decisions on investments in new conservation and generating resources to meet its future needs.

During the past five years, Bonneville, the region's utilities, and state and local governments have made significant strides in preparing the Northwest for the challenges we face.

Bonneville and utility programs have saved an estimated 350 megawatts of energy at less than half the cost of the same amount of power from a coal plant. If the same amount of power were produced by a large generating plant, the Northwest would spend $1.4 billion more than the cost of conservation over the life of the plant.

The federal, state and local governments, in cooperation with Bonneville and the utilities, have adopted new efficiency standards for new buildings and appliances. Over the next 20 years, these actions will save an estimated 800 megawatts in the high-demand forecast. State governments also have implemented energy-efficiency programs that have saved an additional 200 megawatts of electricity.

The Council developed model conservation standards in 1983, at the direction of the Northwest Power Act. All of the Northwest's utilities now promote efficiency through practical programs and incentives. In addition, approximately 120 local governments throughout the Northwest have adopted the standards as part of their building codes.

In February 1990, Washington became the first state in the Northwest to adopt the full model conservation standards for residential construction. In 1991, the state of Oregon also adopted a statewide building code providing energy savings equivalent to the model conservation standards. The adoption of these new codes in Washington and Oregon means that 87 percent of all electrically heated single homes and 96 percent of the electrically heated multifamily units will meet the energy savings levels of the model conservation standards.

Idaho recently adopted a statewide energy code that will improve building practices substantially. Under the new code, Idaho utilities are prohibited from serving new homes that have not obtained permits guaranteeing compliance with the new code.

In 1989, Montana used an administrative procedure to adopt a more energy-efficient residential building code. In addition, Montana is conducting a statewide education program to move construction practice toward the level required by the model conservation standards.

The Northwest has been a leader in the country and the world in integrated least-cost planning. The Council, Bonneville, utilities and other regional interests have worked together to develop common analytical tools and improve information on energy use, forecasting, and new resources. For the past two years, the Council and Bonneville have developed a joint forecast of future electricity needs and joint estimates of the cost and future supply of conservation and generating resources.

The utility regulatory commissions in Idaho, Oregon and Washington now require the investor-owned utilities they regulate to prepare resource plans similar in general outline to the Council's plan. All of the region's investor-owned utilities have completed or are developing such plans. Several utilities are working on their second plans.

In addition, a number of public utilities have developed integrated least-cost plans and participate in the development of Bonneville's Resource Program. All of the public utilities have developed conservation plans as part of Bonneville's programs.

As a result of all these efforts, there appears to be a general consensus on the plan's underlying data and analysis, and the focus has shifted to implementation of the regional plan.

The costs of electricity have generally stabilized, and Bonneville's rates have actually declined after adjusting for inflation.

All of these accomplishments will help the region meet the challenges of the 1990s. Unfortunately, there are also areas where the Northwest fell short of achieving the objectives of the past plans.

One of the objectives was to test and perfect conservation programs that could be ready for aggressive implementation when the region needed more power. Bonneville and the region's utilities have run pilot programs in the commercial, industrial and agricultural sectors. But more work is needed before the region has the capability to capture all the cost-effective energy efficiency in all sectors of the Northwest economy.

Another objective of previous plans was to build up an inventory of resources with short lead times that could be used to meet future load growth. The Creston coal project has successfully completed siting and licensing, and the Washington Energy Facility Site Evaluation Council has extended the site certificate for the project. No other large generating projects have completed the pre-construction phase, although several hydroelectric sites have been licensed and could be developed within several years.

State siting agencies in Montana, Oregon and Washington have modified their procedures to allow resource developers to delay construction of a resource after receiving permits, site certification and licenses. However, a number of significant contractual, legal, regulatory and institutional issues must be resolved before decisions to site, license and design a resource can be separated from decisions to begin construction.

Some of the legal barriers surrounding the Washington Public Power Supply System plants have been resolved, but a number of significant issues remain that raise questions about whether those two plants could be completed if they were needed.

Finally, little progress has been made in demonstrating the cost-effectiveness of renewable resources in the Northwest. Bonneville has proposed to co-sponsor a geothermal demonstration project. The Council, working with a broadly representative advisory committee, has proposed a research, development and demonstration agenda for geothermal, wind and solar resources.

Given the status of the region's conservation programs and the current inventory of resources with short lead times, the region can only support about one percent annual growth in electricity use over the next five years. If electricity growth is higher than that, the region will have a deficit of firm resources, and it will need to depend on less reliable nonfirm power and purchases from outside the Northwest.

The lessons from the 1980s are clear: the future is very uncertain, and it is very important to invest in activities that will prepare the region to meet whatever happens. The Council's planning strategy and Action Plan respond to these lessons.

CHAPTER 3

THE COUNCIL'S PLANNING STRATEGY

The Council's Goals

Because the future is uncertain and conditions are likely to change, flexibility and risk management are underlying principles throughout the Council's planning strategy.

The overall goal of the power plan is to ensure that the region can provide adequate, efficient, and reliable electrical energy services at the lowest cost, while at the same time minimizing the risk of future uncertainties in the cost and supply of energy services in the Northwest.

The plan would achieve that goal by planning for sufficient resources to meet the region's future energy needs under varying conditions of growth and service requirements.

The Council seeks to balance the sometimes competing attributes of lowest cost, highest reliability, and least exposure to risk. The Council believes this plan, if fully implemented, will meet the region's electric energy needs at the lowest cost and lowest risk to the economy and environment of the Northwest.

The Council developed this electrical power plan with the following specific goals in mind:

- provide the region an adequate, efficient and reliable supply of electrical energy service at the lowest possible cost;
- select resources following the cost–effectiveness principles and priorities in the Northwest Power Act;
- develop a flexible strategy so that the plan can be modified as conditions change and new information becomes available;
- encourage the greatest rate predictability and stability for the region;
- evaluate all resources from a total regional system perspective and ensure their compatibility with the existing power system;
- select resources with the least adverse impacts on the environment, or those with adverse environmental impacts that can be mitigated; and
- select resources that are consistent with protecting and enhancing fish and wildlife, and that mitigate power system impacts on fish and wildlife.

Integrated Resource Planning

Integrated resource planning (also known as least–cost planning) means ordering resource acquisitions in such a way as to result in the lowest overall total societal cost to the region. But it means much more than the cost to build and operate a resource. It also means lowest cost in terms of environmental consequences, and lowest cost in terms of risk management (that is, lessening the risk of overbuilding or underbuilding resources when you have to deal with an uncertain future).

Economic and Load Projections

The Council begins its planning process with a thorough analysis of the region's demographic trends, economic development potential and existing energy demands. It uses these patterns of use and predicted growth to develop ranges of power demand for the next 20 years, rather than the single–point prediction used by utilities in the region.

Resource Analysis

The Council then compares alternative resources on a consistent basis to determine which ones can most reliably and cost–effectively meet the region's energy needs. Electricity saved through efficiency improvements is considered a resource comparable to any generating resource.

The keystone of the Council's planning philosophy is the recognition of the uncertainty surrounding virtually every aspect of energy planning. Instead of fixing on a single-point prediction of the region's energy future, the Council's methodology embraces a range of possible futures.

The Council reviews hundreds of scenarios that reflect the inherent uncertainty of both the future demand for electricity and the cost and availability of new conservation and generating resources.

The purpose of this analysis is to identify the actions that are necessary to prepare the region to respond to the uncertainty we face.

Public Review

An important reality check in the Council's planning process is public involvement. The Council forms broadly representative advisory committees to review the forecasts and resource assessments. The details of this analysis are published and circulated, and public comment is taken at the Council's regular meetings as well as in writing. This preliminary analysis encourages organizations and individuals to challenge the assumptions and methodology used by the Council and improves the quality of the final product.

The Council works with all interested organizations in the region to develop commonly accepted analytic tools. As a result, regional debates can focus on important policy considerations rather than on differences in the computer models used by various organizations. In addition to improving the quality of information and focusing policy debates, the Council's public process helps ensure that all interested parties share the same set of factual assumptions. This enhances communication and helps build a consensus for action.

The Council's Planning Process

In selecting the resources described in this plan, the Council followed the directions of the Northwest Power Act. The Act sets many guidelines for the Council's planning process. First, it requires the Council to produce a plan for developing resources, including conservation measures. The Council must consider environmental quality, compatibility with the existing regional power system, as well as protection, mitigation and enhancement of fish and wildlife. The Act also specifically requires that the Council develop and include model conservation standards.[1]

In accordance with the Act, the Council selects resources that are cost-effective. The Act defines a cost-effective measure or resource as one that is forecast to be reliable and available within the time it is needed, at an estimated incremental system cost[2] no greater than that of the least-cost similarly reliable and available alternative. Cost-effectiveness is a function of need, relative cost, reliability and availability. The plan is based on the premise that the region should buy only the resources that it needs. When the region needs power, it should buy the lowest-cost resources, counting all the costs involved on a consistent basis. And, the region should only depend on resources that will be reliable and available when they are needed.

The Act requires the Council to give first priority to conservation, second to renewable resources, third to generating resources using waste heat or generating resources of high fuel-conversion efficiency, and last to all other resources. Finally, the Act provides a 10-percent advantage in calculating the estimated incremental system costs for conservation measures.

Step 1: Dealing with an Uncertain Future

The planning process starts with the recognition that the future is uncertain, and that electrical energy needs cannot be predicted with any precision. The Council has chosen to deal with this uncertainty by defining plausible boundaries for the region's energy growth. To do this, the Council develops a range of high, medium-high, medium, medium-low and low electrical load growth scenarios over the next 20 years. The region's actual demand for electricity is most likely to be between the medium-high and medium-low boundaries.

The high forecast in the Council's range projects an average annual growth rate of 2.5 percent. This outcome would be the result of record regional economic growth relative to the nation over the next 20 years. In fact, it is based on assumptions that would produce relative economic growth over 20 years at a higher rate than any previous 20-year period in the Northwest's history. Employment in the region would grow 87 percent faster than projections for a fast-growing national economy.

The Council selects a high upper bound to ensure that the region has the ability to supply electricity for any potential need. While the Council develops an inventory of actions that would permit acquisition of resources to meet this upper bound, the region will not build all these resources unless high growth actually occurs.

1. Model conservation standards apply to new and existing structures, utility, customer, and governmental conservation programs and other consumer actions for achieving conservation. These standards must be designed to produce all power savings that are cost-effective for the region and economically feasible for consumers.

2. System cost is defined to be an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, costs for distribution and transmission, waste disposal, end of cycle, and fuel costs, as well as quantifiable environmental costs and benefits. The Council also is required to take into account projected resource operations based on appropriate historical experience with similar measures or resources.

The lower boundary of the range forecast is an average annual rate of growth of -0.4 percent. It is based on assumptions that the region might grow more slowly than the rest of the nation, with employment growing significantly slower than a low national forecast. The economic assumptions in this forecast would be well below what the region has experienced historically.

The Council translates economic assumptions into corresponding electricity requirements using the best available demand forecasting models. Please see Volume II, Chapter 5 for details of the economic forecast and Volume II, Chapter 6 for the demand forecast.

The range forecast represents the prudent span of future energy use patterns and defines the magnitude and schedule of actions needed to meet that range of use.

The Council produces its best estimate of the existing resource base, including any known additions or reductions (e.g., resources nearing completion or retirement, and power contracts that expire or begin within the next 20 years). The existing resources and power transactions are described in Volume II, Chapter 4. Existing resources then are subtracted from the range of future electricity demands to determine the amount of conservation and generating resources needed.

Step 2: Comparing all Resources

Concurrent with development of the range of energy-use forecasts, the Council examines the availability, reliability and costs of all conservation and generating resources.

This approach explicitly recognizes that there is no demand for electricity per se, but rather for services, such as heating and lighting, which can be met either by improving the efficiency of electricity use or increasing supply. Measures that improve the energy efficiency of a building provide the same service (a comfortable place to live or work) and free up electricity that can be used to provide other services. The Northwest Power Act specifically defines conservation as a resource.

Environmental impacts are also assessed, and costs are included for adapting technologies to avoid or reduce to acceptable levels the impacts of each resource on the environment and on fish and wildlife. The Council also developed a method for analyzing other environmental costs and benefits, and used judgment in weighing the non-quantifiable effects of each resource alternative.

The products of this analysis are "supply curves" for each resource. These curves estimate how many megawatts of a resource are available across a range of costs. In order to evaluate all resources on a comparable basis, all costs are calculated on a levelized life-cycle basis using 1990 levelized nominal dollars.

Resources are divided into "cost-effective" and "promising" categories. Cost-effective resources must use commercially available technology, have predictable and competitive costs and performance, and must use a demonstrated resource base. Development of the resource must not have institutional constraints (legal, financial or regulatory), and the resource must be environmentally acceptable according to current policies, laws, regulations and the Council's Columbia River Basin Fish and Wildlife Program. Promising resources may be considered for acquisition in future power plans if their availability, reliability or costs improve. The plan includes research, development and demonstration activities to promote the development of promising resources.

Volume II, Chapters 7, 8 and 9 describe the conservation and generation resource analysis and environmental considerations used by the Council. The Recommended Activities for Implementing the Power Plan, Volume II, Chapter 1, includes the Council's research, development and demonstration recommendations.

Step 3: Analyzing Load and Resource Uncertainty

The Council assumes that the future can play itself out along an infinite number of paths. In addition to uncertain future energy needs, the Council must also address the uncertainty associated with conservation and generating resources. To do this, we study dozens of alternative resource packages, looking primarily at plausible conditions under which the region's energy future could be altered. In a departure from earlier plans, the Council developed four resource portfolios instead of one. These four respond to the major questions confounding resource planners:

- How much and how fast will the region's use of electricity grow?
- Will coal and nuclear power plants be available and acceptable?
- How much conservation can actually be achieved?
- How stable are natural gas prices and supplies?

Power planners don't get to know the answers to these questions. The economic scenarios are only one part of the equation. Resources carry their own uncertainties, including the lead time required, construction costs, operation and maintenance costs, the future costs of fuel and its availability, resource performance (savings and output), regulatory changes, public acceptance, and the question of will anyone sponsor resource development.

By developing and testing a series of alternative resource portfolios, the Council was able to identify the most significant load-and resource-related risks the region might face and compile the best set of actions to ensure an adequate and reliable power supply. Immediate actions that are common to several portfolios have the highest priority in the Action Plan.

In these studies, the Council shifted resources around, testing the power system's sensitivity to changes in any one of them. This was an opportunity to explore more fully the effects on the region of calling on different resources with different lead times, different costs and different environmental impacts.

State-of-the-art computer models are used to simulate how each resource would operate within the existing power system to determine the actual costs the region is likely to incur. This analysis also determines the compatibility of each resource with the existing power system. Alternative resources are evaluated against hundreds of different load scenarios to simulate the uncertainty and volatility of future energy needs.

Several resource characteristics have been identified as important in providing the flexibility to adapt to uncertainties. For example, the Council recognizes that resources with short lead times, small plant sizes and low capital costs can reduce risk. Resources that can be constructed and brought into operation quickly and in small increments give the region a much better chance of matching supply to energy needs. Resources that are correlated to load growth, such as conservation from building and appliance efficiency standards, also help reduce uncertainty by supplying increased energy savings as the population and economy grow.

Volume II, Chapter 10 describes the Council's resource portfolio analysis. Chapter 15 provides a description of the risk assessment and decision analysis used by the Council.

Step 4: Policy Considerations

In evaluating the cost-effectiveness of both non-discretionary and discretionary resources, there are other significant attributes that must be included concerning the cost-effectiveness and appropriateness of each resource included in the plan. In deciding on the cost-effectiveness of individual actions, the Council included environmental concerns such as indoor air quality, acid rain, mining impacts, transportation, employment, and fish and wildlife, and the potential for global warming. In addition, some of the resources included in the Council's plan will help reduce future load growth uncertainty, and some resources are particularly flexible and, therefore, will help the region adapt to the wide range of uncertainty it is facing. The Council also made judgments about fuel diversity and the risks of fuel cost escalations. Finally, due to the significant uncertainty over the cost and availability of each resource included in the Council's portfolio, the Council must decide whether enough valid cost and performance information is available on which to make an informed judgment.

The Council has relied upon its demand forecasting, system analysis and decision models as aids to decision-making. It is important to emphasize, however, that the models are used to analyze decision alternatives and not to make decisions. The Action Plan and resource portfolio analysis presented in this plan outlines a program for managing the uncertainties and minimizing the risks faced by the region in its energy future. The Action Plan and resource portfolio reflect prudent judgments that necessarily go beyond the Council's analytic models.

Step 5: Action Plan

The actions called for in this plan are chosen to meet most plausible economic growth and changes in the cost and availability of resources. These actions will prepare the region to meet future energy needs. These actions are described in Volume I and Volume II, Chapter 1. Because these actions require significant effort and investment, the Action Plan is the most important part of the plan.

Although the plan is based on the best available information, the Council realizes that circumstances change, some cost-effective resources are not included in the plan and other resources may become cost-effective. Therefore, the Council carefully monitors electrical load growth and the cost and availability of resources to determine when modification of the plan and Action Plan is needed. The Council also expects that conservation and generating resources will be developed through a variety of competitive acquisition processes. These processes should identify resources that are cost-competitive with the resources included in the plan.

The Council's planning strategy continues to be based on what has come to be known as a societal perspective. The objective of the Council's plan is to minimize the total present-value system costs, whether those costs are borne by utilities, and thus reflected in electric rates, or by individuals, businesses and governments acting in their own self interest—in other words, the total "society" served. This approach does not necessarily result in the lowest electricity rates in the short term, but, rather, minimizes the total long-term cost of providing energy services for all ratepayers in the region.

This approach assures that all costs of resources are considered when comparing two or more resources, whether they are conservation or generation. Conservation resources can be acquired through financial assistance, regulatory standards or rate designs. In many cases, financial payments will be needed to acquire all cost-effective conservation. Bonneville and utilities should require conservation at costs up to the region's marginal cost. These payments should not be diluted simply to avoid rate impacts.

Flexible Resources

Conservation

The Council has found that conservation is a flexible resource that also can reduce uncertainty and risk. The Northwest has a large supply of potential conservation measures that cost much less than building a new thermal power plant.

Conservation programs to improve the efficiency of new buildings tend to track load growth. During rapid growth, more buildings are built and the energy that is

The Council believes a least-cost plan should establish the value of conservation in order to select the conservation measures that will lead to a least-cost solution for society. It is of paramount importance that conservation and generation compete on a level playing field. Failure to provide a level field will result in society shifting scarce capital from other more productive economic development to the construction of inefficient resources.

Conservation as a Resource

The Council recognizes the possibility that purchasing conservation in lieu of generation can create inequity in the rates participants pay for electricity when compared with the rates non-participants in conservation programs pay. However, the Council believes that equity is best addressed through rate design and ratemaking. Acquisition of virtually every type of resource has an impact on rates. Rate impacts that could result from acquiring conservation can be minimized through program design and by offering comprehensive conservation programs to all customers. Comprehensive programs reduce all customers' electricity bills. The Council believes that rates are important, but if rates are allowed to become the overriding objective of least-cost planning, the costs imposed on all society can be enormous.

One of the most significant issues addressed by the Council is the effect of conservation on non-participants. Some argue that conservation programs should not increase the electric rates of individuals who do not directly participate in the program. This is sometimes referred to as the "no-losers test." Conservation can affect rates because conservation programs do not increase the amount of power a utility sells. Therefore, even though conservation programs may cost less than generation, because their costs are spread over a smaller base, they can raise rates relative to generation.

The Council reviewed this issue and found that strict adherence to a no-losers test leads to a higher total cost for all ratepayers than the economic decision rules used by the Council. In choosing between conservation and generating resources, the Council selects all conservation measures that have a total societal cost[3] that is expected to be less than or equal to the expected marginal cost of all resources needed to meet forecast load growth. The following example compares the total system costs and rate impacts of an all-generation strategy, conservation under the no-losers test, and the Council's approach. It shows that the Council's treatment of conservation results in the lowest present-value cost to all ratepayers with minimal effects on electric rates.

An Analysis of Three Approaches to Meet Load Growth

Remembering that the planning goal is to provide energy service at the lowest total cost to society, this section provides a simple numerical example of how a growing power system could pursue several distinct resource acquisition paths. This example will show how different acquisition strategies affect total societal costs and also how non-participants (in conservation acquisition) are affected. These strategies are shown in Table 3-1. In this example, the base power system has an existing load of 100,000 gigawatt-hours[4] and is expected to grow by 10,000 gigawatt-hours.

Three distinct strategies are analyzed to meet this load growth. The first involves the all-generation strategy. This proposal is to meet the entire 10,000 gigawatt-hour load growth with new generation estimated to cost 6 cents per kilowatt-hour. The second strategy involves a conservation strategy based on adherence to the "no-losers test" described above and discussed later. The third strategy chooses all conservation up to the point at which the marginal conservation measure is estimated to cost the same as the marginal generation resource.

If the base power system serves its 100,000 gigawatt-hour total load at an average rate of 5 cents per kilowatt-hour, the annual revenue requirement is $5 billion per year. The present value of this annual requirement, using an 8.15-percent nominal discount rate[5] over a 30-year period, is $55.5 billion.

3. The total societal cost of conservation measures includes the direct costs of any equipment or materials that are required to achieve the efficiency gain, the labor required to install the improved equipment or materials, and the overhead and administrative costs required to manage and direct programs to acquire the measures.

4. A gigawatt-hour is 1,000 megawatt-hours, or one million kilowatt-hours. The system used for this example has a total load of 11,400 average megawatts. For comparison purposes, the Pacific Northwest system has a current load of about 20,000 average megawatts or 175,000 gigawatt-hours.

5. The Council uses a 3-percent real discount rate and an assumed long-term inflation rate of 5 percent. These combine to a nominal discount rate of 8.15 percent.

Table 3-1
Alternative Resource Strategies

	Base Power System	Case I Generation Strategy	Case II Conservation Strategy "No-Losers Test"	Case III Marginal Conservation up to Marginal Generation
Existing Load (gWh)	100,000	100,000	100,000	100,000
Load Growth (gWh)	—	10,000	10,000	10,000
Conservation (gWh)	—	—	1,667	10,000
Generation (gWh)	—	10,000	8,333	0
Total Load (gWh)	100,000	110,000	108,333	100,000
Existing Rate (cents/kWh)	5.0	—	—	—
Existing Annual Revenue Requirement ($ billion)	5.0	5.0	5.0	5.0
New Generation (gWh)	—	10,000	8,333	0
Generation Cost (cents/kWh)	—	6.0	6.0	—
Conservation Cost (cents/kWh)	—	—	0.5	3.0
Generation Revenue Requirement ($ billion/year)	—	0.6	0.5	—
Conservation Revenue Requirement ($ billion/year)	—	—	.008	0.3
Total Annual Revenue Requirement ($ billion/year)	5.0	5.6	5.508	5.3
Average Rate (cents/kWh)	5.0	5.09	5.08	5.3
Total Present Value Revenue Requirement @ 8.15% ($ billion)	55.5	62.2	61.1	58.8

Strategy 1: All Generation

Assuming the system grows by 10,000 gigawatt-hours and load growth is met with new generation costing 6 cents per kilowatt-hour, the annual revenue requirement will increase by $600 million to a total of $5.6 billion per year. This means that the average rate for all customers, under the generation strategy, would increase to 5.09 cents per kilowatt-hour. The total present-value revenue requirement of the generation strategy increases to $62.2 billion. Acquiring new generation to meet the increased load, in other words, results in a $6.7 billion increase in the total present-value revenue requirement.

Strategy 2: No-Losers Test

The second strategy involves selecting all conservation measures that do not violate the decision rule known as the "no-losers" test. This test, in its simplest form, limits conservation programs so that electric rates are no higher than if the same amount of power came from new generating resources. This test would restrict payment for new conservation measures to no more than the difference between the marginal cost of new generation and the current rate for the existing system. As in the previous example, the average rate of the existing system is 5 cents per kilowatt-hour. Subtracting this average rate from the marginal cost of new generation of 6 cents per kilowatt-hour leaves a maximum payment of 1 cent per kilowatt-hour for conservation measures.

Advocates of this rule base their position on two specific reasons. The first reason is to provide for equity among all the ratepayers of a utility. The second is that they have adopted, explicitly or implicitly, the objective of minimizing rates, as opposed to minimizing the total cost of energy services.

To demonstrate how conservation fits into utility planning, it is necessary at the outset to estimate the potential for energy savings available in any given system. One such conservation supply curve or function is shown in Figure 3-2. This curve shows the amount of load reduction that can be achieved through the purchase of energy-efficiency saved reduces the need for generating resources. During periods of slow growth, fewer buildings are built and thus less money is expended on these programs.

Programs to improve the efficiency of existing buildings and other electricity uses also are flexible. Once a program has been developed and tested, it can create savings relatively quickly. These savings can be developed in small units and can be timed to match growing power needs. If the region's electrical energy needs grow rapidly, the conservation programs can be accelerated. If slower growth occurs, they can be maintained at a minimum level. While conservation programs are capital intensive, the expenditures usually begin to produce savings immediately. Conservation programs can be paced to deliver the needed amount of savings much more easily than new central station power plants.

An added benefit to conservation is that it helps reduce uncertainty. Because more savings are available in high load growth, conservation actually reduces the range of future energy needs. In addition, well insulated buildings and energy-efficient industrial plants are more resistant to changes in energy prices. Therefore, they are less likely to contribute to fluctuations in power demand or switching to another fuel.

Shortening the Lead Time for Generating Resources

It is likely that the Pacific Northwest will need resources in addition to conservation. The Council has been working to improve the flexibility of generating resources in order to reduce the risk they pose for utility systems and ratepayers. The key element of the concept is the explicit recognition of at least *two* decision points for a long lead-time resource. The first is a decision to initiate engineering and siting. The second decision point is to begin construction.

Under this two-step approach, a resource would move through the time-consuming but relatively inexpensive siting, design and licensing stages, after which it could be placed in a "ready condition." In that condition, the project could be constructed, placed on hold, or terminated, depending on the demand for electricity. For this concept to be successful, the Bonneville Power Administration or a utility would need to provide financial assistance to a resource sponsor in exchange for the right to decide when conditions warrant beginning construction. This concept is similar to an option contract for a piece of land. The developer pays for the future right to develop the land. In power planning, such options would provide a relatively low-cost inventory that would allow the region to be ready for high growth rates without prematurely committing to build to those rates.

The cost of design, siting and licensing is typically very small compared to the costs associated with constructing a resource. Completing these pre-construction activities can substantially reduce the lead time of resources. By having a licensed or readily licensable resource effectively "on hold," the period over which electricity needs must be forecast could be reduced to the resource construction period, which may be as little as half of the total time that is now needed. Figure 3-1 shows the cumulative costs of the pre-construction and construction phases for several resources. For example, the total lead time to site, license, design and construct a new coal plant is about 11 years. The activities of siting, licensing and detailed design would take four years and cost $24 per kilowatt, compared to the $1,325 per kilowatt for the construction phase. It then would then take another six years to complete construction. Thus, the time between the decision to build and the date of completion of a coal plant can be effectively reduced by four years for approximately 2 percent of the total potential cost.

Separating the decisions related to construction from those of pre-construction is critical. The objective of an effective risk management strategy is to move decisions involving the commitment of large sums of capital as close as possible to the anticipated time power will be needed. This will significantly reduce the likelihood of beginning construction on a project that is not needed. Another benefit of this approach is its potential for reducing environmental degradation. For example, if generating plant construction can be postponed until need is more certain, the accompanying environmental impacts also can be postponed and, if the plant is not needed, they can be avoided. This approach will have less effect on the environment than building and operating resources that may not be needed.

The Council believes that the region needs to secure projects that have been sited, licensed and designed. These resources would be needed to meet a very high level of economic growth. If the region actually experiences lower growth rates, some of these projects would be delayed or even abandoned at a minimal cost to the region. This concept is comparable to an insurance policy—paying low-cost premiums to be prepared for a high-cost event. It improves the region's ability to match energy supply to actual demand and reduces the chance of overbuilding resources, an event that historically has been very costly.

Utilities need to be able to recover the costs for siting, licensing and design activities to make a second decision point possible. These changes in existing regulations would allow a utility to be relatively indifferent about whether the plant is actually constructed. Without changes in utility regulation, the utility cannot recover the pre-construction costs until the plant is built and operating, thus precluding a second decision point.

The Council has identified three specific ways to reduce lead time, each of which provides the region with ways to limit future power costs:

Resource Cost and Timing

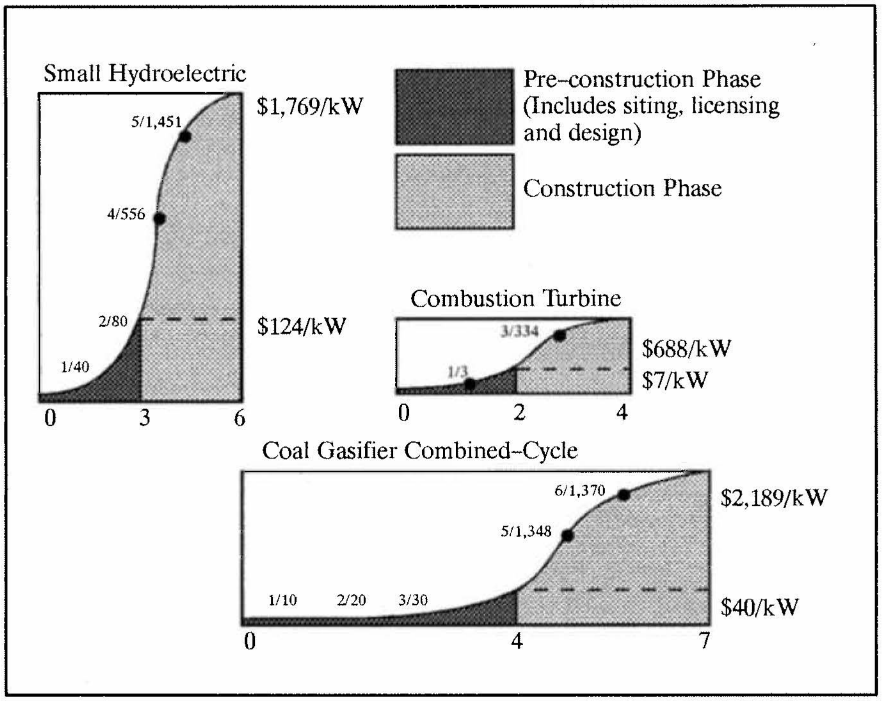


Figure 3-1
Cost and Timing of Resource Pre-Construction and Construction

- *Resource banking*: A resource could be sited, licensed and designed. At the end of the pre-construction process, a second decision would be made to construct the resource or put it on hold until it is needed.
- *Callback provisions on power sales*: Another way to provide flexibility would involve the sale of surplus power from a new or existing resource. Contract provisions would allow the power to be called back with some notice. These kinds of transactions could provide a regional benefit by generating revenue that reduces power costs in the Northwest. At the same time, they would avoid situations in which resources are sold for their entire lifetimes, potentially forcing the region to build new resources to meet its own needs.
- *Use of existing resources*: In response to temporary resource needs, the output of an existing resource could be acquired by paying for its operating costs (e.g., existing combustion turbines inside the region or excess generation in California or British Columbia).

It is important to note that, even with no additional ability to hold a resource beyond the time current regulations allow, the explicit recognition of a significant second decision to begin construction has value to regional power planning. The Council has analyzed the value to the region of being able to option resources. It found that a two-stage decision-making process could save the region $700 million across the range of future load growth. Separate decision points in resource development will improve the region's ability to minimize the cost and risk associated with matching resources to load growth.

The Council believes that shortening resource lead-times has great promise to provide the region additional flexibility in meeting its resource needs at the lowest risk and cost. To establish the practicality of this concept, the Council, Bonneville, utilities and other resource developers have been working to identify and resolve institutional, regulatory and legal barriers to its successful operation. The state energy siting organizations in Montana, Oregon and Washington have incorporated this concept into their procedures. Unfortunately, there are still significant contractual, legal, regulatory and institutional issues that need to be resolved before this concept can be fully implemented. The Action Plan includes a number of activities to address these problems.

The Role of Conservation in Least-Cost Planning

Because conservation's total cost to society is less than the cost of many other resources, and because it can respond flexibly to changes in loads, conservation plays a major part in the Council's plan to achieve this objective. This section discusses some of the issues addressed by the Council in treating conservation as a resource.

improvements at various cost levels. The main point of the hypothetical curve in Figure 3–2 is that the average cost of conservation is significantly less than the cost of the last measure selected. This characteristic of conservation is frequently ignored by those engaged in the "no–losers" debate. The supply function in Figure 3–2 shows that by purchasing all conservation measures with an expected total societal cost of less than 6 cents per kilowatt–hour, a total savings of 10,000 gigawatt–hours can be achieved.

For Strategy 2, the conservation achievable for less than 1 cent per kilowatt–hour is estimated to be 1,667 gigawatt–hours. Therefore, an additional 8,333 gigawatt–hours of generation are needed at 6 cents per kilowatt–hour. Since the supply function is assumed to be linear, the average cost of all conservation measures under 1 cent per kilowatt–hour is 0.5 cents per kilowatt–hour. The increase in the total annual revenue requirement for generating and conservation resources is $0.5 billion and $0.008 billion per year respectively. This means that the total annual requirement of the combined system is $5.508 billion per year with an average rate of 5.08 cents per kilowatt–hour. In comparison with the rate of 5.09 cents per kilowatt–hour found in Strategy 1, Strategy 2 has preserved a situation with a lower rate for all customers after the acquisition of conservation measures. With respect to the objective of minimizing the total present–value cost of energy services, Strategy 2 has a lower present–value system cost of $61.1 billion, $1.1 billion less than Strategy 1. Therefore, it appears that Strategy 2, involving the acquisition of all conservation measures which do not violate the "no–losers" test, helps both to reduce rates and to reduce the total present–value cost of all energy services, in comparison with the "all–generation" strategy.

Strategy 3: The Council's Approach

Strategy 3 is to acquire all conservation measures with a marginal cost up to the marginal cost of new generation. The supply function in Figure 3–2 shows that it is possible to acquire 10,000 gigawatt–hours of energy–efficiency improvements at less than 6 cents per kilowatt–hour. Because the marginal cost of new generation was assumed to be 6 cents per kilowatt–hour, and the total amount of load growth was assumed to be 10,000 gigawatt–hours, it is possible to meet the entire load growth through conservation. Again, assuming a linear supply function, the average cost of all conservation measures that are less than 6 cents per kilowatt–hour is estimated to be 3 cents per kilowatt–hour. This means that the annual revenue required for the purchase of such measures is $300 million. The total annual revenue requirement of the system, therefore, increases to $5.3 billion and, because there has been a reduction of the total system load, the average rate increases to 5.3

Conservation Supply Functions

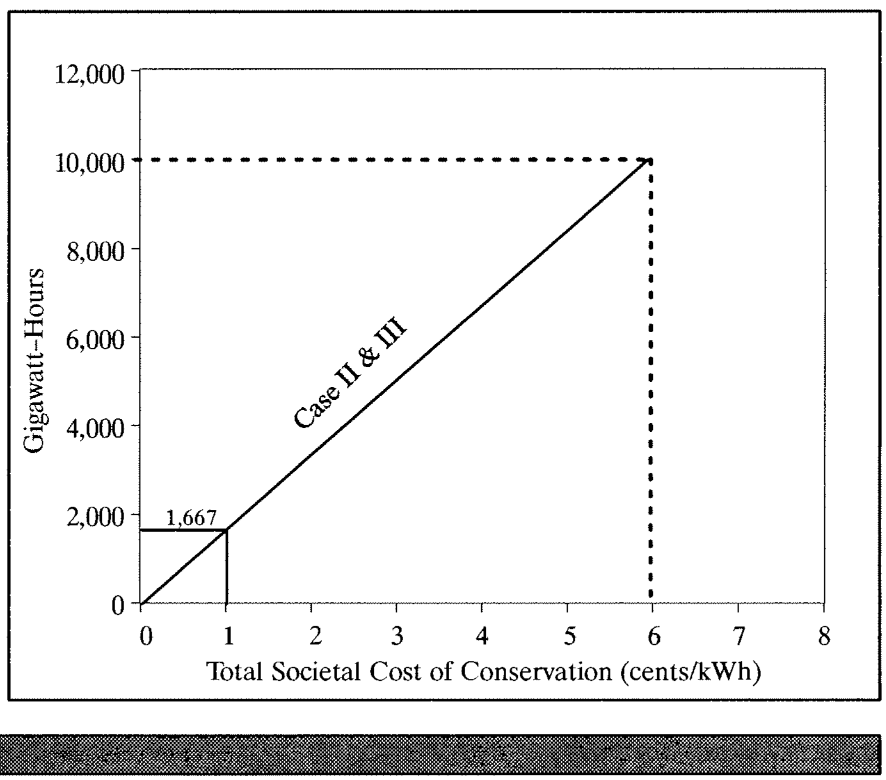


Figure 3–2
Assumed Conservation Supply Functions

cents per kilowatt–hour. Significantly, the total present–value system cost for providing exactly the same energy services as were provided in Strategy 1 has declined to $58.8 billion. By acquiring all conservation measures up to the marginal cost of generation, the present value of the total cost of meeting society's energy service requirements has been reduced by $3.4 billion when compared with the all–generation strategy in Strategy 1, and by $2.3 billion when compared with Strategy 2, which uses the "no–losers" test decision rule.

Conclusion of this Example

If a least–cost plan calls for the acquisition of all conservation measures with a total societal cost less than the cost of alternative resources, it is possible to reduce significantly the total present–value cost of meeting society's energy service requirements. This may, in fact, lead to a higher electricity rate. As discussed below, the Council has adopted strategies to limit the effects of rate increases on utility customers.

In the examples shown above, a relatively large power system was assumed to grow by 10 percent. When this growth was met entirely through conservation measures that are cost–effective to society, rates increased by 4 percent. The reduction in the total present–value system cost of $3.4 billion reduces the average consumer's electricity bill and is sufficiently large to compensate all ratepayers for the increased rates. A substantial amount of ratepayer capital is also freed up to be spent on other goods and services. Saving $3.4 billion in present–value utility bills will have a substantial impact on the region's economy, to the benefit of all ratepayers.

Some people are concerned that if utilities offer to purchase conservation savings up to the avoided cost of new generation, consumers will invest in conservation measures that are not cost–effective from a total societal perspective. If utilities offer to pay up to 6 cents for every kilowatt–hour of efficiency improvement, then consumers may be expected to invest in measures that are forecast to cost much more. This happens because their bills are reduced by the current utility rate of 5 cents for each kilowatt–hour conserved and with utility financial assistance, they could invest in conservation measures up to the sum of the utility payment plus the savings in their electricity bills. This would mean consumers might invest in conservation measures that cost up to 11 cents per kilowatt–hour (6 cents offered by utility financial assistance plus the 5 cent reduction in utility rates). Such an outcome would not be economically efficient and would divert significant resources from other uses. For this reason, great care must be taken to design conservation programs so only those measures that have met strict societal cost–effectiveness criteria are included in utility conservation programs.

Design of Conservation Programs

The Council's cost–effectiveness test first evaluates the total societal cost of all conservation measures. Conservation measures are evaluated in incremental steps, and each incremental improvement in efficiency is evaluated to determine its total societal costs. When these incremental improvements are ordered from lowest to highest cost, a supply function for each sector or subsector is created. These supply functions estimate the cost and performance of all efficiency improvements that are available for inclusion in a least–cost plan.

Conservation measures that cost more than the avoided cost limits established by evaluating the mix of all available resources are excluded from further consideration. The Council calculates the expected present–value costs of all resources included in the resource mix. Any conservation measure that increases the expected present–value costs above the minimum achievable level is excluded from the plan. For a more detailed discussion of resource cost–effectiveness, see Volume II, Chapter 14.

Substantial efficiency gains are possible by selecting only those individual conservation measures that cost less than the expected cost of other available and similarly reliable resource alternatives. There is a significant distinction between the identification of cost–effective conservation measures and the design of conservation programs to acquire these measures. The Council approaches these two issues sequentially.

In the design of conservation programs, the Council recognizes that many consumers are likely to understand and appreciate the benefits of the efficiency improvements that are cost–effective to the regional power system. These consumers are willing to participate financially in the installation of such efficiency improvements. To determine the effectiveness and cost of various conservation programs, the Council, the Bonneville Power Administration and the region's utilities have been developing and testing many alternative conservation program designs. This activity has demonstrated that many conservation measures can be acquired at substantially less than the estimated total cost of the measures.

Some have argued that conservation programs are not necessary—that the free market will promote economically justified efficiency improvements. This might be true if electricity rates were set at the true marginal cost of new resources and if consumers had access to information and capital.

In actual practice, electric rates are usually based on the average costs of the utility. Also, utilities generally have access to large amounts of low–cost capital and have historically invested in energy–producing facilities and recovered their costs over the 30– to 40–year life of the plant. Consumers, on the other hand, have much less access to discretionary capital, and when they invest have a much shorter payback criterion. Research into consumer behavior indicates that consumer actions to invest in energy conservation generally reflect an implicit consumer discount rate that ranges from 20 to 100 percent. This translates to simple payback requirements of five years to one year, respectively. High discount rates indicate the difficulty consumers face in evaluating energy conservation investments. Embodied in the high implicit discount rates are the consumer's time value of money, lack of information, inability to process information, riskiness of future returns versus known current costs and other market barriers.

The Council has been careful to identify the barriers to efficient decision-making and has concentrated a major part of its efforts toward removing these barriers.

Bidding Strategies for the Acquisition of Conservation Measures

The Federal Energy Regulatory Commission and many states allow outside contractors to bid to secure conservation measures as a way of meeting a utility's load growth.

There does not appear to be any significant conceptual difference between soliciting bids for new generation or for conservation. The major concern is that only those measures judged to be cost-effective (on a societal cost basis) be allowed in a bidder's proposal. To accomplish this, the utility would need a comprehensive least-cost plan, with specific cost-effectiveness criteria for conservation measures available in each of the sectors in its service territory. Other conservation measures that have not been anticipated or included also could be submitted; however, the bidder should be required to include estimates of the total societal cost of these measures and to illustrate that they meet the overall cost-effectiveness criteria.

Because each conservation resource and generation resource has different characteristics and will probably be evaluated based on those characteristics, it makes no difference whether the bidding system is integrated or separate. The important point is that conservation be treated on a level playing field with generating resources and that the bidding system not inadvertently acquire resources with higher societal costs than other available resources.

Bidding for conservation measures would require detailed specification of the technical and economic characteristics that are desirable from the utility's perspective. These specifications should require that programs be designed to capture all cost-effective conservation so that bidders do not "cream-skim" only the low-cost conservation and create lost opportunities. If cost-effective conservation measures can be secured through bidding, it is possible that competition will drive the total costs of those measures down. For this reason, the Council believes that a wide variety of conservation delivery mechanisms should be investigated. Through bidding and increased competition, the process of acquiring conservation resources should become more efficient, and both the utility system and society will benefit.

The Council's goal in including efficiency improvements in its plan is to acquire all cost-effective conservation measures that have a total societal cost that is expected to be less than or equal to the expected marginal cost of resources needed to meet load growth. The process of establishing cost-effectiveness is an open competition among all resources. This establishes a clear and structured economic competition for all resources, and thereby encourages the development of those resources that can meet the region's collective needs at the lowest present-value system cost.

CHAPTER 4

THE EXISTING REGIONAL ELECTRICAL POWER SYSTEM

Regional Generating Resources

Currently, the Pacific Northwest electrical power system is capable of delivering about 20,300 average megawatts of guaranteed (firm) energy. Of that total, about 12,500 megawatts, or 62 percent, come from the region's network of hydropower dams. Coal plants account for a little over 3,200 megawatts, or 16 percent, and nuclear plants account for a little less than half that amount, or about 7 percent. Gas-fired turbines can produce about 1,250 average megawatts of energy,[1] but they are relied upon to produce only about 500 megawatts of firm energy, representing about 2 percent of the region's total.

The region's utilities also have access to energy from resources outside of the Northwest. These utilities are either co-owners of out-of-region generating resources or have the contractual rights to part of their output. Firm energy imports, primarily from out-of-region coal-fired plants, supply about 11 percent of the region's total needs. The remaining 2 percent comes from smaller resources including cogeneration and renewable sources. Figure 4-1 illustrates the diversity in the region's firm energy generating capability.[2]

Investor-owned utilities have access to about 45 percent of the firm resources in the region, followed by the Bonneville Power Administration, the region's Federal power marketing agency, with 43 percent and the public utilities with 12 percent. The breakdown of resource types by group is illustrated in Figure 4-2. Bonneville and the public utilities have access to about 76 percent of the region's hydropower, while private utilities own 90 percent of the coal generation.[3]

Utilities must plan to have enough resources, on average, to meet their annual energy needs. They must also have enough resources to meet their daily peak demand. This measure of a utility's resources is referred to as peaking capability. The hydropower system in the Northwest has an inherently large peaking capability. For any given peak demand hour, the hydropower system can provide almost 30,000 megawatts of capacity, which represents about 75 percent of the total for the region. Total peaking capacity for the region is a little over 40,000 megawatts. Bonneville has estimated that the region currently has about 2,600 megawatts of surplus capacity, most of which is on the federal system.[4]

Hydropower

Hydropower is the cornerstone of the Northwest's energy system. The regional hydropower system includes the Columbia River, its tributaries and the coastal streams of Washington and Oregon. The Columbia River dominates the area, stretching over 1,200 miles from its source, Columbia Lake in Canada's Selkirk Mountain Range, to the Pacific Ocean. The basin covers about 260,000 square miles, of which 15.2 percent lies in Canada.[5] In Canada, the system includes the operation of the Duncan, Keenleyside and Mica reservoirs.

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1. This is estimated by taking the peaking capacity of 1,468 megawatts and multiplying by an assumed availability factor of .85 which yields approximately 1,250 megawatts.

2. Source: Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast of Power Loads and Resources.* March 1991.

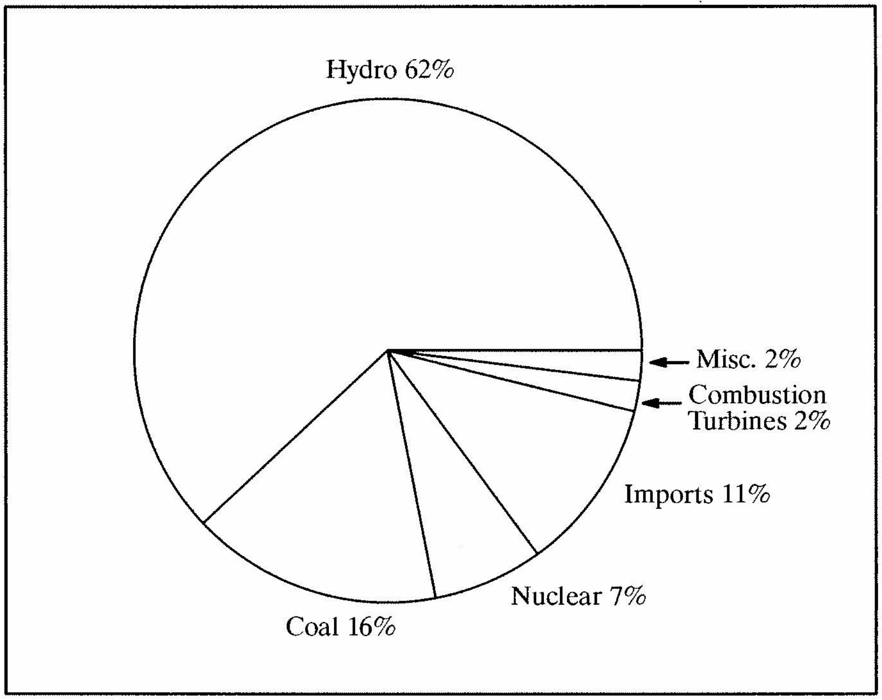
3. For more information on individual resources, see Appendix 4-A.

4. Marketable surplus capacity is calculated based on sustaining a 50 hours per week peak delivery and is limited by monthly and daily variations in water flow. Bonneville Power Administration. *1989 Pacific Northwest Loads and Resources Study.* November 1989.

5. Pacific Northwest River Basins Commission. *Columbia River System Power Operation.* September 1981.

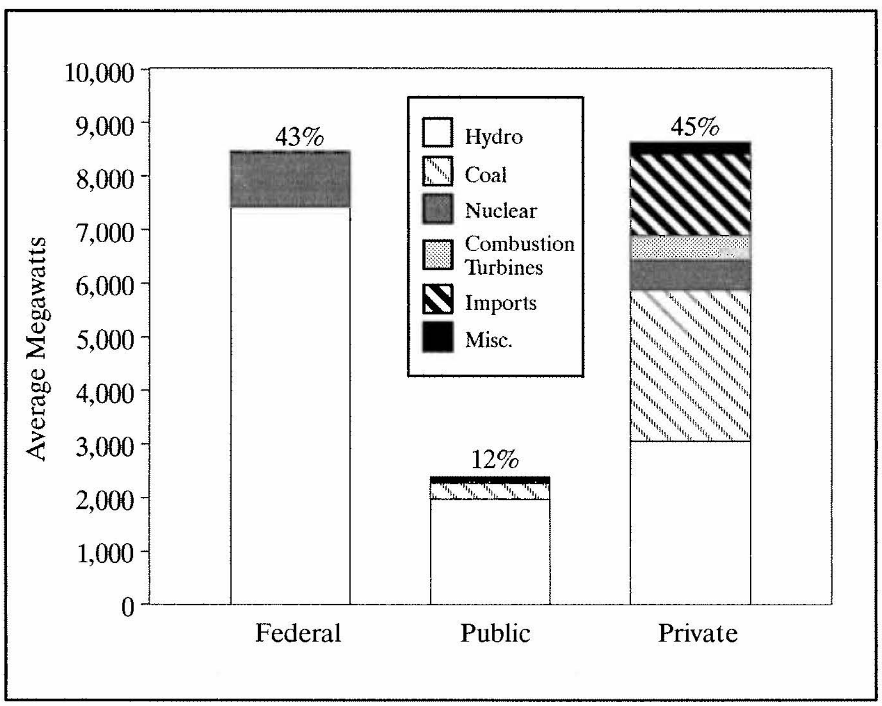
Firm Energy Resources

Figure 4-1
Existing Firm Energy Resources in the Northwest



Energy Resources by Subgroup

Figure 4-2
Firm Energy Resources by Subgroup



The Columbia River Treaty between the United States and Canada and the Pacific Northwest Coordination Agreement provide that the Columbia River hydroelectric system operate as one system in order to maximize the energy output. The operation at the Canadian reservoirs is designed to increase power generation downstream in the United States and to aid in the control of flooding. Storage at the Canadian projects is considered an element in the Columbia Basin power system and the downstream power benefits from this operation are shared equally between the United States and Canada.

The natural flow of the Columbia River peaks in spring and early summer, when the snowpacks melt. Energy production from the hydropower system depends on this flow of water. If reservoirs were not available to store water for later use, the energy derived from the hydropower system would rise and fall with the natural flow of the river. This would not be a very reliable or valuable source of energy, especially because the peak in river flow does not coincide with peak electricity demand.

Reservoir storage, however, is limited to about 40 percent of the average January to July volume of water that flows down the river system. Thus, energy derived from the hydropower system still depends somewhat on fluctuations in the natural river flows. Guaranteed (firm) energy from that system must be based on the lowest annual runoff expected. In that way, planners can expect at least that much energy in any given year. This sequence of worst water conditions is commonly referred to as the critical period or critical water and is represented by the historical water conditions that occurred from 1929 to 1932. Based on this sequence, the amount of firm energy available from the hydropower system is estimated to be about 12,500 average megawatts.

Annual energy generation from the hydropower system varies widely, depending on annual rainfall and snowpack accumulation. Because water conditions for most years will be better than critical flows, the hydropower system typically will produce more than its firm energy generating capability. In good water years it can produce as much as 20,000 megawatts, but on average it generates about 16,600 megawatts. The approximately 4,100 megawatt difference[6] between firm energy capability and average energy production is referred to as nonfirm energy and is used to serve interruptible loads, to displace the generation from high-operating-cost thermal resources and to sell to utilities in California.

Because of the availability of nonfirm energy, the hydropower system generates about 75 percent of the region's electricity, on average. Nonfirm energy often displaces generation from coal plants (because it is cheaper) so that actual electricity produced by coal plants is only about eight percent of the region's total requirements. Nonfirm energy also displaces the operation of gas-fired combustion turbines. In fact, turbines usually run only during the worst water conditions, thus providing less than one percent of the region's electricity, on average.

The amount of firm energy derived from the hydroelectric system also depends on the characteristics and operating constraints for each dam. When any of those constraints or characteristics is changed, the firm energy generating capability of the system changes. For example, the regional hydropower capability has been adjusted to take into consideration the effects of the Council's fish and wildlife program. An important element of this program is the water budget, which is a volume of water released in the spring to improve streamflows for downstream migration of salmon and steelhead. The water budget operation reduces the firm energy generating capability of the hydropower system by about 300 average megawatts.

Other constraints on the hydropower system include the fish bypass spill program, irrigation, navigation and other at-site operating constraints. All of these factors have been taken into account in determining the hydropower system's firm energy generating capability. Effects of the current fish bypass spill program reduce the firm energy capability by about 100 average megawatts.[7] The loss due to the spill program, however, is only temporary. Once mechanical bypass systems are in place, the spill program should no longer be needed, and the hydropower system firm energy generating capability will increase by about 100 average megawatts.

Large Thermal Resources

The character of the Northwest's power system has changed over the years. Between 1937 and 1960, hydropower was the only large-scale resource in the region. Since 1960, the region has built 14 coal plants and two nuclear plants, making what was once almost exclusively a hydroelectric system into one that now receives about one-quarter of its energy from thermal plants.

Large thermal resources currently available to the region include the Washington Public Power Supply System nuclear project 2 (WNP-2) and the Trojan nuclear plant. The combined generating capability of these two units is 1,493 average megawatts.

Of the 14 coal plants that supply the region with electricity, only three are located in the region; the Boardman plant in eastern Oregon and the two Centralia plants in Washington. The remaining coal plants are only partially dedicated to serving Northwest loads. These plants are generally located near coal sources to minimize fuel transportation costs. Four Colstrip coal plants are located in Colstrip, Montana, four Jim Bridger coal plants are near Rock Springs, Wyoming, two Valmy coal plants are in Nevada and the Corette coal plant is in Montana. The total

6. Based on a 102-year water record.

7. Bonneville Power Administration. *Balancing the Uses of the River, Programs in Perspective.* September 1989.

generating capability of these 14 coal plants is almost 7,000 average megawatts but firm energy available to the region amounts to only about 3,200 average megawatts. More information about the existing thermal plants can be found in Appendix 4–A.[8]

Combustion Turbines

Because combustion turbines have low capital costs and high operating costs, they are best used as peaking resources; that is, resources that are used only during times of exceptionally high electricity demand. Because of the hydropower system in the Northwest and its inherently large peaking capacity, turbines are rarely used as peaking resources, although areas exist within the Northwest that have peaking limitations.

As firm base–load resources, existing turbines would not be cost–effective unless used in conjunction with the hydropower system.[9] In that mode of operation, turbines are often displaced by cheaper hydro nonfirm energy, lowering the overall operating costs of the turbines. The Council has recommended the use of combustion turbines as one method of better using the hydropower system.[10]

The region's gas–fired combustion turbines have a peaking capacity of 1,468 megawatts. If no restrictions were placed on turbine operation and assuming an unlimited supply of fuel, they could provide about 1,250 average megawatts of energy to the region. In 1978, the Powerplant and Industrial Fuel Use Act limited the use of turbines. Combustion turbines could be run for peaking purposes or for system reliability but, in general, were limited to 1,500 hours of operation per year. Taking these and other limitations into account, the net energy available to the region was about 200 average megawatts.

The Fuel Use Act has since been amended to allow unrestricted operation of combustion turbines under certain conditions. Utilities can declare that their turbines could be run with alternate fuels if natural gas becomes unavailable or too expensive. Utilities then could use turbines as base–load plants. With the exception of Portland General Electric's Bethel plant, all gas–fired turbines in the region have applied for and received unrestricted status.[11]

Assuming no limitations on fuel supply and an average availability of 85 percent, the net firm energy available to the region is a little more than 1,250 average megawatts. Currently, utilities are declaring only 485 average megawatts as firm combustion turbine energy. Utilities have been reluctant to rely on combustion turbines as firm energy resources primarily due to the volatility of gas prices and the uncertainty in gas availability. By counting too heavily on turbines, a sharp increase in gas prices accompanied by poor water conditions could have a drastic effect on rates.

Out–of–Region Transactions

Due to interconnecting transmission lines between regions, utilities can look outside of this region to sell energy in times of surplus or to purchase energy during times of need. The total firm resources available to this region include the net effect of these transactions. Transmission interconnections also support sales of nonfirm energy to other regions. Nonfirm energy sales, however, do not affect firm regional resources.[12]

Interregional transactions involve the transfer of energy and/or the sharing of generating capacity between utilities in different regions. Capacity is defined as the maximum power output that a generating plant is designed to produce continuously. A utility may purchase the rights to this capacity from an out–of–region utility system in order to ensure that it will have adequate generation to meet its daily peak demands. The purchasing utility may never call upon that resource for power, but it pays a fee for the right to the generation, even if no energy is ever delivered. If energy is delivered during peak hours, an equivalent amount of energy is then returned to the selling utility during the off–peak hours. This type of transaction is more predominant for utilities whose firm resource mix is made up primarily of thermal resources. Most transactions combine capacity purchases with energy transfers.

Although interregional transactions involve only two basic commodities—energy and capacity—they may be packaged in many forms. Typically, transactions fit into five basic categories:

- ***Capacity Sales***. Payment is made in dollars for capacity guaranteed during the peak demand hours of the day. If energy is delivered, an equivalent amount of energy is returned to the sending utility during the lightly loaded hours of the night and on weekends. No net energy is transferred between regions over the specified period, usually a week.

8. Some of the generation from out–of–region coal plants that serves regional demands is categorized as imported energy.

9. Actually, in terms of cost–effectiveness, newer technology combined–cycle plants are very competitive with coal plants at low gas prices.

10. Northwest Power Planning Council. *1986 Northwest Conservation and Electric Power Plan—Volume Two*, Chapter 7. 1986. Staff Issue Paper number 89–37, *Better Use of the Hydropower System*. October 16, 1989.

11. Bethel's operation is limited to 2,000 hours per year during specified hours of the day only.

12. For further information about out–of–region sales, see: Northwest Power Planning Council. Western Electricity Study Briefing Paper number 87–14, *Interregional Transactions*. December 28, 1987. Staff Briefing Paper number 89–15, *Adequacy of the Northwest's Electricity Supply*. April 13, 1989.

- *Capacity/Energy Exchanges*. This transaction is similar to a capacity sale, but payment for capacity is made in energy instead of dollars. As in a capacity sale, capacity is provided during the peak demand hours of the day. If energy is delivered, an equivalent amount of energy is returned to the sending utility. Payment for the capacity provided is made in the form of additional energy returned by the purchasing utility to the sending utility. This additional energy may be returned during the same week or during a different part of the year. This type of transaction represents a net energy import for the region.

- *Seasonal Exchanges*. Capacity and/or energy is provided to a utility during a specified part of the year. An equivalent amount of capacity and/or energy is later made available to the sending utility during a different part of the year. Usually, in these arrangements, no money is exchanged. This type of transaction is most beneficial for two regions that have system loads that peak in different seasons.

- *Firm Energy Sales*. Energy is purchased on a guaranteed basis. Firm energy sales can be either long-term or short-term. Transactions that span periods of time greater than 18 months are typically referred to as long-term sales. Energy may be delivered 24 hours a day or during the peak demand hours only. Sometimes energy is delivered only during a specified season of the year. Often these types of transactions also specify a maximum amount of capacity to be provided along with the equivalent energy amount.

  Long-term firm energy sales represent a net loss of energy to the selling region. Without recall provisions, these types of sales could force a region to acquire or develop new resources sooner than expected. If, however, the energy from these sales can be recalled when needed, the schedule for new resources would not be affected. By structuring long-term energy sales with recall provisions, a region can sell surplus energy without increasing the risk that new energy supplies will be needed any sooner.

  Long-term energy sales can also be structured so that, upon recall, they convert to capacity/energy exchanges (defined above). Under that type of contract, the selling region would realize a net energy gain.

  Recall provisions are only one way to protect a region from higher long-run marginal costs. Another way that is built into some current contracts is to price those sales so that if and when higher marginal cost resources are required, the extra-regional buyer bears the brunt of those costs.

- *Economy Sales*. Energy is delivered on an hour-by-hour and as-available basis, usually scheduled one day in advance. These transactions take advantage of the diversity that exists in short-term operating costs due to different fuel sources in different regions and the short-term variability in water supply in a hydroelectric system. These types of transactions are also referred to as nonfirm energy sales because the energy cannot be guaranteed.

Ever since the interregional transmission lines were built, Bonneville and other Northwest utilities have successfully marketed energy and capacity to California utilities under both short-term and long-term contracts. For the 1992 operating year, long-term energy contracts to out-of-region utilities add up to 674 average megawatts, increase to almost 700 average megawatts by the mid-1990s, and then decline to about 200 average megawatts by 2011.[13]

Recallable contracts make up 270 average megawatts of the firm exports. The Bonneville Power Administration has three recallable contracts (totaling 212 average megawatts) and Pacific Power and Light has one (57 average megawatts). The three Bonneville contracts convert to capacity/energy exchanges upon recall.

Most of the region's imported energy comes from out-of-region coal plants that are owned, in part, by regional utilities. Imported energy for the 1992 operating year amounts to 2,227 average megawatts[14] and declines to 1,653 average megawatts by 2011. Appendix 4-B summarizes all existing out-of-region transactions.

The Columbia River Treaty

The Columbia River Treaty signed in 1961 and ratified in 1964 by the United States and Canada provided for increased storage on the Columbia River. The downstream power benefits were shared equally between the two countries. The Canadians sold their share of the downstream power benefits to utilities in the Pacific Northwest because, at the time, Canada did not need the energy. That share of benefits, known as the Canadian Entitlement, is scheduled to be returned to Canada beginning in 1998. Under that agreement, the energy to be returned amounts to under 100 average megawatts in the first year and increases to over 500 average megawatts by 2004.

13. These values do not include the return of Canadian Entitlement energy to Canada. See Appendix 4-B, Table 4-B-1.

14. These totals do not include all out-of-region coal generation that serves regional demands.

Uncertainty in the Existing Power System

The amount of electricity that the existing power system produces is not static. It depends on certain conditions and assumptions. It depends on how much rain and snow falls. It depends on how different agencies and organizations operate the region's network of hydropower dams, on how much water they keep in reservoirs; on how much they release for fish migration, for irrigation or for other uses. It depends on the price and availability of coal, natural gas and other fuels. And it depends on federal and state regulations governing pollution and waste disposal at coal, nuclear and gas-fired plants. A change in any of these factors may alter the amount of power the region can expect out of its existing system.

This section provides a discussion of some of the factors that can alter the amount of energy available from the region's existing generating resources. This is not intended to be an exhaustive list. Many of the problems discussed here are not easily resolved, yet it is important to point out that uncertainty surrounds the existing system just as it does predictions of future demand and potential future resources.

Potential Effects of Endangered Species Proceeding

On April 2, 1990, the Shoshone-Bannock Tribe filed a petition under the Endangered Species Act seeking the designation of upper Snake River sockeye salmon as a threatened or endangered species. On June 7, four additional petitions were filed by other parties, seeking the designation of Snake River spring, summer, and fall chinook salmon and lower Columbia River coho salmon as threatened or endangered species.

In April 1991, the National Marine Fisheries Service proposed to list Snake River sockeye as an endangered species. In June 1991, the Service proposed to list Snake River spring and summer chinook as a single threatened species. The Service also proposed to list Snake River fall chinook as a threatened species but did not propose a listing of lower Columbia River coho.

Final decisions on the listing proposals, and recovery plans, are expected within approximately one year of the notices of proposed listing.

At the invitation of U.S. Senator Mark Hatfield of Oregon, a working group of interested parties, including federal agencies, was convened in October 1990 and worked with the assistance of professional mediators to develop measures to improve the salmon runs. The Council participated in this effort, known as the Salmon Summit. The Salmon Summit concluded its work in March with agreement on some issues. Summit participants continued to meet to discuss other issues, including flows and harvest.

The Council has begun a review of the water budget and will change it if it is determined to be inadequate. The Council expects the flow levels in the Columbia River Basin Fish and Wildlife Program, or any flow levels determined to be appropriate under the Endangered Species Act, to be firm constraints on hydropower system shaping and will further amend the Program as necessary to ensure this. It is not now possible to estimate the likely impact on the power system of additional measures to improve the salmon runs, and therefore this description of the existing regional electrical power system does not reflect any reductions in available hydropower that might result from such measures.

Potential Effects of Hydropower Relicensing

Non-federal hydropower projects are licensed for construction and operation by the Federal Energy Regulatory Commission. Approximately 70 of the 155 hydropower projects in the Northwest will require relicensing between 1990 to 2010. These projects represent approximately 2,950 average megawatts of firm energy.

A key aspect of the Commission's relicensing regulations is that renewed licenses will not automatically be issued to the current licensee. The relicensing procedures mandate extensive consultation with relevant resource management agencies. The procedures also extend consideration of project-related environmental effects to those that may occur outside the project's boundaries. These factors are expected to lead to in-depth consideration of project-related environmental effects and implementation of additional mitigation, especially at older projects, during the relicensing process.

The relicensing process would involve a re-evaluation of the use of the hydro project and a potential lowering of its generating capability due to non-power constraints such as fish survival. On the other hand, the relicensing process provides an opportunity for making efficiency improvements, which could lead to increased generation.

In addition to the factors on which competing applications will be judged, all applicants are required to submit adequate plans to protect, mitigate damages to, and enhance fish and wildlife. The rule treats this mitigation plan as a threshold requirement; that is, no applicant can receive a license unless the applicant fully satisfies this requirement, regardless of how the mitigation proposed by an applicant compares to that proposed by other applicants.

This may have significant effects on the cost and energy capability of older projects built at a time when environmental concerns were not as important as at present. Environmental mitigation measures may require additional capital investment or operating and maintenance costs, and may require additional in-stream flow, reducing the energy production of a project. In rare cases, license renewal might be denied for projects found to be unacceptable by contemporary standards.

Figure 4-3 illustrates the timing and amount of energy subject to relicensing.

In previous plans, no assumptions were made concerning loss or gain in firm energy due to the relicensing process. Because the magnitude of any potential change is impossible to predict, the most reasonable action is to assume no change until more information is available.

Nuclear Spent Fuel Storage and Disposal

Spent commercial nuclear power plant fuel contains highly radioactive fission products and long-lived radioactive transuranic isotopes. The disposal of spent fuel must be managed carefully to prevent the release of these materials into the environment. Spent fuel may be reprocessed to remove the radioactive isotopes for recycling or special disposal, placed unprocessed in a permanent repository, or placed in interim retrievable storage pending the selection and development of permanent storage options.

Originally, the nuclear industry and the federal government planned to develop commercial reprocessing plants for the separation of fission products and transuranic materials from commercial spent fuel. Materials with no commercial use would be placed in permanent disposal facilities, while unburned uranium and transuranic isotopes would be recycled as refabricated nuclear fuel.

In the late 1970s, the United States abandoned the reprocessing option because of nuclear proliferation concerns, and chose to dispose of spent commercial fuel in permanent repositories. In 1982, Congress passed the Nuclear Waste Policy Act, making the federal government responsible for the ultimate disposal of high-level nuclear wastes, including spent nuclear fuel. Operators of nuclear plants were required to contract with the federal government for spent fuel disposal services as a condition of maintaining the operating license for their plants. Payment for this service was set at one mill per kilowatt-hour, with adjustments to be made as the costs of the program were better defined. The contract specifies that the U.S. Department of Energy will take title to the spent fuel and begin disposal operations not later than January 31, 1998.

Significant delays have occurred in the program, however, and progress continues to be disappointing. Opening of a national repository has been delayed until 2010. In the past, the Council has not had to act on this issue because both Trojan and WNP-2 have adequate on-site storage to last through 1998, the date when the U.S. government was to assume responsibility for the spent fuel. (WNP-2 can store spent fuel through 1998 and Trojan through 2007.)

Firm Energy Capability

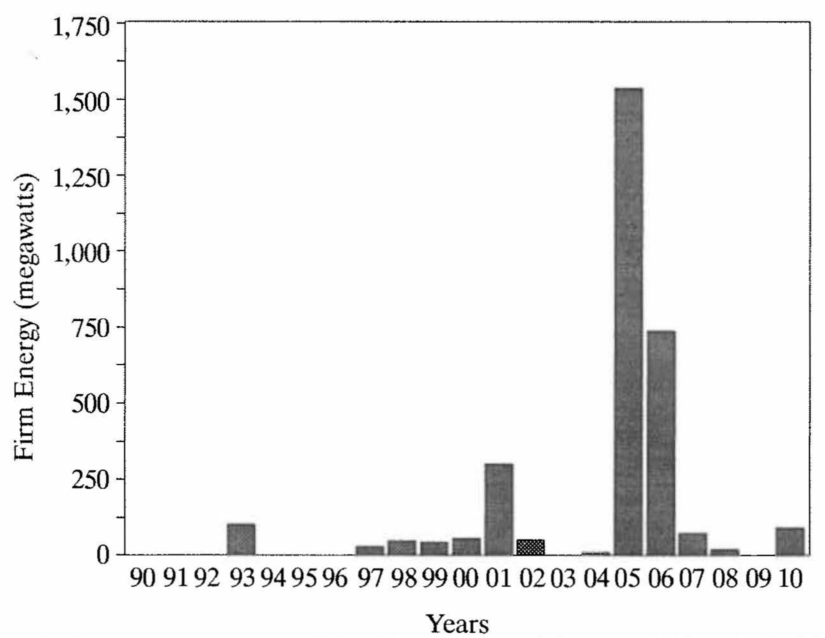


Figure 4-3
Firm Hydropower Energy Capability Subject to Relicensing 1990-2010

It is unlikely that this issue will force the shutdown or derating of the existing nuclear plants. Temporary storage facilities, such as above-ground dry storage casks, have proven to be technically feasible and cost-effective. The cost of such actions is relatively small compared to other nuclear costs and is likely to be in the range of 1 mill per kilowatt-hour or less. The Council assumes, therefore, that some kind of on-site storage through the year 2010 will be utilized for both Trojan and WNP-2 and that the cost of such storage will be added to their respective operating costs.

Clean Air Act

The combustion of coal produces several airborne pollutants of concern. These include sulfur dioxide and oxides of nitrogen, precursors of acid rain. The Clean Air Act of 1970, along with the 1977 amendments, established federal controls on the release of these pollutants for new power plants. However, prior to 1990, existing power plants were generally exempt from any federal restrictions on emissions of sulfur dioxide and nitrogen oxides.

Congress recently passed the Clean Air Act Amendments of 1990, which extend coverage to existing plants. Title IV of the Act establishes for power plants a two-phase pollution control program that is intended to reduce sulfur dioxide emissions by 11 million tons annually in the year 2000, and to reduce emissions of oxides of nitrogen beginning in 1995. The 1990 Amendments are expected to affect about 110 existing power plants.

Only three of the affected plants serve load in the region. Those plants are Boardman (in eastern Oregon), Centralia (in western Washington), and Corette (in eastern Montana). The other coal-fired plants within the region already are achieving emissions within the limits of the 1990 amendments.

Under Phase I of the 1990 Amendments, existing power plants must reduce emissions to not more than 2.5 pounds of sulfur dioxide per million Btu multiplied by the plant's annual average baseline fuel consumption in 1985 through 1987. During Phase II, which begins in 2000, the limit drops to 1.2 pounds. As of 2000, sulfur dioxide emissions from power plants in the United States are permanently capped at 8.9 million tons per year.

The Clean Air Act Amendments of 1990 contain a complex set of mechanisms for allocating emissions allowances. The emissions allowances can be applied to existing plants, banked, marketed, or used for capacity expansion. It is possible for a non-complying plant to continue in service without installing additional pollution control equipment if the utility acquires sufficient emissions allowances. Emissions allowances can be purchased from others or earned in a number of ways. For example, bonus allowances can be earned by reducing emissions below the required levels, or by meeting load growth with conservation or solar, geothermal, wind, or biomass resources.

Typical emissions from the Centralia plants (Centralia 1 and 2) have been about 1.7 pounds per million Btu, while Corette has been at 1.5 pounds per million Btu. Thus, the Corette and Centralia plants will exceed the Phase II limits, and will therefore need to either reduce emissions or purchase allowances beginning in 2000.

It is too early to predict exactly how the region's utilities will choose to meet these new emissions requirements. However, it appears that Centralia may be able to meet the requirements by using low sulfur coal, either from selectively mining at the Centralia site, or by importing low sulfur coal from another source such as Montana or Wyoming. The Corette plant is now being considered as a proof-of-concept demonstration of magnetohydrodynamic (MHD) generation, a process that produces lower emissions than conventional combustion.

Boardman faces a different problem. Its emissions are around .58 pounds of sulfur dioxide per million Btu, well below the Phase II limits. However, during the years considered in determining baseline emissions (1985-1987), the region had surplus electricity and Boardman was operated only a few weeks.

Because the Act allocates allowances based on actual emissions during the baseline period, Boardman may not qualify for enough allowances to run full time after 2000. The operators of Boardman are now seeking to obtain adequate allowances based on certain provisions of the Act which deal with special circumstances. If they are unsuccessful, Boardman will be required to install pollution control equipment or purchase additional allowances in order to operate as a base-load plant after 2000.

In order to provide some estimate of the cost of compliance in this power plan's modelling of existing resources, two assumptions were included in the cost of power expected to be produced by the Centralia and Corette plants: 1) that the plants will use a very low-sulfur coal or a high-heat-value low-sulfur coal beginning in 2001, and 2) that, starting in 1992, the plants will need to set aside one-half mill per kilowatt hour to purchase emissions allowances or pollution control equipment.

The costs of controlling nitrogen oxide emissions to current new source performance standards are relatively low compared to the cost of controlling emissions of sulfur dioxide. The Electric Power Research Institute has estimated that, for a new plant, flue gas desulfurization represents about 17.4 percent of the cost of the plant, compared to 1.3 percent for control of oxides of nitrogen. For this reason, it is unlikely that the revised nitrogen oxide release limits will significantly affect future operating costs or performance characteristics of existing coal-fired plants in the region, and no additional costs are assumed in the modelling of these resources. Nitrogen oxide control could be a more significant problem at combustion turbine and combined-cycle power plants, but it is too early to estimate what the costs of control might be at such plants.

Control of Carbon Dioxide Releases

Carbon dioxide releases from fossil fuel-fired power plants may be one of the major factors leading to an increase in atmospheric carbon dioxide and possible global warming. It may be necessary to control the production of carbon dioxide and other greenhouse gases to constrain global warming. The National Energy Policy Act, recently passed by the U.S. Senate, requires the United States to develop strategies for reducing emissions of carbon dioxide up to 20 percent by 2005. Also, the state of Oregon Senate Bill 576 requires state agencies to develop a strategy for reducing the emission of gasses that add to global warming by 20 percent by 2005.

In fossil fuel power plants, carbon dioxide is formed by combustion of the carbon contained in the fuel. Carbon combustion is one of the two principal chemical reactions (the other is combustion of hydrogen to form water) involved in the release of chemical energy of fossil fuel to produce heat. As such, the carbon reaction is inherent to the use of fossil fuels. It is more important for coal, with its high carbon-to-hydrogen ratio, than for oil or natural gas, which are progressively richer in hydrogen.

The release of carbon dioxide from fossil fuel power plants could be controlled by switching to hydrogen-rich fuels, such as natural gas, increasing plant efficiency, recapturing carbon dioxide using reforestation, reducing plant operation through conservation or substitution of other generating resources, or by use of flue gas recovery systems for carbon dioxide. Carbon dioxide recovery systems, while used in some industrial applications, have not been used for power plant applications. Power plant applications would be of far larger scale than any existing carbon dioxide recovery systems and, moreover, would present significant problems relative to the transport and disposal of the recovered carbon dioxide.

As with sulfur and nitrogen oxides, any attempt to reduce these emissions will force the price of electricity to rise. Because no regulations currently exist governing the emission of carbon dioxide, no assumptions will be made concerning the potential effects on plant operation. The regional cost of increasing fuel cost by 25 percent, to simulate a carbon tax, is $350 million. More information on this analysis can be found in Volume II, Chapter 10.

APPENDIX 4-A

EXISTING REGIONAL GENERATING RESOURCES

Key to Tables in Appendix 4–A

Abbreviated Name	Full Name
Utilities/Operators	
Albany	City of Albany
Bonners Ferry	City of Bonners Ferry
BPA	Bonneville Power Administration
Chelan	Chelan County PUD #1
Clallam	Clallam County PUD
Clark	Clark Public Utilities
Coos Curry	Coos Curry Electric Cooperative, Inc.
Cowlitz	Cowlitz County PUD #1
CPN	CP National
Douglas	Douglas County PUD #1
EWEB	Eugene Water and Electric Board
GECC	General Electric Credit Corporation
Grant	Grant County PUD #1
Idaho Falls	City of Idaho Falls
IPC	Idaho Power Company
Lower Valley	Lower Valley Power and Light Company
MPC	Montana Power Company
OTEC	Oregon Trail Electric Cooperative
Pacific	Pacific County PUD #2
Park	Park Electric Cooperative, Inc.
Pend Oreille	Pend Oreille County PUD #1
PGE	Portland General Electric Company

Key to Tables in Appendix 4-A (cont.)

Abbreviated Name	Full Name
Utilities/Operators (cont.)	
PNGC	Pacific Northwest Generating Cooperative
Portland	City of Portland
PP&L	Pacific Power and Light Company
PSPL	Puget Sound Power and Light Company
Seattle	Seattle City Light
Snohomish	Snohomish County PUD #1
Soda Springs	City of Soda Springs
SPPC	Sierra Pacific Power Company
Tacoma	City of Tacoma—Light Division
USBI	U.S. Bureau of Indian Affairs
USBR	U.S. Bureau of Reclamation
USCE	U.S. Army Corps of Engineers
USTC	United States Trust Company
WPPSS	Washington Public Power Supply System
WWP	The Washington Water Power Company
Granted Status	
LA	License application submitted
LC	Licensed
EX	Exempted (from Federal Energy Regulatory Commission license)
RL	Relicensing application submitted

Table 4-A-1
Federal Hydropower Projects

	Operator	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Federal Columbia River Power System						
Albeni Falls	USCE	43	39	31	32	1955
Anderson Ranch	USBR	40	36	18	11	1950
Big Cliff	USCE	18	6	12	10	1954
Black Canyon	USBR	8	9	9	11	1986
Boise Diversion	USBR	2	0	0	0	1912
Bonneville	USCE	1,093	1,147	711	555	1938
Chandler	USBR	12	4	10	6	1956
Chief Joseph	USCE	2,457	2,614	1,470	1,167	1955
Cougar	USCE	25	6	17	13	1964
Detroit	USCE	100	96	46	37	1953
Dexter	USCE	15	8	10	8	1955
Dworshak	USCE	400	460	239	177	1974
Felt	USCE	1	2	1	1	N/A
Foster	USCE	20	10	14	13	1968
Grand Coulee	USBR	6,494	6,678	2,321	1,916	1941
Green Peter	USCE	80	73	28	22	1967
Hills Creek	USCE	30	30	18	15	1962
Hungry Horse[c]	USBR	321	306	109	97	1952
Ice Harbor	USCE	603	693	324	215	1961
John Day	USCE	2,160	2,484	1,279	927	1968
Libby	USCE	525	492	218	175	1975
Little Goose	USCE	810	932	339	214	1970
Lookout Point	USCE	120	67	36	26	1954
Lost Creek	USCE	49	18	35	23	1977
Lower Granite	USCE	810	932	339	214	1975
Lower Monumental	USCE	810	932	320	202	1969
McNary	USCE	980	1127	831	654	1953
Minidoka	USBR	13	13	11	9	1909
Palisades	USBR	127	122	74	61	1957
Roza	USBR	13	10	7	5	1958
The Dalles	USCE	1,807	2,074	1,018	737	1957

Table 4-A-1 (cont.)
Federal Hydropower Projects

	Operator	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Other Federal Hydropower						
Big Creek	USBI	1.0	1	0	0	1916
Green Springs[d]	USBR	16	18	7	7	1960
Savage Rapids Diversion	USBR	N/A	N/A	< 1	< 1	1955
Wapato Drop 2	USBI	2	N/A	1	1	1942
Wapato Drop 3	USBI	1	N/A	< 1	< 1	1932

[a] Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast*. March 1991.

[b] Operating years 1992 through 2011. Peak capacity is for January. Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast*. March 1991.

[c] Includes uprating, scheduled for completion by August 1992.

[d] Contracted to Pacific Power and Light Company.

Table 4–A–2
Investor–Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Albany	Albany	1	c	c	c	1923
American Falls	IPC	92	0	46	32	1978
Bend Power	PP&L	1	c	c	c	1913
Big Fork	PP&L	4	c	c	c	1910
Black Eagle	MPC	17	k	k	k	N/A
Bliss	IPC	75	75	50	45	1949
Brownlee	IPC	585	675	309	223	1958
Bull Run	PGE	21	22	12	10	1912
C.J. Strike	IPC	83	85	61	55	1952
Cabinet Gorge	WWP	200	230	124	100	1952
Cascade[j]	IPC	12	5	6	4	1926
Cochrane	MPC	48	k	k	k	N/A
Clear Lake	IPC	3	d	d	d	1937
Clearwater 1	PP&L	15	e	e	e	1953
Clearwater 2	PP&L	26	e	e	e	1953
Cline Falls	PP&L	1	c	c	c	1913
Condit	PP&L	10	c	c	c	1913
Copco 1	PP&L	20	f	f	f	1918
Copco 2	PP&L	27	f	f	f	1925
Eagle Point	PP&L	3	h	h	h	1957
East Side	PP&L	3	f	f	f	1924
Electron	PSPL	26	i	i	i	1904
Fall Creek	PP&L	2	c	c	c	1903
Faraday	PGE	35	43	23	17	1907
Fish Creek	PP&L	11	e	e	e	1952
Hauser	MPC	17	k	k	k	N/A
Hell's Canyon	IPC	392	450	247	177	1967
Holter	MPC	38	k	k	k	N/A
Iron Gate	PP&L	18	f	f	f	1962
John C. Boyle	PP&L	80	f	f	f	1958
Kerr	MPC	168	k	k	k	1938
Lemolo 1	PP&L	29	e	e	e	1955
Lemolo 2	PP&L	33	e	e	e	1956

Table 4–A–2 (cont.)
Investor–Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Little Falls	WWP	32	34	24	19	1910
Long Lake	WWP	70	71	54	42	1914
Lower Baker	PSPL	64	63	45	38	1925
Lower Malad	IPC	14	d	d	d	1911
Lower Salmon Falls	IPC	60	68	34	29	1910
Madison	MPC	9	k	k	k	N/A
Merwin	PP&L	136	128	64	52	1931
Meyers Falls	WWP	1	1	1	1	1915
Milltown	MPC	4	k	k	k	1906
Monroe Street	WWP	15	6	6	5	1890
Moroney	MPC	45	k	k	k	N/A
Mystic Lake	MPC	10	k	k	k	N/A
Naches	PP&L	6	c	c	c	1909
Naches Drop	PP&L	1	c	c	c	1914
Nine Mile	WWP	12	18	13	10	1908
Nooksack	PSPL	2	i	i	i	1906
North Fork	PGE	38	54	26	19	1958
Noxon Rapids	WWP	467	536	210	148	1960
Oak Grove	PGE	51	49	30	26	1924
Oxbow	IPC	190	220	124	91	1961
Pelton	PGE	97	108	40	34	1957
Post Falls	WWP	15	16	11	8	1906
Powerdale	PP&L	6	c	c	c	1923
Prospect 1	PP&L	4	h	h	h	1912
Prospect 2	PP&L	32	h	h	h	1920
Prospect 3	PP&L	7	h	h	h	1932
Prospect 4	PP&L	1	h	h	h	1944
Rainbow	MPC	37	k	k	k	N/A
River Mill	PGE	19	23	13	10	1911
Round Butte	PGE	247	300	100	82	1964
Ryan	MPC	48	k	k	k	N/A
Shoshone Falls	IPC	12	13	11	10	1907
Slide Creek	PP&L	18	e	e	e	1951

Table 4–A–2 (cont.)
Investor–Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Snoqualmie Falls 1	PSPL	12	i	i	i	1898
Snoqualmie Falls 2	PSPL	29	i	i	i	1910
Soda Springs	PP&L	11	e	e	e	1952
Stayton	PP&L	1	c	c	c	1937
Swan Falls	IPC	10	12	9	9	1910
Swift 1	PP&L	204	182	76	52	1958
T.W. Sullivan	PGE	15	16	14	14	1985
Thompson Falls	MPC	30	k	k	k	1915
Thousand Springs	IPC	9	d	d	d	1912
Toketee	PP&L	43	e	e	e	1950
Twin Falls	IPC	8	10	8	7	1935
Upper Baker	PSPL	94	92	42	35	1959
Upper Falls	WWP	10	10	9	8	1922
Upper Malad	IPC	8	d	d	d	1948
Upper Salmon A	IPC	18	20	18	18	1937
Upper Salmon B	IPC	17	18	16	16	1947
Wallowa Falls	PP&L	1	c	c	c	1921
West Side	PP&L	1	f	f	f	1908
White River	PSPL	70	62	36	27	1912
Yale	PP&L	108	112	65	52	1953

[a] Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast*. March 1991.

[b] Values for operating years 1991 through 2010. Peak capacity is for January. Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast*. March 1991.

[c] Totals for Pacific Power and Light Company's small projects: Peak, 33; Average, 27; Critical 26.

[d] Totals for Idaho Power Company's Spring projects: Peak, 30; Average, 28; Critical, 29.

[e] Totals for Pacific Power and Light Company's Umpqua River projects: Peak, 175; Average, 129; Critical, 97.

[f] Totals for Pacific Power and Light Company's Klamath projects: Peak, 92; Average, 41; Critical, 22.

[g] Totals for The Washington Water Power Company's Spokane River projects: Peak, 155; Average, 117; Critical, 92.

[h] Totals for Pacific Power and Light Company's Rogue River projects: Peak, 25; Average, 43; Critical, 35.

[i] Totals for Puget Sound Power and Light Company's small projects: Peak, 72; Average, 55; Critical, 49.

[j] Includes 1984 expansion.

[k] Approximately 40 percent of the capability of Montana Power Company projects is available to serve regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

Table 4–A–3
Publicly Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Alder	Tacoma	50	39	26	20	1945
Boundary[f]	Seattle	1,034	845	502	360	1967
Box Canyon	Pend Oreille	60	81	49	51	1955
Calispel Creek[c]	Pend Oreille	1	1	0	0	1920
Carmen–Smith	EWEB	80	34	17	16	1963
Cedar Falls	Seattle	20	[d]	[d]	[d]	1905
Chelan	Chelan	48	56	48	42	1928
City	Idaho Falls	8	[e]	[e]	[e]	1982
Cushman 1	Tacoma	43	29	12	11	1926
Cushman 2	Tacoma	81	88	25	24	1930
Diablo	Seattle	122	159	97	83	1936
Gorge	Seattle	171	177	113	95	1924
Henry M. Jackson	Snohomish	112	103	53	41	1984
Idaho Falls Lower	Idaho Falls	11	[e]	[e]	[e]	1904
Idaho Falls Upper	Idaho Falls	8	[e]	[e]	[e]	1938
LaGrande	Tacoma	64	65	41	33	1912
Leaburg Dam	EWEB	14	14	13	12	1930
Mayfield Dam	Tacoma	162	172	78	64	1963
Mossyrock	Tacoma	300	309	118	93	1968
Moyie Falls 1–Upper[c]	Bonners Ferry	< 1	1	1	1	1921
Moyie Falls 2–Lower[c]	Bonners Ferry	2	1	1	1	1941
Newhalem Creek	Seattle	2	[d]	[d]	[d]	1921
Packwood Lake	WPPSS	26	30	11	7	1964
Priest Rapids	Grant	789	896	580	482	1959
Rock Island	Chelan	620	613	404	339	1933
Rocky Reach	Chelan	1,212	1,284	723	582	1961
Ross	Seattle	360	357	90	70	1952
Strawberry Creek	Lower Valley	2	[e]	[e]	[e]	1951
Swift 2	Cowlitz	70	76	25	20	1958
Trail Bridge	EWEB	10	4	4	4	1963
Walterville	EWEB	8	9	8	7	1911
Wanapum	Grant	831	910	536	428	1963
Wells[g]	Douglas	774	820	426	345	1967

Table 4-A-3 (cont.)
Publicly Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Yelm	Centralia	10	10	9	9	1930

[a] Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast*. March 1991.

[b] Values for operating years 1992 through 2011. Peak capacity is for January. Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast*. March 1991.

[c] Totals for Big Creek, Calispel Creek, Moyie Falls 1 and 2 (Flathead Irrigation Projects) are: Peak, 4; Average, 2; Critical, 2.

[d] Totals for Cedar Falls and Newhalem Creek are: Peak, 31; Average, 13; Critical, 9.

[e] Totals for City, Idaho Falls Upper, Idaho Falls Lower, and Strawberry Creek are: Peak, 19; Average, 20; Critical, 20.

[f] Includes Units 55 and 56.

[g] Includes upgrades scheduled for completion by 1989.

Table 4-A-4
Contracted Resources[a]

Project	Fuel	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MW)	In-Service Year
Wind					
Whiskey Run		PP&L[b]	1.25	0.01	1981
Wind Subtotal			1.25	0.01	
Thermal					
AEM Corporation[c]	Coal	MPC	12.0	N/A	1985
Afton Generating Company[d]	Wood	IPC	7.5	5.8	1984
Big Horn Energy[c]	Coal	MPC	15.0	N/A	1986
Biomass One[d]	Wood	PP&L	25.0	18.3	1986
Biosolar[d]	Biomass	PP&L	25.0	17.5	1987
Blue Mountain Forest Products[d]	Wood	OTEC	6.0	2.6	1986
Boeing (Auburn)[d]	Gas	PSPL	9.0	8.0	N/A
Boise Cascade (Emmett, Idaho)[d]	Wood	IPC	14.0	8.2	1985
Boise Cascade (Medford)	Wood	PP&L	8.5	0.3	pre-1961
Bozeman Woodwaste[c]	Wood	MPC	12.0	N/A	1985
Champion International (Libby)	Wood	PP&L	13.3	1.8	pre-1960
Cristad Enterprises[d]	Wood	OTEC	7.0	2.7	1986
Daw Forest Products	Wood	PP&L	10.0	0.9	pre-1960
Gorge Energy[d]	Wood	PP&L	8.5	2.9	N/A
Great Western Malting[d]	Gas	Clark	20.0	17.9	1983
Husky Industries[d]	Biomass	PP&L	5.0	3.8	1989
D.R. Johnson (CPN)[d]	Biomass	CPN	7.5	5.6	1986
D.R. Johnson (PP&L)[d]	Biomass	PP&L	7.5	5.7	1987
Kinzua[d]	Wood	PGE	10.0	7.4	1985
Lakeview Power Company[d]	Biomass	PP&L	15.0	11.3	1987
Lane Plywood[d]	N/A	EWEB	0.8	N/A	N/A
Metro West Point[d]	Sewage Methane	Seattle	3.9	1.2	1982
Ogden-Martin	MSW	PGE	14	7.6	1986
Pacific Crown (Woodpower, Inc.)[d]	Wood	WWP	6.3	4.5	1983
Perkins Power[c]	Coal	MPC	12.0	N/A	1985
Pine Products	Wood	PP&L	5.75	N/A	1987
Potlatch (Lewiston #1)[d]	N/A	WWP	126.2	55.0	1991
Red Lodge	Coal	MPC	10.0	N/A	1986
Roseburg Lumber	Wood	PP&L	45.0	26.0	1983

Table 4-A-4 (cont.)
Contracted Resources[a]

Project	Fuel	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MW)	In-Service Year
Thermal (cont.)					
Simplot Fertilizer	Sulphur	IPC	15.0	9.0	1986
Tamarack Energy[d]	Wood	IPC	5.0	4.1	1983
Vaagen Brothers Lumber[d]	Wood	WWP	4.0	4.0	1980
Warm Springs Forest Products	Wood	PP&L	9.0	0.5	pre-1960
Weyco[d]	Pulping Liquor	EWEB	51.2	15.0	1976
Weyerhauser (Everett)[d]	N/A	Snohomish[e]	12.5	10.0	N/A
Thermal Subtotal			558.45	257.6	

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Granted Status	In-Service Year
Hydropower						
Amy Ranch	08700-01		0.00	0.00	EX	1986
Barber Dam	04881-17	IPC	3.70	2.28	LA	
Barney Creek	07754-02	Park	0.07	0.04	EX	1986
Big Sheep Creek	05118-03		4.00	1.83	EX	1985
Billingsley Creek	06208-01	IPC	0.14	0.13	EX	1986
Birch Creek	07194-05	PP&L	2.85	0.34	LA	1987
Birch Creek	06458A01	IPC	0.02	0.03	EX	1984
Birch Creek	06458B01	IPC	0.04	0.03	EX	1984
Black Canyon No. 3	06137-00	IPC	0.15	0.06	EX	1983
Blind Canyon	08375-02	IPC	1.30	0.65	EX	
Box Canyon	06543-01	IPC	0.56	0.36	EX	1983
Briggs	08083-02	PP&L	0.25	0.20	EX	1986
Briggs Creek	04360-02	IPC	0.75	0.60	EX	1985
Brunswick Creek	06564-01	PGE	0.04	0.25	EX	1982
Bull Run No. 1	02821A05	PGE	23.75	7.31	LA	1981
Bull Run No. 2	02821B05	PGE	12.00	5.25	LA	1982
Burnham Creek	09654-10	Pacific	0.02	0.00	LA	
Burton Creek	07577-00		0.80	0.40	EX	
Bypass Site	09070-00	IPC	9.90	3.81	EX	1988
Canal Creek	05572-00		1.10	0.47	EX	1984
Canyon Creek	06414-00	PGE	0.12	0.06	EX	1985

Table 4–A–4 (cont.)
Contracted Resources[a]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Granted Status	In-Service Year
Hydropower (cont.)						
Cascade Creek	06629–00	MPC	0.08	0.04	EX	1983
Cedar Draw Creek	08278–04	IPC	2.92	0.71	LA	1986
Cereghino	05865–00	IPC	1.10	0.73	EX	1987
Cowiche Hydroelectric Project	07337–02	PP&L	1.35	0.58	LA	1986
Deep Creek Micro Hydroelectric Project	05991–01		0.27	0.06	EX	1983
Denny Creek	07350–00		0.05	0.04	EX	1985
Dietrich Drop	08909–11	IPC	4.80	2.48	LA	1988
Doug Hull	06676–01	IPC	0.25	0.13	EX	1983
Dry Creek	09134–00		3.60	2.02	EX	
Dry Creek	02907–00		0.01	0.00	LC	1980
Ebey Hill	10428–00	Snohomish	0.10	0.07	EX	
Elk Creek	03503–09	IPC	2.20	0.59	EX	1984
Eltopia Branch Canal 4.6	03842–03	Seattle/ Tacoma	2.40	0.98	LA	1983
Falls Creek No. 1	06661–04	PP&L	4.00	1.70	EX	1984
Falls Creek No. 2	05497–04	Clallam	0.20	0.02	EX	
Farmers Irrigation District Project No. 2	07532–00	PP&L	3.00	1.48	EX	1985
Faulkner Land and Livestock Company	07592–03	IPC	0.40	0.02	EX	1987
Felt	05089–18	BPA	1.87	1.00	LA	1985
Ferguson Ridge	06621–00		1.66	0.63	EX	1984
Fid Project #3	06801–03	PP&L	1.80	0.85	EX	
Fisheries Development No. 1	07885–01	IPC	0.31	0.25	EX	
Ford (Jim Ford Creek)	07986–00	WWP	1.50	0.84	LA	1987
Galesville	07161–15	PP&L	1.80	0.68	LA	1987
Geo–Bon No. 2	07548–02	IPC	0.81	0.54	EX	1986
Georgetown	06445–00	PP&L	0.45	0.21	EX	1985
Ground Water Pumping Station	07052–00	Portland	4.50	2.50	EX	1985
Hailey	07016–02	IPC	0.05	0.06	EX-GTD	1985
Hecla Power Project	06965–06		0.50	0.23	EX	
Hettinger	03041–00		0.01	-0.00	LC	1960
Ingram Warm Springs Ranch	08498B09		1.70	1.26	LA	1986

Table 4–A–4 (cont.)
Contracted Resources[a]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Granted Status	In-Service Year
Hydropower (cont.)						
Ingram Warm Springs Ranch	08498A09		0.90	0.66	LA	1986
James E. White	03922–00	PP&L	0.24	0.11	EX	1981
Jim Boyd	07269–07	PP&L	1.10	0.48	LA	
Jim Knight	07686–01	IPC	0.29	0.24	EX	1984
Kasel–Witherspoon	06410–00	IPC	1.00	0.70	EX	1983
Kaster Riverview	04608B01	IPC	0.16	0.16	EX	1983
Kaster Riverview	04608A01	IPC	0.16	0.16	EX	1983
Koyle Ranch	04052–03	IPC	1.41	0.73	EX	1983
Lacomb	06648–00	PP&L	0.96	0.63	EX	1986
Kake Creek No. 1	06595–01	PP&L	0.05	0.04	EX	1984
Last Chance Canal	04580–00	PP&L	1.66	0.94	EX	1982
Lateral No. 10	06250–02	IPC	3.00	1.76	EX	1985
Leishman Irrigation System	07684–00		0.03	0.01	EX	
Lemoyne	04563–02		0.04	0.03	EX	1985
Lilliwaup Falls	03482–03		1.20	1.20	EX	1983
Little Gold	08660–04		0.45	0.22	LA	
Little Mac	06443–00	IPC	0.25	0.24	EX	1984
Little Wood R Ranch No. 1	07530–00	IPC	0.66	0.46	EX	1986
Little Wood R Ranch No. 2	07427–01	IPC	1.93	0.95	EX	1988
Low Line Canal Drop	03216–01	IPC	9.00	5.35	EX	1984
Lower Low Line No. 2	08961–00	IPC	2.35	1.80	EX	
Lucky Peak	02832–14	Seattle	101.60	28.00	LA	1988
Macks Creek	06631–03		0.01	0.00	EX	1984
Magic Dam	03407–27	IPC	9.00	3.56	LA	
Main Canal Headworks	02849–12	Seattle/ Tacoma	26.00	9.86	LA	1986
Middle Fork Irrigation District 1	04458A04	PP&L	2.10	1.72	EX	1987
Middle Fork Irrigation District 2	04458B04	PP&L	0.60	0.47	EX	1987
Middle Fork Irrigation District 3	04458C04	PP&L	0.60	0.39	EX	1987
Mill Creek	05390–02	CPN	0.63	0.29	EX	1905
Mill Creek	04949–00		0.50	0.27	EX	1983
Mink Creek	08646–07	PP&L	2.75	1.07	LA	1988
Mirror Lake	07747–00	PSPL	1.00	0.71	EX	1985

Table 4–A–4 (cont.)
Contracted Resources[a]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Granted Status	In–Service Year
Hydropower (cont.)						
Mitchell Butte	05357–08	IPC	1.68	0.61	LA	1989
Mt. Tabor	06957–00		0.17	0.13	EX	1985
Mud Creek	04769A01	IPC	0.44	0.40	EX	1982
Mud Creek/White	04769B01	IPC	0.22	0.15	EX	1982
N–32 (Northside Canal)	06778–01	IPC	0.55	0.04	EX	1985
Nichols Gap	08704–00	PP&L	0.80	0.30	EX	1986
Nicholson	07865–01	PP&L	0.35	0.31	EX	1986
North Willow Creek	07804–13	MPC	0.40	0.40	LA	
O.J. Power Company	07719–03	PP&L	0.15	0.15	EX	
Odell Creek	06057–01	PP&L	0.07	0.05	EX	1984
Opal Springs	05891–03	PP&L	1.25	2.66	LA	1920
Orchard Avenue	07338–02	PP&L	1.44	0.64	LA	1986
Oregon City	02233C21		1.50	0.00	LA	
Owyhee Dam	04354–04	IPC	4.34	1.82	LA	1985
Owyhee Tunnel No. 1	04359–11	IPC	8.00	2.72	LA	
PEC Headworks	02840–16	Seattle/ Tacoma	6.50	2.27	LA	
Philipsburg (a)	06639A00		0.09	0.08	EX	1981
Philipsburg (b)	06639B00		0.07	0.00	EX	1981
Pickell	02794–03		0.00	0.00	LC	1953
Pine Creek	08546–20	MPC	0.37	0.21	LA	1975
Ponds Lodge	01413–05		0.25	0.11	RL	1936
Port Townsend Mill	05411–00		0.40	0.31	EX	1982
Potholes E Canal 66	03843–03	Seattle/ Tacoma	2.30	1.35	LA	1985
Preston	05892–00		0.41	0.34	EX	1987
Project No 1	08865–03	IPC	0.12	0.07	LC	1979
Project No 2	08866–03	IPC	0.09	0.06	LA	1980
Quincy Chute	02937–03	Grant	7.80	3.34	LA	1984
Reynolds Irrigation District	06229–00	IPC	0.35	0.21	EX	1985
Rock Creek #1	06450–00	IPC	2.54	1.30	EX	1983
Rock Creek #2	06015–37	IPC	1.90	1.61	LA	
Rocky Brook	03783–03	Mason	1.50	0.80	EX	1985

Table 4–A–4 (cont.)
Contracted Resources[a]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Granted Status	In-Service Year
Hydropower (cont.)						
Rocky Mountain Embryos	05731–02	IPC	0.18	0.18	EX	1984
Russell D. Smith	02926–02	Seattle/ Tacoma	6.10	2.59	LA	1982
Sagebrush Project	08046–02	IPC	0.32	0.25	EX	1985
Salmon Falls Creek	07211–11	IPC	0.27	0.20	LA	
Schaffner Project	08438–01	IPC	0.25	0.26	EX	1986
Shingle Creek	04025–03	IPC	0.12	0.12	LA	1984
Shoshone	09967A20	IPC	0.33	0.29	LA	1982
Skyview Ranch Power	09179–00	Coos Curry	0.04	0.01	EX	1983
Slaughterhouse Gulch Creek	06375–00	IPC	0.12	0.05	EX	1983
Smith Creek	08436–68	EWEB	38.15	9.76	LA	1989
Snake River Pottery	05651–03	IPC	0.09	0.04	EX	1984
Soda Creek	07959–00	Soda Springs	0.71	0.45	EX	1987
South Dry Creek	08831–00		1.80	0.81	EX	1985
South Willow Creek	07856B10	MPC	0.03	0.01	LA	1980
South Willow Creek	07856A10	MPC	0.29	0.16	LA	1986
Spencer Lake Hydro	06625–01		0.04	0.02	EX	1983
Spring Creek	07214–01		0.01	0.01	LA	
Summer Falls	03295–10	Seattle/ Tacoma	92.00	37.10	LA	1984
Sunshine	09907–02	IPC	0.11	0.06	LA	
Sygitowicz Creek	05069–01	PSPL	0.19	0.20	EX	1986
Telford	05637–00	PP&L	0.15	0.12	EX	1984
Thompson's Mills	09169–00	PP&L	0.10	0.07	EX	1986
Trinity	00719–03		0.29	0.29	RL	1923
Tuttle Ranch	04055–05		1.06	0.38	EX	1983
Twin Falls Reservoirs	10376–00	IPC	0.00	8.30	EX	1988
Upper Indian Creek	07405–01	CP National	0.08	0.07	EX	
Upper Little Sheep Creek	05573–00		4.25	1.69	EX	1984
Upper Pine Creek	08727–01		0.01	0.00	EX	1985
Water Street	06943–01	PP&L	0.16	0.11	EX	1985
Weeks Falls	07563–08	IPC	3.40	1.80	LA	1985
West Linn	02233A21		3.60	0.00	LA	

Table 4-A-4 (cont.)
Contracted Resources[a]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Granted Status	In-Service Year
Hydropower (cont.)						
White Ranch	04115-04	IPC	0.15	0.04	EX	1986
White Water Ranch	06271C00	IPC	0.10	0.04	EX	1983
White Water Ranch	06271A00	IPC	0.18	0.04	EX	
Whitefish	06941-01		0.19	0.11	EX	1985
Wisconsin-Noble	09482-07	MPC	0.66	0.29	LA	
Wolf Creek	07058-00	PGE	0.12	0.06	EX	1987
Woods Creek	03602-01		0.60	19.41	EX	1982
Y-8 Hydroelectric Project	06630-02		0.08	0.09	EX	1983
Hydropower Subtotal			479.15	215.96		
Contracted Resource Total			1,037.60	473.56		

[a] From various sources compiled by the Council including: Pacific Northwest Utilities Conference Committee. *Cogeneration Compendium.* April 1990. Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast.* March 1991. Pacific Northwest Hydropower Data Base; Idaho Public Utility Commission, Oregon Public Utility Commissioner, Montana Power Company, Washington State Energy Office.

[b] Research and demonstration contract.

[c] Cogeneration.

[d] Unknown whether or not project is cogeneration.

[e] Negotiating.

Table 4-A-5
Large Thermal Units

Project and Unit	Fuel	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	In-Service Year
Boardman	Coal	PGE: 65%; IPC: 10%; PNGC: 10%; GECC: 15%	560	425	316[e]	1980
Centralia 1	Coal	PP&L: 47.5%; WWP: 15%; PSPL: 11%; Snohomish: 8%; Tacoma: 8%; Seattle: 8%; PGE: 2.5%	730	640	543	1971
Centralia 2	Coal	PP&L: 47.5%; WWP: 15%; PSPL: 11%; Snohomish: 8%; Tacoma: 8%; Seattle: 8%; PGE: 2.5%	730	640	543	1972
Colstrip 1	Coal	MPC: 50%; PSPL: 50%	358	158[c]	126.5[c]	1975
Colstrip 2	Coal	MPC: 50%; PSPL: 50%	358	158[c]	126.5[c]	1976
Colstrip 3	Coal	MPC: 30%; PSPL: 25%; PGE: 20%; WWP: 15%; PP&L: 10%	778	415[c]	392[c]	1984
Colstrip 4	Coal	USTC: 30%; PSPL: 25%; PGE: 20%; WWP: 15%; PP&L: 10%	778	504[c,f]	415[c,f]	1986
J.E. Corette	Coal	MPC	172	50[c]	39[c]	1968
Jim Bridger 1	Coal	PP&L: 66-2/3%; IPC: 33-1/3%	509	170.2[d]	141.5[d]	1974
Jim Bridger 2	Coal	PP&L: 66-2/3%; IPC: 33-1/3%	509	170.2[d]	141.5[d]	1975
Jim Bridger 3	Coal	PP&L: 66-2/3%; IPC: 33-1/3%	509	170.2[d]	141.5[d]	1976
Jim Bridger 4	Coal	PP&L: 66-2/3%; IPC: 33-1/3%	509	170.2[d]	141.5[d]	1979
Valmy 1	Coal	IPC: 50%; SPPC: 50%	254	121	98	1981
Valmy 2	Coal	IPC: 50%; SPPC: 50%	267	121	98	1985
Trojan	Nuclear	PGE: 67.5%; EWEB: 30%; PP&L: 2.5	1,216	1,152	726	1976
WNP-2	Nuclear	WPPSS	1,154	1,095	711	1984
Kettle Falls	Wood	WWP	51	47	40	1983

[a] Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast.* March 1991.

[b] Declared by sponsors to be available to the region. Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast.* March 1991.

[c] Approximately 40 percent of the capability of Montana Power Company resources is available to meet regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

[d] The portion of the Pacific Power and Light Company share of Jim Bridger is treated as an import to the region in accordance with Northwest power planning convention.

[e] General Electric Credit Corporation share to be sold to San Diego Gas and Electric on a 25-year contract beginning in 1989.

[f] United States Trust Company share of Colstrip 4 is leased back to Montana Power Company.

Table 4-A-6
Other Thermal Units

Project and Unit	Primary Fuel	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[a]	Firm Energy (MWa)[b]	In-Service Year
Combustion Turbine						
Bethel 1	Gas	PGE	56.7	58.0	26.0	1973
Bethel 2	Gas	PGE	56.7	58.0	26.0	1973
Frederickson 1	Gas	PSPL	85.0	89.0	2.0	1981
Frederickson 2	Gas	PSPL	85.0	89.0	2.0	1981
Fredonia 1	Gas	PSPL	123.6	123.5	3.0	1984
Fredonia 2	Gas	PSPL	123.6	123.5	3.0	1984
Northeast	Gas	WWP	61.2	68.0	54.0	1978
Point Whitehorn 1	Oil	PSPL	61.0	68.0	13.0	1974
Point Whitehorn 2	Gas	PSPL	85.0	89.0	13.0	1981
Point Whitehorn 3	Gas	PSPL	85.0	89.0	13.0	1981
Whidbey Island	Oil	PSPL	27.0	29.0	1.0	1972
Wood River	Gas	IPC	50.0	50.0	1.0	1974
Diesel						
Bonners Ferry 1	Oil	Bonners Ferry	0.2	0.0	0.0	1930
Bonners Ferry 2	Oil	Bonners Ferry	1.1	1.0	1.0	1930
Bonners Ferry 3	Oil	Bonners Ferry	1.1	1.0	1.0	1973
Crystal Mountain	Oil	PSPL	2.8	3.0	0.1	1969
Summit 1	Oil	PGE	2.8	3.0	0.5	1970
Summit 2	Oil	PGE	2.8	3.0	0.5	1973
Steam-Electric						
Shuffleton 1	Oil	PSPL	35.0	43.0	1.0	1930
Shuffleton 2	Oil	PSPL	35.0	43.0	1.0	1930
Steam Plant 2	Coal/MSW/Wood	Tacoma	50.0	38.0	32.0	1990
Combined Cycle						
Beaver	Gas	PGE	586	534	328	1977
Total				1,603	522	

[a] Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast.* March 1991.

[b] Declared by sponsors to be available as firm energy. Pacific Northwest Utilities Conference Committee. *Northwest Regional Forecast.* March 1991.

Table 4-A-7
Thermal Resource Operating Costs[a]

Project and Unit	Primary Fuel	Heat Rate (Btu/kWh)	Fixed Fuel Cost ($/kW/yr.)	Variable Fuel Cost ($/MMBtu)	Average Fuel Real Escalation (%)	Fixed[b] O&M ($/kW/yr.)	Variable[b] O&M (mills/kWh)
Boardman	Coal	10,800	1.26	2.41	0.9	24.06	0.11
Centralia 1	Coal	10,230	0.00	1.59	1.9	12.41	0.94
Centralia 2	Coal	10,230	0.00	1.59	1.9	12.41	0.94
Colstrip 1	Coal	11,250	3.52	0.42	4.0	24.19	1.52
Colstrip 2	Coal	11,250	3.52	0.42	4.0	24.19	1.52
Colstrip 3	Coal	10,390	3.68	0.41	4.0	16.09	0.76
Colstrip 4	Coal	10,390	3.68	0.41	4.0	16.09	0.76
Corette	Coal	11,030	13.15	0.44	3.1	10.45	0.83
Jim Bridger 1	Coal	9,980	0.00	1.10	1.9	14.56	1.35
Jim Bridger 2	Coal	9,980	0.00	1.10	1.9	14.56	1.35
Jim Bridger 3	Coal	9,980	0.00	1.10	1.9	14.56	1.35
Jim Bridger 4	Coal	9,980	0.00	1.10	1.9	14.56	1.35
Valmy 1	Coal	9,556	0.00	1.91	1.3	24.61	1.56
Valmy 2	Coal	9,515	0.00	1.92	1.3	24.61	1.56
Beaver	Gas	8,800	0.21	3.16	2.8	6.94	1.46
Point Whitehorn 1	Gas	11,850	0.00	3.16	2.8	10.52	8.95
Point Whitehorn 2	Gas	10,320	1.04	3.16	2.8	16.33	8.95
Point Whitehorn 3	Gas	10,320	1.04	3.16	2.8	16.33	8.95
Bethel	Gas	13,300	0.31	3.16	2.8	6.71	0.00
Frederickson 1	Gas	10,320	2.90	3.16	2.8	1.46	8.95
Frederickson 2	Gas	10,320	2.90	3.16	2.8	1.46	8.95
Fredonia 1	Gas	10,485	5.19	3.16	2.8	1.12	8.95
Fredonia 2	Gas	10,485	5.19	3.16	2.8	1.12	8.95
Trojan	Nuclear	10,339	32.58	0.49	0.12	43.38	1.71[c]
WNP-2	Nuclear	10,225	27.72	0.51	0.85	19.77	1.14[c]

[a] January 1990 dollars.

[b] O&M real escalation for coal and gas is zero.

[c] O&M escalation for Trojan and WNP-2 is 3 percent real in 1988 and declines linearly to 0 percent by 2000.

APPENDIX 4-B

REGIONAL IMPORTS AND EXPORTS

Key to Tables in Appendix 4–B

Abbreviated Name	Full Name
Anaheim	City of Anaheim
BC Hydro	British Columbia Hydro Power Authority
BGP	Cities of Burbank, Glendale and Pasadena
BPA	Bonneville Power Administration
Burbank	City of Burbank
Glendale	City of Glendale
IPC	Idaho Power Company
MPC	Montana Power Company
MSR	Cities of Modesto, Santa Clara and Rosa
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PP&L	Pacific Power and Light Company
PSPL	Puget Sound Power and Light Company
Riverside	City of Riverside
SCE	Southern California Edison
SCL	Seattle City Light
SMUD	Sacramento Municipal Utility District
Tacoma	City of Tacoma—Light Division
UPC	Utah Power Company
WAPA	Western Area Power Agency
WWP	Washington Water Power

Table 4-B-1
Summary of Firm Energy Exports (Average Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BPA to BC Hydro	0	0	0	0	0	0	14	121	318	314	311	368	548	542	536	531	525	519	513	508
BPA to BGP	26	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	18	0	0	0
BPA to MPC No. 1	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
BPA to MPC No. 2	65	65	65	65	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA to MSR	0	9	50	50	50	73	75	75	75	75	75	75	75	75	75	75	75	30	0	0
BPA to SCE	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	123	0	0
BPA to UPC	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
IPC to MPC	12	12	12	12	12	13	6	0	0	0	0	0	0	0	0	0	0	0	0	0
IPC to MPC	50	50	50	50	44	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PGE to SCE	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	30
PGE to SCE	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	25	26
PGE to WAPA	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
PGE to Burbank No. 1	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
PGE to Burbank No. 2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PGE to Glendale No. 1	13	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PGE to Glendale No. 2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 4–B–1 (cont.)
Summary of Firm Energy Exports (Average Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PP&L to PG&E	28	28	28	28	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L to SCE	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	13	0	0	0	0
PP&L to SCE	0	0	7	7	7	7	7	7	7	7	7	7	7	7	7	5	0	0	0	0
PP&L to SMUD	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Puget to PG&E	12	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	35	0	0	0
SCL to PG&E	0	0	7	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Tacoma to WAPA No. 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0
WWP to PG&E	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Total	668	717	769	792	772	673	682	783	980	976	973	1,030	1,210	1,204	1,198	1,147	1,101	986	819	718

Table 4–B–2
Summary of Firm Energy Imports (Average Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Anaheim to BPA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1
BC Hydro to PSPL	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
BC Hydro to SCL	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Burbank to PGE	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glendale to PGE	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC	332	332	333	339	340	305	303	305	305	305	315	315	315	315	315	315	315	315	315	315
MPC to BPA	29	29	29	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0
MPC to IPC	12	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC to PSPL	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
MPC to WWP	37	36	33	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MSR to BPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25
PG&E to PSPL	24	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	24	0	0	0
PG&E to SCL	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
PG&E to WWP	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
PP&L (Wyo) to PP&L	1,179	1,119	1,121	1,116	992	974	963	894	895	896	813	836	826	752	754	756	675	698	690	690
Riverside to BPA	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1

Table 4–B–2 (cont.)
Summary of Firm Energy Imports (Average Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
SCE to PGE	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	0
SCE to PP&L	0	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	0	0	0	0
UPC	437	441	438	442	443	444	445	446	446	447	448	449	449	451	452	453	454	455	457	458
Total	2,227	2,191	2,225	2,215	2,075	2,023	2,011	1,933	1,934	1,936	1,835	1,859	1,849	1,777	1,788	1,783	1,672	1,672	1,666	1,653

Table 4-B-3
Summary of Peaking Capacity Exports (Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BPA to Anaheim	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	0
BPA to BC Hydro	0	0	0	0	0	0	0	100	600	600	600	600	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
BPA to BGP	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	0	0	0
BPA to MPC	76	76	76	76	76	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA to MPC	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0
BPA to MSR	0	0	100	100	100	150	150	150	150	150	150	150	150	150	150	150	150	0	0	0
BPA to Riverside	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	0
BPA to SCE	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	0	0	0
IPC to MPC	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IPC to MPC	75	75	75	75	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PGE to Burbank	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PGE to Glendale	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PGE to SCE	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	0
PGE to WAPA	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
PP&L to PG&E	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L to SCE	200	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0

Table 4–B–3
Summary of Peaking Capacity Exports (Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PP&L to SMUD	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Tacoma to WAPA	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	0
Total	1,130	1,130	1,230	1,230	1,130	1,029	979	1,079	1,579	1,579	1,479	1,479	1,979	1,979	1,979	1,879	1,879	1,693	1,443	1,295

Table 4–B–4
Summary of Peaking Capacity Imports (Megawatts)

Parties Involved	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BC Hydro to PSPL	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
BC Hydro to SCL	174	174	174	174	174	174	174	174	174	174	174	174	174	174	174	174	174	174	174	174
Burbank to PGE	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glendale to PGE	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC to PSPL	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
MPC	494	497	500	501	502	466	449	449	449	449	414	414	414	414	414	414	414	414	414	414
PG&E to SCL	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
PG&E to WWP	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
PG&E to PSPL	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	0	0	0	0
PP&L (Wyo) to PP&L	1,565	1,550	1,518	1,490	1,347	1,313	1,275	1,252	1,223	1,192	1,163	1,133	1,104	1,078	1,051	1,024	998	971	944	944
SCE to PGE	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	0
SCE to PP&L	0	0	72	72	72	72	72	72	72	72	72	72	72	72	72	72	0	0	0	0
UPC	404	405	403	403	403	404	404	404	406	407	409	411	412	414	416	419	421	424	427	428
Total	3,440	3,399	3,640	3,613	3,471	3,402	3,347	3,324	3,297	3,267	3,205	3,177	3,149	3,125	3,100	3,076	2,680	2,656	2,632	2,408

CHAPTER 5

ECONOMIC FORECASTS FOR THE PACIFIC NORTHWEST

Introduction

Under the Pacific Northwest Electric Power Planning and Conservation Act of 1980, Congress charged the Northwest Power Planning Council with forecasting electrical power requirements as the basis for a plan to meet regional electricity needs. The Bonneville Power Administration has prepared regional electricity demand forecasts since 1981 to use as a basis for its planning. These forecasts were developed with Bonneville and will be used as a common basis for resource planning and analysis. This chapter describes economic and demographic assumptions used in developing forecasts of electricity use for the Council's 1991 Power Plan.

Economic and demographic assumptions are the dominant factors influencing the forecasts of demand for electricity. A good rule of thumb is that demand for electricity will parallel economic activity in the absence of other changes. This relationship is modified by shifts in relative energy prices, including the price of electricity and other fuels, by changes in the composition of economic activity; and by the gradual depreciation and replacement of buildings and energy-using equipment in the region.

Recognizing that the future is highly uncertain, the Council and Bonneville have adopted planning strategies that incorporate flexibility and risk management. Economic and demographic assumptions are both extremely important determinants of future electricity needs and are, at the same time, highly uncertain. The objective of the range of planning assumptions discussed in this chapter is to help define the extent of uncertainty. Planning must address a range of future electricity needs that reflects, among other factors, this underlying economic uncertainty.

In order to recognize uncertainty explicitly, the Council and Bonneville have prepared forecasts that bracket the highest and lowest plausible economic scenarios for the next 20 years. The purpose of this approach is to develop a flexible resource strategy that provides an adequate supply of electricity at the lowest cost. The risks are twofold: the risk of not having an adequate supply of electricity, and the risk of being saddled with expensive investments in unnecessary resources.

The Council and Bonneville have developed a range of forecasts for each state in the Northwest. The forecasts are built from analysis of individual sectors of the economy. The forecasts are influenced by results produced by Bonneville's Regional Economic Model, as well as studies and expertise provided by groups and individuals throughout the Northwest. Detailed review was also provided by the Council's Economic Forecasting Advisory Committee and other interested parties.

Because future economic conditions are highly uncertain, the forecasts encompass a wide range of possibilities for future economic growth. The high forecast assures that the Council's plan will accommodate record regional economic growth, should it occur. In the high forecast, total regional employment grows at almost twice the rate of a high national growth in employment. The high forecast represents a case in which the region grows faster relative to the nation than in any historical 20-year period. The low case also implies a relative performance below any historical 20-year period in the region. Table 5-1 shows a comparison of the forecast range to a range of national forecasts prepared by the WEFA Group.[1] Detailed tables showing employment, population and household forecasts by state are in Appendix 5-D.

A more likely range of outcomes is bound by the medium-high and medium-low forecasts. This smaller, more probable range shows growth higher than the nation for most of the range. This is consistent with historical patterns, because the Pacific Northwest has grown faster than the nation over the long term. The medium range of forecasts assumes this will continue to some extent.

1. The WEFA Group. *U.S. Long-Term Economic Outlook*, Volumes 1 and 2, First Quarter 1990 and Third Quarter 1990.

Table 5-1
Comparison of Forecasts—Average Annual Rate of Growth (%) 1989-2010

Region	High	Medium-High	Medium	Medium-Low	Low
Total Employment	2.8	2.0	1.5	1.1	0.7
▪ Manufacturing	1.5	0.8	0.2	-0.7	-1.4
▪ Non-manufacturing	3.0	2.2	1.7	1.4	1.0
Total Population	2.1	1.6	1.3	1.0	0.7
Households	2.8	2.0	1.7	1.5	0.7
Wharton National Outlook			High	Medium	Low
Total Employment			1.5	1.3	1.1
▪ Manufacturing			0.2	-0.2	-0.6
▪ Non-manufacturing			1.8	1.6	1.5
Total Population			1.0	0.8	0.6
Households			1.4	1.2	1.1

The economic and demographic forecasts in this report are similar in many respects to the forecasts for the Council's 1989 Supplement to the 1986 Northwest Conservation and Electric Power Plan. The forecasts encompass a range of employment growth between the years 1987 and 2010 that is smaller than the range in the 1989 supplement, because the medium-low and low cases are somewhat higher than in the previous forecasts. Table 5-2 shows a comparison of the forecast ranges.

Forecasts of employment growth in a number of manufacturing industries are higher in these forecasts than in the 1989 supplement forecasts. These higher growth rates are only partially offset by lower forecasts of productivity growth in many manufacturing industries. As a result, forecasts of manufacturing output are higher in all scenarios except the high case.

Forecasts for Utility Service Areas

The economic and demographic assumptions are divided into public and investor-owned utility service areas to provide inputs into the demand forecasting system, which forecasts electricity consumption by utility type. Industrial production at the detailed industry level, employment in the commercial sector, and housing units are divided into public and investor-owned utility areas for each state. The splits between public and investor-owned utility areas are provided by Bonneville. According to these estimates, approximately 40 percent of regional manufacturing production, commercial employment and households are located in public utility service areas. In the case of major manufacturing industries, the shares of production allocated to public or investor-owned utilities were developed by detailed industry analysis of plant location or county employment patterns. Housing stock shares were allocated on the basis of customer counts in the residential sector at the utility and state level. The commercial sector shares incorporated data provided by Seattle City Light, which showed a decrease in the public utility share of King County's employment in Washington state. This historical shift was assumed to continue for King County. For the rest of Washington state and for the other states and counties, the shares of commercial sector employment were based on residential customer counts by utility and state. They were assumed to remain constant over the forecast period.

Forecast Overview

Overview of the Regional Economy

The Pacific Northwest is blessed with rich natural resources of minerals, agricultural lands, fisheries and forests. The abundance of natural resources has provided the region's inhabitants with jobs and income, as well as a desirable environment for recreation and a high quality of life.

The development of the vast Columbia/Snake River system for navigation, electricity production, irrigation and recreation has contributed to economic growth in the region. Low electricity rates, relative to those found elsewhere in the nation, have attracted electricity-intensive industries, such as the aluminum industry, to the Pacific Northwest.

Table 5-2
Comparison of Forecasts—Average Annual Rate of Growth (%) 1987–2010[a]

	High	Medium-High	Medium	Medium-Low	Low
1989 Supplement to the 1986 Northwest Conservation and Electric Power Plan					
Total Employment	2.8	2.1	1.6	1.1	0.4
▪ Manufacturing	1.3	0.5	0.0	–0.5	–1.3
▪ Non-manufacturing	3.1	2.4	1.8	1.3	0.6
Manufacturing Output	4.9	3.5	2.9	2.3	1.1
Population	2.0	1.5	1.2	0.9	0.4
Households	2.7	2.0	1.6	1.3	0.3
1991 Northwest Conservation and Electric Power Plan					
Total Employment	2.9	2.2	1.8	1.4	1.0
▪ Manufacturing	1.8	1.1	0.6	–0.2	–0.9
▪ Non-manufacturing	3.1	2.4	2.0	1.7	1.3
Manufacturing Output	4.9	4.0	3.4	2.5	1.7
Population	2.1	1.6	1.4	1.1	0.8
Households	2.8	2.1	1.8	1.6	0.9

[a] Growth rates differ from those shown in previous tables because they cover different time periods.

More recently, industries such as electronics have grown in the region, attracted primarily by the quality of the labor force and quality of life. The development of port facilities and growing trade with Alaska and the Pacific Rim countries have provided a source of new jobs for the region. Growth in the non-manufacturing sectors, in general, has been rapid. These developments have provided diversity to a region dependent on resource-based industries.

During the 1960s and 1970s, total employment grew faster in the region than in the nation. Table 5-3 compares growth patterns between the region and the nation for the last three decades. During the 1980s, the region grew at about the same rate as the nation on average. However, this average growth rate masks divergent patterns of growth. In the first half of the decade, the region suffered from a severe recession that hit the region much harder than the nation. The recovery from the recession was slower and more gradual than previous experiences. In the late 1980s, however, the region once again moved into the position of growing faster than the nation. In the last few years, Northwest states have shown up in the list of the 10 fastest growing states in the country.

The region's stronger performance in the late 1980s was fueled by high operating levels in key manufacturing industries, such as forest products, aerospace and aluminum. After enduring a severe depression in the early 1980s, the region's wood products industry set new production records in the late 1980s. During this period, however, productivity gains were so high that employment in 1989 was 20 percent lower than in 1979.

The lumber and wood products category includes logging activities, some of which are related to pulp and paper production. In addition, many companies manufacture both wood and paper products. Including pulp and paper products, the forest products industry accounted for 25 percent of the region's manufacturing employment in 1989.

The second largest regional manufacturing industry is transportation equipment, composed primarily of aerospace. It accounted for 22 percent of manufacturing employment in 1989. After employment declined more than 20 percent in the early 1980s, the industry has recovered, increasing employment more than 70 percent since 1983.

Primary metals is the largest industrial consumer of electricity in the region, accounting for nearly half of all industrial electricity consumption. Most of the electricity consumption is concentrated in the primary aluminum industry, which operates 10 plants in the Northwest. This industry has experienced dramatic swings in prices of aluminum, increasing electricity prices, and increasing competition from lower-cost producing areas. Recently, aluminum smelters have increased their operating rates in response to higher worldwide aluminum prices and more attractive electricity rates.

Pulp and paper is the second largest industrial consumer of electricity, followed by chemicals, lumber and wood products and food processing. In 1989, the top five industrial consumers of electricity accounted for almost 90 percent of the electricity used by industrial customers in the region.

Growth in regional non-manufacturing industries has lagged behind national trends throughout the 1980s and is largely responsible for the somewhat slower growth in the region's economy. Mining and government were the only non-manufacturing categories to perform better than the nation in the 1980s.

Table 5-3
U.S. and Pacific Northwest Employment Trends—Average Annual Rate of Growth (%)

	1960–1979		1979–1989	
	Pacific N.W.	United States	Pacific N.W.	United States
Total Employment	3.0	2.2	1.7	1.8
Manufacturing Employment	2.2	1.2	0.6	-0.7
▪ SIC[a] 20—Food and Kindred Products	1.3	-0.2	-0.1	-0.4
▪ SIC 24—Lumber and Wood Products	1.0	0.8	-2.2	0.0
▪ SIC 26—Pulp and Paper Products	0.3	0.9	0.5	-0.1
▪ SIC 28—Chemicals and Allied Products[b]	-0.1	1.6	1.7	-0.2
▪ SIC 33—Primary Metals	2.9	0.3	-2.4	-4.6
▪ SIC 35—Non-electric Machinery	6.3	2.8	1.8	-1.4
▪ SIC 36, 38 Electrical Equipment and Instruments	9.0	2.2	3.0	0.0
▪ SIC 3—Transportation Equipment	2.3	1.1	2.8	-0.1
▪ Other Manufacturing	3.4	1.0	1.4	-0.1
Non-manufacturing Employment	3.2	2.5	1.9	2.5
▪ Mining	1.2	1.6	-1.5	-2.8
▪ Construction	4.2	2.2	-0.8	1.7
▪ Transportation, Communication and Utilities	1.8	1.5	1.0	1.1
▪ Wholesale and Retail Trade	4.2	3.1	2.2	2.5
▪ Finance, Insurance and Real Estate	5.4	3.4	1.4	3.2
▪ Services	5.7	4.5	4.3	4.6
▪ Government	3.7	3.5	1.3	1.2

[a] Standard Industrial Classification (SIC) code is the classification of industries used in federal statistics. See Appendix 5-B, Table 5-B-1 for list.

[b] Change in classification of a facility in the region to chemicals has artificially raised the rate of growth from 1979-1989. Excluding this facility in the 1989 data would yield a growth rate of 0.8 percent.

Major Trends

There are a number of basic trends common to the range of forecasts. While the extent of change resulting from these trends varies somewhat in each forecast, it nevertheless forms a context for the future. Many of the trends relate to demographic patterns in the existing population.

One of the primary demographic changes that continues to occur is the aging of the population. From 1989 to 2010, the national population between 50 and 59 years of age is projected to increase more than 85 percent, while the population between the ages of 25 and 34 is projected to decline by more than 10 percent. The population over the age of 60 is projected to increase by 34 percent during this period. Figure 5-1 shows the percentage change in population by age group for the nation from 1989 to 2010. Although the age composition of the population in the region will vary among scenarios because of migration, the general patterns of demographic change will persist.

This aging of the population is expected to affect consumption patterns, the labor force, and labor productivity. Consumption patterns are expected to emphasize personal services, clothing, travel and health services, as the older population increases in size. Over the next 20 years, the number of young people entering the labor force will increase at a slower rate than historically. From 1989 to 2010, the population aged 15 to 24 is projected to increase at an average annual rate of only 0.5 percent, compared to the period from 1970 to 1980 when the population in this age group increased at an average annual rate of 1.8 percent. This is the primary reason that the labor force is projected to increase at a slower rate over the next 20 years. The tightening labor supply will put upward pressure on wages. Producers will seek to substitute capital for labor, which tends to increase productivity or output per employee. In addition, the rapid pace of technological change and continuing pressure of international competition will stimulate capital investment as well.

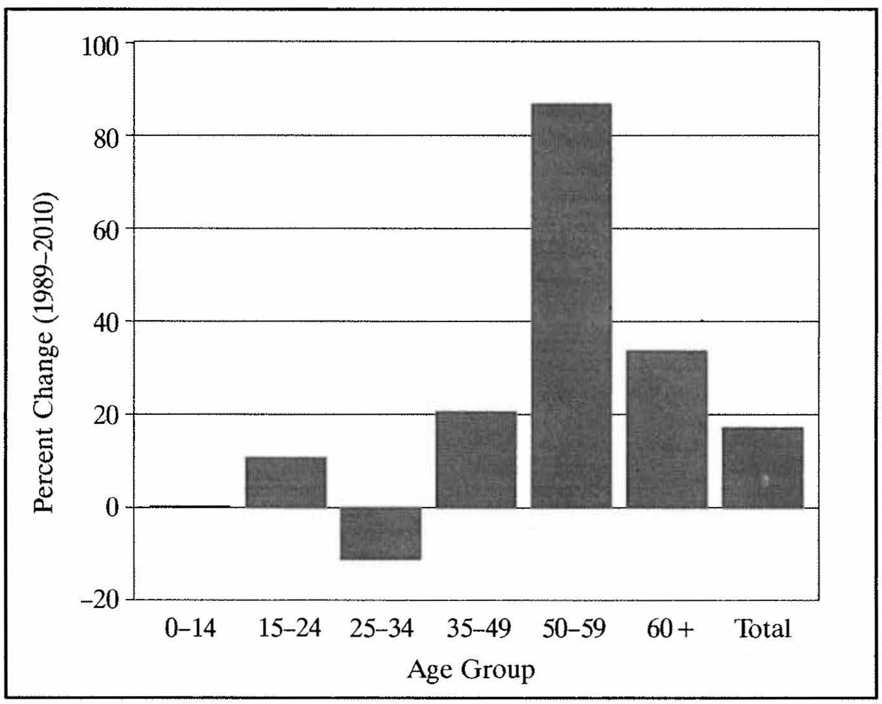
A second major trend is the increase in the proportion of women in the labor force. From 1960 to 1989, the female labor force participation rate increased from 37 percent to 57 percent. This trend is expected to continue to varying extents over most of the forecast range. This is reflected in the increase in the proportion of the population that is employed. The employment to population ratios are shown in Table 5-4.

Growth in the importance of non-manufacturing industries is projected in each of the forecasts. Traditionally, studies of regional economic growth have focused on the manufacturing industries. Recently, the non-manufacturing industries have attracted more attention because of their size and rapid growth. In 1989, non-manufacturing industries accounted for 83.7 percent of total employment in the region. Non-manufacturing employment increased at a rate nearly 70 percent higher than manufacturing employment from 1960 to 1979.

The outlook is strong for industries such as communications and machinery that will play a key role in growing technological changes and productivity-enhancing investments. The foreign trade sector is expected to continue to increase in importance. The Pacific Northwest is well positioned to participate in trade to the Pacific Rim countries, and that possibility is assumed to be an important component of the higher-growth forecasts.

Population Change

Figure 5-1
Percent Population Change by Age Group U.S. 1989-2010



Slower growth of the region's large resource-based industries characterizes all of the forecast range. Lumber, paper and food products are not expected to be important sources of economic growth for the region, even in the high forecasts. As shown in Table 5-4, these industries account for a smaller proportion of manufacturing employment in all scenarios than in 1989.

Table 5-4
Comparison of 1989 and 2010

		2010				
	1989	High	Medium-High	Medium	Medium-Low	Low
Persons per Household	2.53	2.20	2.31	2.31	2.31	2.55
Employment/Population Ratio	0.45	0.51	0.49	0.47	0.46	0.45
Percent of Total Employment	100.0	100.0	100.0	100.0	100.0	100.0
▪ Manufacturing	16.3	12.7	12.6	12.4	11.0	10.3
▪ Non-manufacturing	83.7	87.3	87.4	87.6	89.0	89.7
Percent of Manufacturing	100.0	100.0	100.0	100.0	100.0	100.0
▪ Lumber and Wood Products	20.0	13.0	13.9	14.1	15.7	16.6
▪ Transportation Equipment	21.8	20.2	19.3	18.4	16.6	15.5
▪ Food and Kindred Products	11.8	9.8	10.2	10.6	11.7	12.4
▪ Electronics (SIC 35, 36, 38)	15.9	22.0	21.2	20.8	21.1	21.4
▪ Pulp and Paper Products	4.6	3.4	3.7	4.0	4.9	5.3
▪ Other	25.9	31.7	31.8	32.0	29.8	28.8
Percent of Non-manufacturing	100.0	100.0	100.0	100.0	100.0	100.0
▪ Agriculture	8.5	4.8	5.3	5.5	5.6	5.8
▪ Mining	0.3	0.3	0.3	0.2	0.2	0.2
▪ Construction	5.1	4.5	4.7	4.4	4.3	4.4
▪ Transportation, Communication and Public Utilities	5.9	4.6	4.6	5.0	5.0	4.9
▪ Wholesale and Retail Trade	27.6	29.6	29.8	29.3	29.1	28.7
▪ Finance, Insurance and Real Estate	6.3	7.1	6.9	6.6	6.4	6.1
▪ Services	25.5	30.4	29.5	30.6	30.7	30.8
▪ Government	20.7	18.8	19.0	18.5	18.8	19.1

Description of the Scenarios

The economic assumptions rely on basic policy assumptions, many of which operate at the national level. Each of the five regional economic forecasts was made within the context of a corresponding view of the national economy. Forecasts developed by the WEFA Group were the primary source of national economic variables used in developing regional projections.

Certain results of the national forecasts are included directly in the regional forecasts. These include inflation rates, interest rates, industry-specific productivity growth, and basic demographic patterns. Other assumptions create a greater variation in the regional forecasts than in the national forecasts, however. These include wider fuel price ranges, regional shares of national employment growth by industry, and specific assumptions about the viability of the regional aluminum industry.

In developing the scenarios, it is important to recognize the wide range of possible outcomes for the regional economy. A short-term view of the future was rejected in favor of developing scenarios that would encompass a wide range of uncertainty about the region's economy in the long run. The high case presents quite a different future for the regional economy than the low case. For example, there are 50 percent more jobs in the region in the high case than in the low case by the year 2010.

In addition to an underlying high-growth scenario on the national level, the regional outlook for the high-growth case implies that the region's economy fares better, relative to the nation, than it has in the past. The large resource-based industries, such as forest products, aluminum, agriculture and basic chemicals, maintain a vital presence in the region's economy but are not expected to contribute to new jobs. In the high case, employment in lumber and wood products is projected to decline 10 percent from 1989 to 2010. Other resource-based industries show no increase in jobs. On the other hand, industries such as electronics, trade and services expand rapidly, nearly doubling their employment in 20 years. As shown in Table 5-1, total employment is projected to increase 2.8 percent per year, which is similar to the rate of growth sustained by the region from 1960 through 1980. Population is projected to grow 2.1 percent per year, while households grow 2.8 percent per year. The following conditions are assumed for the high case. The region will continue to be a favorable location for growth, because of: 1) the richness and diversity of its natural resources; 2) the quality of the environment and labor force; 3) the quality of the educational system; 4) relatively lower electricity prices; and 5) proximity to expanding markets in Japan and other Pacific Rim nations.

In the medium-high scenario, rapid growth in high-technology and commercial industries is coupled with moderate levels of activity in forest products, agriculture and basic chemicals. Employment in non-manufacturing industries increases nearly 60 percent. These changes result in employment growth of 2.0 percent per year, and population and household growth of 1.6 and 2.0 percent per year, respectively. Although the overall level of employment growth in the medium-high scenario is slower than the region experienced in the 1960s and 1970s, it still represents a case in which employment growth is one-third faster than national growth in the high case.

In the medium-low growth forecast, traditional industries experience low levels of economic activity, while other manufacturing and commercial industries experience moderate growth levels. Employment in lumber and wood products is projected to decrease by one third. The region continues to increase its share of employment in electronics and non-manufacturing industries, however. Total employment is projected to increase 1.1 percent per year, with population and households increasing 1.0 percent and 1.5 percent per year, as shown in Table 5-1. In the medium-low scenario, employment growth is as slow as national growth in the low case.

The regional outlook for the low case shows very slow growth in total employment over the 20-year forecast horizon. In this scenario, the region plunges into a deep recession in the early 1990s, which is followed by a slow recovery. Manufacturing continues to decline throughout the forecast period. Growth in non-manufacturing is partially offset by declines in many of the larger, traditional industries. Employment in aerospace is projected to decline by almost 50 percent. Total population and households are both projected to increase 0.7 percent per year. This slow level of growth implies net outmigration of population throughout the forecast period.

Employment and Production

Lumber and Wood Products

In 1989, the regional wood products industry accounted for 44 percent of U.S. softwood lumber production and 36 percent of U.S. softwood plywood production. The bulk of production in the region—more than half of lumber production and 70 percent of the softwood plywood production—occurred in Oregon. Furthermore, a large proportion of production in both Oregon and Washington is west of the Cascades. The lumber and wood products industry is the second largest manufacturing industry in the Pacific Northwest, accounting for 20 percent of manufacturing jobs in 1989.

In recent years, the industry has experienced wide swings in production and employment levels. A major factor contributing to volatility in this industry is new housing. New housing accounts for 40 percent of the market for lumber and wood products. Figure 5-2 is a graph showing U.S. housing starts, Pacific Northwest lumber production, and plywood production for 1960 to 1989. The graph shows that regional lumber and plywood production follows a cyclical pattern similar to U.S. housing starts.

Other factors affecting lumber and plywood demand include housing types, average housing unit size, growth in other end uses for lumber and plywood, and international demand. An average-sized single-family unit uses approximately three times as much lumber and wood products as a multifamily unit. From 1970 to 1974, the average share of single-family units to total units was 58 percent. This share increased to 73 percent for the years 1975 to 1979. The share of single-family units is affected by the cost of housing and demographic factors. An area of growing demand for lumber and plywood in the last few years has been in repair and remodeling use. Currently, repair and remodeling account for close to 40 percent of U.S. lumber consumption. The value of the dollar compared to other currencies has an impact on exports of lumber and wood products. Dramatic increases in exports through Northwest ports have occurred over the last few years. Industry and government groups have escalated their efforts to increase exports through marketing programs in recent years as well.

The region's lumber industry has experienced increasing competition from lumber-producing areas in the southeastern United States over the last several decades. Higher transportation, labor and stumpage costs have made it difficult for the Northwest to retain its historical market shares. Northwest lumber mills have responded by seeking lower wage rates and taking steps to improve labor productivity. Although production levels in the late 1980s broke previous records established in the 1970s, employment was nearly 20 percent lower in 1989 than in 1979. In spite of cost cutting, Northwest production costs remain higher than costs faced by Southeastern competitors.

In the Southeast region, timber resources are owned primarily by the forest products industry and other private parties. The timber harvest can respond to fluctuations in demand, relieving pressure on stumpage prices. In addition, the tree growth cycle is faster in the Southeast—approximately 35 years compared to 50 years in the Northwest. In the Northwest, the federal government owns more than half of the commercial timberlands. Timber resources under the management of the U.S. Forest Service are governed by laws limiting cuttings to a level that may be maintained over the long term.

In the Northwest region, controversy over the future of old-growth forests and survival of species such as the northern spotted owl contribute to the uncertainty about future timber availability from federal lands. Other factors that add to the uncertainty of future timber resources include natural disasters, improvement of timber management techniques, and changes in wilderness or recreational designations, to name a few.

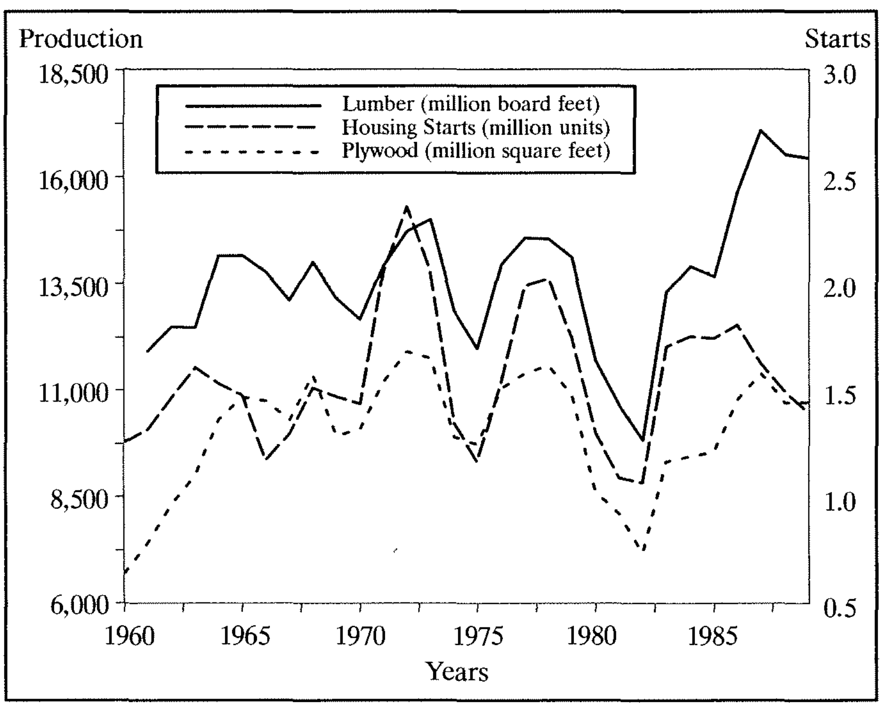
Southeast timber resources are also subject to several uncertain factors. Recent studies show that more privately held timberlands in the Southeast are being lost to other uses, such as agriculture or urban development, than previously thought. New studies indicate that southern timber inventories will soon begin to decline. In addition, the intensity of management applied by non-industry private timber owners is subject to uncertainty.

The Northwest wood products industry also faces competition from Canadian producers. Canadian producers increased their share of the U.S. market rapidly in the late 1970s and early 1980s. U.S. producers prevailed in a dispute involving Canadian government subsidies to private companies, which resulted in a 15-percent export tax on Canadian lumber destined for the United States.

Competition to the region's plywood industry is provided by the introduction of low-cost substitute products. The substitutes include products such as waferboard and oriented strandboard. These products are fabricated from faster-growing trees and waste chips. Their main cost advantage is the use of lower-cost materials. Although there are mills currently in the region or under consideration that produce these products, most of the plants producing waferboard and oriented strandboard are expected to be located in other regions of the country.

Lumber and Plywood Production

Figure 5-2
Comparison of Pacific Northwest Lumber and Plywood Production with U.S. Housing Starts 1960–1989



As the region enters the 1990s, a number of timber supply issues are unresolved. The region is faced with a declining private timber supply, a legacy of harvesting practices of 50 and 60 years ago. In addition, the supply of public timber is declining because of competing uses of public forests and concerns regarding old-growth timber.

The U.S. Fish and Wildlife Service determined in June of 1990 that the northern spotted owl was a threatened species. A federal interagency team of scientists developed a proposal, known as the Jack Ward Thomas report, to prevent the extinction of the spotted owl. Congressional and administrative committees are exploring other alternatives as well. These issues will not be resolved in the near future, as timber interests and environmental interests are sure to carry on the disputes for years.

The reductions in lumber processing from spotted owl set-asides may be partially offset by recently enacted federal legislation that allows states to restrict the export of logs from state-owned lands. This issue also remains unresolved.

The production forecasts presented in this paper are based on recent U.S. Forest Service forecasts. The Forest Service projects demand and supply from the timber-producing regions in the United States to the year 2030. The medium case is based on new Forest Service management plans, with adjustments to reflect old-growth set-asides to protect the spotted owl on federal lands similar to preliminary estimates of the impacts of implementing the Jack Ward Thomas report.

There is a great deal of uncertainty regarding the outcome of spotted owl protection efforts on timber harvests. The ranges around the medium case reflect this. In all the scenarios, production decreases from current levels until the turn of the century. A greater supply of private timber becomes available beginning then as the improved management techniques on private lands over the past few decades begin to bear fruit.

Changes in output per employee are used to convert production forecasts into employment. Production, employment and output-per-employee forecasts for the lumber and wood products industry are shown in Table 5-5.

Pulp and Paper

The pulp and paper industry is the second largest industrial consumer of electricity in the region. In 1989, firms producing pulp and paper products accounted for 20 percent of the electricity consumed by industry as a whole. The pulp and paper industry employed 29,800 people in 1989.

In the Northwest, most of the raw material used in the pulp-making process is wood chips, a byproduct from lumber and plywood plants. Availability and cost of wood chips in the future will operate as a deterrent on capacity expansion in this region. Restrictions on timber supply may lead to lower levels of lumber and plywood production. In addition, lumber and plywood mills have improved the yield from each log. These trends lead to less available log residue for use in pulp and paper production. Another factor has been the growth of the export market for chips.

The long-term outlook for the Pacific Northwest industry is favorable with regard to proximity to markets in the West and in the Pacific Rim. Other factors, however, including fiber availability and comparative production costs (such as the cost of labor), compare less favorably to the Southeastern producing areas. The Northwest's advantage in electricity costs has decreased to some extent as a result of large increases in electricity rates since 1979. Not only are electricity costs a major portion of direct operating costs, but electricity prices also affect the costs of chemicals used in the bleaching process. Chlorine and caustic soda are produced through an electrolytic process, which is highly electricity intensive.

Nationally, the demand for paper products is expected to be strong, with paper holding its own against petroleum-based plastic products. In addition, the Northwest has the largest inventory of preferred long-fiber softwoods, and access to ports to serve world markets.

The production forecasts for the primary production categories of pulp (SIC 2611), paper (SIC 2621) and paperboard (SIC 2631) were based on staff analysis and on work performed by Ekono, Inc., for Bonneville. Ekono supplied Bonneville with a range of projections by industry for the region, based on its analysis of fiber availability and cost compared to other regions.[2] Bonneville and Council staff reviewed historical trends and modified the forecasts to reflect comments from the Economic Forecasting Advisory Committee. Forecasts for regional production, employment and productivity growth in the pulp and paper industry are shown in Table 5-6.

In addition to primary products, the pulp and paper industry includes the production of miscellaneous converted paper products (SIC 264), paperboard containers and boxes (SIC 265), and building paper and board mills (SIC 266). These categories include the manufacture of bags, boxes and containers, writing paper, tissue paper and building board at sites where primary products are not produced. Industries within these categories locate close to population centers. The employment forecasts are shown in Table 5-6.

2. Ekono, Inc. *A Study to Review and Update Production and Energy Consumption Data for the Pacific Northwest Pulp and Paper Industry*, Report No. 02340. Submitted to the Bonneville Power Administration. August 20, 1990.

Table 5–5
Lumber and Wood Products Forecasts 1989–2010

	Production 1989	Production 2000	Production 2010	Average Annual Rate of Growth (%) 1989–2010
Lumber (SIC 2421) (billion board feet)				
High		15.4	17.4	0.3
Medium–High		14.1	15.9	–0.1
Medium	16.4	12.8	14.5	–0.6
Medium–Low		11.6	13.0	–1.1
Low		10.3	11.6	–1.6
Plywood (SIC 2436) (billion square feet)				
High		7.7	8.5	–0.6
Medium–High		7.1	7.8	–1.0
Medium	9.6	6.4	7.1	–1.4
Medium–Low		5.8	6.4	–1.9
Low		5.2	5.7	–2.5

	Employment (thousands)					
		2010				
	1989	High	Medium–High	Medium	Medium–Low	Low
Lumber (SIC 2421)	47.9	42.7	40.7	37.0	33.3	29.6
Plywood (SIC 2436)	19.0	12.4	12.1	11.0	9.9	9.1
Other SIC 24	63.8	61.9	53.7	48.3	45.1	41.1
Total SIC 24	130.7	117.0	106.4	96.3	88.3	79.8

	Output per Employee—Average Annual Rate of Growth (%) 1989–2010				
	High	Medium–High	Medium	Medium–Low	Low
Lumber (SIC 2421)	0.8	0.6	0.6	0.6	0.6
Plywood (SIC 2436)	1.8	1.5	1.5	1.5	1.3
Other SIC 24	1.6	1.4	1.0	1.0	1.0

Chemicals

The manufacture of chemicals consumes approximately 11 percent of the electricity purchased by the industrial sector in the region. Elemental phosphorus production accounts for approximately half of the electricity consumed by the chemicals industry, followed by chlorine and caustic soda, which accounts for approximately 20 percent. In the Council's forecasting models, the consumption of electricity by these two industries is modeled on a plant-by-plant basis. Two of the chlorine and caustic soda plants are direct services industries (DSIs) of Bonneville.

The remainder of the chemicals industry in the region is dominated by nuclear fuels processing and agricultural chemicals (such as fertilizers). The nuclear fuels processing component has exhibited large swings in employment, as policies of the federal government have changed over the last 20 years. The agricultural chemicals component increased at a steady rate in the 1970s, but it has experienced little growth recently.

Table 5–6
Pulp and Paper Products (SIC 26) Forecasts 1989–2010

Industry	1989	High	Medium–High	Medium	Medium–Low	Low
		Production—Average Annual Rate of Growth (%) 1989–2010				
Pulp (SIC 2611)		1.8	1.3	0.8	0.4	0.0
Paper (SIC 2621)		2.9	2.4	1.9	1.4	0.9
Paperboard (SIC 2631)		2.5	2.0	1.5	1.0	0.5
		Employment (thousands) 2010				
	1989	High	Medium–High	Medium	Medium–Low	Low
Pulp (SIC 2611)	2.4	2.1	1.9	1.8	1.7	1.6
Paper (SIC 2621)	12.9	13.4	12.6	12.4	11.2	10.6
Paperboard (SIC 2631)	5.4	5.0	4.7	4.7	4.2	4.0
Other Paper (SIC 26XX)	9.1	9.7	8.7	8.1	8.1	7.1
Total SIC 26	29.8	30.2	28.0	27.0	25.2	23.3
		Output per Employee—Average Annual Rate of Growth (%) 1989–2010				
		High	Medium–High	Medium	Medium–Low	Low
Pulp (SIC 2611)		2.7	2.6	2.4	2.4	2.2
Paper (SIC 2621)		3.0	2.8	2.4	2.4	2.2
Paperboard (SIC 2631)		3.0	2.8	2.4	2.4	2.2

Chlorine and caustic soda are produced at five plants in the region, four located in Washington and one in Oregon. Nationally, over half of the chlorine produced is used within the chemicals industry to manufacture a variety of organic and inorganic chemicals. An additional 13 percent is used by the pulp and paper industry as a bleaching agent in the production of paper. In the Pacific Northwest, a much larger portion of production goes to the pulp and paper industry varying from 32 percent to 80 percent, depending on the plant and temporary shifts in market conditions. Two of the five plants in the region are owned by pulp and paper companies.

The manufacture of chlorine and caustic soda involves the electrolytic separation of salt into two co-products: chlorine and sodium as sodium hydroxide (caustic soda). Approximately 1.12 pounds of caustic soda are produced per pound of chlorine.

The market outlook for the two products differs substantially. In the past, chlorine has held the stronger market and higher price. Expansion plans were based on growth in chlorine demand. As little as 10 years ago, caustic soda was considered an undesirable "byproduct," and for years producers sought to develop a commercial process to produce chlorine without producing caustic soda. In the last few years, the price of caustic soda has risen and supplies have tightened, while chlorine demand has dropped and prices have remained stable.

Industry experts have predicted growth rates for national chlorine demand to range from an average of 1 percent to 3 percent per year, whereas demand for caustic soda could increase at rates ranging from 2.5 percent to 5 percent. This is slower than the rate of growth in production from 1960 to 1980, which averaged 4.1 percent per year. From 1970 to 1980, however, production increased at an annual rate of only 1.6 percent. The outlook for chlorine has been affected by environmental regulations on effluent standards. Pulp and paper producers may substitute other chemicals in pulp bleaching to reduce dioxins. The outlook for caustic soda is much more favorable because it has a broader base of end uses. One of the fastest growing end uses is in the neutralization of waste acids. Tougher environmental standards would enhance the outlook for caustic soda. Soda ash can be substituted for caustic soda, and although the initial investments required to handle soda ash are high, projections of relative price increases for caustic soda and soda ash favor some conversion to soda ash. Production of chlorine and caustic soda is likely to be constrained by the price of chlorine because chlorine is more difficult to store.

Although not all of the chlorine produced in the region is sold to pulp and paper producers, growth in the production of paper (SIC 2621) was chosen as a reasonable indicator of chlorine and caustic soda production growth. The projections presented here are within the range of projections for national production cited in the preceding paragraphs. Comparison of the production growth rates for chlorine and caustic soda and paper (SIC 2621) shows that the range of forecasts are very similar. Table 5-7 shows projections of production for chlorine and caustic soda, SIC 2812.

Elemental phosphorus production is located in only four states (Idaho, Florida, Montana and Tennessee), near deposits of phosphate rock. Elemental phosphorus is extracted from phosphate rock in electric furnaces, and frequently converted nearby to phosphoric acid and other compounds.

Elemental phosphorus plants are classified under industrial inorganic chemicals, not elsewhere classified (SIC 2819). In the Northwest, firms producing elemental phosphorus, nuclear fuel, corn starch, chemical catalysts and a variety of other products are classified under SIC 2819. About half of the nation's total elemental phosphorus production capacity is located in the Northwest. Of this, 85 percent of capacity is located in Idaho, with the remainder in Montana.

The major end-use markets for elemental phosphorus are cleansers and detergents (45 percent), food and beverages (15 percent), metal treating (10 percent) and other chemicals and cleansers (30 percent). The outlook for elemental phosphorus production in the Northwest depends, in part, on the demand for these products.

The detergent market has been projected to remain stable or increase slightly over the forecast period, with growth rates ranging from 0 percent to 1 percent per year. Non-detergent uses, such as food and beverage products and other uses, have been forecast to increase at rates of 1.4 percent to 2.4 percent per year.

The problems facing elemental phosphorus producers in the region include the cost and availability of electricity and the maturity of their markets. The costs of additional electricity beyond current contracted amounts may lead to no expansion in capacity over the forecast period. This was assumed to be the case for the low scenario. The high-case projection is a weighted average of the higher ranges of forecasts for detergent and non-detergent uses of elemental phosphorus. Projections of production are shown in Table 5-7.

The residual category for chemicals (SIC 28XX) includes a wide variety of products manufactured in the region. The larger groups in employment and energy use are the nuclear engineering, fuels and waste processing segments, and agricultural chemicals (primarily fertilizers and pesticides). There also are many other types of chemical products manufactured in the region. The forecasts for the other chemicals category are shown in Table 5-7.

Table 5-7
Chemicals Industry Production Forecasts—Average Annual Rate of Growth (%) 1989-2010

	Production				
Industry	High	Medium-High	Medium	Medium-Low	Low
Chlorine and Caustic Soda (SIC 2812)	3.1	2.3	1.6	1.6	0.9
Elemental Phosphorus (SIC 2819)	1.4	0.8	0.3	-0.2	-0.2
Other Chemicals (SIC 28XX)	3.0	1.9	0.9	0.4	-0.7
	Output per Employee				
Industry	High	Medium-High	Medium	Medium-Low	Low
Chlorine and Caustic Soda (SIC 2812)	3.0	2.2	1.5	1.5	1.5
Elemental Phosphorus (SIC 2819)	1.5	1.0	1.0	1.0	1.0
Other Chemicals (SIC 28XX)	2.5	2.0	1.3	1.0	0.3

The forecast range for the region can be compared to national forecasts for the chemicals industry. The WEFA Group's forecasts for chemicals range from 1.9 percent to 3 percent growth in output from 1989 to 2010. The forecasts for the region are lower because of the slower growth forecast for the agricultural chemicals and the nuclear fuels processing segments of the regional industry.

Agriculture and Food Processing

Over the past decade, agriculture has adjusted to changes in the national economy, federal programs and international markets. Northwest agriculture and food markets are increasingly national and international. Increasing sales of farm products from the Midwest and Northeast to large East Coast markets has put more pressure on Northwest producers to sell overseas, primarily in the Orient. A comprehensive study of Northwest agriculture concluded that if Northwest agriculture is to experience reasonable growth, it must continue to develop foreign markets. Regional agriculture has been fairly successful in doing so.

Agricultural production supports a large food processing industry. In 1989, 76,900 persons were employed in food and kindred products (SIC 20), which represented nearly 12 percent of regional manufacturing jobs. Activity in this industry is concentrated in frozen and canned fruits and vegetables (SIC 203), which accounted for nearly half of the employment in food and kindred products and over half of food processing electricity consumption. Processed potatoes are the major products in this category, accounting for over half of the value added in the regional food processing industry. Another portion of the industry important to coastal areas is the seafood canning and freezing industry. Poor commercial fishing conditions have closed a number of these plants.

The outlook for employment in frozen and canned fruit and vegetable products relies on future demand for processed foods in the United States and Pacific Rim countries. Changes in consumer lifestyle and preferences have prompted the industry to seek specialized market niches. Most food manufacturers have implemented practices to increase the efficient use of labor, management and energy. These changes have become permanently incorporated into the industry structure and are important in the forecasts.[3] The projections of employment and output in food processing for the region are shown in Table 5-8. Only the high and medium-high cases show an increase in regional food processing employment.

The High-Technology Industries

A great deal of attention has been focused recently on the high-technology industries. State and local governments in the United States and national governments around the world have initiated studies and programs designed to understand and attract economic development by encouraging growth in high-technology industries. In past years, the growth of electronics and software firms has been heralded by some as a panacea for stagnation in some of the region's resource-based industries.

The first step in a discussion of high-technology industries is to define the group of industries to be discussed. Several methods of defining high technology have been proposed, but there is no general agreement on which definition is the most appropriate. To a certain extent, the nature of technology-intensive activity makes definition difficult, because the industries are changing so rapidly. New industries are created and others become obsolete, thus causing any definition of high-technology industries to be tied to a particular point in time.

3. Wilkins, John; Stenberg, Cynthia; Farah, Mark; and Burge, Marilyn; Bonneville Power Administration. *Food Processing, SIC 20*. August 1989.

Table 5-8
Food Processing Forecasts 1989-2010

	Employment (thousands)		Average Annual Rate of Growth (%) 1989-2010	
	1989	2010	Employment	Output
High		87.9	0.6	4.4
Medium-High		78.6	0.1	3.7
Medium	76.9	72.5	-0.3	3.3
Medium-Low		65.9	-0.7	2.8
Low		59.6	-1.2	2.2

Most definitions have looked at one or a combination of three factors: research and development expenditures as a proportion of value added, the percentage of scientific and technical personnel in industry employment, and product sophistication. The definition described in this chapter was adopted from a Battelle study[4] for the state of Washington and reflects a combination of all three factors. The Battelle study included a number of chemical industries in its definition of high-technology industries. These industries were excluded from the definition of high-technology industries used in this chapter. The chemical industry forecasts have been discussed in a previous section. The modified list of industries included in the high-technology groups and their SIC codes are shown in Table 5-9.

Even at the level of industry detail shown in Table 5-9, it is difficult to categorize industries as high-technology industries. At more detailed levels of categorization, however, data are not available to analyze the industries because of disclosure laws that protect companies' rights to proprietary information. In the United States, the industries listed in Table 5-9 comprised approximately 5.0 percent of total wage and salary employment in 1987, compared to 5.7 percent for the region. The high-technology share of total employment was 7.6 percent in Washington, 4 percent in Oregon, 4.5 percent in Idaho and 0.5 percent in Montana.

4. Battelle Seattle Research Center. *High Technology Employment, Education and Training in Washington State.* June 1984.

Table 5-9
High-Technology Industries

SIC Code	Industry Name
	Machinery
351	Engine and Turbines
357	Office, Computing and Accounting Machines
	Electrical Equipment
361	Electric Transmission and Distribution Equipment
362	Electrical Industrial Apparatus
365	Radio and Television Receiving Equipment
366	Communication Equipment
367	Electronic Components and Accessories
369	Miscellaneous Electrical Machinery
	Transportation Equipment
372	Aircraft and Parts
376	Guided Missiles and Space Vehicles and Parts
	Professional Instruments
381	Scientific Instruments
382	Measuring and Controlling Instruments
383	Optical Instruments
384	Medical and Dental Instruments
386	Photographic Equipment and Supplies
	Business Services
737	Computer and Data Processing Services
7391	Research and Development Laboratories

In 1987, high-technology industries employed 158,700 persons in the region, with approximately 43 percent of the employment concentrated in the transportation equipment category. The second largest category was electrical equipment, with 20.5 percent, followed with 15.8 percent of high-technology employment. Table 5-10 shows employment in 1987 by state for the major high-technology groupings.

The aerospace industry in the region is dominated by The Boeing Company, which has production facilities in Washington and Oregon. Aerospace employment in Washington has been extremely cyclical, dropping from 104,000 in 1968 to 40,000 by 1971. In 1981, it reached a level of 80,900, only to drop to 65,000 by 1983. From 1983 to 1989, aerospace employment increased more than 70 percent to 113,700.

From 1970 to 1987, the high-technology industries increased employment at an average annual rate of 3.4 percent. This compares to a national growth rate of 2.1 percent over the same period. Removing aerospace from the calculation shows that non-aerospace, high-technology employment increased at an average annual rate of 11.5 percent in the region, compared to a national rate of 2.4 percent.

The factors often cited as favorable for the region's growth in high technology include the quality of the region's labor force, available land, good educational facilities and an environment suitable for maintaining a high quality of life. A survey of high-technology companies regarding location factors was completed by the Congressional Joint Economic Committee in 1982. The results are shown in Table 5-11. The existing concentration of firms in the region also testifies to the importance of spin-off activity from Pacific Northwest firms and California firms.

Table 5-10
Employment in High-Technology Industries 1987

	United States	Pacific Northwest	Washington	Oregon	Idaho	Montana
Machinery (SIC 351, 357)	462,500	12,400	4,800	4,600	3,000	0
▪ Percent of High-Tech	10.8%	7.8%	4.3%	12.9%	26.3%	0.0%
Electrical Equipment (SIC 361, 362, 365, 366, 367, 369)	1,679,300	32,500	17,500	11,300	3,400	300
▪ Percent of High-Tech	39.2%	20.5%	15.8%	31.7%	29.8%	27.3%
Transportation Equipment (SIC 372, 376)	815,100	67,900	65,700	2,200	0	0
▪ Percent of High-Tech	19.0%	42.8%	59.4%	6.2%	0.0%	0.0%
Professional Instruments (SIC 381, 382, 383, 384, 386)	562,800	20,750	7,800	12,200	500	250
▪ Percent of High-Tech	13.1%	13.1%	7.1%	34.3%	4.4%	22.7%
Business Services (SIC 737, 7391)	766,600	25,150	14,800	5,300	4,500	550
▪ Percent of High-Tech	17.9%	15.8%	13.4%	14.9%	39.5%	50.0%
Total High-Tech	4,286,300	158,700	110,600	35,600	11,400	1,100
Percent of Total Employment	5.0%	5.7%	7.6%	4.0%	4.5%	0.5%
Total Employment	85,483,800	2,805,500	1,464,600	883,400	253,300	204,200

SOURCE: U.S. Census Bureau. *County Business Patterns*. 1987. The employment figures shown in this table are based on a survey of employment during the pay period including March 12. As such, they are not comparable to annual average data used in other segments of this report. They are used for illustration purposes here because they are available at the level of industry detail needed for all states.

Table 5-11
Factors that Influence Regional Location of High-Technology Companies

Factor	Percentage of Firms Citing Factors as Significant or Very Significant
Labor Skills and Availability	89.3
Labor Costs	72.2
Tax Climate	67.2
Academic Institutions	58.7
Cost of Living	58.5
Transportation	58.4
Access to Markets	58.1
Regulatory Practices	49.0
Energy Costs and Availability	41.4
Cultural Amenities	36.8
Climate	35.8
Access to Raw Materials	27.6

NOTE: Firms were asked to rate each factor as very significant, significant, somewhat significant, or not significant.

SOURCE: United States Congress, Joint Economic Committee. *Location of High Technology Firms and Regional Economic Development.* June 1982, p. 23. Battelle Seattle Research Center. *High Technology Employment, Education and Training in Washington State.* June 1984.

The factors often cited as unfavorable for the region's growth in high-technology industries include high labor costs, unfavorable tax policies, and complex regulatory practices that make it difficult to expand or locate facilities. There is also some question as to the region's commitment to improving or maintaining the quality of its educational systems in light of tax revolts and state and local budget crises. Many states and cities in the United States are competing aggressively to attract high-technology industries. Some areas of the country, such as New England and North Carolina's Research Triangle Park, enjoy advantages in their traditions of high-quality academic institutions.

Forecasts of employment for high-technology industries are shown in Table 5-12. The table shows forecasts for industries at the two-digit SIC level, which includes some businesses that are not classified as high-technology industries. Electrical equipment and professional instruments are the only categories in which nearly all of the employment is in the high-technology category. In machinery and business services, only 32 percent and 19 percent, respectively, of the employment are in the high-technology industries.

The computer machinery category has been a rapidly growing sector of the machinery industry in the region. Much of the remainder of the machinery industry is farm, construction, logging and other heavy machinery. These categories are not forecast to grow rapidly.

Aerospace employment, which is dominated by the The Boeing Company, accounts for 80 percent of employment in the transportation equipment industry in the region. Commercial aircraft production represents the largest portion of production in the region. During the early 1980s, annual average employment in aerospace declined almost 20 percent. Commercial aircraft orders had dropped substantially because of low profits in the airline industry and declines in passenger miles. Since then, Boeing has increased employment over 70 percent as orders increased, in response to improvements in economic conditions and in the financial condition of airlines. Boeing's primary competition is Airbus Industrie, a European aircraft consortium.[5] The market for commercial aircraft is projected to be strong, although it will probably continue to be highly cyclical. Because employment in this category is dominated so much by one company, the forecasts encompass a wide range of uncertainty.

5. Yee, Dennis; Farah, Mark; Wood, Stephen; West, Peter; and Burge, Marilyn; Bonneville Power Administration. *Transportation Equipment, SIC 37.* August 1989.

Table 5-12
High-Technology Industry Forecasts—Annual Rate of Growth (%) 1989-2010

	Employment				
	High	Medium-High	Medium	Medium-Low	Low
Machinery (SIC 35)	3.1	2.0	1.3	0.5	-0.2
Electrical Equipment (SIC 36)	3.8	2.7	2.1	1.0	-0.2
Transportation Equipment (SIC 37)	1.2	0.2	-0.6	-2.0	-3.0
Professional Instruments (SIC 38)	2.2	1.5	0.9	0.3	-0.2
Business Services (SIC 73)[a]	5.0	3.9	3.5	3.3	3.0
	Output				
	High	Medium-High	Medium	Medium-Low	Low
Machinery (SIC 35)	7.7	6.4	5.6	4.7	3.8
Electrical Equipment (SIC 36)	8.0	6.9	6.2	5.0	4.0
Transportation (SIC 37)	3.9	2.7	1.8	0.4	-0.9
Professional Instruments (SIC 38)	6.5	5.5	4.8	4.2	3.5

[a] Forecasts of output are not developed for the non-manufacturing industries.

Other Manufacturing Industries

There are a number of smaller manufacturing industries that play a relatively minor role in employment and electricity use in the region. The largest of these industries include printing and publishing, fabricated metals, and stone, clay and glass products. Recently, printing and publishing employment has increased rapidly. This is largely because of growth in the demand for computer software manuals and industry changes spurred by advances in desktop publishing systems. The fabricated metals and stone, clay and glass industries are projected to grow slowly, in line with national trends. The forecasts for these industries are shown in Table 5-13.

Growth in Non-manufacturing Industries

The non-manufacturing industries account for most of the region's employment, 83.7 percent in 1989. Employment in non-manufacturing industries has grown faster in the last two decades than employment in manufacturing. Table 5-14 shows the shares of total employment by industry for the region and the United States. The largest category of non-manufacturing employment in the region is wholesale and retail trade, followed by services (which includes such industries as health care, business services and personal services). The third largest non-manufacturing industry is government.

Strong growth in the non-manufacturing sectors has occurred at the national level, as well as at the regional level. A larger proportion of manufactured goods is produced in other countries, which has had a negative impact on the proportion of employment in manufacturing. Productivity gains in the past have been higher in manufacturing industries, and this has lowered employment relative to output. However, computerization of some activities could lead to higher productivity gains in non-manufacturing.

A closer look at specific industries may add some insight into the growth in the non-manufacturing sectors.[6] The services industry was the fastest growing industry in the region from 1970 through 1987, increasing employment at 5.5 percent per year. In 1987, health services accounted for 33 percent of the region's employment in services. Employment in health services increased at an annual rate of 5.3 percent from 1970 through 1987. Growth in this sector resulted from the expansion of health-care benefits for workers and elderly people and growing public interest in personal health.

6. This discussion of non-manufacturing industries relies on data from *County Business Patterns.* The most recent year available for all four states was 1987. Please refer to Table 5-15 for further information.

Table 5-13
Other Manufacturing Industry Forecasts—Average Annual Rate of Growth (%) 1989-2010

	Employment				
	High	Medium-High	Medium	Medium-Low	Low
Printing and Publishing	3.4	2.7	2.4	1.2	0.5
Fabricated Metals	2.1	1.2	0.8	-0.5	-0.9
Stone, Clay and Glass	2.1	1.0	0.2	-1.1	-1.9
Petroleum	1.8	1.1	0.3	-2.5	-3.7
Textiles	1.6	0.4	-0.3	-1.0	-2.0
Apparel	2.5	1.2	0.7	-0.3	-1.4
Furniture	2.7	1.6	1.0	-0.4	-1.0
Rubber and Plastics	4.7	4.3	3.6	1.2	-0.1
Leather Products	1.9	0.9	0.3	-0.5	-2.3
Miscellaneous Manufacturing	2.8	1.7	1.1	-0.5	-2.5
	Output				
	High	Medium-High	Medium	Medium-Low	Low
Printing and Publishing	4.3	3.3	3.0	1.9	0.9
Fabricated Metals	4.2	3.1	2.7	1.4	0.8
Stone, Clay and Glass	5.1	3.7	2.9	1.5	0.4
Petroleum	5.2	4.2	3.5	0.5	-0.7
Textiles	5.9	4.4	3.6	3.0	1.7
Apparel	5.2	3.7	3.1	2.1	0.8
Furniture	5.5	4.3	3.5	2.1	1.3
Rubber and Plastics	7.7	7.0	6.2	3.9	2.4
Leather Products	2.5	1.3	0.7	-0.1	-2.1
Miscellaneous Manufacturing	5.6	4.4	3.8	2.3	0.1

The second largest service category—business services—accounted for 16 percent of the region's employment in services. This category was among the fastest growing sectors in services, increasing employment at an annual rate of 7.7 percent. This category includes a diverse group of industries, such as computer and data processing services, advertising agencies, building services companies and personnel agencies.

Although it only accounted for 3 percent of services employment in 1987, the legal services industry was the fastest growing of the services industries. Employment increased at an annual rate of 8.7 percent from 1970 through 1987.

Employment in construction increased 2.7 percent per year from 1970 through 1987. Even so, construction employment may exceed 1979 levels for the first time in 1990, as a result of slower population growth during most of the 1980s.

The finance, insurance and real estate sector increased employment at an average annual rate of 3.7 percent from 1970 through 1987. The most rapidly growing sectors in this industry were holding and investment offices and credit agencies (other than banks). Deregulation of the financial industry has led to the creation of a wide range of services and financial instruments offered by a diverse group of businesses. The competition has put a great deal of strain on financial institutions. This may result in an industry shakeout in the next few years, accompanied by slower employment growth.

Table 5–14
Total Employment Shares—United States and the Pacific Northwest—Percent of Total (%)

	Pacific Northwest		United States	
	1970	1989	1970	1989
Total Employment	100.0	100.0	100.0	100.0
Manufacturing	20.5	16.3	25.1	17.5
Non-manufacturing	79.5	83.7	74.9	82.5
▪ Mining	0.5	0.3	0.8	0.6
▪ Agriculture	9.0	7.1	4.3	2.9
▪ Construction	4.3	4.3	5.1	4.7
▪ Transportation and Public Utilities	6.2	4.9	5.8	5.1
▪ Wholesale and Retail Trade	20.6	23.2	20.7	23.1
▪ Finance, Insurance and Real Estate	4.6	5.3	5.0	6.1
▪ Services	14.3	21.3	16.0	24.1
▪ Government	20.0	17.3	17.1	15.9

Wholesale and retail trade accounted for the largest share of total employment in 1989, as shown in Table 5–14. Wholesale trade accounted for approximately one-fourth of employment in trade and increased at an annual rate of 2.6 percent from 1970 through 1987. Employment in retail trade increased at a rate of 3.7 percent per year during the same period.

Eating and drinking establishments accounted for 35 percent of employment in retail trade. This was also the fastest growing category of employment in retail trade, increasing at an annual rate of 6.0 percent from 1970 through 1987. The increase in household consumption of food away from home reflects the increase in household income and the increase in the participation of women in the labor force. In addition, a larger proportion of household budgets for persons aged 25 to 44 is spent on food away from home than for other groups. The rapid growth of persons in this age group during the past twenty years contributed to rapid growth in this sector. Because this age group is growing slower in the future than it has over the last 20 years, the rate of employment growth in this sector is expected to slow.

Other fast-growing retail-trade categories included clothing stores, food stores and miscellaneous retail stores, which includes specialty stores and mail-order houses. Employment in these categories increased at average annual rates slightly over 4 percent from 1970 through 1987.

The government sector was the third largest employment category in the region in 1989, as shown in Table 5-14. State and local government accounted for more than 80 percent of employment in government. From 1970 through 1987, employment in the federal government increased 1.1 percent per year, while state and local government employment increased 2.4 percent per year. Education accounts for the largest proportion of state and local government employment. The outlook for future employment changes in this sector depends on the level of population growth and policy decisions.

Employment in transportation, communications and public utilities increased at an annual rate of 2.5 percent from 1970 to 1987. The fastest growing category was transportation services, which include travel agencies, freight forwarding services, and shipping agents and brokers. Employment in transportation services increased at an average annual rate of 9.1 percent from 1970 to 1987. The largest categories of transportation and public utilities employment in 1987 were trucking and warehousing, and communication services, with 29 percent and 32 percent respectively. Trucking and warehousing employment increased at an average annual rate of 3.6 percent. Employment in communications increased at an average annual rate of 1.7 percent.

The discussion of non-manufacturing industries presented thus far has centered on industries as defined by the Standard Industrial Classification (SIC) system. Industries such as the travel industry and port activity are not separated from other economic data to allow historical analysis of their importance to the regional economy.

The travel industry, which includes tourism and business travel, has impacts on retail trade sectors, such as eating and drinking places, retail stores and service stations. It affects transportation industries, such as transportation services, and air or rail transportation. It has an impact on the services industry, which includes hotels and lodging places, personal services, and amusement and recreation services. It also has an impact on the government sector, through parks and recreation, national parks, national and state forests, and the highway system. Because all of these services are consumed by the local population as well as out-of-state travelers, it is difficult to measure the impact of the travel industry on the economy.

Nevertheless, the travel industry is an important activity in the region. The beauty and diversity of the region's natural environment provide opportunities for a variety of recreational activities. Factors that will aid the growth of the travel industry in the future include increases in real income and changes in the age composition of the population. State and local governments in the region have developed programs to promote tourism and conventions, which will add to the industry's growth.

Another economic activity that appears to have increased in importance is port activity related to trade with Alaska and other countries. The expansion of the economies of the Pacific Rim countries and the region's proximity to these countries point to increased trade and transportation activity. The employment impacts are difficult to measure because they are spread across a number of SIC categories. Port activity affects the transportation, wholesale trade, services and financial industries. It has an impact on manufacturing industries, as well, by providing markets for goods produced in the region. A study by the Port of Seattle[7] showed a direct impact of 55,800 jobs resulting from the harbor and airport facilities. This estimate was for 1982, which was a year of worldwide economic slowdown. In addition, the estimate included jobs in King County only, which would underestimate the impact of the port on the state of Washington and the region.

In recent years, more attention has focused on the non-manufacturing industries as an increasing source of jobs to the economy. The traditional approach to understanding regional economic development emphasized manufacturing, agriculture and extractive industries as the basis for economic growth. Other industries were treated as secondary, providing support services to these industries and to the local population. A recent study of the services sector in the central Puget Sound region[8] disputes this approach. The study interviewed firms from selected industries in the services sector and estimated that approximately one-third of the employment in these industries is linked to export markets. The study points out many areas where the dynamics of location and growth of non-manufacturing industries have remained largely unexplored.

In developing the range of forecasts of employment growth in the non-manufacturing industries, the Council and Bonneville have relied on national forecasts developed by the WEFA Group and the Bureau of Labor Statistics, comparing them to historical regional growth rates by industry. Table 5-15 shows a comparison of the forecasts of non-manufacturing employment by industry with historical growth rates.

Changes in Productivity Growth

The early phases of an economic recovery often show large gains in productivity. The conditions may exist at this time, however, for a more sustained growth in labor productivity in the United States that could last well beyond the cyclical impacts of recession and recovery. Some of the factors encouraging higher productivity growth were brought about by the recession. Intense foreign competition and a high value of the U.S. dollar against foreign currencies in the early 1980s put downward pressure on prices. Efforts to increase profitability have focused on improving productivity.

Over the long-term, demographic factors will have an impact on labor productivity growth. With the maturation of the baby-boom generation, there will be fewer young, inexperienced workers in the labor force.

The impact of developments in high technology is just beginning to be observed in office automation, robotics, electronic technology and telecommunications. Spurred by foreign competition and tempted by numerous success stories, U.S. companies are turning to new technology to remain competitive in world markets.

Two factors that may have dampened productivity growth in the 1970s may have contributed to productivity growth in the 1980s by their absence. These are energy price shocks and new federal regulations. The costs of adjusting to higher prices and higher environmental standards diverted funds from investments that contribute more directly to measures of productivity during the 1970s. These factors may have slowed down labor productivity growth in the 1970s.

Table 5-16 shows rates of growth in real output per employee for manufacturing. As shown, productivity growth in the 1970s was slow compared to previous decades. The WEFA Group's long-term forecasts show a continuation of the trends established over the last 20-years. Table 5-A-4 of Appendix 5-A shows productivity forecasts by industry for manufacturing industries.

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7. Port of Seattle. *1982 Economic Impact Study.* October 1984.

8. Beyers, William B.; Alvine, Michael J.; and Johnsen, Erik G.; Central Puget Sound Economic Development District. *The Service Economy: Export of Services in the Central Puget Sound Region.* April 1985.

Table 5–15
Non–manufacturing Employment Projections—Average Annual Rate of Growth (%)

		1989–2010				
	1970–1987[a]	High	Medium–High	Medium	Medium–Low	Low
Construction	2.7	2.3	1.7	0.9	0.6	0.3
Transportation, Communications and Public Utilities	2.3	1.7	1.0	0.9	0.7	0.2
Trade	3.3	3.3	2.6	2.0	1.7	1.2
▪ Wholesale Trade	2.6	3.1	2.5	1.9	1.5	0.9
▪ Retail Trade	3.7	3.3	2.6	2.1	1.7	1.3
• Food Stores	3.8	2.8	1.9	1.2	0.9	0.6
• Eating and Drinking Places	6.0	4.1	3.6	3.2	2.8	2.3
Finance, Insurance and Real Estate	3.7	3.5	2.7	1.9	1.5	0.9
Services	5.5	3.8	2.9	2.6	2.3	2.0
▪ Hotels and Lodging Places	2.5	2.9	2.5	2.1	1.6	1.2
▪ Business Services	7.7	5.0	3.9	3.5	3.3	3.0
▪ Health Services	5.3	4.2	3.3	3.0	2.8	2.4
Government	2.2	2.5	1.8	1.2	0.9	0.7
▪ Federal Government	1.1	1.9	1.3	0.7	0.3	0.0
▪ State and Local Government	2.4	2.6	1.9	1.3	1.1	0.8

[a] Historical data except government employment is based on *County Business Patterns*. The employment figures shown in this table are based on a survey of employment during the pay period including March 12. As such, they are not comparable to annual average data used in other segments of this report. They are used for illustration purposes in this table and in the text, because they are available at the level of industry detail needed.

Table 5–16
Real Output per Employee, U.S. Manufacturing—Average Annual Rate of Growth (%)

Years	Percent
1959–1969	2.6
1969–1979	2.3
1979–1989	3.4
1969–1989	2.9
Forecast 1989–2010	Percent
High	3.0
Medium	2.9
Low	2.7

Population, Households and Housing Stock

Total population in the region was 9.0 million in 1990. Regional population increased at an average annual rate of 1.2 percent from 1980 to 1990, higher than the rate of U.S. population growth (1.0 percent) in the same period. In the 1970s, population growth in the region was twice the rate of U.S. population growth, and more than one-third faster than during the 1950s and 1960s. Washington was the fastest growing state in the region during the 1980s, while Idaho was the fastest growing during the 1970s. Table 5-17 summarizes historical data on population and households.

The number of households in the region and the nation grew at a higher rate than population. Growth in the number of households was most rapid in the 1970s. During the 1970s, the baby-boom generation reached the 20 to 29 year age group, where household formation rates are high. Smaller families also became more common.

Householder rates, or the proportion of the population in an age group designated to represent a household, increased rapidly with the rise in divorce rates and single-person households. In the 1970s, householder rates increased dramatically for females over the age of 65, as more women in this group have maintained their own household, rather than move in with family or to group quarters. In addition, women in the 20 to 29 age group have maintained households at a higher rate. The combination of shifts in age composition and of changes in householder rates lowered average household size in the region from 3.1 in 1970 to 2.7 in 1980. During the 1980s, average household size continued to drop, but at a much slower pace, to 2.5 in 1990.

Table 5-17
Total Population and Households

	Total Population (thousands)				Average Annual Rate of Growth (%)		
	1960	1970	1980	1990	1960-1970	1970-1980	1980-1990
Washington	2,853.2	3,409.2	4,132.2	4,866.7	1.80	1.94	1.65
Oregon	1,768.7	2,091.4	2,633.1	2,842.3	1.69	2.33	0.77
Idaho	667.2	712.6	944.0	1,006.7	0.67	2.85	0.65
Western Montana	231.7	253.5	294.5	303.3	0.90	1.51	0.30
Pacific Northwest	5,520.8	6,466.7	8,003.8	9,019.0	1.59	2.16	1.20
United States	180,671.0	204,878.0	227,020.0	248,710.0	1.27	1.03	0.92
	Total Households (thousands)				Average Annual Rate of Growth (%)		
	1960	1970	1980	1990[a]	1960-1970	1970-1980	1980-1990
Washington	894.0	1,106.0	1,540.5	1,938.9	2.15	3.37	2.33
Oregon	558.0	692.0	991.6	1,155.4	2.18	3.66	1.54
Idaho	194.0	219.0	324.1	367.4	1.22	4.00	1.26
Western Montana	70.0	79.0	106.4	114.9	1.25	3.47	0.77
Pacific Northwest	1,716.0	2,096.0	2,962.6	3,576.6	2.02	3.52	1.90
United States	53,021.0	63,450.0	80,377.0	93,500.0	1.81	2.39	1.52
	Persons per Household						
	1960	1970	1980	1990			
Pacific Northwest	3.22	3.09	2.70	2.52			
United States	3.41	3.23	2.82	2.66			

[a] Estimate.

The population forecast is derived from the forecast of total employment by using an average employment to population ratio. Changes in the employment to population ratio reflect changes in labor force participation, unemployment rates and age composition of the population. The participation of women in the labor force increased rapidly in the 1960s and 1970s. From 1960 to 1989, women in the labor force increased from 37 percent to 57 percent. The employment to population ratios in this forecast incorporate the impacts of continued increases in female labor-force participation, although at slower rates than in the past. The range of projections was based on national trends as forecast by the WEFA Group and the U.S. Bureau of Labor Statistics. Changes in employment to population ratios implied in the national forecasts were tracked in the state-level forecasts, maintaining historical differences between the state and national ratios. Table 5-A-1 in Appendix 5-A shows employment to population ratios for each state for the ranges.

The forecast for total households is obtained from the forecast of population after dividing by average household size. Changes in average household size reflect changes in the age composition of the population and householder rates by age group. The projections are based on national trends as forecast by the U.S. Bureau of the Census. The high and medium cases assume that householder rates will continue to increase, but at much slower rates than in the 1970s. This results in part because of increases in the relative cost of housing and in a slowing of increases in the divorce rate. The low case assumes that householder rates do not increase, but average household size decreases slightly because of changes in age composition. Average household size projections by state for the ranges are shown in Appendix 5-A, Table 5-A-2.

Table 5-18 shows the forecasts of population and households that result from the assumptions described. There were 2.963 million occupied housing units in the region in 1980. Results from the 1980 U.S. Census indicated that approximately 78 percent of the occupied housing stock was single-family units (1 to 4 units per building). An additional 14 percent was multifamily units, and 8 percent were manufactured homes. Change in the housing stock is the result of change in total households plus replacement of existing units. The proportion of new housing units by type is projected for each state. Table 5-A-3 in Appendix 5-A shows the proportion of housing additions by type for each state and scenario. Changes in the stock of housing by type are shown in Table 5-19.

Personal Income

Real per capita income is an important input to many econometric models of energy demand. It plays a far less critical role in the more structural end-use models used by the Council. The only sector it affects directly is the residential sector, where it influences the penetration rate of certain types of appliances and the long-run expected use of appliances. In 1980, the personal income per capita of the Pacific Northwest was $10,392. That was 4.8 percent greater than the U.S. average of $9,916.

Table 5-20 shows historical and forecast growth of real personal income per capita in the Pacific Northwest and for the United States. During the 1960s, income per capita increased at a slightly slower rate in the region than in the United States. In fact, the region's real income per capita dipped below the United States in 1970. Income per capita increased faster in the region than in the United States during the 1970s. Over the entire 20-year period from 1960 to 1980, the region's per capita income increased at almost the identical rate as the United States average. From 1980 to 1989, regional real income per capita increased at half the national rate. The forecasts for 1989 to 2010 are shown in Table 5-20 as well.

Alternative Fuel Prices

Assumptions about the future prices of natural gas, oil and coal are important determinants of demand for electricity. These fuel price assumptions are important for two reasons. First, because these fuels are alternatives to electricity in many uses of energy, their prices will affect the demand for electricity. This is particularly true for the residential and commercial sectors, where electricity, natural gas and oil compete for space heating, water heating, air conditioning and cooking.

The second reason that fuel price are important is that they are highly uncertain. In the last 20 years, crude oil prices have varied between a low of less than $3 a barrel in 1970 and a high of $37 a barrel in 1981. Electricity demand forecasts are much less sensitive to fuel price changes than to changes in economic activity. (Sensitivity tests show that reducing fuel prices by one-half would reduce electricity demand by less than 5 percent.) Nevertheless, the large uncertainty about fuel prices causes them to be a substantial factor in the risks facing electricity planning.

The forecasts of fuel prices reflect an assumption that natural gas prices will tend to follow oil prices in the long run, although the current natural gas bubble is recognized in the forecast. The linkage of oil and natural gas prices results from the competition between residual oil and interruptible natural gas in the industrial sector boiler markets. Coal is not currently competitive in industrial markets in the Northwest. However, as oil and natural gas prices rise, coal could become a third competitor in the industrial market.

Table 5–18
Forecast of Population and Households 1989–2010

Scenario	1980	1990	2010	Average Annual Rate of Growth (%)
Total Population (thousands)				
High			13,799.4	2.1
Medium–High			12,365.5	1.6
Medium	8,003.7	9,019.0	11,641.7	1.3
Medium–Low			11,007.7	1.0
Low			10,260.3	0.6
Total Households (thousands)				
High			6,274.2	2.9
Medium–High			5,343.3	2.0
Medium	2,962.6	3,576.6	5,030.8	1.7
Medium–Low			4,755.2	1.4
Low			4,021.8	0.6

Table 5–19
Housing Stock Projections—Share of Occupied Housing Units (%) 1980–2010

		2010				
	1980	High	Medium–High	Medium	Medium–Low	Low
Single–Family (1–4 units)	77.8	77.1	72.4	70.5	69.1	67.4
Multifamily (5 and more units)	14.4	15.2	17.2	18.5	19.4	21.8
Manufactured Housing	7.8	7.7	10.4	11.0	11.5	10.8

Table 5–20
Real Income per Capita—Average Annual Rate of Growth (%)

	Pacific Northwest	United States
Historical		
1960–1970	2.9	3.2
1970–1980	2.7	2.2
1980–1989	1.0	2.0
Forecast 1989–2010		
High	2.9	1.6
Medium–High	2.4	
Medium	1.8	1.4
Medium–Low	1.4	
Low	1.1	1.1

Prices of oil products, such as heating oil or gasoline, follow world crude oil prices. Thus, assumptions about world crude oil prices are the starting point for forecasts of alternative fuel prices. Shortly after the Council's 1986 plan was published, world oil prices collapsed to less than half their previous levels. This event demonstrated, in many analysts' minds, that oil prices of more than $30 per barrel are not sustainable for long. After 1986, and until Iraq's invasion of Kuwait, oil prices varied between $14 and $18 on an annual basis with more variation on a monthly basis.

Iraq's invasion of Kuwait, and the subsequent blockade of those countries, sent oil prices above $30 during the later part of 1990. Immediately following the beginning of military action against Iraq, oil prices dropped well below $30 and are now back near $20 a barrel. Nearly all analysts agree that future oil prices are likely to be volatile. Recent events in the Middle East are a good example of such volatility that can cause prices to move temporarily above or below the proposed range of assumptions. The potential for such volatility is not reflected in the proposed assumptions. Instead, the assumptions are meant to bracket alternative trends in oil prices about which fluctuations would likely occur.

The range of world oil price assumptions proposed in this paper encompasses the recent forecasts of many analysts. The range is illustrated in Figure 5-3 and Table 5-21. Figure 5-3 also illustrates the historical pattern of oil prices from 1970 to 1990, including the large increases of 1973 and 1979 and the collapse in 1986. It is also clear from Figure 5-3 that the real oil price decreased dramatically between 1981 and 1985 even though that decrease did not cause the stir that resulted from the 1986 collapse.

The medium forecast shows real world oil prices (in 1990 dollars) growing at 3.2 percent per year from current levels, reaching $35 per barrel by the year 2010. The range about this medium forecast reflects a judgment that there is slightly more risk on the high side than on the low side. In 2010 the high oil price is $19 above the medium, while the low oil price is $17 below the medium.

The low forecast assumes that oil prices remain near 1989 levels in real terms; that is, they increase at about the same rate as general economic price inflation. This scenario would be consistent with very favorable oil and natural gas supplies combined with significant progress in improved energy efficiency even with low price incentives. Under such conditions, the Organization of Petroleum Exporting Countries (OPEC) would not be able to exercise effective control of world oil markets.

In the high scenario, per barrel prices recover into the low-20s by 1990 and continue to make significant real gains, reaching $54 by 2010. Such a future could be consistent with OPEC having a fairly secure control of oil markets. That could happen if new oil and gas discoveries are disappointing, the world experiences strong economic growth, and efficiency improvements are slow in being

World Oil Prices

Figure 5-3
World Oil Prices—Historical and Forecast Range to 2010

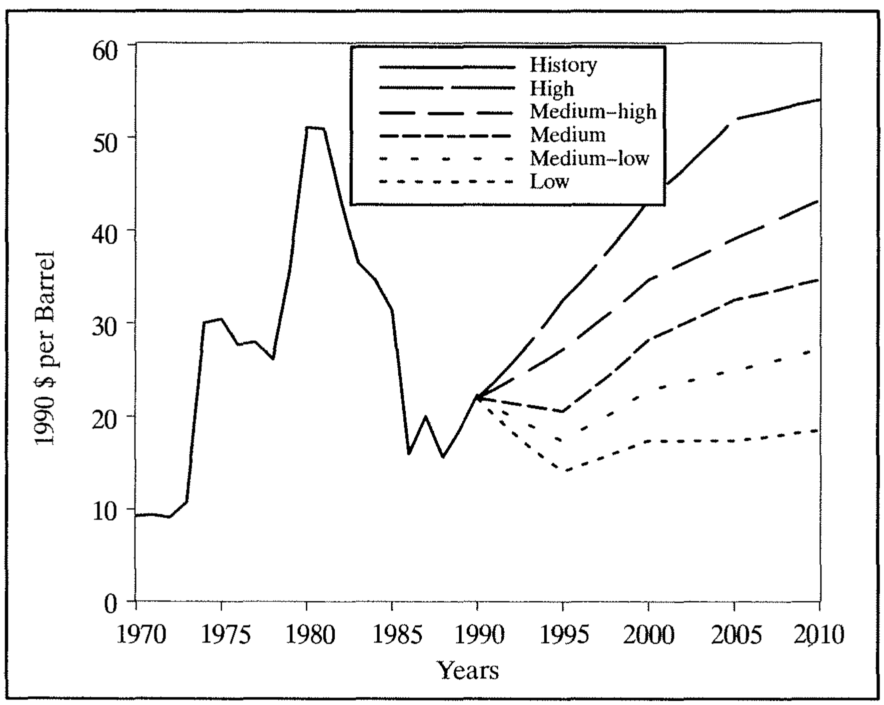


Table 5-21
World Oil Prices (1990 Dollars per Barrel)

	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	18	18	18	18	18
1995	32	27	20	17	14
2000	43	35	28	23	17
2005	52	39	32	25	17
2010	54	43	35	27	18
Growth Rates (%)					
1989–2010	5.4	4.2	3.2	1.9	0.0

realized. The medium-low and medium-high forecasts bound a more likely long-term range that spans from \$27 to \$43 per barrel in 2010.

The range of oil price assumptions is significantly lower than those used for the Council's 1986 Power Plan. Figure 5-4 compares the new assumptions with the Council's 1986 plan range, which is shown with dashed lines. The figure shows that actual oil prices fell below the 1986 low case after 1986. The price assumptions were revised for the Council's 1989 Power Plan Supplement and the August 1989 Bonneville white book forecast. The assumptions for the 1991 Power Plan are similar to those used in these recent forecasts.

As described above, oil price assumptions provide the basis for forecasting retail prices of the important fuel competitors to electricity. Some important assumptions and forecast characteristics can be illustrated by focusing on the industrial sector where the most important inter-fuel competition takes place. The relative forecasts of crude oil prices and the retail prices of fuels are illustrated for the industrial sector medium forecast in Figure 5-5.

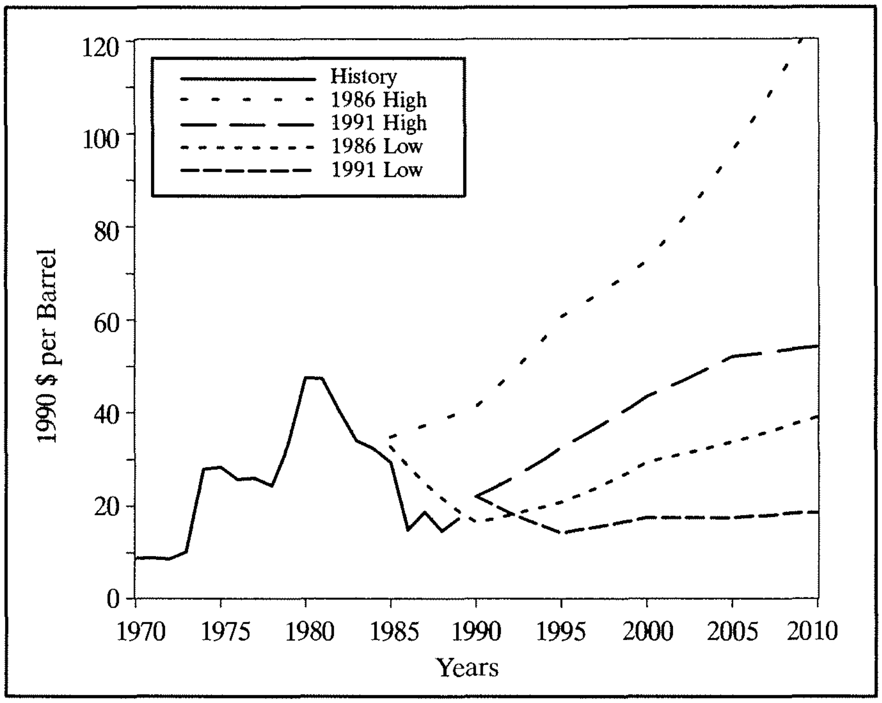
Industrial interruptible natural gas prices are expected to eventually equate to residual oil prices, but remain below that equilibrium condition until the year 2000, reflecting a prolonged weakness in natural gas markets. This weakness reflects the "gas bubble" and the existence of large gas supplies in western Canada with limited transportation to eastern markets. The shaded area in Figure 5-5 shows the near-term weakness in interruptible natural gas price forecasts compared to residual oil.

Coal prices are currently set at a floor that approximates the cost of coal production. There is currently a large amount of excess capacity in western coal mining. This large surplus, combined with slow growth in coal demand, serves to keep coal prices depressed. Only in the later years of the higher oil price scenarios is there significant strengthening of coal prices.

The retail price forecasts for each consuming sector are related to the industrial residual fuel oil price and interruptible natural gas price using average historical price differences. Tables in Appendix 5-C show forecasts of retail prices for the residential, commercial and industrial sectors, respectively. These price forecasts are used in forecasting electricity demand.

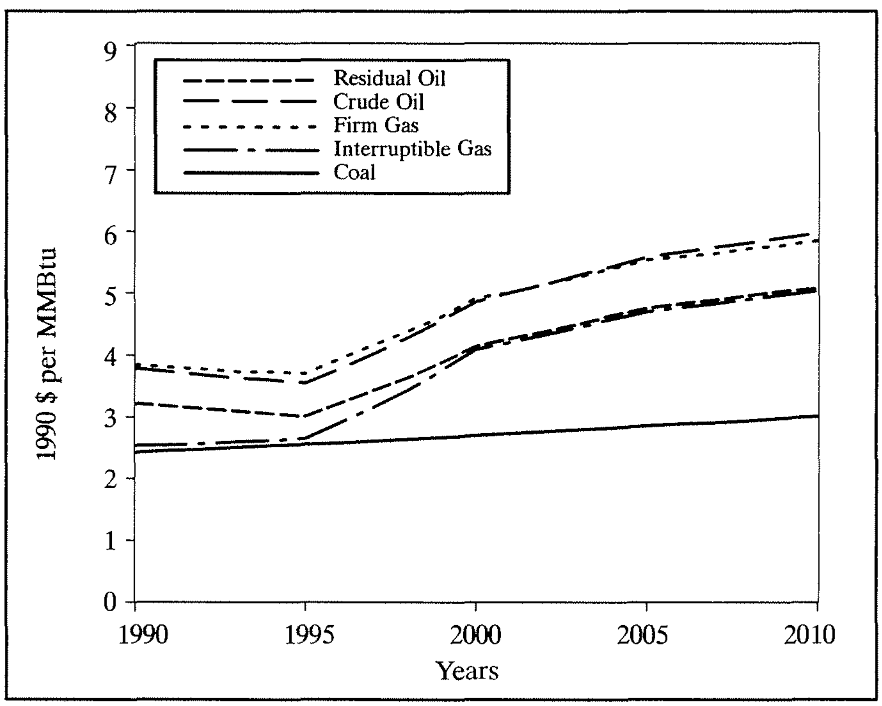
World Oil Prices

Figure 5–4
World Oil Prices—Compared to Council's 1986 Power Plan



Price Comparison

Figure 5–5
Industry Price Comparisons—Medium Case



APPENDIX 5-A

DETAIL ON ECONOMIC INPUT ASSUMPTIONS

Table 5-A-1
Employment-Population Ratios

	1985	1990	1995	2000	2005	2010
Washington						
High	.414	.462	.480	.495	.505	.515
Medium-High	.414	.462	.467	.477	.485	.493
Medium	.414	.462	.456	.462	.468	.473
Medium-Low	.414	.462	.445	.452	.459	.466
Low	.414	.462	.428	.438	.447	.457
Oregon						
High	.422	.474	.493	.510	.520	.531
Medium-High	.422	.474	.479	.490	.500	.508
Medium	.422	.474	.468	.474	.480	.485
Medium-Low	.422	.474	.455	.462	.469	.475
Low	.422	.474	.440	.450	.459	.468
Idaho						
High	.400	.445	.460	.475	.485	.495
Medium-High	.400	.445	.450	.460	.468	.474
Medium	.400	.445	.443	.449	.455	.460
Medium-Low	.400	.445	.436	.438	.439	.440
Low	.400	.445	.423	.427	.430	.433
Western Montana						
High	.321	.354	.370	.385	.395	.405
Medium-High	.321	.354	.359	.370	.378	.386
Medium	.321	.354	.358	.364	.370	.375
Medium-Low	.321	.354	.348	.349	.350	.351
Low	.321	.354	.331	.335	.339	.342
Pacific Northwest						
High	.412	.463	.478	.494	.504	.514
Medium-High	.412	.463	.465	.476	.484	.492
Medium	.412	.463	.455	.461	.467	.472
Medium-Low	.412	.463	.444	.450	.456	.462
Low	.412	.463	.428	.437	.445	.454

Table 5–A–2
Average Household Size

	1980	1985	1990	1995	2000	2005	2010
Washington							
High		2.61	2.51	2.40	2.30	2.22	2.18
Medium	2.68	2.61	2.51	2.42	2.36	2.31	2.29
Low		2.61	2.51	2.56	2.56	2.56	2.56
Oregon							
High		2.56	2.46	2.35	2.28	2.22	2.18
Medium	2.66	2.56	2.46	2.38	2.33	2.29	2.28
Low		2.56	2.46	2.52	2.53	2.54	2.55
Idaho							
High		2.84	2.74	2.54	2.45	2.40	2.36
Medium	2.91	2.84	2.74	2.66	2.60	2.55	2.53
Low		2.84	2.74	2.82	2.84	2.85	2.86
Western Montana							
High		2.70	2.64	2.44	2.35	2.28	2.24
Medium	2.77	2.70	2.64	2.54	2.48	2.42	2.40
Low		2.70	2.64	2.63	2.62	2.61	2.60
Pacific Northwest							
High		2.62	2.52	2.40	2.31	2.24	2.20
Medium	2.70	2.62	2.52	2.44	2.38	2.34	2.31
Low		2.62	2.52	2.52	2.53	2.54	2.55

Table 5-A-3
Share of Housing Additions by Type of Housing Unit 1987-2010 (% of New Housing Starts)

	High	Medium-High	Medium	Medium-Low	Low
Washington					
Single-Family (1-4 units)	75	65	60	55	45
Multifamily (5 and more units)	16	20	23.5	27	35
Manufactured Housing	9	15	16.5	18	20
Oregon					
Single-Family (1-4 units)	76	68	65	62	51
Multifamily (5 and more units)	13	16	17	18	27
Manufactured Housing	11	16	18	20	22
Idaho					
Single-Family (1-4 units)	81	71	67.5	64	55
Multifamily (5 and more units)	8	10	11	12	17
Manufactured Housing	11	19	21.5	24	28
Western Montana					
Single-Family (1-4 units)	82	70	62.5	55	45
Multifamily (5 and more units)	05	10	12.5	15	20
Manufactured Housing	13	20	25	30	35

Table 5-A-4
Production per Employee by Industry[a]—Average Annual Rate of Growth (%) 1989-2010

SIC	High	Medium[b]	Low
20	3.1	2.9	2.7
22	4.1	3.9	3.7
23	2.8	2.6	2.4
25	2.4	2.2	2.0
27	1.0	0.8	0.6
29	3.4	3.2	3.0
30	3.2	3.0	2.8
31	2.2	2.0	1.8
32	2.4	2.2	2.0
33XX	1.6	1.5	1.5
34	2.3	2.1	1.9
35	4.7	4.5	4.3
36	4.5	4.3	4.1
37	3.1	2.8	2.6
38	4.1	3.9	3.7
39	4.3	4.3	4.4

[a] Refer to Appendix 5-B, Table 5-B-1 for a listing of SIC Codes.

[b] Growth rates shown are used in the medium-high, medium and medium-low cases except for the lumber, paper and chemicals industries. Forecasts for production per employee for the lumber, paper and chemicals industries are shown in the sections discussing the outlook for those industries.

APPENDIX 5-B

MANUFACTURING FORECASTS

Table 5-B-1
SIC Code Listings

SIC Code	Industry Name	SIC Code	Industry Name
20	Food and Kindred Products	3334	Primary Aluminum
22	Textiles	40–49	Transportation and Public Utilities
23	Apparel	50–51	Wholesale Trade
25	Furniture	52, 53+	Retail Trade except Food Stores (54) and Eating and Drinking Places (58)
27	Printing and Publishing	54	Food Stores
29	Petroleum Refining	58	Eating and Drinking Places
30	Rubber and Plastics	60–67	Finance, Insurance and Real Estate
31	Leather and Leather Products	70	Hotels and Lodging
32	Stone, Clay, Glass and Concrete	72	Personal Services
33XX	Primary Metals except Aluminum	73	Business Services
34	Fabricated Metals	76	Miscellaneous Repair Services
35	Machinery except Electrical	80	Health Services
36	Electrical Machinery	81	Legal Services
37	Transportation Equipment	82, 941	Educational Services
38	Professional Instruments	83	Social Services
39	Miscellaneous Manufacturing	75, 78+	Other Services
2421	Sawmills and Planing Mills	89	Miscellaneous Services
2436	Softwood Veneer and Plywood	90–99	Government except Education (941)
24XX	Other Lumber and Wood Products		
2611	Pulp Mills		
2621	Paper Mills		
2631	Paperboard Mills		
26XX	Other Paper Products		
2812	Alkalies and Chlorine		
2819	Elemental Phosphorus		
28XX	Other Chemicals		

APPENDIX 5-C

FUEL PRICE FORECASTS

Table 5-C-1
Residential Fuel Prices

	Natural Gas (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	5.53	5.53	5.53	5.53	5.53
2000	8.65	7.40	6.44	5.65	4.86
2010	10.24	8.65	7.40	6.30	5.02
Growth Rates (%)					
1989-2010	3.00	2.20	1.40	0.60	-0.50
	Heating Oil (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	6.43	6.43	6.43	6.43	6.43
2000	9.21	7.69	6.39	5.42	4.44
2010	11.27	9.21	7.69	6.28	4.66
Growth Rates (%)					
1989-2010	2.70	1.70	0.90	-0.10	-1.50

Table 5-C-2
Commercial Fuel Prices

	Natural Gas (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	4.64	4.64	4.64	4.64	4.64
2000	7.80	6.53	5.58	4.78	3.99
2010	9.39	7.80	6.53	5.43	4.15
Growth Rates (%)					
1989-2010	3.40	2.50	1.60	0.80	-0.50
	Oil (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	5.29	5.29	5.29	5.29	5.29
2000	8.77	7.15	5.96	4.98	4.01
2010	10.72	8.77	7.15	5.85	4.22
Growth Rates (%)					
1989-2010	3.40	2.40	1.40	0.50	-1.10

Table 5-C-3
Industrial Fuel Prices

	Natural Gas (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	3.37	3.37	3.37	3.37	3.37
2000	6.61	5.34	4.40	3.61	2.80
2010	8.20	6.61	5.34	4.24	2.96
Growth Rates (%)					
1989-2010	4.30	3.30	2.20	1.10	-0.60
	Oil (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	4.30	4.30	4.30	4.30	4.30
2000	8.55	6.97	5.79	4.79	3.79
2010	10.54	8.55	6.97	5.59	3.98
Growth Rates (%)					
1989-2010	4.40	3.30	2.30	1.30	-0.40
	Coal (1990 dollars per million British thermal units)				
	High	Medium-High	Medium	Medium-Low	Low
Prices					
1989	2.35	2.35	2.35	2.35	2.35
2000	3.09	2.91	2.68	2.42	2.12
2010	3.87	3.48	2.99	2.48	1.95
Growth Rates (%)					
1989-2010	2.40	1.90	1.20	0.30	-0.90

APPENDIX 5-D

DETAILED TABLES

MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	73.900	71.965	72.925	75.550	76.475	78.300	80.298	81.347	82.097	82.848	83.600	85.500	87.200	87.900
22	3.000	2.550	2.900	3.100	3.100	3.500	3.720	3.739	3.859	3.880	4.000	4.100	4.200	4.200
23	10.025	8.900	8.550	8.950	9.050	9.450	10.666	11.235	11.705	12.176	12.550	13.450	14.400	15.100
25	6.150	7.240	7.050	7.950	7.850	8.250	9.217	9.736	10.156	10.577	10.950	12.000	12.853	13.450
27	29.650	34.000	37.925	39.850	41.025	41.775	47.600	49.925	52.150	54.475	56.700	66.400	74.700	82.300
29	2.800	2.225	2.350	2.450	2.450	2.750	3.076	3.154	3.234	3.316	3.400	3.600	3.700	3.800
30	6.900	8.575	10.025	11.210	12.010	12.540	14.757	15.966	17.176	17.987	19.000	24.150	28.500	31.750
31	0.700	0.925	1.080	1.160	1.260	1.140	1.538	1.576	1.616	1.658	1.700	1.800	1.800	1.800
32	13.100	10.725	11.580	12.490	12.900	14.100	14.906	15.512	15.968	16.424	16.730	18.250	19.371	20.300
33XX	20.800	15.350	15.550	16.550	17.550	18.450	19.807	20.085	20.305	20.526	20.750	20.900	20.900	20.800
34	26.750	22.850	22.975	24.350	26.625	27.250	28.368	29.187	30.007	30.728	31.450	34.900	38.150	41.100
35	37.750	38.625	37.525	40.650	43.175	44.900	52.325	55.050	57.675	59.800	61.800	72.500	79.400	83.300
36	22.550	28.875	30.175	28.700	32.325	35.025	42.367	44.257	45.866	47.496	49.050	56.075	64.104	70.025
37	109.450	99.825	118.150	129.500	141.500	142.700	158.123	163.399	166.679	169.962	171.250	174.750	178.450	181.500
38	25.950	25.725	23.320	28.330	27.940	26.850	29.805	30.771	31.751	32.744	33.750	37.503	41.550	45.100
39	7.350	7.400	8.600	10.350	11.900	10.650	12.894	13.613	14.458	15.404	16.250	18.100	18.950	19.700
2421	52.427	44.300	47.250	47.200	47.000	44.900	47.568	48.999	47.761	45.828	45.816	41.016	42.350	42.691
2436	26.582	20.900	21.900	20.900	20.750	19.125	21.208	21.607	20.701	19.018	18.379	13.606	12.944	12.413
24XX	61.066	57.100	60.100	63.400	62.650	59.450	63.806	63.577	63.685	63.792	63.900	63.520	62.826	61.868
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.478	2.458	2.435	2.413	2.393	2.290	2.191	2.097
2621	14.143	13.410	12.650	12.900	13.700	13.700	13.670	13.647	13.627	13.609	13.587	13.498	13.435	13.391
2631	5.037	5.000	4.900	4.850	5.447	5.550	5.524	5.498	5.470	5.443	5.418	5.288	5.160	5.036
26XX	7.896	7.815	8.750	8.500	8.500	8.600	9.173	9.308	9.438	9.563	9.684	10.094	10.205	9.708
2812	0.763	0.700	0.700	0.700	0.600	0.700	0.702	0.704	0.706	0.708	0.710	0.717	0.708	0.688
2819	6.567	8.890	8.780	9.780	9.583	9.980	10.684	10.988	11.398	11.794	12.097	12.589	13.090	13.561
28XX	7.470	7.650	7.650	7.900	8.004	8.600	8.578	8.636	8.680	8.726	8.773	8.982	9.118	9.155
3334	10.350	7.250	5.850	7.300	7.600	7.500	7.600	7.600	7.600	7.600	7.600	7.600	7.600	7.600
SUBTOT	592.100	560.870	591.260	626.670	653.468	658.235	720.458	741.573	756.204	768.497	781.287	823.177	867.855	900.331

NON-MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	179.500	176.500	181.550	187.700	196.700	203.600	211.300	216.014	221.869	227.414	232.654	254.484	270.705	284.046
50-51	194.000	195.700	203.375	213.275	229.000	239.200	249.519	258.487	267.140	277.780	288.756	338.631	385.307	433.276
52,53+	275.100	279.300	300.050	314.100	332.675	346.650	359.042	372.210	383.358	398.772	414.807	483.415	544.613	606.233
54	75.100	92.400	105.125	110.800	117.300	123.900	129.400	135.100	139.269	143.432	147.217	167.784	188.374	207.476
58	195.500	218.400	233.275	241.600	250.100	261.300	287.683	302.080	316.274	332.383	349.319	425.862	501.947	584.455
60-67	188.900	193.400	202.450	205.550	210.750	215.550	240.654	251.445	262.719	274.500	286.808	339.045	387.421	437.428
70	40.200	42.600	45.800	48.850	52.300	55.400	57.532	59.733	61.693	64.110	66.489	76.635	86.107	95.482
72	29.600	35.000	36.075	34.100	35.275	37.150	44.698	46.329	48.088	49.933	51.795	58.081	64.199	70.126
73	89.800	109.800	138.475	123.200	133.650	142.750	170.900	180.350	189.500	197.700	205.900	258.874	313.423	376.371
76	9.800	10.500	11.350	12.750	14.225	14.814	16.030	16.755	17.400	17.993	18.641	21.505	24.755	28.150
80	179.800	212.350	231.100	240.600	252.300	269.000	293.972	308.063	322.829	338.040	353.721	435.217	516.158	598.509
81	17.400	22.700	25.700	26.900	27.925	29.300	33.175	35.086	37.096	39.210	41.435	52.669	64.858	79.061
83	31.800	41.800	47.525	56.500	61.000	63.900	69.000	72.265	74.737	77.102	79.934	94.498	109.902	125.413
89	36.400	36.000	39.100	65.800	71.150	75.300	82.039	87.400	92.850	97.369	101.969	118.556	130.331	141.700
75,78+	122.600	141.125	150.850	158.900	168.500	177.600	190.473	198.074	205.960	214.044	222.439	254.751	284.921	315.007
82	19.800	24.200	27.500	32.800	34.600	35.800	35.500	36.300	37.100	37.900	38.700	43.700	49.200	54.800
941	279.700	280.275	291.400	299.600	306.700	317.900	327.700	336.700	345.700	355.000	364.500	414.474	466.337	522.495
90-99	230.300	236.100	248.300	257.500	266.400	276.300	289.358	299.580	310.271	321.686	333.747	380.513	419.350	456.664
Const	161.300	132.600	140.600	153.750	171.050	184.600	181.301	187.171	192.124	196.561	200.985	225.185	250.961	276.406
Agric	292.200	286.600	286.200	285.055	284.100	288.295	288.778	289.158	289.538	289.919	290.300	293.000	295.599	298.100
Mining	13.300	9.875	9.075	10.075	10.900	11.800	13.391	14.187	14.487	14.891	15.200	16.300	17.000	17.500
Fd Gvt	117.300	116.350	118.300	120.550	122.200	127.200	136.251	138.126	139.926	141.951	144.100	155.700	168.200	181.800
SUBTOT	2779.400	2893.575	3073.175	3199.955	3348.800	3497.309	3707.696	3840.613	3969.928	4107.690	4249.417	4908.879	5539.668	6190.498
TOTAL	3371.500	3454.446	3664.435	3826.625	4002.269	4155.544	4428.154	4582.186	4726.132	4876.187	5030.704	5732.057	6407.523	7090.830

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME HIGH SCENARIO - REGION 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	2304.022	2428.959	2496.974	2566.797	2648.227	2708.515	2904.320	3011.029	3111.863	3221.097	3336.717	3842.219	4360.053	4834.096
MF	427.732	492.379	515.462	529.422	544.345	556.469	592.308	611.664	630.040	650.171	671.358	766.310	864.356	953.878
MO	230.919	280.062	293.064	299.991	306.619	311.642	334.323	345.087	354.773	365.180	376.182	417.407	455.395	486.176
TOTAL	2962.673	3201.400	3305.500	3396.211	3499.190	3576.626	3830.950	3967.781	4096.676	4236.448	4384.257	5025.936	5679.804	6274.150
POPUL	8003.820	8389.700	8532.000	8668.200	8860.400	9019.000	9539.356	9790.400	10015.808	10261.819	10520.617	11612.527	12721.094	13799.382
HHLDS	2962.673	3201.400	3305.500	3396.210	3499.190	3576.626	3830.950	3967.781	4096.676	4236.448	4384.257	5025.936	5679.804	6274.150
PCI	10360.21	10444.04	10790.19	10978.09	11372.39	11453.48	12078.08	12416.06	12764.35	13124.62	13494.49	15586.98	18004.77	20797.36

MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	31.900	31.100	32.300	34.200	35.500	35.900	35.700	36.300	36.600	36.900	37.100	38.000	39.000	39.000
22	1.000	0.900	1.000	1.200	1.200	1.300	1.500	1.500	1.600	1.600	1.700	1.700	1.700	1.700
23	6.500	6.200	5.700	6.000	6.000	6.200	7.200	7.700	8.100	8.500	8.800	9.500	10.300	11.000
25	3.300	3.800	3.800	4.200	4.000	4.300	5.100	5.500	5.800	6.100	6.400	7.000	7.500	8.000
27	15.800	17.600	20.100	21.400	22.100	22.000	25.500	26.500	27.500	28.500	29.500	35.000	40.000	45.500
29	2.100	1.800	1.800	1.900	1.900	2.200	2.357	2.416	2.476	2.537	2.600	2.800	2.900	3.000
30	3.500	4.500	5.100	5.800	6.200	6.500	7.300	7.700	8.100	8.400	8.700	10.800	12.500	14.000
31	0.400	0.400	0.400	0.500	0.600	0.500	0.619	0.638	0.658	0.679	0.700	0.800	0.800	0.800
32	6.900	6.400	6.900	7.300	7.500	7.900	8.200	8.500	8.800	9.100	9.300	10.300	11.000	11.600
33XX	9.000	6.900	6.900	7.100	7.300	7.600	8.598	8.697	8.797	8.898	9.000	9.300	9.500	9.600
34	11.800	9.700	10.500	10.900	11.800	12.200	12.600	12.900	13.200	13.700	14.200	16.600	18.500	20.000
35	15.000	17.100	16.200	18.000	19.000	19.500	22.000	23.000	24.000	25.000	26.000	31.000	35.000	37.000
36	11.200	12.100	13.200	10.500	11.700	12.100	16.559	17.139	17.738	18.358	19.000	22.000	26.000	29.000
37	98.350	89.600	106.200	116.200	128.500	128.900	142.000	147.000	150.000	153.000	154.000	156.900	160.000	162.500
38	6.400	10.700	10.800	14.600	14.900	14.700	15.500	16.000	16.500	17.000	17.500	19.000	20.500	21.500
39	4.600	4.500	4.800	5.500	5.900	5.600	6.800	7.200	7.700	8.100	8.500	9.000	9.500	10.000
2421	16.027	13.400	14.500	15.200	15.300	14.700	15.715	15.901	15.301	14.469	14.343	12.302	12.663	12.891
2436	4.982	4.200	3.900	3.600	3.100	3.000	3.198	3.240	3.099	2.844	2.736	2.056	1.991	1.935
24XX	25.991	20.700	22.000	22.800	22.700	21.900	23.055	22.788	22.831	22.875	22.919	22.783	22.534	22.190
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.478	2.458	2.435	2.413	2.393	2.290	2.191	2.097
2621	8.818	9.000	8.400	8.700	9.300	9.300	9.278	9.262	9.247	9.237	9.221	9.161	9.118	9.088
2631	1.637	1.200	1.200	1.200	1.600	1.600	1.593	1.585	1.577	1.569	1.562	1.524	1.488	1.452
26XX	4.171	4.400	4.950	5.100	4.900	5.000	5.452	5.514	5.576	5.639	5.703	5.954	6.081	5.891
2812	0.513	0.500	0.500	0.500	0.400	0.500	0.501	0.503	0.505	0.506	0.507	0.512	0.505	0.491
2819	5.300	7.700	7.700	8.700	8.500	8.900	9.600	9.900	10.307	10.700	11.000	11.500	12.013	12.500
28XX	2.887	3.100	3.300	3.300	3.300	3.500	3.579	3.607	3.636	3.664	3.693	3.817	3.863	3.846
3334	7.700	5.800	4.400	5.600	5.900	5.900	5.900	5.900	5.900	5.900	5.900	5.900	5.900	5.900
SUBTOT	308.750	295.400	318.600	342.100	361.600	364.200	397.881	409.348	417.982	426.188	432.977	457.499	483.048	502.481

NON-MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	91.400	93.600	98.500	101.900	107.900	112.000	114.000	115.875	118.983	122.174	125.451	138.362	147.520	155.381
50-51	100.500	105.700	111.400	116.400	124.600	132.100	136.004	140.000	144.645	151.241	158.137	187.458	214.796	243.185
52,53+	141.000	146.900	161.200	168.800	179.100	189.000	196.001	202.643	206.699	215.082	223.805	261.808	296.068	330.808
54	38.200	49.200	57.400	59.900	62.300	65.400	68.000	71.000	73.000	75.000	77.000	89.000	101.000	110.822
58	101.600	118.900	128.200	132.500	135.000	141.600	158.931	167.234	175.970	185.163	194.836	238.424	282.080	329.680
60-67	91.800	99.600	107.500	109.400	112.300	116.300	128.211	134.083	140.224	146.647	153.363	181.975	208.715	236.532
70	17.800	20.100	21.500	22.900	24.700	26.100	26.755	27.926	29.150	30.426	31.759	37.322	42.391	47.574
72	16.000	19.900	20.800	19.700	20.400	21.500	26.806	27.754	28.736	29.752	30.805	33.847	37.151	40.298
73	52.900	61.000	78.000	70.000	76.500	83.700	98.700	103.000	108.000	112.000	116.000	145.000	175.837	215.147
76	5.500	5.600	5.900	6.900	8.000	8.400	8.807	9.045	9.200	9.400	9.652	11.061	12.922	14.914
80	95.800	117.400	129.300	134.600	140.800	151.200	164.172	171.919	180.032	188.527	197.424	243.545	290.375	342.114
81	9.200	12.400	14.400	15.000	15.600	16.500	18.041	19.055	20.126	21.257	22.452	28.836	35.797	43.905
83	15.600	22.600	25.000	27.200	29.700	31.400	34.000	35.565	36.537	37.402	38.834	46.098	54.302	63.189
89	19.500	21.100	23.100	37.500	40.700	43.000	46.122	49.239	52.397	55.596	58.838	70.102	75.188	80.768
75,78+	66.800	83.500	89.000	95.400	101.100	106.700	112.616	117.193	121.956	126.912	132.070	151.347	170.235	189.189
82	8.900	12.000	13.100	14.700	15.900	16.700	15.600	16.000	16.400	16.900	17.300	19.700	22.500	25.600
941	145.500	143.600	151.100	156.000	160.600	166.300	170.400	174.900	179.500	184.200	189.100	215.400	245.300	279.400
90-99	117.400	129.100	135.500	141.300	146.800	152.100	158.465	164.597	170.967	177.584	184.456	211.524	234.457	256.758
Const	92.600	80.600	88.900	96.600	106.600	115.300	112.919	115.828	118.813	121.875	125.015	141.160	158.777	176.455
Agric	119.300	115.100	114.400	113.300	112.300	113.812	114.094	114.377	114.661	114.946	115.231	115.840	117.153	118.086
Mining	3.200	2.700	3.000	3.300	3.600	4.000	4.439	4.879	4.919	5.059	5.100	5.200	5.300	5.400
Fd Gvt	67.900	70.100	70.600	71.400	72.000	74.500	82.660	83.940	85.240	86.560	87.900	95.000	102.600	110.900
SUBTOT	1418.400	1530.700	1647.800	1714.700	1796.500	1887.612	1995.743	2066.052	2136.155	2213.703	2294.528	2668.009	3030.464	3416.105
TOTAL	1727.150	1826.100	1966.400	2056.800	2158.100	2251.812	2393.624	2475.400	2554.137	2639.891	2727.505	3125.508	3513.512	3918.585

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME — HIGH SCENARIO - WASHINGTON — 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	1193.211	1266.263	1310.322	1352.553	1407.204	1444.958	1544.719	1597.752	1649.085	1708.845	1770.317	2059.622	2358.996	2635.070
MF	250.130	298.560	315.713	325.258	337.281	345.690	367.380	379.066	390.390	403.520	417.018	480.649	546.396	607.041
MO	97.169	126.178	134.965	139.189	144.801	148.276	159.084	164.162	168.916	174.562	180.291	205.016	228.595	248.211
TOTAL	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	2071.183	2140.979	2208.391	2286.927	2367.626	2745.286	3133.986	3490.323
POPUL	4132.160	4406.000	4538.000	4619.000	4761.000	4866.700	5136.533	5266.809	5388.475	5534.363	5682.302	6314.158	6957.450	7608.904
HHLDS	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	2071.183	2140.979	2208.391	2286.927	2367.626	2745.286	3133.986	3490.323
PCI	10725.00	10924.00	11258.00	11383.00	11774.00	11798.00	12464.50	12813.50	13172.20	13541.10	13920.20	15981.30	18347.50	21064.10

MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	24.300	23.800	24.000	23.700	23.600	24.900	24.838	24.978	25.118	25.258	25.400	26.000	26.500	27.000
22	2.000	1.600	1.800	1.800	1.800	2.100	2.120	2.139	2.159	2.180	2.200	2.300	2.400	2.400
23	3.200	2.400	2.500	2.600	2.700	2.900	3.058	3.117	3.177	3.238	3.300	3.500	3.600	3.600
25	2.600	2.700	2.500	2.900	3.000	3.200	3.058	3.117	3.177	3.238	3.300	3.600	3.803	3.800
27	10.000	11.500	12.800	13.200	13.500	14.100	15.900	16.900	17.900	19.000	20.000	23.000	25.500	27.000
29	0.600	0.400	0.500	0.500	0.500	0.500	0.619	0.638	0.658	0.679	0.700	0.700	0.700	0.700
30	2.400	3.200	3.800	4.600	4.900	5.000	6.300	7.000	7.700	8.200	8.800	11.500	13.800	15.300
31	0.300	0.400	0.500	0.500	0.500	0.500	0.719	0.738	0.758	0.779	0.800	0.800	0.800	0.800
32	4.500	3.100	3.600	4.000	4.200	4.900	5.100	5.300	5.400	5.500	5.600	6.000	6.400	6.700
33XX	9.600	8.200	8.600	9.300	10.100	10.700	10.800	10.900	11.000	11.100	11.200	11.000	10.800	10.600
34	12.700	11.000	10.200	11.200	12.300	12.400	12.600	13.000	13.400	13.600	13.800	14.500	15.400	16.500
35	17.700	15.500	15.800	16.800	17.600	18.000	22.000	23.000	24.000	24.700	25.300	28.400	30.200	31.000
36	9.800	13.900	13.600	14.100	15.600	17.200	19.500	20.300	21.000	21.700	22.300	25.800	29.400	32.000
37	10.300	9.200	10.800	11.600	11.400	12.200	14.357	14.515	14.675	14.836	15.000	15.500	16.000	16.500
38	19.300	14.600	12.100	13.200	12.500	11.600	13.596	14.003	14.423	14.855	15.300	17.400	19.800	22.200
39	2.200	2.400	3.200	3.800	4.900	3.800	4.800	5.100	5.400	5.900	6.300	7.500	7.800	8.000
2421	23.800	20.500	22.000	21.400	20.800	19.000	20.430	20.643	19.804	18.677	18.488	15.721	16.184	16.442
2436	20.100	15.500	16.800	16.100	16.300	14.900	16.925	17.256	16.487	15.048	14.484	10.367	9.789	9.317
24XX	25.600	27.600	29.200	31.300	29.900	27.300	30.863	30.897	30.932	30.967	31.001	30.817	30.480	30.015
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	5.100	4.160	4.000	3.900	4.100	4.100	4.093	4.086	4.082	4.074	4.069	4.041	4.023	4.009
2631	2.000	2.100	2.000	1.900	2.000	2.000	1.990	1.981	1.971	1.962	1.952	1.905	1.859	1.814
26XX	3.300	2.840	3.200	2.800	3.000	3.000	3.102	3.160	3.213	3.260	3.301	3.417	3.401	3.132
2812	0.250	0.200	0.200	0.200	0.200	0.200	0.201	0.201	0.202	0.202	0.203	0.205	0.202	0.197
2819	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
28XX	2.050	1.900	1.900	1.900	2.000	2.300	2.135	2.151	2.155	2.159	2.164	2.185	2.211	2.202
3334	1.400	0.600	0.700	0.900	0.900	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
SUBTOT	215.100	199.300	206.300	214.200	218.300	217.600	239.904	245.921	249.591	251.912	255.763	266.959	281.852	292.028

NON-MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	60.500	57.300	58.500	60.500	62.800	65.100	69.000	71.000	73.000	74.700	75.900	82.000	86.500	90.006
50-51	67.400	65.800	68.200	72.900	78.200	80.800	86.000	90.000	93.000	96.000	99.000	115.481	131.551	148.069
52,53+	96.200	92.900	98.700	104.200	109.700	112.000	116.541	121.176	125.996	131.007	136.218	158.424	178.109	197.843
54	24.600	29.500	33.800	36.400	39.400	42.000	44.000	46.000	47.500	49.000	50.000	55.423	61.185	67.964
58	67.400	70.400	76.000	78.900	82.300	85.000	92.152	96.846	101.779	106.963	112.412	136.703	160.720	186.661
60-67	70.000	66.800	72.100	73.300	75.300	75.800	85.654	89.422	93.356	97.463	101.750	119.976	136.738	153.982
70	14.800	14.600	15.600	17.100	18.400	19.700	20.000	20.500	20.800	21.500	22.200	25.200	28.200	30.998
72	9.800	10.400	10.800	10.400	10.900	11.600	12.642	13.144	13.665	14.208	14.772	17.022	18.960	20.866
73	24.900	35.000	45.500	43.000	46.700	48.100	59.000	63.000	66.000	69.000	72.000	90.000	108.000	125.862
76	3.000	3.500	4.100	4.400	4.600	4.700	5.400	5.800	6.200	6.500	6.800	7.800	8.800	9.800
80	62.100	69.400	74.400	77.600	82.100	87.200	97.000	102.000	107.000	112.000	117.000	144.000	170.000	192.006
81	5.600	7.300	8.100	8.500	8.700	9.000	10.896	11.554	12.252	12.993	13.778	17.525	21.549	26.177
83	11.400	14.000	16.900	23.300	24.400	25.200	26.900	28.000	29.000	30.000	31.000	36.000	41.000	45.624
89	11.100	10.300	11.300	17.200	19.000	20.500	23.517	25.218	26.953	27.723	28.531	32.054	36.443	40.032
75,78+	42.200	43.500	47.400	47.900	50.800	53.500	59.463	61.824	64.278	66.830	69.483	80.068	89.184	98.148
82	7.100	8.300	10.300	13.800	14.300	14.600	15.000	15.300	15.600	15.800	16.000	18.000	20.000	21.700
941	94.200	94.600	97.400	99.300	101.200	104.100	108.200	111.400	114.700	118.200	121.700	138.400	154.900	170.000
90-99	78.200	73.500	77.700	80.200	81.700	84.300	89.443	92.726	96.129	99.657	103.314	117.326	128.778	139.688
Const	46.500	33.100	35.300	39.900	45.200	47.900	46.000	48.500	50.000	51.000	52.000	57.000	62.000	66.655
Agric	96.300	98.800	99.700	100.300	101.000	103.272	103.369	103.467	103.565	103.662	103.760	105.318	106.177	107.098
Mining	2.300	1.500	1.400	1.300	1.400	1.400	2.057	2.115	2.175	2.237	2.300	2.500	2.700	2.800
Fd Gvt	30.800	29.600	30.600	31.700	32.200	34.200	34.500	34.800	35.000	35.400	35.900	38.800	41.900	45.200
SUBTOT	926.400	930.100	993.800	1042.100	1090.300	1129.972	1206.734	1253.792	1297.948	1341.843	1385.818	1595.020	1793.394	1987.179
TOTAL	1141.500	1129.400	1200.100	1256.300	1308.600	1347.572	1446.638	1499.713	1547.539	1593.755	1641.581	1861.979	2075.246	2279.207

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME HIGH SCENARIO - OREGON 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	766.113	797.066	817.839	839.543	863.560	883.597	952.975	988.529	1020.845	1052.323	1087.280	1233.817	1390.702	1528.674
MF	143.583	154.439	159.705	163.574	166.210	169.693	181.460	187.549	193.096	198.502	204.493	229.695	256.589	280.207
MO	81.898	92.495	96.456	98.883	100.189	102.117	111.014	114.974	118.376	121.564	125.154	137.776	150.393	160.059
TOTAL	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1245.449	1291.053	1332.317	1372.389	1416.927	1601.289	1797.684	1968.941
POPUL	2633.160	2675.800	2690.000	2741.000	2791.000	2842.300	3026.440	3111.438	3184.237	3252.562	3329.779	3650.939	3990.858	4292.292
HHLDS	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1245.449	1291.053	1332.317	1372.389	1416.927	1601.289	1797.684	1968.941
PCI	9897.80	9845.90	10162.10	10402.20	10731.30	10804.40	11297.50	11636.40	11985.50	12345.10	12715.50	14740.70	17088.50	19810.30

MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	17.000	16.600	16.100	17.100	16.900	17.000	19.200	19.500	19.800	20.100	20.500	20.900	21.100	21.300
22	0.000	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
23	0.300	0.250	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
25	0.250	0.600	0.600	0.700	0.700	0.600	0.850	0.900	0.950	1.000	1.000	1.100	1.200	1.300
27	3.100	4.200	4.300	4.500	4.600	4.800	5.300	5.600	5.800	6.000	6.200	7.200	7.800	8.300
29	0.100	0.025	0.050	0.050	0.050	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
30	1.000	0.850	1.100	0.800	0.900	1.000	1.100	1.200	1.300	1.300	1.400	1.700	2.000	2.200
31	0.000	0.100	0.150	0.150	0.150	0.100	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150
32	1.300	0.900	0.800	0.900	0.900	1.000	1.300	1.400	1.450	1.500	1.500	1.600	1.600	1.600
33XX	1.200	0.100	0.000	0.100	0.100	0.100	0.259	0.269	0.279	0.289	0.300	0.300	0.300	0.300
34	2.100	1.900	2.000	2.000	2.300	2.400	2.800	2.900	3.000	3.000	3.000	3.300	3.700	4.000
35	5.000	5.800	5.200	5.500	6.200	7.000	7.900	8.600	9.200	9.600	10.000	12.500	13.500	14.500
36	1.500	2.800	3.300	4.000	4.900	5.600	6.200	6.700	7.000	7.300	7.600	8.100	8.500	8.800
37	0.700	0.950	1.100	1.600	1.500	1.500	1.600	1.700	1.800	1.900	2.000	2.000	2.000	2.000
38	0.150	0.300	0.300	0.400	0.400	0.400	0.550	0.600	0.650	0.700	0.750	0.850	0.950	1.050
39	0.400	0.325	0.300	0.400	0.400	0.500	0.519	0.538	0.558	0.579	0.600	0.700	0.700	0.700
2421	8.100	6.400	6.600	6.700	7.000	7.200	7.320	7.982	8.111	8.126	8.321	8.325	8.654	8.562
2436	0.500	0.400	0.400	0.400	0.400	0.400	0.342	0.350	0.351	0.355	0.366	0.373	0.367	0.366
24XX	6.775	6.700	6.400	6.800	7.400	7.600	7.131	7.127	7.148	7.169	7.190	7.147	7.069	6.961
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.225	0.250	0.250	0.300	0.300	0.300	0.299	0.299	0.298	0.298	0.298	0.296	0.294	0.293
2631	0.850	0.950	0.950	1.000	1.100	1.200	1.194	1.189	1.183	1.177	1.171	1.144	1.116	1.089
26XX	0.425	0.575	0.600	0.600	0.600	0.600	0.619	0.634	0.649	0.664	0.680	0.722	0.722	0.684
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	1.067	1.000	0.900	0.900	0.900	0.900	0.903	0.906	0.909	0.912	0.914	0.907	0.898	0.884
28XX	2.433	2.600	2.400	2.600	2.600	2.700	2.764	2.776	2.788	2.800	2.812	2.873	2.935	2.999
3334	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SUBTOT	54.475	54.625	54.200	57.900	60.700	63.350	68.801	71.820	73.874	75.419	77.251	82.688	86.056	88.539

NON-MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	20.100	19.200	17.900	18.600	19.100	19.500	20.800	21.200	21.700	22.100	22.600	24.500	26.400	27.800
50-51	22.300	20.800	20.500	20.600	22.700	22.700	23.615	24.423	25.260	26.125	27.019	30.329	32.916	35.292
52,53+	29.900	31.300	31.500	32.400	35.100	36.800	37.200	38.391	39.927	41.524	43.185	49.836	55.591	61.269
54	9.400	10.700	11.100	11.400	12.100	12.700	13.200	13.600	14.069	14.632	15.217	17.561	19.589	21.590
58	19.000	21.600	21.600	22.700	24.400	26.100	27.700	28.800	29.025	30.457	31.960	38.568	44.994	51.852
60-67	23.400	23.600	19.200	19.200	19.300	19.500	22.768	23.748	24.770	25.836	26.948	31.555	35.719	39.949
70	5.100	5.200	5.800	6.000	6.500	6.800	7.500	7.900	8.200	8.500	8.700	9.700	10.600	11.500
72	3.000	3.800	3.600	3.100	3.200	3.300	4.300	4.381	4.555	4.736	4.924	5.674	6.320	6.955
73	11.000	12.100	12.800	8.000	8.800	9.200	11.200	12.100	13.000	14.000	15.000	20.000	25.000	30.000
76	1.000	1.100	1.000	1.100	1.200	1.264	1.323	1.385	1.450	1.518	1.589	1.894	2.183	2.486
80	15.500	17.900	19.100	20.000	20.700	21.800	23.600	24.544	25.797	27.113	28.497	34.672	40.783	47.389
81	2.100	2.400	2.500	2.700	2.900	3.000	3.400	3.600	3.800	4.000	4.200	5.200	6.200	7.444
83	3.400	4.000	4.100	4.500	4.800	5.000	5.500	5.800	6.000	6.300	6.500	7.800	9.100	10.500
89	4.800	3.900	3.900	10.300	10.700	11.000	11.500	12.000	12.500	13.000	13.500	15.000	17.000	19.000
75,78+	10.300	10.800	11.000	12.100	13.100	13.900	14.500	15.000	15.500	15.900	16.300	18.000	19.500	21.000
82	3.800	3.900	4.100	4.300	4.400	4.500	4.900	5.000	5.100	5.200	5.400	6.000	6.700	7.500
941	31.100	32.300	33.400	34.900	35.300	37.700	38.900	39.800	40.500	41.100	41.700	46.500	50.800	56.700
90-99	26.400	26.100	27.700	28.600	29.900	31.700	32.300	32.800	33.400	34.341	35.533	39.973	43.466	46.696
Const	17.400	15.100	13.600	14.200	16.000	18.000	18.800	19.100	19.400	19.600	19.700	21.980	24.423	26.796
Agric	69.100	65.400	64.800	64.155	63.500	63.911	63.902	63.894	63.885	63.877	63.868	64.403	64.662	65.147
Mining	4.700	3.800	2.600	3.300	3.600	3.800	4.095	4.193	4.293	4.395	4.500	5.000	5.100	5.100
Fd Gvt	13.000	11.800	12.200	12.500	12.900	13.300	13.813	14.030	14.250	14.473	14.700	15.900	17.200	18.600
SUBTOT	345.800	346.800	344.000	354.655	370.200	385.475	404.816	415.689	426.381	438.727	451.540	510.045	564.246	620.565
TOTAL	400.275	401.425	398.200	412.555	430.900	448.825	473.617	487.509	500.255	514.146	528.791	592.733	650.302	709.104

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME HIGH SCENARIO - IDAHO 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	262.386	280.726	283.014	288.209	290.562	292.540	312.507	324.970	336.955	350.031	363.962	413.200	456.982	499.990
MF	25.070	29.289	29.842	30.395	30.657	30.882	32.873	34.128	35.336	36.652	38.051	43.045	47.501	51.873
MO	36.714	43.986	44.144	44.395	44.236	43.987	46.168	47.275	48.275	49.382	50.564	53.085	54.196	55.143
TOTAL	324.170	354.000	357.000	363.000	365.455	367.409	391.548	406.373	420.567	436.064	452.577	509.330	558.678	607.006
POPUL	944.000	1004.000	1000.500	1004.400	1005.000	1006.700	1057.181	1080.952	1101.884	1125.046	1149.546	1247.858	1340.828	1432.533
HHLDS	324.170	354.000	357.000	363.000	365.455	367.409	391.548	406.373	420.567	436.064	452.577	509.330	558.678	607.006
PCI	8611.20	8400.50	8573.30	8785.80	9226.40	9457.00	9726.50	10028.00	10338.90	10659.40	10989.90	12802.20	14913.50	17372.90

MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	0.700	0.465	0.525	0.550	0.475	0.500	0.560	0.569	0.579	0.590	0.600	0.600	0.600	0.600
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.025	0.050	0.050	0.050	0.050	0.050	0.108	0.118	0.128	0.138	0.150	0.150	0.200	0.200
25	0.000	0.140	0.150	0.150	0.150	0.150	0.209	0.219	0.229	0.239	0.250	0.300	0.350	0.350
27	0.750	0.700	0.725	0.750	0.825	0.875	0.900	0.925	0.950	0.975	1.000	1.200	1.400	1.500
29	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	0.000	0.025	0.025	0.010	0.010	0.040	0.057	0.066	0.076	0.087	0.100	0.150	0.200	0.250
31	0.000	0.025	0.030	0.010	0.010	0.040	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
32	0.400	0.325	0.280	0.290	0.300	0.300	0.306	0.312	0.318	0.324	0.330	0.350	0.371	0.400
33XX	1.000	0.150	0.050	0.050	0.050	0.050	0.150	0.219	0.229	0.239	0.250	0.300	0.300	0.300
34	0.150	0.250	0.275	0.250	0.225	0.250	0.368	0.387	0.407	0.428	0.450	0.500	0.550	0.600
35	0.050	0.225	0.325	0.350	0.375	0.400	0.425	0.450	0.475	0.500	0.500	0.600	0.700	0.800
36	0.050	0.075	0.075	0.100	0.125	0.125	0.108	0.118	0.128	0.138	0.150	0.175	0.204	0.225
37	0.100	0.075	0.050	0.100	0.100	0.100	0.166	0.184	0.204	0.226	0.250	0.350	0.450	0.500
38	0.100	0.125	0.120	0.130	0.140	0.150	0.159	0.168	0.178	0.189	0.200	0.253	0.300	0.350
39	0.150	0.175	0.300	0.650	0.700	0.750	0.775	0.775	0.800	0.825	0.850	0.900	0.950	1.000
2421	4.500	4.000	4.150	3.900	3.900	4.000	4.103	4.473	4.545	4.556	4.664	4.667	4.849	4.797
2436	1.000	0.800	0.800	0.800	0.950	0.825	0.742	0.760	0.764	0.771	0.794	0.810	0.797	0.795
24XX	2.700	2.100	2.500	2.500	2.650	2.650	2.757	2.765	2.773	2.781	2.790	2.773	2.743	2.701
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2631	0.550	0.750	0.750	0.750	0.747	0.750	0.747	0.743	0.739	0.736	0.732	0.715	0.698	0.681
26XX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	0.200	0.190	0.180	0.180	0.183	0.180	0.181	0.181	0.182	0.182	0.183	0.181	0.180	0.177
28XX	0.100	0.050	0.050	0.100	0.104	0.100	0.101	0.102	0.102	0.103	0.104	0.107	0.109	0.108
3334	1.250	0.850	0.750	0.800	0.800	0.800	0.900	0.900	0.900	0.900	0.900	0.900	0.900	0.900
SUBTOT	13.775	11.545	12.160	12.470	12.868	13.085	13.872	14.484	14.757	14.978	15.296	16.032	16.900	17.284

NON-MANUFACTURING EMPLOYMENT (1000'S) HIGH SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	7.500	6.400	6.650	6.700	6.900	7.000	7.500	7.939	8.186	8.440	8.703	9.622	10.285	10.859
50-51	3.800	3.400	3.275	3.375	3.500	3.600	3.900	4.064	4.235	4.414	4.600	5.363	6.044	6.730
52,53+	8.000	8.200	8.650	8.700	8.775	8.850	9.300	10.000	10.736	11.159	11.599	13.347	14.845	16.313
54	2.900	3.000	2.825	3.100	3.500	3.800	4.200	4.500	4.700	4.800	5.000	5.800	6.600	7.100
58	7.500	7.500	7.475	7.500	8.400	8.600	8.900	9.200	9.500	9.800	10.111	12.167	14.153	16.262
60-67	3.700	3.400	3.650	3.650	3.850	3.950	4.021	4.192	4.369	4.554	4.747	5.539	6.249	6.965
70	2.500	2.700	2.900	2.850	2.700	2.800	3.277	3.407	3.543	3.684	3.830	4.413	4.916	5.410
72	0.800	0.900	0.875	0.900	0.775	0.750	0.950	1.050	1.132	1.237	1.294	1.538	1.768	2.007
73	1.000	1.700	2.175	2.200	1.650	1.750	2.000	2.250	2.500	2.700	2.900	3.874	4.586	5.362
76	0.300	0.300	0.350	0.350	0.425	0.450	0.500	0.525	0.550	0.575	0.600	0.750	0.850	0.950
80	6.400	7.650	8.300	8.400	8.700	8.800	9.200	9.600	10.000	10.400	10.800	13.000	15.000	17.000
81	0.500	0.600	0.700	0.700	0.725	0.800	0.838	0.877	0.918	0.960	1.005	1.108	1.312	1.535
83	1.400	1.200	1.525	1.500	2.100	2.300	2.600	2.900	3.200	3.400	3.600	4.600	5.500	6.100
89	1.000	0.700	0.800	0.800	0.750	0.800	0.900	0.943	1.000	1.050	1.100	1.400	1.700	1.900
75,78+	3.300	3.325	3.450	3.500	3.500	3.500	3.894	4.057	4.226	4.402	4.586	5.336	6.002	6.670
82	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
941	8.900	9.775	9.500	9.400	9.600	9.800	10.200	10.600	11.000	11.500	12.000	14.174	15.337	16.395
90-99	8.300	7.400	7.400	7.400	8.000	8.200	9.150	9.457	9.775	10.104	10.444	11.690	12.649	13.522
Const	4.800	3.800	2.800	3.050	3.250	3.400	3.582	3.743	3.911	4.086	4.270	5.045	5.761	6.500
Agric	7.500	7.300	7.300	7.300	7.300	7.300	7.413	7.420	7.427	7.434	7.441	7.439	7.607	7.769
Mining	3.100	1.875	2.075	2.175	2.300	2.600	2.800	3.000	3.100	3.200	3.300	3.600	3.900	4.200
Fd Gvt	5.600	4.850	4.900	4.950	5.100	5.200	5.278	5.356	5.436	5.518	5.600	6.000	6.500	7.100
SUBTOT	88.800	85.975	87.575	88.500	91.800	94.250	100.403	105.080	109.444	113.417	117.530	135.805	151.564	166.649
TOTAL	102.575	97.520	99.735	100.970	104.668	107.335	114.275	119.564	124.201	128.395	132.826	151.837	168.464	183.933

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME HIGH SCENARIO - WESTERN MONTANA 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	82.313	84.905	85.799	86.492	86.901	87.420	94.118	99.779	104.978	109.899	115.158	135.580	153.374	170.362
MF	8.950	10.092	10.201	10.195	10.197	10.205	10.595	10.921	11.218	11.497	11.796	12.921	13.870	14.756
MO	15.138	17.403	17.500	17.524	17.393	17.262	18.058	18.676	19.205	19.672	20.173	21.529	22.211	22.763
TOTAL	106.400	112.400	113.500	114.211	114.491	114.886	122.770	129.376	135.401	141.068	147.127	170.030	189.455	207.881
POPUL	294.500	303.900	303.500	303.800	303.400	303.300	319.203	331.202	341.211	349.849	358.990	399.571	431.958	465.653
HHLDS	106.400	112.400	113.500	114.211	114.491	114.886	122.770	129.376	135.401	141.068	147.127	170.030	189.455	207.881
PCI	7793.00	7983.00	8666.10	8983.50	9312.50	9653.50	11555.40	11555.40	11555.40	11555.40	11555.40	13832.00	16557.10	19819.10

MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	73.900	71.965	72.925	75.550	76.475	78.300	79.000	79.300	79.500	79.500	79.500	79.100	78.800	78.600
22	3.000	2.550	2.900	3.100	3.100	3.500	3.330	3.309	3.289	3.270	3.250	3.250	3.250	3.250
23	10.025	8.900	8.550	8.950	9.050	9.450	9.789	9.979	10.169	10.359	10.550	11.075	11.375	11.675
25	6.150	7.240	7.050	7.950	7.850	8.250	8.345	8.565	8.835	9.080	9.300	9.850	10.403	10.900
27	29.650	34.000	37.925	39.850	41.025	41.775	45.200	47.225	49.250	50.875	52.600	60.200	65.900	71.000
29	2.800	2.225	2.350	2.450	2.450	2.750	3.000	3.000	3.100	3.100	3.200	3.300	3.300	3.300
30	6.900	8.575	10.025	11.210	12.010	12.340	14.354	15.459	16.464	17.169	17.875	22.475	26.300	29.200
31	0.700	0.925	1.080	1.160	1.260	1.140	1.419	1.438	1.458	1.479	1.500	1.450	1.450	1.450
32	13.100	10.725	11.580	12.490	12.900	14.100	14.306	14.512	14.618	14.724	14.830	15.450	15.821	16.100
33XX	20.800	15.350	15.550	16.550	17.550	18.450	19.409	19.519	19.679	19.739	19.800	19.900	19.950	19.850
34	26.750	22.850	22.975	24.350	26.625	27.250	27.759	28.369	29.058	29.328	29.600	31.300	33.000	34.300
35	37.750	38.625	37.525	40.650	43.175	44.900	49.125	50.425	51.450	52.575	53.500	58.775	64.150	67.000
36	22.550	28.875	30.175	28.700	32.325	35.025	40.897	42.101	43.011	44.027	45.150	50.075	53.704	56.625
37	109.450	99.825	118.150	129.500	141.500	142.700	149.808	154.918	159.928	160.038	159.050	155.000	151.450	147.900
38	25.950	25.725	23.320	28.330	27.940	26.850	28.372	28.822	29.377	29.837	30.300	33.225	35.953	39.075
39	7.350	7.400	8.600	10.350	11.900	10.550	11.868	12.412	12.957	13.503	14.050	14.900	15.500	15.900
2421	52.427	44.300	47.250	47.200	47.000	44.900	45.499	45.095	44.034	42.338	42.414	38.364	39.984	40.714
2436	26.582	20.900	21.900	20.900	20.750	19.125	20.300	19.914	19.154	17.650	17.097	12.841	12.401	12.066
24XX	61.066	57.100	60.100	63.400	62.650	59.450	60.829	60.461	60.193	59.927	59.662	57.656	55.651	53.656
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.470	2.438	2.407	2.377	2.347	2.202	2.066	1.939
2621	14.143	13.410	12.650	12.900	13.700	13.700	13.634	13.572	13.510	13.454	13.391	13.111	12.863	12.632
2631	5.037	5.000	4.900	4.850	5.450	5.550	5.508	5.464	5.421	5.378	5.338	5.133	4.937	4.747
26XX	7.896	7.815	8.750	8.500	8.500	8.600	8.880	8.942	9.005	9.068	9.133	9.330	9.322	8.735
2812	0.763	0.700	0.700	0.700	0.600	0.700	0.701	0.702	0.703	0.704	0.705	0.709	0.705	0.693
2819	6.567	8.890	8.780	9.780	9.580	9.980	10.481	10.781	11.082	11.283	11.483	11.673	11.862	12.049
28XX	7.470	7.650	7.650	7.900	8.000	8.600	8.330	8.304	8.279	8.255	8.243	8.257	8.218	8.137
3334	10.350	7.250	5.850	7.300	7.600	7.500	7.000	6.900	6.700	6.600	6.500	6.200	6.200	6.200
SUBTOT	592.100	560.870	591.260	626.670	653.465	657.935	689.612	701.926	712.632	715.638	720.368	734.799	754.515	767.694

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	179.500	176.500	181.550	187.700	196.700	203.600	207.780	210.204	213.029	215.856	218.986	229.951	237.599	245.424
50-51	194.000	195.700	203.375	213.275	229.000	239.200	244.570	250.420	256.232	262.077	267.597	304.291	340.394	378.109
52,53+	275.100	279.300	300.050	314.100	332.675	346.650	354.347	361.767	368.919	375.078	381.095	418.364	460.126	502.775
54	75.100	92.400	105.125	110.800	117.300	123.900	126.400	129.400	131.200	133.000	134.300	146.469	158.737	172.304
58	195.500	218.400	233.275	241.600	250.100	261.300	276.556	287.527	298.812	310.626	323.217	385.742	452.712	529.162
60-67	188.900	193.400	202.450	205.550	210.750	215.550	228.673	235.784	243.113	250.668	258.456	294.176	329.151	366.698
70	40.200	42.600	45.800	48.850	52.300	55.400	56.500	57.800	59.180	60.738	62.232	70.487	79.325	88.507
72	29.600	35.000	36.075	34.100	35.275	37.150	42.409	43.396	44.207	45.009	45.822	50.259	54.369	58.575
73	89.800	109.800	138.475	123.200	133.650	142.750	154.400	160.150	166.050	170.950	176.150	220.000	277.588	305.008
76	9.800	10.500	11.350	12.750	14.225	14.750	15.485	16.029	16.469	16.810	17.156	18.760	20.225	21.393
80	179.800	212.350	231.100	240.600	252.300	269.000	282.564	293.885	304.275	313.939	322.982	380.340	439.066	500.444
81	17.400	22.700	25.700	26.900	27.925	29.300	31.911	33.012	34.063	35.444	36.894	45.154	54.192	64.757
83	31.800	41.800	47.525	56.500	61.000	63.900	66.800	68.700	70.400	72.300	73.700	84.300	97.000	110.500
89	36.400	36.000	39.100	65.800	71.150	75.300	79.192	82.511	85.493	88.205	91.217	106.965	119.557	129.652
75,78+	122.600	141.125	150.850	158.900	168.500	177.600	184.158	188.807	192.483	196.084	199.712	216.158	230.603	244.914
82	19.800	24.200	27.500	32.800	34.600	35.800	36.600	37.100	37.600	38.000	38.400	41.200	44.200	46.700
941	279.700	280.275	291.400	299.600	306.700	317.900	333.600	329.200	335.700	342.300	349.000	382.352	418.009	456.865
90-99	230.300	236.100	248.300	257.500	266.400	276.300	281.635	286.827	292.024	297.625	304.399	336.010	364.837	393.552
Const	161.300	132.600	140.600	153.750	171.050	184.600	175.163	177.921	180.813	183.963	187.169	202.054	224.255	247.972
Agric	292.200	286.600	286.200	285.055	284.100	285.061	284.819	284.537	284.257	283.978	283.700	282.300	280.900	279.399
Mining	13.300	9.875	9.075	10.075	10.900	11.800	12.638	12.778	13.018	13.158	13.300	14.200	14.800	15.000
Fd Gvt	117.300	116.350	118.300	120.550	122.200	127.200	130.432	131.491	132.830	134.106	135.300	141.800	150.100	158.900
SUBTOT	2779.400	2893.575	3073.175	3199.955	3348.800	3494.011	3606.632	3679.246	3760.167	3839.915	3920.784	4371.333	4847.745	5316.611
TOTAL	3371.500	3454.446	3664.435	3826.625	4002.265	4151.946	4296.244	4381.172	4472.799	4555.552	4641.152	5106.132	5602.260	6084.304

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDHI SCENARIO - REGION 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	2304.022	2428.959	2489.849	2549.162	2618.800	2669.739	2759.153	2822.938	2891.608	2955.069	3017.379	3299.969	3605.368	3865.669
MF	427.732	492.379	518.178	536.073	555.502	571.187	595.374	613.677	633.298	651.673	669.825	752.721	842.754	921.358
MO	230.919	280.062	297.473	310.976	324.888	335.701	355.668	369.314	383.819	396.807	409.308	461.547	514.882	556.283
TOTAL	2962.673	3201.400	3305.500	3396.211	3499.190	3576.626	3710.194	3805.930	3908.724	4003.549	4096.512	4514.238	4963.004	5343.310
POPUL	8003.820	8389.700	8532.000	8668.200	8860.400	9019.000	9313.117	9477.615	9655.058	9812.608	9975.740	10736.523	11569.374	12365.505
HHLDS	2962.673	3201.400	3305.500	3396.210	3499.190	3576.626	3710.195	3805.930	3908.724	4003.549	4096.513	4514.238	4963.004	5343.311
PCI	10360.21	10444.04	10785.29	10968.18	11357.44	11433.36	11907.71	12184.28	12467.66	12757.35	13053.39	14680.15	16514.06	18574.33

MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	31.900	31.100	32.300	34.200	35.500	35.900	35.400	35.600	35.800	36.000	36.000	36.000	36.000	36.000
22	1.000	0.900	1.000	1.200	1.200	1.300	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400
23	6.500	6.200	5.700	6.000	6.000	6.200	6.700	6.900	7.100	7.300	7.500	8.000	8.300	8.600
25	3.300	3.800	3.800	4.200	4.000	4.300	4.700	4.900	5.100	5.300	5.500	6.000	6.500	7.000
27	15.800	17.600	20.100	21.400	22.100	22.000	24.400	25.400	26.300	27.100	28.000	32.000	35.000	38.000
29	2.100	1.800	1.800	1.900	1.900	2.200	2.300	2.300	2.400	2.400	2.500	2.600	2.600	2.600
30	3.500	4.500	5.100	5.800	6.200	6.500	7.200	7.600	8.000	8.300	8.500	10.400	12.000	13.500
31	0.400	0.400	0.400	0.500	0.600	0.500	0.619	0.638	0.658	0.679	0.700	0.700	0.700	0.700
32	6.900	6.400	6.900	7.300	7.500	7.900	8.000	8.100	8.200	8.300	8.400	8.800	9.000	9.100
33XX	9.000	6.900	6.900	7.100	7.300	7.600	8.359	8.419	8.479	8.539	8.600	8.800	9.000	9.100
34	11.800	9.700	10.500	10.900	11.800	12.200	12.400	12.500	12.700	12.800	12.900	13.800	14.700	15.500
35	15.000	17.100	16.200	18.000	19.000	19.500	21.000	21.500	22.000	22.500	23.000	25.000	27.000	28.500
36	11.200	12.100	13.200	10.500	11.700	12.100	15.789	16.083	16.383	16.689	17.000	18.500	19.500	20.300
37	98.350	89.600	106.200	116.200	128.500	128.900	135.000	140.000	145.000	145.000	144.000	140.000	136.500	133.000
38	6.400	10.700	10.800	14.600	14.900	14.700	15.000	15.200	15.500	15.700	15.900	17.300	18.400	19.500
39	4.600	4.500	4.800	5.500	5.900	5.600	6.300	6.600	7.000	7.400	7.800	8.100	8.300	8.500
2421	16.027	13.400	14.500	15.200	15.300	14.700	15.028	14.637	14.106	13.360	13.281	11.507	11.952	12.291
2436	4.982	4.200	3.900	3.600	3.100	3.000	3.062	2.986	2.866	2.637	2.545	1.941	1.909	1.879
24XX	25.991	20.700	22.000	22.800	22.700	21.900	21.782	21.686	21.590	21.494	21.399	20.680	19.961	19.245
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.470	2.438	2.407	2.377	2.347	2.202	2.066	1.939
2621	8.818	9.000	8.400	8.700	9.300	9.300	9.255	9.213	9.173	9.134	9.091	8.900	8.733	8.576
2631	1.637	1.200	1.200	1.200	1.600	1.600	1.587	1.575	1.563	1.550	1.539	1.480	1.423	1.368
26XX	4.171	4.400	4.950	5.100	4.900	5.000	5.341	5.401	5.462	5.523	5.585	5.711	5.662	5.229
2812	0.513	0.500	0.500	0.500	0.400	0.500	0.501	0.501	0.502	0.503	0.504	0.507	0.503	0.495
2819	5.300	7.700	7.700	8.700	8.500	8.900	9.400	9.700	10.000	10.200	10.400	10.600	10.800	11.000
28XX	2.887	3.100	3.300	3.300	3.300	3.500	3.426	3.432	3.437	3.442	3.447	3.458	3.437	3.389
3334	7.700	5.800	4.400	5.600	5.900	5.900	5.400	5.300	5.100	5.000	4.900	4.700	4.700	4.700
SUBTOT	308.750	295.400	318.600	342.100	361.600	364.200	381.819	390.008	398.225	400.627	402.737	409.084	416.047	421.411

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	91.400	93.600	98.500	101.900	107.900	112.000	113.000	114.000	115.500	117.000	119.000	125.000	129.000	133.000
50-51	100.500	105.700	111.400	116.400	124.600	132.100	134.000	136.000	138.437	140.879	143.467	164.463	185.440	208.236
52,53+	141.000	146.900	161.200	168.800	179.100	189.000	194.347	197.665	201.082	204.000	206.601	225.296	248.867	273.774
54	38.200	49.200	57.400	59.900	62.300	65.400	66.400	68.000	69.000	70.000	70.500	78.000	85.000	91.715
58	101.600	118.900	128.200	132.500	135.000	141.600	152.738	159.168	165.869	172.852	180.129	215.670	253.929	297.761
60-67	91.800	99.600	107.500	109.400	112.300	116.300	121.513	125.407	129.425	133.571	137.851	157.257	176.452	197.177
70	17.800	20.100	21.500	22.900	24.700	26.100	26.500	27.000	27.534	28.471	29.440	33.913	38.425	43.360
72	16.000	19.900	20.800	19.700	20.400	21.500	25.209	25.691	26.183	26.684	27.194	29.979	32.504	35.095
73	52.900	61.000	78.000	70.000	76.500	83.700	87.000	90.000	93.000	95.000	97.000	120.000	157.967	170.000
76	5.500	5.600	5.900	6.900	8.000	8.400	8.600	8.800	9.000	9.200	9.400	10.200	11.000	11.500
80	95.800	117.400	129.300	134.600	140.800	151.200	155.864	160.985	166.275	171.739	177.382	210.340	245.266	284.828
81	9.200	12.400	14.400	15.000	15.600	16.500	17.500	18.000	18.439	19.189	19.969	24.492	29.541	35.487
83	15.600	22.600	25.000	27.200	29.700	31.400	33.000	34.000	34.800	35.700	36.300	41.000	48.000	56.000
89	19.500	21.100	23.100	37.500	40.700	43.000	45.000	47.000	49.000	51.000	53.000	63.000	70.000	77.000
75,78+	66.800	83.500	89.000	95.400	101.100	106.700	109.000	112.000	114.000	116.000	118.000	128.000	136.000	144.018
82	8.900	12.000	13.100	14.700	15.900	16.700	17.000	17.200	17.400	17.600	17.800	19.000	20.500	21.900
941	145.500	143.600	151.100	156.000	160.600	166.300	168.100	170.300	173.500	176.800	180.200	198.000	217.500	239.000
90-99	117.400	129.100	135.500	141.300	146.800	152.100	154.000	157.000	160.000	163.000	167.024	185.034	201.603	218.750
Const	92.600	80.600	88.900	96.600	106.600	115.300	109.963	111.921	113.914	115.942	118.006	128.015	141.962	158.016
Agric	119.300	115.100	114.400	113.300	112.300	112.090	112.194	112.298	112.402	112.507	112.611	111.609	111.327	110.678
Mining	3.200	2.700	3.000	3.300	3.600	4.000	4.000	4.000	4.000	4.000	4.000	4.000	4.000	4.000
Fd Gvt	67.900	70.100	70.600	71.400	72.000	74.500	78.080	78.969	79.869	80.779	81.700	86.500	91.600	96.900
SUBTOT	1418.400	1530.700	1647.800	1714.700	1796.500	1885.890	1933.008	1975.404	2018.629	2061.913	2106.574	2358.768	2635.883	2908.195
TOTAL	1727.150	1826.100	1966.400	2056.800	2158.100	2250.090	2314.827	2365.412	2416.854	2462.540	2509.311	2767.852	3051.930	3329.606

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME   MEDHI SCENARIO - WASHINGTON   2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	1193.211	1266.263	1305.589	1341.154	1387.480	1419.142	1458.186	1493.915	1530.662	1564.674	1599.835	1753.968	1926.726	2073.886
MF	250.130	298.560	317.582	329.759	345.070	355.887	368.996	381.105	393.547	405.166	417.158	470.708	530.383	582.485
MO	97.169	126.178	137.830	146.087	156.737	163.895	172.669	180.573	188.610	195.906	203.361	234.064	266.977	292.871
TOTAL	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1999.851	2055.593	2112.820	2165.746	2220.354	2458.740	2724.086	2949.242
POPUL	4132.160	4406.000	4538.000	4619.000	4761.000	4866.700	4999.627	5097.871	5197.536	5284.421	5373.257	5802.625	6292.638	6753.765
HHLDS	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1999.851	2055.593	2112.820	2165.746	2220.354	2458.740	2724.086	2949.242
PCI	10725.00	10924.00	11258.00	11383.00	11774.00	11798.00	12343.50	12627.40	12917.80	13214.90	13518.90	15146.70	16970.60	19014.10

MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	24.300	23.800	24.000	23.700	23.600	24.900	24.700	24.700	24.700	24.700	24.700	24.800	24.900	25.000
22	2.000	1.600	1.800	1.800	1.800	2.100	1.880	1.859	1.839	1.820	1.800	1.800	1.800	1.800
23	3.200	2.400	2.500	2.600	2.700	2.900	2.800	2.800	2.800	2.800	2.800	2.800	2.800	2.800
25	2.600	2.700	2.500	2.900	3.000	3.200	2.720	2.740	2.760	2.780	2.800	2.800	2.803	2.800
27	10.000	11.500	12.800	13.200	13.500	14.100	14.800	15.600	16.500	17.200	17.900	20.400	22.400	23.900
29	0.600	0.400	0.500	0.500	0.500	0.500	0.600	0.600	0.600	0.600	0.600	0.600	0.600	0.600
30	2.400	3.200	3.800	4.600	4.900	5.000	6.200	6.800	7.400	7.800	8.300	10.800	12.800	14.100
31	0.300	0.400	0.500	0.500	0.500	0.500	0.600	0.600	0.600	0.600	0.600	0.600	0.600	0.600
32	4.500	3.100	3.600	4.000	4.200	4.900	4.800	4.900	5.000	5.000	5.100	5.300	5.400	5.500
33XX	9.600	8.200	8.600	9.300	10.100	10.700	10.700	10.700	10.800	10.800	10.800	10.700	10.600	10.400
34	12.700	11.000	10.200	11.200	12.300	12.400	12.500	12.900	13.379	13.539	13.700	14.300	15.000	15.500
35	17.700	15.500	15.800	16.800	17.600	18.000	20.500	21.000	21.300	21.700	21.900	24.000	26.000	27.000
36	9.800	13.900	13.600	14.100	15.600	17.200	19.000	19.600	20.000	20.500	21.100	24.000	26.200	28.000
37	10.300	9.200	10.800	11.600	11.400	12.200	13.200	13.200	13.200	13.200	13.200	13.200	13.200	13.200
38	19.300	14.600	12.100	13.200	12.500	11.600	12.713	12.929	13.149	13.373	13.600	15.000	16.500	18.400
39	2.200	2.400	3.200	3.800	4.900	3.800	4.400	4.600	4.700	4.800	4.900	5.400	5.800	6.000
2421	23.800	20.500	22.000	21.400	20.800	19.000	19.546	18.997	18.260	17.256	17.112	14.708	15.280	15.681
2436	20.100	15.500	16.800	16.100	16.300	14.900	16.200	15.903	15.257	13.969	13.473	9.783	9.378	9.057
24XX	25.600	27.600	29.200	31.300	29.900	27.300	29.463	29.333	29.203	29.074	28.945	27.972	26.999	26.031
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	5.100	4.160	4.000	3.900	4.100	4.100	4.081	4.062	4.042	4.025	4.006	3.924	3.848	3.779
2631	2.000	2.100	2.000	1.900	2.000	2.000	1.985	1.970	1.954	1.939	1.924	1.850	1.779	1.712
26XX	3.300	2.840	3.200	2.800	3.000	3.000	2.936	2.935	2.933	2.932	2.930	2.990	3.022	2.881
2812	0.250	0.200	0.200	0.200	0.200	0.200	0.200	0.201	0.201	0.201	0.202	0.203	0.201	0.198
2819	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
28XX	2.050	1.900	1.900	1.900	2.000	2.300	2.078	2.048	2.018	1.990	1.973	1.980	1.967	1.940
3334	1.400	0.600	0.700	0.900	0.900	0.800	0.800	0.800	0.800	0.800	0.800	0.700	0.700	0.700
SUBTOT	215.100	199.300	206.300	214.200	218.300	217.600	229.402	231.776	233.395	233.397	235.165	240.609	250.579	257.580

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	60.500	57.300	58.500	60.500	62.800	65.100	67.000	68.000	69.000	70.000	70.800	73.900	76.000	78.500
50-51	67.400	65.800	68.200	72.900	78.200	80.800	83.500	86.500	89.000	91.500	93.500	105.000	116.000	126.483
52,53+	96.200	92.900	98.700	104.200	109.700	112.000	114.000	117.000	120.000	122.500	125.000	138.000	151.000	163.329
54	24.600	29.500	33.800	36.400	39.400	42.000	43.000	44.000	44.500	45.000	45.400	48.066	51.330	56.108
58	67.400	70.400	76.000	78.900	82.300	85.000	88.318	91.859	95.543	99.374	103.359	122.563	142.914	165.966
60-67	70.000	66.800	72.100	73.300	75.300	75.800	81.440	83.883	86.399	88.991	91.660	104.055	116.186	129.199
70	14.800	14.600	15.600	17.100	18.400	19.700	19.700	20.000	20.400	20.700	21.000	23.400	26.300	28.644
72	9.800	10.400	10.800	10.400	10.900	11.600	12.200	12.500	12.800	13.000	13.200	14.336	15.466	16.617
73	24.900	35.000	45.500	43.000	46.700	48.100	55.000	57.000	59.000	61.000	63.000	79.000	94.000	105.176
76	3.000	3.500	4.100	4.400	4.600	4.700	5.200	5.500	5.700	5.800	5.900	6.500	7.000	7.500
80	62.100	69.400	74.400	77.600	82.100	87.200	94.500	99.500	103.400	106.800	109.300	126.000	142.000	157.316
81	5.600	7.300	8.100	8.500	8.700	9.000	10.311	10.787	11.284	11.805	12.350	15.074	18.094	21.632
83	11.400	14.000	16.900	23.300	24.400	25.200	26.000	26.500	27.000	27.500	28.000	32.000	36.000	40.000
89	11.100	10.300	11.300	17.200	19.000	20.500	22.022	23.029	23.700	24.200	25.000	29.000	33.000	35.000
75,78+	42.200	43.500	47.400	47.900	50.800	53.500	57.183	58.355	59.552	60.773	62.019	66.578	71.477	76.418
82	7.100	8.300	10.300	13.800	14.300	14.600	14.800	15.000	15.200	15.300	15.400	16.500	17.500	18.000
941	94.200	94.600	97.400	99.300	101.200	104.100	116.700	109.000	111.400	113.900	116.400	127.800	139.600	151.500
90-99	78.200	73.500	77.700	80.200	81.700	84.300	86.800	88.400	90.000	92.000	94.045	103.524	112.075	120.832
Const	46.500	33.100	35.300	39.900	45.200	47.900	43.100	43.600	44.199	45.121	46.063	49.439	54.934	60.788
Agric	96.300	98.800	99.700	100.300	101.000	102.338	102.150	101.962	101.775	101.588	101.401	101.472	100.897	100.380
Mining	2.300	1.500	1.400	1.300	1.400	1.400	1.938	1.978	2.018	2.058	2.100	2.300	2.500	2.500
Fd Gvt	30.800	29.600	30.600	31.700	32.200	34.200	34.052	34.108	34.368	34.532	34.600	35.300	37.400	39.600
SUBTOT	926.400	930.100	993.800	1042.100	1090.300	1129.038	1178.914	1198.461	1226.238	1253.442	1279.497	1419.807	1561.673	1701.488
TOTAL	1141.500	1129.400	1200.100	1256.300	1308.600	1346.638	1408.316	1430.237	1459.633	1486.839	1514.662	1660.416	1812.251	1959.068

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDHI SCENARIO - OREGON 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	766.113	797.066	816.018	834.922	856.126	873.533	910.996	929.122	951.992	973.921	992.752	1080.791	1171.484	1248.725
MF	143.583	154.439	160.388	165.307	168.999	173.471	182.592	187.247	193.007	198.558	203.398	226.290	249.931	270.534
MO	81.898	92.495	97.594	101.770	104.834	108.403	116.565	120.133	124.721	129.003	132.477	147.255	161.337	172.159
TOTAL	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1210.154	1236.502	1269.721	1301.482	1328.628	1454.336	1582.752	1691.418
POPUL	2633.160	2675.800	2690.000	2741.000	2791.000	2842.300	2964.876	3004.700	3060.028	3110.543	3162.134	3388.604	3624.503	3856.433
HHLDS	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1210.154	1236.502	1269.721	1301.482	1328.628	1454.336	1582.752	1691.418
PCI	9897.80	9845.90	10162.10	10402.20	10731.30	10804.40	11188.10	11467.80	11754.50	12048.40	12349.60	13972.40	15808.50	17885.90

MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	17.000	16.600	16.100	17.100	16.900	17.000	18.400	18.500	18.500	18.300	18.300	17.800	17.400	17.100
22	0.000	0.050	0.100	0.100	0.100	0.100	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
23	0.300	0.250	0.300	0.300	0.300	0.300	0.239	0.229	0.219	0.209	0.200	0.200	0.200	0.200
25	0.250	0.600	0.600	0.700	0.700	0.600	0.750	0.750	0.800	0.800	0.800	0.800	0.800	0.800
27	3.100	4.200	4.300	4.500	4.600	4.800	5.100	5.300	5.500	5.600	5.700	6.600	7.200	7.700
29	0.100	0.025	0.050	0.050	0.050	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
30	1.000	0.850	1.100	0.800	0.900	0.800	0.900	1.000	1.000	1.000	1.000	1.200	1.400	1.500
31	0.000	0.100	0.150	0.150	0.150	0.100	0.150	0.150	0.150	0.150	0.150	0.100	0.100	0.100
32	1.300	0.900	0.800	0.900	0.900	1.000	1.200	1.200	1.100	1.100	1.000	1.000	1.050	1.100
33XX	1.200	0.100	0.000	0.100	0.100	0.100	0.250	0.250	0.250	0.250	0.250	0.250	0.200	0.200
34	2.100	1.900	2.000	2.000	2.300	2.400	2.600	2.700	2.700	2.700	2.700	2.900	3.000	3.000
35	5.000	5.800	5.200	5.500	6.200	7.000	7.200	7.500	7.700	7.900	8.100	9.200	10.500	10.800
36	1.500	2.800	3.300	4.000	4.900	5.600	6.000	6.300	6.500	6.700	6.900	7.400	7.800	8.100
37	0.700	0.950	1.100	1.600	1.500	1.500	1.500	1.600	1.600	1.700	1.700	1.600	1.500	1.400
38	0.150	0.300	0.300	0.400	0.400	0.400	0.500	0.525	0.550	0.575	0.600	0.700	0.800	0.900
39	0.400	0.325	0.300	0.400	0.400	0.400	0.418	0.437	0.457	0.478	0.500	0.500	0.500	0.500
2421	8.100	6.400	6.600	6.700	7.000	7.200	7.002	7.345	7.476	7.512	7.703	7.786	8.171	8.166
2436	0.500	0.400	0.400	0.400	0.400	0.400	0.327	0.323	0.325	0.329	0.340	0.352	0.351	0.356
24XX	6.775	6.700	6.400	6.800	7.400	7.600	6.932	6.803	6.773	6.743	6.713	6.488	6.262	6.037
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.225	0.250	0.250	0.300	0.300	0.300	0.299	0.297	0.296	0.295	0.293	0.287	0.282	0.277
2631	0.850	0.950	0.950	1.000	1.100	1.200	1.191	1.181	1.172	1.162	1.154	1.109	1.067	1.026
26XX	0.425	0.575	0.600	0.600	0.600	0.600	0.603	0.606	0.610	0.614	0.618	0.630	0.637	0.624
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	1.067	1.000	0.900	0.900	0.900	0.900	0.901	0.901	0.901	0.902	0.903	0.894	0.885	0.874
28XX	2.433	2.600	2.400	2.600	2.600	2.700	2.725	2.724	2.723	2.723	2.722	2.718	2.713	2.709
3334	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SUBTOT	54.475	54.625	54.200	57.900	60.700	63.050	65.337	66.772	67.453	67.892	68.496	70.664	72.969	73.620

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	20.100	19.200	17.900	18.600	19.100	19.500	20.500	20.800	21.000	21.200	21.400	22.800	24.000	25.000
50-51	22.300	20.800	20.500	20.600	22.700	22.700	23.367	24.109	24.874	25.663	26.478	30.161	33.793	37.707
52,53+	29.900	31.300	31.500	32.400	35.100	36.800	36.800	37.500	38.000	38.500	39.169	43.713	47.979	52.445
54	9.400	10.700	11.100	11.400	12.100	12.700	13.000	13.200	13.400	13.600	13.900	15.403	16.907	18.481
58	19.000	21.600	21.600	22.700	24.400	26.100	26.700	27.500	28.200	29.000	29.976	35.718	41.851	48.838
60-67	23.400	23.600	19.200	19.200	19.300	19.500	21.720	22.394	23.089	23.806	24.545	27.864	31.113	34.597
70	5.100	5.200	5.800	6.000	6.500	6.800	7.300	7.600	7.800	8.000	8.100	8.900	9.734	10.985
72	3.000	3.800	3.600	3.100	3.200	3.300	4.100	4.200	4.197	4.276	4.356	4.779	5.155	5.539
73	11.000	12.100	12.800	8.000	8.800	9.200	10.500	11.100	11.800	12.500	13.500	17.500	21.500	25.000
76	1.000	1.100	1.000	1.100	1.200	1.200	1.210	1.239	1.269	1.300	1.331	1.460	1.575	1.693
80	15.500	17.900	19.100	20.000	20.700	21.800	23.200	24.100	25.000	25.600	26.300	32.000	38.000	43.000
81	2.100	2.400	2.500	2.700	2.900	3.000	3.300	3.400	3.500	3.600	3.700	4.600	5.400	6.288
83	3.400	4.000	4.100	4.500	4.800	5.000	5.300	5.500	5.700	6.000	6.200	7.400	8.600	9.800
89	4.800	3.900	3.900	10.300	10.700	11.000	11.300	11.600	11.900	12.100	12.300	14.000	15.500	16.500
75,78+	10.300	10.800	11.000	12.100	13.100	13.900	14.300	14.700	15.100	15.400	15.700	17.200	18.400	19.400
82	3.800	3.900	4.100	4.300	4.400	4.500	4.800	4.900	5.000	5.100	5.200	5.700	6.200	6.800
941	31.100	32.300	33.400	34.900	35.300	37.700	38.700	39.500	40.100	40.600	41.100	44.000	47.500	52.100
90-99	26.400	26.100	27.700	28.600	29.900	31.700	32.100	32.500	32.900	33.300	33.800	37.100	40.100	42.205
Const	17.400	15.100	13.600	14.200	16.000	18.000	18.600	18.800	19.000	19.100	19.200	20.300	22.659	24.068
Agric	69.100	65.400	64.800	64.155	63.500	63.333	63.149	62.965	62.781	62.598	62.416	62.051	61.447	61.060
Mining	4.700	3.800	2.600	3.300	3.600	3.800	4.000	4.000	4.100	4.100	4.100	4.500	4.700	4.700
Fd Gvt	13.000	11.800	12.200	12.500	12.900	13.300	13.100	13.214	13.374	13.536	13.700	14.500	15.300	16.200
SUBTOT	345.800	346.800	344.000	354.655	370.200	384.833	397.046	404.821	412.084	418.879	426.471	471.649	517.413	562.406
TOTAL	400.275	401.425	398.200	412.555	430.900	447.883	462.383	471.593	479.537	486.771	494.967	542.313	590.382	636.026

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDHI SCENARIO - IDAHO 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	262.386	280.726	282.675	287.023	288.875	290.394	300.300	307.289	313.637	318.579	324.136	354.114	385.426	412.750
MF	25.070	29.289	29.910	30.632	30.995	31.312	32.807	33.895	34.895	35.699	36.592	41.387	46.407	50.899
MO	36.714	43.986	44.415	45.345	45.585	45.703	48.045	49.563	50.870	51.760	52.778	57.937	62.873	66.718
TOTAL	324.170	354.000	357.000	363.000	365.455	367.409	381.152	390.747	399.401	406.039	413.506	453.439	494.706	530.367
POPUL	944.000	1004.000	1000.500	1004.400	1005.000	1006.700	1036.733	1055.017	1070.396	1084.123	1099.926	1178.940	1261.500	1341.827
HHLDS	324.170	354.000	357.000	363.000	365.455	367.409	381.152	390.747	399.401	406.039	413.506	453.439	494.706	530.367
PCI	8611.20	8400.50	8573.30	8785.80	9226.40	9457.00	9613.60	9854.00	10100.30	10352.80	10611.70	12006.10	13583.80	15368.80

MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	0.700	0.465	0.525	0.550	0.475	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.075	0.075	0.075
25	0.000	0.140	0.150	0.150	0.150	0.150	0.175	0.175	0.175	0.200	0.200	0.250	0.300	0.300
27	0.750	0.700	0.725	0.750	0.825	0.875	0.900	0.925	0.950	0.975	1.000	1.200	1.300	1.400
29	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	0.000	0.025	0.025	0.010	0.010	0.040	0.054	0.059	0.064	0.069	0.075	0.075	0.100	0.100
31	0.000	0.025	0.030	0.010	0.010	0.040	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
32	0.400	0.325	0.280	0.290	0.300	0.300	0.306	0.312	0.318	0.324	0.330	0.350	0.371	0.400
33XX	1.000	0.150	0.050	0.050	0.050	0.050	0.100	0.150	0.150	0.150	0.150	0.150	0.150	0.150
34	0.150	0.250	0.275	0.250	0.225	0.250	0.259	0.269	0.279	0.289	0.300	0.300	0.300	0.300
35	0.050	0.225	0.325	0.350	0.375	0.400	0.425	0.425	0.450	0.475	0.500	0.575	0.650	0.700
36	0.050	0.075	0.075	0.100	0.125	0.125	0.108	0.118	0.128	0.138	0.150	0.175	0.204	0.225
37	0.100	0.075	0.050	0.100	0.100	0.100	0.108	0.118	0.128	0.138	0.150	0.200	0.250	0.300
38	0.100	0.125	0.120	0.130	0.140	0.150	0.159	0.168	0.178	0.189	0.200	0.225	0.253	0.275
39	0.150	0.175	0.300	0.650	0.700	0.750	0.750	0.775	0.800	0.825	0.850	0.900	0.900	0.900
2421	4.500	4.000	4.150	3.900	3.900	4.000	3.923	4.117	4.192	4.209	4.319	4.363	4.580	4.576
2436	1.000	0.800	0.800	0.800	0.950	0.825	0.710	0.701	0.706	0.716	0.739	0.765	0.763	0.773
24XX	2.700	2.100	2.500	2.500	2.650	2.650	2.651	2.639	2.628	2.616	2.605	2.517	2.429	2.342
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2631	0.550	0.750	0.750	0.750	0.750	0.750	0.744	0.738	0.732	0.727	0.721	0.693	0.667	0.641
26XX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	0.200	0.190	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.181	0.179	0.177	0.175
28XX	0.100	0.050	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.101	0.101	0.101	0.100	0.099
3334	1.250	0.850	0.750	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
SUBTOT	13.775	11.545	12.160	12.470	12.865	13.085	13.053	13.370	13.558	13.721	13.970	14.443	14.921	15.082

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDHI SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	7.500	6.400	6.650	6.700	6.900	7.000	7.280	7.404	7.529	7.656	7.786	8.251	8.599	8.924
50-51	3.800	3.400	3.275	3.375	3.500	3.600	3.703	3.811	3.921	4.035	4.152	4.667	5.161	5.683
52,53+	8.000	8.200	8.650	8.700	8.775	8.850	9.200	9.602	9.837	10.078	10.325	11.355	12.280	13.227
54	2.900	3.000	2.825	3.100	3.500	3.800	4.000	4.200	4.300	4.400	4.500	5.000	5.500	6.000
58	7.500	7.500	7.475	7.500	8.400	8.600	8.800	9.000	9.200	9.400	9.753	11.791	14.018	16.597
60-67	3.700	3.400	3.650	3.650	3.850	3.950	4.000	4.100	4.200	4.300	4.400	5.000	5.400	5.725
70	2.500	2.700	2.900	2.850	2.700	2.800	3.000	3.200	3.446	3.567	3.692	4.274	4.866	5.518
72	0.800	0.900	0.875	0.900	0.775	0.750	0.900	1.005	1.027	1.049	1.072	1.165	1.244	1.324
73	1.000	1.700	2.175	2.200	1.650	1.750	1.900	2.050	2.250	2.450	2.650	3.500	4.121	4.832
76	0.300	0.300	0.350	0.350	0.425	0.450	0.475	0.490	0.500	0.510	0.525	0.600	0.650	0.700
80	6.400	7.650	8.300	8.400	8.700	8.800	9.000	9.300	9.600	9.800	10.000	12.000	13.800	15.300
81	0.500	0.600	0.700	0.700	0.725	0.800	0.800	0.825	0.840	0.850	0.875	0.988	1.157	1.350
83	1.400	1.200	1.525	1.500	2.100	2.300	2.500	2.700	2.900	3.100	3.200	3.900	4.400	4.700
89	1.000	0.700	0.800	0.800	0.750	0.800	0.870	0.882	0.893	0.905	0.917	0.965	1.057	1.152
75,78+	3.300	3.325	3.450	3.500	3.500	3.500	3.675	3.752	3.831	3.911	3.993	4.380	4.726	5.078
82	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
941	8.900	9.775	9.500	9.400	9.600	9.800	10.100	10.400	10.700	11.000	11.300	12.552	13.409	14.265
90-99	8.300	7.400	7.400	7.400	8.000	8.200	8.735	8.927	9.124	9.325	9.530	10.352	11.059	11.765
Const	4.800	3.800	2.800	3.050	3.250	3.400	3.500	3.600	3.700	3.800	3.900	4.300	4.700	5.100
Agric	7.500	7.300	7.300	7.300	7.300	7.300	7.326	7.312	7.299	7.285	7.272	7.168	7.229	7.281
Mining	3.100	1.875	2.075	2.175	2.300	2.600	2.700	2.800	2.900	3.000	3.100	3.400	3.600	3.800
Fd Gvt	5.600	4.850	4.900	4.950	5.100	5.200	5.200	5.200	5.219	5.259	5.300	5.500	5.800	6.200
SUBTOT	88.800	85.975	87.575	88.500	91.800	94.250	97.664	100.560	103.216	105.680	108.242	121.108	132.776	144.521
TOTAL	102.575	97.520	99.735	100.970	104.665	107.335	110.717	113.930	116.774	119.401	122.212	135.551	147.697	159.603

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDHI SCENARIO - WESTERN MONTANA 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	82.313	84.905	85.568	86.062	86.319	86.669	89.671	92.612	95.316	97.895	100.656	111.097	121.731	130.308
MF	8.950	10.092	10.297	10.374	10.439	10.518	10.978	11.430	11.849	12.249	12.677	14.337	16.033	17.440
MO	15.138	17.403	17.634	17.775	17.732	17.700	18.389	19.045	19.618	20.138	20.691	22.290	23.695	24.535
TOTAL	106.400	112.400	113.500	114.211	114.491	114.886	119.038	123.088	126.783	130.282	134.025	147.723	161.460	172.283
POPUL	294.500	303.900	303.500	303.800	303.400	303.300	311.880	320.027	327.099	333.522	340.423	366.354	390.732	413.480
HHLDS	106.400	112.400	113.500	114.211	114.491	114.886	119.038	123.088	126.783	130.282	134.025	147.723	161.460	172.283
PCI	7793.00	7983.00	8527.20	8697.80	8871.70	9049.10	9991.00	9991.00	9991.00	9991.00	9991.00	11030.90	12179.00	13446.70

MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - REGION 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	73.900	71.965	72.925	75.550	76.475	78.300	76.895	76.690	76.885	76.880	76.675	75.275	73.750	72.450
22	3.000	2.550	2.900	3.100	3.100	3.550	3.050	3.050	3.050	2.950	2.950	2.800	2.800	2.800
23	10.025	8.900	8.550	8.950	9.050	9.500	9.089	9.179	9.269	9.359	9.550	9.825	10.125	10.425
25	6.150	7.240	7.050	7.950	7.850	8.320	8.050	8.050	8.150	8.250	8.350	8.875	9.177	9.475
27	29.650	34.000	37.925	39.850	41.025	41.775	42.400	44.125	46.325	48.150	49.275	57.600	62.500	66.300
29	2.800	2.225	2.350	2.450	2.450	2.750	2.875	2.775	2.875	2.875	2.875	2.825	2.775	2.775
30	6.900	8.575	10.025	11.210	12.010	12.390	13.840	14.742	15.545	15.947	16.850	20.450	23.463	25.463
31	0.700	0.925	1.080	1.160	1.260	1.150	1.238	1.317	1.307	1.298	1.288	1.288	1.288	1.288
32	13.100	10.725	11.580	12.490	12.900	14.100	13.603	13.706	13.709	13.812	13.815	13.725	13.636	13.550
33XX	20.800	15.350	15.550	16.550	17.550	18.450	18.350	18.500	18.625	18.525	18.525	18.450	18.200	18.000
34	26.750	22.850	22.975	24.350	26.625	27.250	26.155	26.260	26.865	27.070	27.175	28.775	30.575	31.475
35	37.750	38.625	37.525	40.650	43.175	44.900	45.200	46.500	47.425	48.050	48.350	51.900	55.150	57.950
36	22.550	28.875	30.175	28.700	32.325	35.075	39.108	40.418	41.628	42.038	42.150	45.175	47.804	49.925
37	109.450	99.825	118.150	129.500	141.500	142.700	142.205	144.909	148.314	149.020	148.725	142.850	135.175	125.600
38	25.950	25.725	23.320	28.330	27.940	26.850	26.459	26.718	26.828	27.039	26.350	29.625	31.653	33.925
39	7.350	7.400	8.600	10.350	11.900	10.550	11.450	11.775	12.000	12.100	12.400	13.400	13.800	14.000
2421	52.427	44.300	47.250	47.200	47.000	44.900	43.349	40.997	40.026	38.489	38.557	34.867	36.363	37.018
2436	26.582	20.900	21.900	20.900	20.750	19.125	19.344	18.110	17.408	16.044	15.541	11.681	11.270	10.966
24XX	61.066	57.100	60.100	63.400	62.650	59.450	59.634	58.234	57.523	56.821	56.128	53.403	50.812	48.345
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.459	2.421	2.384	2.347	2.310	2.135	1.974	1.824
2621	14.143	13.410	12.650	12.900	13.700	13.700	13.623	13.546	13.475	13.400	13.328	12.982	12.671	12.382
2631	5.037	5.000	4.900	4.850	5.450	5.550	5.501	5.453	5.404	5.357	5.310	5.080	4.862	4.651
26XX	7.896	7.815	8.750	8.500	8.500	8.600	8.525	8.508	8.480	8.479	8.492	8.440	8.441	8.113
2812	0.763	0.700	0.700	0.700	0.600	0.700	0.701	0.701	0.702	0.703	0.704	0.712	0.715	0.714
2819	6.567	8.890	8.780	9.780	9.580	9.980	10.174	10.167	10.061	10.054	10.048	9.418	8.988	8.459
28XX	7.470	7.650	7.650	7.900	8.000	8.600	7.950	7.926	7.903	7.879	7.856	7.753	7.639	7.514
3334	10.350	7.250	5.850	7.300	7.600	7.600	6.300	6.100	6.000	5.940	5.900	5.650	5.600	5.600
SUBTOT	592.100	560.870	591.260	626.670	653.465	658.315	657.527	660.878	668.166	668.877	669.475	674.959	681.204	680.988

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - REGION 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	179.500	176.500	181.550	187.700	196.700	203.600	204.671	206.456	209.641	211.828	214.516	225.080	233.048	238.793
50-51	194.000	195.700	203.375	213.275	229.000	239.200	240.097	242.084	244.472	247.888	252.628	276.361	305.383	336.067
52,53+	275.100	279.300	300.050	314.100	332.675	346.650	348.779	352.050	355.124	357.101	359.806	385.344	408.412	437.912
54	75.100	92.400	105.125	110.800	117.300	123.900	124.850	125.900	126.950	127.800	128.550	134.700	141.984	150.972
58	195.500	218.400	233.275	241.600	250.100	261.300	269.308	277.712	286.781	296.260	306.249	361.689	420.417	486.845
60-67	188.900	193.400	202.450	205.550	210.750	215.550	216.900	222.950	230.200	234.650	237.500	262.789	289.285	316.502
70	40.200	42.600	45.800	48.850	52.300	55.400	55.800	56.500	57.000	57.572	58.631	64.948	72.400	80.124
72	29.600	35.000	36.075	34.100	35.275	37.150	40.800	42.500	43.050	43.604	43.921	46.998	49.804	52.533
73	89.800	109.800	138.475	123.200	133.650	142.750	146.850	151.950	157.050	161.700	166.350	208.000	246.600	281.000
76	9.800	10.500	11.350	12.750	14.225	14.750	14.950	15.360	15.680	16.111	16.243	17.181	17.886	18.390
80	179.800	212.350	231.100	240.600	252.300	269.000	279.500	289.833	300.909	309.600	317.700	370.000	420.200	469.200
81	17.400	22.700	25.700	26.900	27.925	29.300	30.873	31.555	32.389	33.340	34.455	41.317	48.855	57.541
83	31.800	41.800	47.525	56.500	61.000	63.900	65.700	67.500	68.700	70.300	71.850	81.250	93.600	105.206
89	36.400	36.000	39.100	65.800	71.150	75.300	78.375	81.285	83.805	86.125	88.546	103.446	117.244	127.746
75,78+	122.600	141.125	150.850	158.900	168.500	177.600	181.490	185.475	189.467	192.468	195.478	210.256	224.782	236.012
82	19.800	24.200	27.500	32.800	34.600	35.800	35.900	36.200	36.700	37.100	37.300	39.700	41.500	43.600
941	279.700	280.275	291.400	299.600	306.700	317.900	320.982	324.361	329.143	334.029	338.818	363.783	383.228	399.854
90-99	230.300	236.100	248.300	257.500	266.400	276.300	279.052	281.787	284.524	287.363	290.505	311.035	330.121	348.998
Const	161.300	132.600	140.600	153.750	171.050	184.600	171.050	172.400	176.139	178.400	175.840	188.400	199.600	209.888
Agric	292.200	286.600	286.200	285.055	284.100	283.357	282.463	281.580	280.700	279.824	278.950	274.551	270.151	265.850
Mining	13.300	9.875	9.075	10.075	10.900	11.800	11.770	11.589	11.309	11.380	11.500	11.650	11.800	11.900
Fd Gvt	117.300	116.350	118.300	120.550	122.200	127.200	125.400	124.500	123.919	124.137	124.350	129.200	134.500	140.950
SUBTOT	2779.400	2893.575	3073.175	3199.955	3348.800	3492.307	3525.560	3581.527	3643.652	3698.580	3749.687	4107.678	4460.800	4815.883
TOTAL	3371.500	3454.446	3664.435	3826.625	4002.265	4150.623	4183.086	4242.405	4311.818	4367.457	4419.162	4782.637	5142.004	5496.871

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDIUM SCENARIO - REGION 2/12/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	20[illegible]
HOUSING														
SF	2304.022	2428.959	2486.587	2541.383	2603.354	2649.937	2707.672	2759.719	2814.922	2860.251	2900.775	3131.736	3356.560	3548.464
MF	427.732	492.379	520.091	540.652	564.666	582.969	604.561	623.759	644.392	661.644	677.336	765.107	852.057	929.785
MO	230.919	280.062	298.822	314.176	331.171	343.720	359.378	373.311	387.903	399.466	409.479	464.406	513.570	552.512
TOTAL	2962.673	3201.400	3305.500	3396.210	3499.190	3576.626	3671.611	3756.789	3847.218	3921.361	3987.590	4361.248	4722.187	5030.761
POPUL	8003.820	8389.700	8532.000	8668.200	8860.400	9019.000	9216.418	9354.876	9503.011	9611.076	9710.118	10372.261	11007.329	11641.684
HHLDS	2962.673	3201.400	3305.500	3396.210	3499.190	3576.626	3671.611	3756.789	3847.218	3921.361	3987.590	4361.248	4722.187	5030.761
PCI	10360.21	10444.04	10785.29	10968.18	11357.44	11433.36	11779.98	11984.38	12194.09	12405.44	12619.33	13786.26	15063.38	16459.67

MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - WASHINGTON 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	31.900	31.100	32.300	34.200	35.500	35.900	35.100	35.000	34.900	34.700	34.600	34.000	33.500	33.000
22	1.000	0.900	1.000	1.200	1.200	1.300	1.300	1.300	1.300	1.200	1.200	1.150	1.150	1.150
23	6.500	6.200	5.700	6.000	6.000	6.200	6.200	6.300	6.400	6.500	6.700	7.100	7.400	7.700
25	3.300	3.800	3.800	4.200	4.000	4.300	4.500	4.600	4.700	4.800	4.900	5.400	5.700	6.000
27	15.800	17.600	20.100	21.400	22.100	22.000	22.100	23.100	24.500	25.500	26.000	31.000	34.000	36.000
29	2.100	1.800	1.800	1.900	1.900	2.200	2.200	2.200	2.300	2.300	2.300	2.300	2.300	2.300
30	3.500	4.500	5.100	5.800	6.200	6.500	7.000	7.300	7.600	7.700	7.900	9.500	11.000	12.000
31	0.400	0.400	0.400	0.500	0.600	0.500	0.600	0.600	0.600	0.600	0.600	0.600	0.600	0.600
32	6.900	6.400	6.900	7.300	7.500	7.900	7.900	7.800	7.900	8.000	8.000	8.000	8.000	8.000
33XX	9.000	6.900	6.900	7.100	7.300	7.600	7.500	7.600	7.600	7.600	7.600	7.600	7.600	7.600
34	11.800	9.700	10.500	10.900	11.800	12.200	12.000	11.800	12.000	12.200	12.300	12.800	13.400	13.900
35	15.000	17.100	16.200	18.000	19.000	19.500	19.900	20.600	21.000	21.100	21.200	22.500	23.700	24.950
36	11.200	12.100	13.200	10.500	11.700	12.100	15.300	15.400	15.500	15.600	15.700	16.400	17.000	17.600
37	98.350	89.600	106.200	116.200	128.500	128.900	129.800	131.500	134.300	134.600	134.200	128.000	120.000	109.900
38	6.400	10.700	10.800	14.600	14.900	14.700	14.800	15.000	15.000	15.000	14.500	15.500	16.200	17.000
39	4.600	4.500	4.800	5.500	5.900	5.600	6.100	6.300	6.500	6.700	7.000	7.500	7.500	7.500
2421	16.027	13.400	14.500	15.200	15.300	14.700	14.321	13.309	12.819	12.148	12.075	10.454	10.868	11.179
2436	4.982	4.200	3.900	3.600	3.100	3.000	2.916	2.716	2.605	2.398	2.313	1.765	1.734	1.709
24XX	25.991	20.700	22.000	22.800	22.700	21.900	21.582	21.000	20.706	20.417	20.131	19.154	18.225	17.340
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.459	2.421	2.384	2.347	2.310	2.135	1.974	1.824
2621	8.818	9.000	8.400	8.700	9.300	9.300	9.250	9.196	9.147	9.096	9.048	8.813	8.601	8.405
2631	1.637	1.200	1.200	1.200	1.600	1.600	1.586	1.571	1.557	1.544	1.531	1.464	1.401	1.340
26XX	4.171	4.400	4.950	5.100	4.900	5.000	5.068	5.081	5.094	5.107	5.120	5.090	5.093	4.881
2812	0.513	0.500	0.500	0.500	0.400	0.500	0.500	0.501	0.502	0.502	0.503	0.508	0.511	0.510
2819	5.300	7.700	7.700	8.700	8.500	8.900	9.100	9.100	9.000	9.000	9.000	8.400	8.000	7.500
28XX	2.887	3.100	3.300	3.300	3.300	3.500	3.280	3.271	3.261	3.251	3.242	3.202	3.155	3.101
3334	7.700	5.800	4.400	5.600	5.900	5.900	4.800	4.700	4.600	4.540	4.500	4.300	4.300	4.300
SUBTOT	308.750	295.400	318.600	342.100	361.600	364.200	367.162	369.267	373.776	374.450	374.473	374.636	372.910	367.289

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - WASHINGTON 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	91.400	93.600	98.500	101.900	107.900	112.000	112.600	113.500	115.000	116.000	118.000	123.000	127.000	130.000
50-51	100.500	105.700	111.400	116.400	124.600	132.100	133.000	134.500	136.000	138.209	140.631	151.340	167.748	185.170
52,53+	141.000	146.900	161.200	168.800	179.100	189.000	191.000	193.000	195.000	196.000	197.000	210.783	221.371	238.315
54	38.200	49.200	57.400	59.900	62.300	65.400	65.600	66.000	66.500	67.000	67.400	70.000	74.160	79.836
58	101.600	118.900	128.200	132.500	135.000	141.600	148.108	153.519	159.128	164.942	170.969	202.189	235.761	273.869
60-67	91.800	99.600	107.500	109.400	112.300	116.300	115.500	120.200	125.800	128.500	129.300	144.189	158.885	174.307
70	17.800	20.100	21.500	22.900	24.700	26.100	26.300	26.600	26.800	27.072	27.831	31.592	35.361	39.418
72	16.000	19.900	20.800	19.700	20.400	21.500	24.000	25.300	25.600	25.800	26.000	28.000	29.800	31.518
73	52.900	61.000	78.000	70.000	76.500	83.700	86.000	88.500	91.000	93.000	95.000	118.000	140.000	158.900
76	5.500	5.600	5.900	6.900	8.000	8.400	8.300	8.500	8.700	9.000	9.000	9.500	9.800	10.100
80	95.800	117.400	129.300	134.600	140.800	151.200	154.000	159.033	165.009	170.000	175.000	205.000	233.000	261.000
81	9.200	12.400	14.400	15.000	15.600	16.500	17.100	17.400	17.800	18.200	18.732	22.530	26.720	31.561
83	15.600	22.600	25.000	27.200	29.700	31.400	32.500	33.500	34.000	34.800	35.600	40.000	47.000	54.406
89	19.500	21.100	23.100	37.500	40.700	43.000	44.800	46.800	48.500	50.000	51.500	60.500	68.000	74.000
75,78+	66.800	83.500	89.000	95.400	101.100	106.700	109.000	112.000	115.000	117.000	119.000	127.000	135.800	141.000
82	8.900	12.000	13.100	14.700	15.900	16.700	16.800	17.000	17.200	17.400	17.500	18.500	19.500	20.700
941	145.500	143.600	151.100	156.000	160.600	166.300	167.000	168.200	170.700	173.300	175.900	189.300	198.000	205.500
90-99	117.400	129.100	135.500	141.300	146.800	152.100	153.000	154.000	155.000	156.000	157.300	168.700	178.954	189.914
Const	92.600	80.600	88.900	96.600	106.600	115.300	106.300	106.800	110.089	111.900	108.890	118.000	126.000	133.000
Agric	119.300	115.100	114.400	113.300	112.300	111.402	111.266	111.131	110.996	110.861	110.726	108.545	107.066	105.311
Mining	3.200	2.700	3.000	3.300	3.600	4.000	3.800	3.600	3.300	3.300	3.300	3.300	3.300	3.300
Fd Gvt	67.900	70.100	70.600	71.400	72.000	74.500	74.700	74.800	74.900	75.000	75.000	78.000	81.000	85.000
SUBTOT	1418.400	1530.700	1647.800	1714.700	1796.500	1885.202	1900.674	1933.883	1972.022	2003.284	2029.579	2227.968	2424.226	2626.125
TOTAL	1727.150	1826.100	1966.400	2056.800	2158.100	2249.402	2267.836	2303.150	2345.798	2377.734	2404.052	2602.604	2797.136	2993.414

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDIUM SCENARIO - WASHINGTON 2/12/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	1193.211	1266.263	1303.362	1335.748	1377.932	1406.557	1440.932	1468.327	1500.162	1523.942	1545.052	1665.803	1782.353	1884.547
MF	250.130	298.560	319.108	333.483	351.732	364.707	379.971	392.537	406.878	418.100	428.311	485.828	542.486	594.206
MO	97.169	126.178	138.530	147.769	159.622	167.660	177.190	184.707	193.348	199.675	205.168	235.378	262.514	284.815
TOTAL	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1998.094	2045.572	2100.389	2141.717	2178.531	2387.009	2587.354	2763.568
POPUL	4132.160	4406.000	4538.000	4619.000	4761.000	4866.700	4995.234	5073.018	5166.957	5225.790	5272.044	5633.342	5976.787	6328.571
HHLDS	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1998.094	2045.572	2100.389	2141.717	2178.531	2387.009	2587.354	2763.568
PCI	10725.00	10924.00	11258.00	11383.00	11774.00	11798.00	12191.90	12395.50	12602.50	12813.00	13027.00	14151.70	15373.50	16700.80

MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - OREGON 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	24.300	23.800	24.000	23.700	23.600	24.900	24.400	24.300	24.300	24.500	24.500	24.000	23.500	23.200
22	2.000	1.600	1.800	1.800	1.800	2.100	1.700	1.700	1.700	1.700	1.700	1.600	1.600	1.600
23	3.200	2.400	2.500	2.600	2.700	2.900	2.600	2.600	2.600	2.600	2.600	2.500	2.500	2.500
25	2.600	2.700	2.500	2.900	3.000	3.200	2.700	2.600	2.600	2.600	2.600	2.600	2.602	2.600
27	10.000	11.500	12.800	13.200	13.500	14.100	14.400	14.900	15.700	16.400	16.900	19.500	20.800	22.000
29	0.600	0.400	0.500	0.500	0.500	0.500	0.600	0.500	0.500	0.500	0.500	0.450	0.400	0.400
30	2.400	3.200	3.800	4.600	4.900	5.000	6.000	6.500	7.000	7.300	8.000	10.000	11.500	12.500
31	0.300	0.400	0.500	0.500	0.500	0.500	0.500	0.579	0.569	0.560	0.550	0.550	0.550	0.550
32	4.500	3.100	3.600	4.000	4.200	4.900	4.300	4.600	4.600	4.600	4.600	4.500	4.400	4.300
33XX	9.600	8.200	8.600	9.300	10.100	10.700	10.600	10.600	10.700	10.600	10.600	10.500	10.300	10.100
34	12.700	11.000	10.200	11.200	12.300	12.400	11.500	11.700	12.100	12.000	12.000	13.000	14.200	14.600
35	17.700	15.500	15.800	16.800	17.600	18.000	17.800	18.200	18.500	18.900	19.000	20.500	22.000	23.000
36	9.800	13.900	13.600	14.100	15.600	17.250	17.900	18.900	19.800	20.000	20.000	21.800	23.400	24.600
37	10.300	9.200	10.800	11.600	11.400	12.200	10.900	11.800	12.500	12.900	13.000	13.500	14.000	14.500
38	19.300	14.600	12.100	13.200	12.500	11.600	11.000	11.000	11.100	11.300	11.100	13.300	14.550	15.950
39	2.200	2.400	3.200	3.800	4.900	3.800	4.200	4.300	4.300	4.200	4.200	4.700	5.100	5.300
2421	23.800	20.500	22.000	21.400	20.800	19.000	18.620	17.269	16.598	15.686	15.552	13.366	13.901	14.254
2436	20.100	15.500	16.800	16.100	16.300	14.900	15.440	14.463	13.866	12.696	12.247	8.900	8.523	8.231
24XX	25.600	27.600	29.200	31.300	29.900	27.300	28.700	28.203	27.875	27.551	27.230	25.909	24.651	23.455
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	5.100	4.160	4.000	3.900	4.100	4.100	4.076	4.053	4.033	4.011	3.988	3.884	3.792	3.706
2631	2.000	2.100	2.000	1.900	2.000	2.000	1.983	1.965	1.947	1.930	1.913	1.831	1.752	1.676
26XX	3.300	2.840	3.200	2.800	3.000	3.000	2.893	2.859	2.814	2.796	2.792	2.793	2.784	2.686
2812	0.250	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.201	0.201	0.201	0.203	0.204	0.204
2819	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
28XX	2.050	1.900	1.900	1.900	2.000	2.300	1.878	1.872	1.867	1.861	1.856	1.833	1.806	1.775
3334	1.400	0.600	0.700	0.900	0.900	0.900	0.800	0.700	0.700	0.700	0.700	0.650	0.600	0.600
SUBTOT	215.100	199.300	206.300	214.200	218.300	217.750	215.690	216.364	218.468	218.092	218.328	222.369	229.415	234.287

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - OREGON 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	60.500	57.300	58.500	60.500	62.800	65.100	64.900	65.500	67.000	68.000	68.500	72.000	75.000	77.000
50-51	67.400	65.800	68.200	72.900	78.200	80.800	81.000	81.100	81.300	81.816	83.079	92.645	101.887	111.589
52,53+	96.200	92.900	98.700	104.200	109.700	112.000	112.500	113.000	113.500	114.000	115.325	123.250	132.188	141.146
54	24.600	29.500	33.800	36.400	39.400	42.000	42.500	43.000	43.300	43.500	43.700	46.000	48.000	50.000
58	67.400	70.400	76.000	78.900	82.300	85.000	86.000	88.593	91.653	94.818	98.093	114.888	132.670	152.625
60-67	70.000	66.800	72.100	73.300	75.300	75.800	77.300	78.400	79.500	80.500	82.000	89.000	98.000	107.000
70	14.800	14.600	15.600	17.100	18.400	19.700	19.500	19.600	19.700	19.800	19.900	21.100	23.500	25.759
72	9.800	10.400	10.800	10.400	10.900	11.600	12.000	12.200	12.400	12.600	12.700	13.400	14.100	14.754
73	24.900	35.000	45.500	43.000	46.700	48.100	49.000	51.000	53.000	55.000	57.000	72.000	85.000	97.000
76	3.000	3.500	4.100	4.400	4.600	4.700	5.000	5.200	5.300	5.400	5.500	5.800	6.100	6.200
80	62.100	69.400	74.400	77.600	82.100	87.200	93.700	98.200	102.500	105.500	108.000	124.000	140.000	155.000
81	5.600	7.300	8.100	8.500	8.700	9.000	9.923	10.305	10.703	11.116	11.545	13.786	16.231	19.039
83	11.400	14.000	16.900	23.300	24.400	25.200	25.600	26.100	26.500	27.000	27.500	31.000	35.000	38.000
89	11.100	10.300	11.300	17.200	19.000	20.500	21.500	22.000	22.500	23.000	23.500	27.000	31.000	33.500
75,78+	42.200	43.500	47.400	47.900	50.800	53.500	54.827	55.461	56.101	56.749	57.405	62.578	67.137	72.000
82	7.100	8.300	10.300	13.800	14.300	14.600	14.500	14.600	14.800	14.900	15.000	16.000	16.500	17.000
941	94.200	94.600	97.400	99.300	101.200	104.100	105.500	107.000	108.600	110.300	111.900	120.000	127.800	134.400
90-99	78.200	73.500	77.700	80.200	81.700	84.300	85.600	86.900	88.200	89.500	90.800	97.300	103.500	109.000
Const	46.500	33.100	35.300	39.900	45.200	47.900	42.800	43.500	44.000	44.500	45.000	47.000	49.000	51.000
Agric	96.300	98.800	99.700	100.300	101.000	101.710	101.305	100.902	100.501	100.101	99.703	98.687	97.036	95.512
Mining	2.300	1.500	1.400	1.300	1.400	1.400	1.670	1.689	1.709	1.730	1.750	1.850	1.950	1.950
Fd Gvt	30.800	29.600	30.600	31.700	32.200	34.200	33.000	32.000	31.300	31.339	31.450	32.450	34.050	35.700
SUBTOT	926.400	930.100	993.800	1042.100	1090.300	1128.410	1139.625	1156.250	1174.067	1191.169	1209.350	1321.734	1435.649	1545.174
TOTAL	1141.500	1129.400	1200.100	1256.300	1308.600	1346.160	1355.315	1372.614	1392.535	1409.261	1427.678	1544.103	1665.064	1779.461

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDIUM SCENARIO - OREGON 2/12/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	766.113	797.066	815.229	833.166	851.116	867.474	884.640	902.438	918.703	935.139	949.374	1025.865	1103.232	1166.036
MF	143.583	154.439	160.683	165.922	171.176	176.024	181.095	186.341	191.197	196.108	200.454	223.712	247.407	267.453
MO	81.898	92.495	98.088	102.912	107.668	111.908	116.294	120.774	124.748	128.687	131.934	148.535	164.158	175.719
TOTAL	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1182.029	1209.553	1234.648	1259.934	1281.762	1398.112	1514.796	1609.207
POPUL	2633.160	2675.800	2690.000	2741.000	2791.000	2842.300	2895.972	2939.215	2975.503	3011.242	3050.594	3257.601	3468.884	3668.991
HHLDS	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1182.029	1209.553	1234.648	1259.934	1281.762	1398.112	1514.796	1609.207
PCI	9897.80	9845.90	10162.10	10402.20	10731.30	10804.40	11057.50	11267.60	11481.70	11699.80	11922.10	13098.60	14391.20	15811.30

MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - IDAHO 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	17.000	16.600	16.100	17.100	16.900	17.000	16.900	16.900	17.200	17.200	17.100	16.800	16.300	15.800
22	0.000	0.050	0.100	0.100	0.100	0.150	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
23	0.300	0.250	0.300	0.300	0.300	0.350	0.239	0.229	0.219	0.209	0.200	0.150	0.150	0.150
25	0.250	0.600	0.600	0.700	0.700	0.670	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
27	3.100	4.200	4.300	4.500	4.600	4.800	5.000	5.200	5.200	5.300	5.400	6.000	6.500	7.000
29	0.100	0.025	0.050	0.050	0.050	0.050	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
30	1.000	0.850	1.100	0.800	0.900	0.850	0.800	0.900	0.900	0.900	0.900	0.900	0.900	0.900
31	0.000	0.100	0.150	0.150	0.150	0.110	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
32	1.300	0.900	0.800	0.900	0.900	1.000	1.100	1.000	0.900	0.900	0.900	0.900	0.900	0.900
33XX	1.200	0.100	0.000	0.100	0.100	0.100	0.200	0.250	0.250	0.250	0.250	0.250	0.200	0.200
34	2.100	1.900	2.000	2.000	2.300	2.400	2.400	2.500	2.500	2.600	2.600	2.700	2.700	2.700
35	5.000	5.800	5.200	5.500	6.200	7.000	7.100	7.300	7.500	7.600	7.700	8.400	8.900	9.400
36	1.500	2.800	3.300	4.000	4.900	5.600	5.800	6.000	6.200	6.300	6.300	6.800	7.200	7.500
37	0.700	0.950	1.100	1.600	1.500	1.500	1.400	1.500	1.400	1.400	1.400	1.200	1.000	1.000
38	0.150	0.300	0.300	0.400	0.400	0.400	0.500	0.550	0.550	0.550	0.550	0.600	0.650	0.700
39	0.400	0.325	0.300	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400
2421	8.100	6.400	6.600	6.700	7.000	7.200	6.671	6.676	6.798	6.829	7.006	7.079	7.431	7.423
2436	0.500	0.400	0.400	0.400	0.400	0.400	0.311	0.294	0.295	0.299	0.309	0.320	0.319	0.324
24XX	6.775	6.700	6.400	6.800	7.400	7.600	6.802	6.507	6.442	6.379	6.316	6.009	5.717	5.440
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.225	0.250	0.250	0.300	0.300	0.300	0.298	0.297	0.295	0.293	0.292	0.284	0.277	0.271
2631	0.850	0.950	0.950	1.000	1.100	1.200	1.189	1.179	1.169	1.159	1.148	1.099	1.051	1.006
26XX	0.425	0.575	0.600	0.600	0.600	0.600	0.564	0.568	0.572	0.576	0.580	0.558	0.565	0.547
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	1.067	1.000	0.900	0.900	0.900	0.900	0.895	0.889	0.884	0.879	0.873	0.849	0.823	0.799
28XX	2.433	2.600	2.400	2.600	2.600	2.700	2.692	2.684	2.676	2.668	2.660	2.621	2.583	2.544
3334	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SUBTOT	54.475	54.625	54.200	57.900	60.700	63.280	62.186	62.748	63.275	63.616	63.809	64.843	65.492	65.929

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - IDAHO 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	20.100	19.200	17.900	18.600	19.100	19.500	20.100	20.300	20.400	20.500	20.600	22.300	23.000	23.500
50-51	22.300	20.800	20.500	20.600	22.700	22.700	22.500	22.800	23.400	24.000	24.962	27.972	30.914	34.024
52,53+	29.900	31.300	31.500	32.400	35.100	36.800	36.200	36.800	37.200	37.500	37.700	40.700	43.500	46.359
54	9.400	10.700	11.100	11.400	12.100	12.700	12.900	13.000	13.200	13.300	13.400	14.300	15.224	16.336
58	19.000	21.600	21.600	22.700	24.400	26.100	26.500	26.800	27.100	27.500	28.000	33.694	39.194	45.419
60-67	23.400	23.600	19.200	19.200	19.300	19.500	20.100	20.300	20.800	21.500	22.000	25.000	27.500	29.900
70	5.100	5.200	5.800	6.000	6.500	6.800	7.100	7.300	7.400	7.500	7.600	8.300	9.100	9.986
72	3.000	3.800	3.600	3.100	3.200	3.300	4.000	4.100	4.100	4.200	4.200	4.500	4.740	5.031
73	11.000	12.100	12.800	8.000	8.800	9.200	10.000	10.500	11.000	11.500	12.000	15.000	18.000	21.000
76	1.000	1.100	1.000	1.100	1.200	1.200	1.200	1.200	1.210	1.231	1.253	1.351	1.436	1.520
80	15.500	17.900	19.100	20.000	20.700	21.800	22.900	23.600	24.200	24.700	25.200	30.000	35.000	40.000
81	2.100	2.400	2.500	2.700	2.900	3.000	3.100	3.100	3.136	3.257	3.382	4.058	4.801	5.657
83	3.400	4.000	4.100	4.500	4.800	5.000	5.200	5.400	5.600	5.800	6.000	7.000	8.000	9.000
89	4.800	3.900	3.900	10.300	10.700	11.000	11.300	11.700	12.000	12.300	12.700	15.000	17.200	19.100
75,78+	10.300	10.800	11.000	12.100	13.100	13.900	14.100	14.400	14.700	15.000	15.300	16.600	17.500	18.400
82	3.800	3.900	4.100	4.300	4.400	4.500	4.600	4.600	4.700	4.800	4.800	5.200	5.500	5.900
941	31.100	32.300	33.400	34.900	35.300	37.700	38.500	39.000	39.500	39.900	40.300	42.800	45.100	47.000
90-99	26.400	26.100	27.700	28.600	29.900	31.700	32.000	32.300	32.600	33.000	33.400	35.400	37.500	39.400
Const	17.400	15.100	13.600	14.200	16.000	18.000	18.500	18.600	18.500	18.400	18.300	19.500	20.500	21.588
Agric	69.100	65.400	64.800	64.155	63.500	62.945	62.627	62.311	61.996	61.683	61.371	60.348	59.096	58.099
Mining	4.700	3.800	2.600	3.300	3.600	3.800	3.800	3.800	3.800	3.800	3.800	3.750	3.700	3.700
Fd Gvt	13.000	11.800	12.200	12.500	12.900	13.300	12.600	12.600	12.600	12.639	12.700	13.350	13.950	14.650
SUBTOT	345.800	346.800	344.000	354.655	370.200	384.445	389.827	394.511	399.142	404.010	408.968	446.123	480.455	515.569
TOTAL	400.275	401.425	398.200	412.555	430.900	447.725	452.013	457.259	462.417	467.626	472.777	510.966	545.947	581.498

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDIUM SCENARIO - IDAHO 2/12/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	262.386	280.726	282.559	286.612	288.292	289.653	294.926	300.430	306.005	309.504	313.007	338.706	362.270	383.255
MF	25.070	29.289	29.947	30.747	31.164	31.531	32.539	33.587	34.649	35.376	36.107	41.132	45.869	50.238
MO	36.714	43.986	44.494	45.641	45.999	46.225	47.663	49.139	50.601	51.366	52.095	57.858	62.403	66.162
TOTAL	324.170	354.000	357.000	363.000	365.455	367.409	375.127	383.156	391.256	396.246	401.209	437.696	470.543	499.654
POPUL	944.000	1004.000	1000.500	1004.400	1005.000	1006.700	1020.345	1034.521	1048.566	1057.976	1067.216	1138.010	1199.884	1264.125
HHLDS	324.170	354.000	357.000	363.000	365.455	367.409	375.127	383.156	391.256	396.246	401.209	437.696	470.543	499.654
PCI	8611.20	8400.50	8573.30	8785.80	9226.40	9457.00	9531.30	9727.60	9928.00	10132.50	10341.30	11451.20	12680.30	14041.30

MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - WESTERN MONTANA 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	0.700	0.465	0.525	0.550	0.475	0.500	0.495	0.490	0.485	0.480	0.475	0.475	0.450	0.450
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.075	0.075	0.075
25	0.000	0.140	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.175	0.175	0.175
27	0.750	0.700	0.725	0.750	0.825	0.875	0.900	0.925	0.925	0.950	0.975	1.100	1.200	1.300
29	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	0.000	0.025	0.025	0.010	0.010	0.040	0.040	0.042	0.045	0.047	0.050	0.050	0.063	0.063
31	0.000	0.025	0.030	0.010	0.010	0.040	0.038	0.038	0.038	0.038	0.038	0.038	0.038	0.038
32	0.400	0.325	0.280	0.290	0.300	0.300	0.303	0.306	0.309	0.312	0.315	0.325	0.336	0.350
33XX	1.000	0.150	0.050	0.050	0.050	0.050	0.050	0.050	0.075	0.075	0.075	0.100	0.100	0.100
34	0.150	0.250	0.275	0.250	0.225	0.250	0.255	0.260	0.265	0.270	0.275	0.275	0.275	0.275
35	0.050	0.225	0.325	0.350	0.375	0.400	0.400	0.400	0.425	0.450	0.450	0.500	0.550	0.600
36	0.050	0.075	0.075	0.100	0.125	0.125	0.108	0.118	0.128	0.138	0.150	0.175	0.204	0.225
37	0.100	0.075	0.050	0.100	0.100	0.100	0.105	0.109	0.114	0.120	0.125	0.150	0.175	0.200
38	0.100	0.125	0.120	0.130	0.140	0.150	0.159	0.168	0.178	0.189	0.200	0.225	0.253	0.275
39	0.150	0.175	0.300	0.650	0.700	0.750	0.750	0.775	0.800	0.800	0.800	0.800	0.800	0.800
2421	4.500	4.000	4.150	3.900	3.900	4.000	3.738	3.743	3.811	3.827	3.925	3.968	4.163	4.161
2436	1.000	0.800	0.800	0.800	0.950	0.825	0.676	0.638	0.642	0.650	0.672	0.695	0.694	0.703
24XX	2.700	2.100	2.500	2.500	2.650	2.650	2.550	2.524	2.499	2.475	2.450	2.331	2.218	2.111
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2631	0.550	0.750	0.750	0.750	0.750	0.750	0.743	0.737	0.731	0.724	0.718	0.687	0.657	0.629
26XX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	0.200	0.190	0.180	0.180	0.180	0.180	0.179	0.178	0.177	0.176	0.175	0.170	0.165	0.160
28XX	0.100	0.050	0.050	0.100	0.100	0.100	0.100	0.099	0.099	0.099	0.099	0.097	0.096	0.094
3334	1.250	0.850	0.750	0.800	0.800	0.800	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
SUBTOT	13.775	11.545	12.160	12.470	12.865	13.085	12.489	12.500	12.646	12.719	12.866	13.111	13.386	13.483

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDIUM SCENARIO - WESTERN MONTANA 2/12/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	7.500	6.400	6.650	6.700	6.900	7.000	7.071	7.156	7.241	7.328	7.416	7.780	8.048	8.293
50-51	3.800	3.400	3.275	3.375	3.500	3.600	3.597	3.684	3.772	3.863	3.956	4.404	4.834	5.284
52,53+	8.000	8.200	8.650	8.700	8.775	8.850	9.079	9.250	9.424	9.601	9.781	10.611	11.353	12.092
54	2.900	3.000	2.825	3.100	3.500	3.800	3.850	3.900	3.950	4.000	4.050	4.400	4.600	4.800
58	7.500	7.500	7.475	7.500	8.400	8.600	8.700	8.800	8.900	9.000	9.187	10.918	12.792	14.932
60-67	3.700	3.400	3.650	3.650	3.850	3.950	4.000	4.050	4.100	4.150	4.200	4.600	4.900	5.295
70	2.500	2.700	2.900	2.850	2.700	2.800	2.900	3.000	3.100	3.200	3.300	3.956	4.439	4.961
72	0.800	0.900	0.875	0.900	0.775	0.750	0.800	0.900	0.950	1.004	1.021	1.098	1.164	1.230
73	1.000	1.700	2.175	2.200	1.650	1.750	1.850	1.950	2.050	2.200	2.350	3.000	3.600	4.100
76	0.300	0.300	0.350	0.350	0.425	0.450	0.450	0.460	0.470	0.480	0.490	0.530	0.550	0.570
80	6.400	7.650	8.300	8.400	8.700	8.800	8.900	9.000	9.200	9.400	9.500	11.000	12.200	13.200
81	0.500	0.600	0.700	0.700	0.725	0.800	0.750	0.750	0.750	0.767	0.796	0.943	1.103	1.284
83	1.400	1.200	1.525	1.500	2.100	2.300	2.400	2.500	2.600	2.700	2.750	3.250	3.600	3.800
89	1.000	0.700	0.800	0.800	0.750	0.800	0.775	0.785	0.805	0.825	0.846	0.946	1.044	1.146
75,78+	3.300	3.325	3.450	3.500	3.500	3.500	3.563	3.614	3.666	3.719	3.773	4.078	4.345	4.612
82	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
941	8.900	9.775	9.500	9.400	9.600	9.800	9.982	10.161	10.343	10.529	10.718	11.683	12.328	12.954
90-99	8.300	7.400	7.400	7.400	8.000	8.200	8.452	8.587	8.724	8.863	9.005	9.635	10.167	10.684
Const	4.800	3.800	2.800	3.050	3.250	3.400	3.450	3.500	3.550	3.600	3.650	3.900	4.100	4.300
Agric	7.500	7.300	7.300	7.300	7.300	7.300	7.265	7.236	7.207	7.179	7.150	6.971	6.953	6.928
Mining	3.100	1.875	2.075	2.175	2.300	2.600	2.500	2.500	2.500	2.550	2.650	2.750	2.850	2.950
Fd Gvt	5.600	4.850	4.900	4.950	5.100	5.200	5.100	5.100	5.119	5.159	5.200	5.400	5.500	5.600
SUBTOT	88.800	85.975	87.575	88.500	91.800	94.250	95.434	96.883	98.421	100.117	101.789	111.853	120.470	129.015
TOTAL	102.575	97.520	99.735	100.970	104.665	107.335	107.923	109.383	111.067	112.836	114.655	124.964	133.856	142.498

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDIUM SCENARIO - WESTERN MONTANA 2/12/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	82.313	84.905	85.437	85.857	86.014	86.253	87.174	88.524	90.052	91.666	93.343	101.362	108.705	114.626
MF	8.950	10.092	10.354	10.500	10.594	10.706	10.956	11.293	11.667	12.059	12.464	14.435	16.294	17.889
MO	15.138	17.403	17.709	17.854	17.882	17.927	18.231	18.691	19.206	19.739	20.282	22.634	24.494	25.816
TOTAL	106.400	112.400	113.500	114.211	114.491	114.886	116.361	118.508	120.925	123.464	126.088	138.431	149.493	158.331
POPUL	294.500	303.900	303.500	303.800	303.400	303.300	304.867	308.121	311.985	316.068	320.264	343.308	361.774	379.995
HHLDS	106.400	112.400	113.500	114.211	114.491	114.886	116.361	118.508	120.925	123.464	126.088	138.431	149.493	158.331
PCI	7793.00	7983.00	8527.20	8697.80	8871.70	9049.10	9991.00	9991.00	9991.00	9991.00	9991.00	11030.90	12179.00	13446.70

MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	73.900	71.965	72.925	75.550	76.475	78.300	74.490	73.979	73.369	72.760	71.950	68.950	67.100	65.900
22	3.000	2.550	2.900	3.100	3.100	3.550	2.450	2.450	2.450	2.450	2.450	2.450	2.450	2.450
23	10.025	8.900	8.550	8.950	9.050	9.470	8.197	7.846	7.796	7.747	7.700	8.075	8.275	8.475
25	6.150	7.240	7.050	7.950	7.850	8.310	7.008	6.858	6.888	6.918	6.950	7.000	7.050	7.150
27	29.650	34.000	37.925	39.850	41.025	41.775	40.750	41.550	42.275	43.000	43.600	46.800	49.750	52.600
29	2.800	2.225	2.350	2.450	2.450	2.750	2.450	2.350	2.250	2.150	2.050	1.750	1.650	1.550
30	6.900	8.575	10.025	11.210	12.010	12.340	12.275	12.475	12.675	12.875	13.075	14.175	14.975	15.475
31	0.700	0.925	1.080	1.160	1.260	1.140	1.100	1.100	1.100	1.100	1.100	1.100	1.100	1.100
32	13.100	10.725	11.580	12.490	12.900	14.100	11.200	10.800	10.300	10.300	10.300	10.300	10.300	10.300
33XX	20.800	15.350	15.550	16.550	17.550	18.450	16.940	15.958	16.038	16.120	16.200	16.625	16.850	16.850
34	26.750	22.850	22.975	24.350	26.625	27.250	24.409	23.109	23.189	23.269	23.350	23.800	24.000	24.250
35	37.750	38.625	37.525	40.650	43.175	44.900	42.650	41.050	41.175	41.700	42.100	44.325	46.450	48.475
36	22.550	28.875	30.175	28.700	32.325	35.025	33.208	31.718	32.528	33.338	34.150	36.175	37.904	39.825
37	109.450	99.825	118.150	129.500	141.500	142.700	136.798	126.497	116.397	111.298	106.100	101.500	97.200	93.100
38	25.950	25.725	23.320	28.330	27.940	26.850	25.626	25.354	25.484	25.716	25.850	27.225	28.703	30.275
39	7.350	7.400	8.600	10.350	11.900	10.550	9.850	9.375	9.100	9.225	9.325	9.625	9.825	10.025
2421	52.427	44.300	47.250	47.200	47.000	44.900	39.005	36.896	36.041	34.641	34.701	31.374	32.727	33.309
2436	26.582	20.900	21.900	20.900	20.750	19.125	17.405	16.304	15.663	14.436	13.986	10.507	10.142	9.877
24XX	61.066	57.100	60.100	63.400	62.650	59.450	57.709	56.966	56.233	55.509	54.794	51.369	48.147	45.117
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.450	2.404	2.356	2.310	2.266	2.052	1.860	1.685
2621	14.143	13.410	12.650	12.900	13.700	13.700	13.554	13.414	13.277	13.136	13.000	12.359	11.769	11.226
2631	5.037	5.000	4.900	4.850	5.450	5.550	5.475	5.400	5.326	5.253	5.181	4.836	4.515	4.215
26XX	7.896	7.815	8.750	8.500	8.500	8.600	8.441	8.454	8.466	8.479	8.492	8.440	8.441	8.113
2812	0.763	0.700	0.700	0.700	0.600	0.700	0.701	0.701	0.702	0.703	0.704	0.698	0.691	0.714
2819	6.567	8.890	8.780	9.780	9.580	9.980	5.469	5.359	5.248	5.138	5.028	4.978	4.930	4.885
28XX	7.470	7.650	7.650	7.900	8.000	8.600	7.844	7.806	7.767	7.728	7.690	7.505	7.321	7.139
3334	10.350	7.250	5.850	7.300	7.600	7.200	5.100	4.780	4.720	4.660	4.600	4.500	4.500	4.500
SUBTOT	592.100	560.870	591.260	626.670	653.465	657.765	612.554	590.952	578.814	571.959	566.692	558.494	558.625	558.581

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	179.500	176.500	181.550	187.700	196.700	203.600	202.600	200.750	203.800	206.450	208.700	215.600	222.100	227.798
50-51	194.000	195.700	203.375	213.275	229.000	239.200	234.594	234.361	237.981	241.780	245.954	266.903	289.360	310.481
52,53+	275.100	279.300	300.050	314.100	332.675	346.650	341.808	342.818	345.728	349.540	353.754	373.699	395.771	417.771
54	75.100	92.400	105.125	110.800	117.300	123.900	122.900	123.450	124.200	124.750	125.300	130.350	135.300	140.100
58	195.500	218.400	233.275	241.600	250.100	261.300	261.581	267.295	274.803	282.811	291.170	339.025	390.355	447.723
60-67	188.900	193.400	202.450	205.550	210.750	215.550	212.100	213.404	219.358	223.948	228.574	249.774	269.885	288.744
70	40.200	42.600	45.800	48.850	52.300	55.400	55.000	55.100	55.500	55.900	56.400	61.560	66.663	72.879
72	29.600	35.000	36.075	34.100	35.275	37.150	39.104	39.379	39.653	40.003	40.355	43.240	45.569	47.798
73	89.800	109.800	138.475	123.200	133.650	142.750	145.700	149.150	152.700	156.500	160.600	199.700	237.500	269.600
76	9.800	10.500	11.350	12.750	14.225	14.750	14.253	14.366	14.578	14.891	15.004	15.599	16.058	16.514
80	179.800	212.350	231.100	240.600	252.300	269.000	276.253	284.700	293.900	300.800	307.200	354.600	401.500	448.800
81	17.400	22.700	25.700	26.900	27.925	29.300	30.107	30.658	31.146	31.742	32.415	38.115	44.255	51.092
83	31.800	41.800	47.525	56.500	61.000	63.900	64.600	65.200	66.100	67.300	68.450	77.300	86.900	96.300
89	36.400	36.000	39.100	65.800	71.150	75.300	76.953	79.170	81.288	83.406	86.124	98.726	109.729	119.139
75,78+	122.600	141.125	150.850	158.900	168.500	177.600	178.399	182.140	184.981	188.022	191.064	203.594	214.594	224.486
82	19.800	24.200	27.500	32.800	34.600	35.800	35.550	35.770	36.100	36.350	36.500	38.000	39.300	40.400
941	279.700	280.275	291.400	299.600	306.700	317.900	319.012	321.510	324.410	327.738	331.138	352.202	370.127	386.756
90-99	230.300	236.100	248.300	257.500	266.400	276.300	277.700	277.900	279.600	281.600	283.600	300.700	316.500	331.400
Const	161.300	132.600	140.600	153.750	171.050	184.600	157.400	154.303	157.200	161.300	164.600	176.700	186.600	195.400
Agric	292.200	286.600	286.200	285.055	284.100	281.652	280.104	278.615	277.134	275.664	274.200	266.800	259.400	252.300
Mining	13.300	9.875	9.075	10.075	10.900	11.800	9.659	9.518	9.478	9.439	9.400	9.300	9.300	9.300
Fd Gvt	117.300	116.350	118.300	120.550	122.200	127.200	120.400	119.700	118.800	119.000	119.200	121.700	126.200	130.400
SUBTOT	2779.400	2893.575	3073.175	3199.955	3348.800	3490.603	3455.777	3479.257	3528.438	3578.934	3629.702	3933.187	4232.966	4525.181
TOTAL	3371.500	3454.446	3664.435	3826.625	4002.265	4148.368	4068.331	4070.209	4107.252	4150.893	4196.394	4491.682	4791.591	5083.761

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDLO SCENARIO - REGION 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	2304.022	2428.959	2483.225	2532.928	2591.588	2633.923	2676.055	2714.749	2745.018	2773.581	2800.527	2974.687	3147.574	3284.533
MF	427.732	492.379	522.134	545.683	571.859	592.672	613.153	631.793	647.003	661.823	676.377	762.498	849.478	924.336
MO	230.919	280.062	300.141	317.599	335.744	350.032	364.296	377.287	387.274	396.437	404.919	458.048	507.345	544.060
TOTAL	2962.673	3201.400	3305.500	3396.210	3499.191	3576.626	3653.504	3723.829	3779.295	3831.842	3881.823	4195.233	4504.397	4752.928
POPUL	8003.820	8389.700	8532.000	8668.200	8860.400	9019.000	9170.988	9272.746	9335.019	9391.394	9452.263	9978.136	10501.972	11002.465
HHLDS	2962.673	3201.400	3305.500	3396.210	3499.190	3576.626	3653.504	3723.829	3779.295	3831.842	3881.823	4195.233	4504.397	4752.927
PCI	10360.21	10444.04	10785.29	10968.18	11357.44	11433.36	11700.75	11864.47	12029.36	12196.81	12366.47	13281.23	14264.67	15322.29

MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	31.900	31.100	32.300	34.200	35.500	35.900	34.000	33.800	33.500	33.300	33.000	32.000	31.200	30.500
22	1.000	0.900	1.000	1.200	1.200	1.300	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
23	6.500	6.200	5.700	6.000	6.000	6.200	5.800	5.500	5.500	5.500	5.500	5.900	6.100	6.300
25	3.300	3.800	3.800	4.200	4.000	4.300	3.900	3.740	3.760	3.780	3.800	3.900	4.000	4.100
27	15.800	17.600	20.100	21.400	22.100	22.000	21.500	22.000	22.300	22.600	22.900	24.800	26.700	28.500
29	2.100	1.800	1.800	1.900	1.900	2.200	2.000	1.900	1.800	1.700	1.600	1.400	1.300	1.200
30	3.500	4.500	5.100	5.800	6.200	6.500	6.500	6.600	6.700	6.800	6.900	7.500	7.800	8.000
31	0.400	0.400	0.400	0.500	0.600	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
32	6.900	6.400	6.900	7.300	7.500	7.900	6.100	6.100	6.100	6.100	6.100	6.100	6.100	6.100
33XX	9.000	6.900	6.900	7.100	7.300	7.600	7.040	7.079	7.119	7.160	7.200	7.400	7.600	7.600
34	11.800	9.700	10.500	10.900	11.800	12.200	11.500	10.240	10.260	10.280	10.300	10.500	10.600	10.700
35	15.000	17.100	16.200	18.000	19.000	19.500	18.500	18.000	18.000	18.400	18.800	19.500	20.500	21.400
36	11.200	12.100	13.200	10.500	11.700	12.100	11.500	11.000	11.500	12.000	12.500	13.400	14.100	14.900
37	98.350	89.600	106.200	116.200	128.500	128.900	125.000	115.000	105.000	100.000	95.000	90.800	86.800	83.000
38	6.400	10.700	10.800	14.600	14.900	14.700	14.400	14.000	14.000	14.100	14.100	14.600	15.200	15.800
39	4.600	4.500	4.800	5.500	5.900	5.600	5.300	5.000	5.100	5.200	5.300	5.600	5.800	6.000
2421	16.027	13.400	14.500	15.200	15.300	14.700	12.884	11.982	11.544	10.935	10.859	9.412	9.785	10.057
2436	4.982	4.200	3.900	3.600	3.100	3.000	2.625	2.443	2.345	2.157	2.083	1.589	1.561	1.538
24XX	25.991	20.700	22.000	22.800	22.700	21.900	20.699	20.432	20.169	19.910	19.653	18.425	17.269	16.182
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.450	2.404	2.356	2.310	2.266	2.052	1.860	1.685
2621	8.818	9.000	8.400	8.700	9.300	9.300	9.200	9.106	9.012	8.917	8.822	8.388	7.988	7.620
2631	1.637	1.200	1.200	1.200	1.600	1.600	1.579	1.557	1.536	1.515	1.494	1.395	1.302	1.215
26XX	4.171	4.400	4.950	5.100	4.900	5.000	5.068	5.081	5.094	5.107	5.120	5.090	5.093	4.881
2812	0.513	0.500	0.500	0.500	0.400	0.500	0.500	0.501	0.502	0.502	0.503	0.495	0.486	0.510
2819	5.300	7.700	7.700	8.700	8.500	8.900	4.400	4.300	4.200	4.100	4.000	4.000	4.000	4.000
28XX	2.887	3.100	3.300	3.300	3.300	3.500	3.225	3.209	3.193	3.178	3.162	3.086	3.011	2.935
3334	7.700	5.800	4.400	5.600	5.900	5.900	4.000	3.680	3.620	3.560	3.500	3.400	3.400	3.400
SUBTOT	308.750	295.400	318.600	342.100	361.600	364.200	341.170	326.154	315.710	310.610	305.962	302.232	301.055	299.623

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	91.400	93.600	98.500	101.900	107.900	112.000	112.000	112.000	113.500	115.000	116.500	119.500	123.000	126.000
50-51	100.500	105.700	111.400	116.400	124.600	132.100	131.000	131.500	133.500	135.500	138.000	148.000	158.000	168.372
52,53+	141.000	146.900	161.200	168.800	179.100	189.000	187.000	187.000	189.000	192.000	195.000	204.000	215.000	226.241
54	38.200	49.200	57.400	59.900	62.300	65.400	65.000	65.300	65.800	66.000	66.200	69.200	72.200	75.400
58	101.600	118.900	128.200	132.500	135.000	141.600	143.581	148.027	152.611	157.338	162.210	189.470	218.796	251.705
60-67	91.800	99.600	107.500	109.400	112.300	116.300	114.000	114.611	119.618	122.660	125.737	137.077	148.846	160.855
70	17.800	20.100	21.500	22.900	24.700	26.100	26.200	26.400	26.500	26.600	26.800	29.401	32.508	35.797
72	16.000	19.900	20.800	19.700	20.400	21.500	23.453	23.609	23.767	23.926	24.086	26.000	27.500	29.000
73	52.900	61.000	78.000	70.000	76.500	83.700	85.500	87.500	89.500	91.200	92.900	115.500	137.000	154.100
76	5.500	5.600	5.900	6.900	8.000	8.400	8.200	8.300	8.500	8.700	8.800	9.200	9.500	9.800
80	95.800	117.400	129.300	134.600	140.800	151.200	153.000	157.000	162.000	166.000	170.000	197.000	223.000	251.000
81	9.200	12.400	14.400	15.000	15.600	16.500	16.800	17.000	17.100	17.300	17.570	20.722	24.163	28.061
83	15.600	22.600	25.000	27.200	29.700	31.400	32.200	33.000	33.400	34.000	34.600	39.000	44.000	49.000
89	19.500	21.100	23.100	37.500	40.700	43.000	44.000	45.500	47.000	48.500	50.500	58.000	64.000	69.000
75,78+	66.800	83.500	89.000	95.400	101.100	106.700	108.000	111.000	113.000	115.000	117.000	124.000	130.000	135.000
82	8.900	12.000	13.100	14.700	15.900	16.700	16.700	16.800	16.900	17.000	17.100	17.900	18.600	19.200
941	145.500	143.600	151.100	156.000	160.600	166.300	166.800	167.800	169.000	170.628	172.326	182.633	191.300	200.000
90-99	117.400	129.100	135.500	141.300	146.800	152.100	152.500	152.500	153.000	153.500	154.000	163.000	171.000	179.000
Const	92.600	80.600	88.900	96.600	106.600	115.300	100.000	98.000	100.000	102.000	103.000	111.000	117.000	122.000
Agric	119.300	115.100	114.400	113.300	112.300	110.714	110.337	109.961	109.586	109.213	108.841	105.481	102.806	99.943
Mining	3.200	2.700	3.000	3.300	3.600	4.000	2.900	2.900	2.900	2.900	2.900	2.900	2.900	2.900
Fd Gvt	67.900	70.100	70.600	71.400	72.000	74.500	71.000	71.500	71.500	71.500	71.500	72.700	75.300	78.000
SUBTOT	1418.400	1530.700	1647.800	1714.700	1796.500	1884.514	1870.171	1887.208	1917.682	1946.465	1975.570	2141.684	2306.419	2470.374
TOTAL	1727.150	1826.100	1966.400	2056.800	2158.100	2248.714	2211.342	2213.363	2233.392	2257.076	2281.532	2443.916	2607.473	2769.998

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME   MEDLO SCENARIO - WASHINGTON   2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	1193.211	1266.263	1300.855	1329.754	1367.751	1393.316	1418.433	1439.091	1454.088	1468.608	1483.746	1570.665	1655.455	1722.570
MF	250.130	298.560	320.920	337.800	358.989	374.112	389.070	401.886	411.969	421.870	432.129	489.725	547.510	597.732
MO	97.169	126.178	139.225	149.446	162.546	171.496	180.220	187.398	192.635	197.628	202.736	230.667	256.242	275.420
TOTAL	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1987.723	2028.375	2058.691	2088.106	2118.611	2291.057	2459.208	2595.721
POPUL	4132.160	4406.000	4538.000	4619.000	4761.000	4866.700	4969.307	5030.370	5064.381	5094.979	5127.038	5406.894	5680.770	5944.201
HHLDS	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1987.723	2028.375	2058.691	2088.106	2118.611	2291.057	2459.208	2595.721
PCI	10725.00	10924.00	11258.00	11383.00	11774.00	11798.00	12115.30	12278.90	12444.60	12612.60	12782.90	13669.40	14617.30	15631.00

MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	24.300	23.800	24.000	23.700	23.600	24.900	23.600	23.500	23.400	23.300	23.100	22.000	21.500	21.000
22	2.000	1.600	1.800	1.800	1.800	2.100	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400
23	3.200	2.400	2.500	2.600	2.700	2.900	2.158	2.118	2.078	2.038	2.000	2.000	2.000	2.000
25	2.600	2.700	2.500	2.900	3.000	3.200	2.400	2.400	2.400	2.400	2.400	2.400	2.400	2.400
27	10.000	11.500	12.800	13.200	13.500	14.100	13.600	13.600	13.900	14.200	14.500	15.400	16.200	17.000
29	0.600	0.400	0.500	0.500	0.500	0.500	0.400	0.400	0.400	0.400	0.400	0.300	0.300	0.300
30	2.400	3.200	3.800	4.600	4.900	5.000	5.000	5.100	5.200	5.300	5.400	5.900	6.400	6.700
31	0.300	0.400	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
32	4.500	3.100	3.600	4.000	4.200	4.900	4.000	3.600	3.100	3.100	3.100	3.100	3.100	3.100
33XX	9.600	8.200	8.600	9.300	10.100	10.700	9.700	8.679	8.719	8.760	8.800	9.000	9.000	9.000
34	12.700	11.000	10.200	11.200	12.300	12.400	10.559	10.619	10.679	10.739	10.800	11.000	11.100	11.200
35	17.700	15.500	15.800	16.800	17.600	18.000	17.000	16.500	16.500	16.500	16.500	17.500	18.200	18.900
36	9.800	13.900	13.600	14.100	15.600	17.200	16.000	15.500	15.600	15.700	15.800	16.500	17.200	18.000
37	10.300	9.200	10.800	11.600	11.400	12.200	10.398	10.297	10.197	10.098	10.000	9.700	9.500	9.200
38	19.300	14.600	12.100	13.200	12.500	11.600	10.717	10.836	10.956	11.077	11.200	12.000	12.800	13.700
39	2.200	2.400	3.200	3.800	4.900	3.800	3.600	3.400	3.000	3.000	3.000	3.000	3.000	3.000
2421	23.800	20.500	22.000	21.400	20.800	19.000	16.755	15.540	14.949	14.116	14.005	12.024	12.508	12.828
2436	20.100	15.500	16.800	16.100	16.300	14.900	13.890	13.022	12.475	11.424	11.021	8.005	7.668	7.416
24XX	25.600	27.600	29.200	31.300	29.900	27.300	27.997	27.637	27.281	26.930	26.584	24.922	23.359	21.889
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	5.100	4.160	4.000	3.900	4.100	4.100	4.057	4.015	3.975	3.931	3.894	3.700	3.524	3.360
2631	2.000	2.100	2.000	1.900	2.000	2.000	1.972	1.946	1.918	1.892	1.866	1.742	1.626	1.519
26XX	3.300	2.840	3.200	2.800	3.000	3.000	2.809	2.805	2.800	2.796	2.792	2.793	2.784	2.686
2812	0.250	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.201	0.201	0.201	0.203	0.204	0.204
2819	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
28XX	2.050	1.900	1.900	1.900	2.000	2.300	1.846	1.837	1.828	1.819	1.810	1.767	1.723	1.680
3334	1.400	0.600	0.700	0.900	0.900	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500	0.500
SUBTOT	215.100	199.300	206.300	214.200	218.300	217.300	201.060	195.951	193.956	192.122	191.572	187.356	188.496	189.481

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	60.500	57.300	58.500	60.500	62.800	65.100	64.000	62.000	63.400	64.400	65.000	67.700	70.000	72.100
50-51	67.400	65.800	68.200	72.900	78.200	80.800	78.000	77.000	78.200	79.500	80.665	88.751	97.836	105.200
52,53+	96.200	92.900	98.700	104.200	109.700	112.000	110.000	110.500	111.000	111.500	112.500	120.000	128.000	136.000
54	24.600	29.500	33.800	36.400	39.400	42.000	41.500	41.600	41.700	41.900	42.100	43.100	44.100	45.000
58	67.400	70.400	76.000	78.900	82.300	85.000	84.500	85.418	87.892	90.438	93.058	107.678	123.201	140.386
60-67	70.000	66.800	72.100	73.300	75.300	75.800	74.800	75.400	76.000	77.000	78.000	85.000	91.000	96.000
70	14.800	14.600	15.600	17.100	18.400	19.700	19.000	18.800	18.900	19.000	19.100	20.300	21.210	23.127
72	9.800	10.400	10.800	10.400	10.900	11.600	11.101	11.195	11.289	11.385	11.481	12.101	12.612	13.089
73	24.900	35.000	45.500	43.000	46.700	48.100	48.800	50.000	51.300	53.000	55.000	68.000	81.000	93.000
76	3.000	3.500	4.100	4.400	4.600	4.700	4.500	4.500	4.500	4.600	4.600	4.700	4.800	4.900
80	62.100	69.400	74.400	77.600	82.100	87.200	92.200	96.200	100.000	102.500	104.500	119.000	134.000	148.000
81	5.600	7.300	8.100	8.500	8.700	9.000	9.707	9.965	10.230	10.502	10.781	12.592	14.541	16.728
83	11.400	14.000	16.900	23.300	24.400	25.200	25.000	24.800	25.100	25.500	25.900	29.000	32.500	36.000
89	11.100	10.300	11.300	17.200	19.000	20.500	21.000	21.400	21.800	22.200	22.600	25.600	28.600	31.000
75,78+	42.200	43.500	47.400	47.900	50.800	53.500	53.000	53.400	54.000	54.800	55.600	60.000	64.000	68.000
82	7.100	8.300	10.300	13.800	14.300	14.600	14.400	14.500	14.700	14.800	14.800	15.300	15.700	16.000
941	94.200	94.600	97.400	99.300	101.200	104.100	104.000	105.000	106.200	107.500	108.800	117.000	124.000	130.000
90-99	78.200	73.500	77.700	80.200	81.700	84.300	85.000	85.000	86.000	87.300	88.600	94.600	100.600	105.000
Const	46.500	33.100	35.300	39.900	45.200	47.900	36.000	35.603	36.200	38.000	40.000	43.000	46.000	49.000
Agric	96.300	98.800	99.700	100.300	101.000	101.082	100.459	99.840	99.224	98.613	98.005	95.901	93.174	90.644
Mining	2.300	1.500	1.400	1.300	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400	1.400
Fd Gvt	30.800	29.600	30.600	31.700	32.200	34.200	32.000	31.000	30.000	30.100	30.200	31.000	32.400	33.500
SUBTOT	926.400	930.100	993.800	1042.100	1090.300	1127.782	1110.367	1114.521	1129.035	1145.938	1162.690	1261.723	1360.674	1454.074
TOTAL	1141.500	1129.400	1200.100	1256.300	1308.600	1345.082	1311.427	1310.472	1322.991	1338.060	1354.262	1449.079	1549.170	1643.555

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDLO SCENARIO - OREGON 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	766.113	797.066	814.652	831.457	850.551	865.985	878.701	892.054	903.450	914.823	923.751	982.648	1042.468	1088.948
MF	143.583	154.439	160.844	166.463	170.859	175.989	180.357	184.922	188.942	192.969	196.311	217.294	238.833	256.783
MO	81.898	92.495	98.505	104.080	108.549	113.432	117.373	121.443	124.812	128.097	130.526	146.210	161.116	171.865
TOTAL	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1176.432	1198.420	1217.204	1235.889	1250.588	1346.152	1442.417	1517.595
POPUL	2633.160	2675.800	2690.000	2741.000	2791.000	2842.300	2882.258	2912.161	2933.462	2953.774	2976.400	3136.534	3303.135	3460.117
HHLDS	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1176.432	1198.420	1217.204	1235.889	1250.588	1346.152	1442.417	1517.595
PCI	9897.80	9845.90	10162.10	10402.20	10731.30	10804.40	10981.70	11151.90	11324.70	11500.30	11678.50	12612.10	13620.30	14709.10

MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	17.000	16.600	16.100	17.100	16.900	17.000	16.400	16.200	16.000	15.700	15.400	14.500	14.000	14.000
22	0.000	0.050	0.100	0.100	0.100	0.150	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
23	0.300	0.250	0.300	0.300	0.300	0.320	0.189	0.178	0.168	0.159	0.150	0.100	0.100	0.100
25	0.250	0.600	0.600	0.700	0.700	0.660	0.600	0.600	0.600	0.600	0.600	0.550	0.500	0.500
27	3.100	4.200	4.300	4.500	4.600	4.800	4.800	5.100	5.200	5.300	5.300	5.600	5.800	6.000
29	0.100	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
30	1.000	0.850	1.100	0.800	0.900	0.800	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750
31	0.000	0.100	0.150	0.150	0.150	0.100	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
32	1.300	0.900	0.800	0.900	0.900	1.000	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
33XX	1.200	0.100	0.000	0.100	0.100	0.100	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150
34	2.100	1.900	2.000	2.000	2.300	2.400	2.100	2.000	2.000	2.000	2.000	2.050	2.050	2.100
35	5.000	5.800	5.200	5.500	6.200	7.000	6.800	6.200	6.300	6.400	6.400	6.900	7.300	7.700
36	1.500	2.800	3.300	4.000	4.900	5.600	5.600	5.100	5.300	5.500	5.700	6.100	6.400	6.700
37	0.700	0.950	1.100	1.600	1.500	1.500	1.300	1.100	1.100	1.100	1.000	0.900	0.800	0.800
38	0.150	0.300	0.300	0.400	0.400	0.400	0.350	0.350	0.350	0.350	0.350	0.400	0.450	0.500
39	0.400	0.325	0.300	0.400	0.400	0.400	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
2421	8.100	6.400	6.600	6.700	7.000	7.200	6.002	6.007	6.119	6.145	6.304	6.368	6.687	6.680
2436	0.500	0.400	0.400	0.400	0.400	0.400	0.280	0.264	0.266	0.269	0.278	0.288	0.287	0.291
24XX	6.775	6.700	6.400	6.800	7.400	7.600	6.493	6.410	6.327	6.246	6.166	5.780	5.418	5.077
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.225	0.250	0.250	0.300	0.300	0.300	0.297	0.294	0.291	0.288	0.285	0.271	0.258	0.246
2631	0.850	0.950	0.950	1.000	1.100	1.200	1.184	1.168	1.152	1.136	1.120	1.046	0.977	0.912
26XX	0.425	0.575	0.600	0.600	0.600	0.600	0.564	0.568	0.572	0.576	0.580	0.558	0.565	0.547
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	1.067	1.000	0.900	0.900	0.900	0.900	0.891	0.882	0.874	0.865	0.856	0.815	0.775	0.738
28XX	2.433	2.600	2.400	2.600	2.600	2.700	2.673	2.660	2.647	2.634	2.621	2.557	2.494	2.433
3334	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SUBTOT	54.475	54.625	54.200	57.900	60.700	63.180	58.699	57.256	57.441	57.443	57.285	56.957	57.035	57.498

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	20.100	19.200	17.900	18.600	19.100	19.500	19.600	19.700	19.800	19.900	20.000	21.000	21.500	22.000
50-51	22.300	20.800	20.500	20.600	22.700	22.700	22.100	22.300	22.652	23.082	23.521	26.000	29.000	32.000
52,53+	29.900	31.300	31.500	32.400	35.100	36.800	36.000	36.400	36.700	36.900	37.000	39.800	42.300	44.500
54	9.400	10.700	11.100	11.400	12.100	12.700	12.700	12.800	12.900	13.000	13.100	13.900	14.700	15.300
58	19.000	21.600	21.600	22.700	24.400	26.100	25.000	25.300	25.700	26.385	27.202	31.774	36.691	42.210
60-67	23.400	23.600	19.200	19.200	19.300	19.500	19.500	19.700	20.000	20.500	21.000	23.500	25.500	27.000
70	5.100	5.200	5.800	6.000	6.500	6.800	7.000	7.100	7.200	7.300	7.400	8.200	8.900	9.500
72	3.000	3.800	3.600	3.100	3.200	3.300	3.800	3.800	3.797	3.842	3.888	4.139	4.357	4.567
73	11.000	12.100	12.800	8.000	8.800	9.200	9.600	9.800	10.000	10.300	10.600	13.600	16.400	19.000
76	1.000	1.100	1.000	1.100	1.200	1.200	1.128	1.141	1.153	1.166	1.179	1.249	1.308	1.364
80	15.500	17.900	19.100	20.000	20.700	21.800	22.200	22.600	22.900	23.200	23.500	28.000	32.500	37.000
81	2.100	2.400	2.500	2.700	2.900	3.000	2.900	3.000	3.100	3.200	3.300	3.900	4.500	5.083
83	3.400	4.000	4.100	4.500	4.800	5.000	5.100	5.200	5.300	5.400	5.500	6.400	7.200	8.000
89	4.800	3.900	3.900	10.300	10.700	11.000	11.200	11.500	11.700	11.900	12.200	14.200	16.100	18.000
75,78+	10.300	10.800	11.000	12.100	13.100	13.900	14.000	14.300	14.500	14.700	14.900	15.800	16.600	17.300
82	3.800	3.900	4.100	4.300	4.400	4.500	4.450	4.470	4.500	4.550	4.600	4.800	5.000	5.200
941	31.100	32.300	33.400	34.900	35.300	37.700	38.300	38.700	39.100	39.400	39.700	41.700	43.500	45.000
90-99	26.400	26.100	27.700	28.600	29.900	31.700	31.900	32.000	32.100	32.200	32.300	33.900	35.300	37.400
Const	17.400	15.100	13.600	14.200	16.000	18.000	18.000	17.500	17.700	17.900	18.100	19.000	19.800	20.500
Agric	69.100	65.400	64.800	64.155	63.500	62.556	62.104	61.654	61.208	60.766	60.326	58.644	56.744	55.138
Mining	4.700	3.800	2.600	3.300	3.600	3.800	2.959	2.918	2.878	2.839	2.800	2.700	2.700	2.700
Fd Gvt	13.000	11.800	12.200	12.500	12.900	13.300	12.400	12.200	12.300	12.400	12.500	13.000	13.500	13.900
SUBTOT	345.800	346.800	344.000	354.655	370.200	384.056	381.941	384.083	387.188	390.830	394.616	425.206	454.100	482.662
TOTAL	400.275	401.425	398.200	412.555	430.900	447.236	440.640	441.339	444.629	448.273	451.901	482.163	511.135	540.160

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDLO SCENARIO - IDAHO 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	262.386	280.726	282.438	286.192	287.693	288.891	292.606	296.416	299.481	301.299	303.132	325.179	347.133	366.072
MF	25.070	29.289	29.978	30.870	31.332	31.742	32.625	33.530	34.300	34.840	35.386	40.576	45.831	50.598
MO	36.714	43.986	44.584	45.938	46.429	46.776	48.041	49.308	50.262	50.710	51.132	57.640	63.630	68.562
TOTAL	324.170	354.000	357.000	363.000	365.455	367.409	373.272	379.255	384.042	386.849	389.650	423.395	456.595	485.231
POPUL	944.000	1004.000	1000.500	1004.400	1005.000	1006.700	1015.299	1023.988	1029.233	1032.887	1036.470	1100.828	1164.316	1227.635
HHLDS	324.170	354.000	357.000	363.000	365.455	367.409	373.272	379.255	384.042	386.849	389.650	423.395	456.595	485.231
PCI	8611.20	8400.50	8573.30	8785.80	9226.40	9457.00	9427.00	9568.40	9711.90	9857.60	10005.40	10778.70	11611.70	12509.10

MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	0.700	0.465	0.525	0.550	0.475	0.500	0.490	0.479	0.469	0.460	0.450	0.450	0.400	0.400
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.075	0.075	0.075
25	0.000	0.140	0.150	0.150	0.150	0.150	0.108	0.118	0.128	0.138	0.150	0.150	0.150	0.150
27	0.750	0.700	0.725	0.750	0.825	0.875	0.850	0.850	0.875	0.900	0.900	1.000	1.050	1.100
29	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	0.000	0.025	0.025	0.010	0.010	0.040	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
31	0.000	0.025	0.030	0.010	0.010	0.040	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
32	0.400	0.325	0.280	0.290	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
33XX	1.000	0.150	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.075	0.100	0.100
34	0.150	0.250	0.275	0.250	0.225	0.250	0.250	0.250	0.250	0.250	0.250	0.250	0.250	0.250
35	0.050	0.225	0.325	0.350	0.375	0.400	0.350	0.350	0.375	0.400	0.400	0.425	0.450	0.475
36	0.050	0.075	0.075	0.100	0.125	0.125	0.108	0.118	0.128	0.138	0.150	0.175	0.204	0.225
37	0.100	0.075	0.050	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
38	0.100	0.125	0.120	0.130	0.140	0.150	0.159	0.168	0.178	0.189	0.200	0.225	0.253	0.275
39	0.150	0.175	0.300	0.650	0.700	0.750	0.650	0.675	0.700	0.725	0.725	0.725	0.725	0.725
2421	4.500	4.000	4.150	3.900	3.900	4.000	3.364	3.367	3.428	3.444	3.533	3.570	3.747	3.743
2436	1.000	0.800	0.800	0.800	0.950	0.825	0.609	0.574	0.578	0.585	0.604	0.626	0.625	0.633
24XX	2.700	2.100	2.500	2.500	2.650	2.650	2.519	2.487	2.455	2.423	2.392	2.243	2.102	1.970
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2631	0.550	0.750	0.750	0.750	0.750	0.750	0.740	0.730	0.720	0.710	0.700	0.654	0.610	0.570
26XX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	0.200	0.190	0.180	0.180	0.180	0.180	0.178	0.176	0.175	0.173	0.171	0.163	0.155	0.148
28XX	0.100	0.050	0.050	0.100	0.100	0.100	0.100	0.099	0.099	0.098	0.098	0.095	0.093	0.091
3334	1.250	0.850	0.750	0.800	0.800	0.800	0.600	0.600	0.600	0.600	0.600	0.600	0.600	0.600
SUBTOT	13.775	11.545	12.160	12.470	12.865	13.085	11.625	11.591	11.707	11.783	11.873	11.950	12.039	11.979

NON-MANUFACTURING EMPLOYMENT (1000'S) MEDLO SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	7.500	6.400	6.650	6.700	6.900	7.000	7.000	7.050	7.100	7.150	7.200	7.400	7.600	7.698
50-51	3.800	3.400	3.275	3.375	3.500	3.600	3.494	3.561	3.629	3.698	3.768	4.152	4.524	4.909
52,53+	8.000	8.200	8.650	8.700	8.775	8.850	8.808	8.918	9.028	9.140	9.254	9.899	10.471	11.030
54	2.900	3.000	2.825	3.100	3.500	3.800	3.700	3.750	3.800	3.850	3.900	4.150	4.300	4.400
58	7.500	7.500	7.475	7.500	8.400	8.600	8.500	8.550	8.600	8.650	8.700	10.103	11.667	13.422
60-67	3.700	3.400	3.650	3.650	3.850	3.950	3.800	3.693	3.740	3.788	3.837	4.197	4.539	4.889
70	2.500	2.700	2.900	2.850	2.700	2.800	2.800	2.800	2.900	3.000	3.100	3.659	4.045	4.455
72	0.800	0.900	0.875	0.900	0.775	0.750	0.750	0.775	0.800	0.850	0.900	1.000	1.100	1.142
73	1.000	1.700	2.175	2.200	1.650	1.750	1.800	1.850	1.900	2.000	2.100	2.600	3.100	3.500
76	0.300	0.300	0.350	0.350	0.425	0.450	0.425	0.425	0.425	0.425	0.425	0.450	0.450	0.450
80	6.400	7.650	8.300	8.400	8.700	8.800	8.853	8.900	9.000	9.100	9.200	10.600	12.000	12.800
81	0.500	0.600	0.700	0.700	0.725	0.800	0.700	0.693	0.716	0.740	0.764	0.901	1.051	1.220
83	1.400	1.200	1.525	1.500	2.100	2.300	2.300	2.200	2.300	2.400	2.450	2.900	3.200	3.300
89	1.000	0.700	0.800	0.800	0.750	0.800	0.753	0.770	0.788	0.806	0.824	0.926	1.029	1.139
75,78+	3.300	3.325	3.450	3.500	3.500	3.500	3.399	3.440	3.481	3.522	3.564	3.794	3.994	4.186
82	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
941	8.900	9.775	9.500	9.400	9.600	9.800	9.912	10.010	10.110	10.210	10.312	10.869	11.327	11.756
90-99	8.300	7.400	7.400	7.400	8.000	8.200	8.300	8.400	8.500	8.600	8.700	9.200	9.600	10.000
Const	4.800	3.800	2.800	3.050	3.250	3.400	3.400	3.200	3.300	3.400	3.500	3.700	3.800	3.900
Agric	7.500	7.300	7.300	7.300	7.300	7.300	7.204	7.160	7.116	7.072	7.028	6.774	6.676	6.575
Mining	3.100	1.875	2.075	2.175	2.300	2.600	2.400	2.300	2.300	2.300	2.300	2.300	2.300	2.300
Fd Gvt	5.600	4.850	4.900	4.950	5.100	5.200	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
SUBTOT	88.800	85.975	87.575	88.500	91.800	94.250	93.298	93.445	94.533	95.701	96.826	104.574	111.773	118.071
TOTAL	102.575	97.520	99.735	100.970	104.665	107.335	104.923	105.036	106.240	107.484	108.699	116.524	123.812	130.050

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME MEDLO SCENARIO - WESTERN MONTANA 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	82.313	84.905	85.280	85.525	85.593	85.731	86.315	87.188	87.999	88.851	89.897	96.195	102.518	106.943
MF	8.950	10.092	10.393	10.551	10.679	10.828	11.101	11.454	11.793	12.145	12.551	14.903	17.304	19.224
MO	15.138	17.403	17.827	18.135	18.219	18.328	18.662	19.138	19.566	20.001	20.526	23.531	26.356	28.213
TOTAL	106.400	112.400	113.500	114.211	114.491	114.886	116.078	117.780	119.357	120.997	122.974	134.629	146.178	154.380
POPUL	294.500	303.900	303.500	303.800	303.400	303.300	304.124	306.227	307.941	309.753	312.354	333.880	353.750	370.512
HHLDS	106.400	112.400	113.500	114.211	114.491	114.886	116.078	117.780	119.357	120.997	122.974	134.629	146.178	154.380
PCI	7793.00	7983.00	8527.20	8697.80	8871.70	9049.10	9991.00	9991.00	9991.00	9991.00	9991.00	11030.90	12179.00	13446.70

MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	73.900	71.965	72.925	75.550	76.475	78.300	72.945	71.240	70.250	69.387	68.525	65.000	62.200	59.600
22	3.000	2.550	2.900	3.100	3.100	3.500	2.229	2.209	2.189	2.169	2.150	2.050	1.950	1.950
23	10.025	8.900	8.550	8.950	9.050	9.450	7.880	7.509	7.255	7.127	7.000	6.925	6.825	6.725
25	6.150	7.240	7.050	7.950	7.850	8.250	6.500	6.300	6.137	6.218	6.250	6.300	6.300	6.300
27	29.650	34.000	37.925	39.850	41.025	41.775	39.600	39.200	39.625	39.950	40.150	41.900	43.500	45.000
29	2.800	2.225	2.350	2.450	2.450	2.750	2.278	1.957	1.837	1.718	1.600	1.400	1.300	1.200
30	6.900	8.575	10.025	11.210	12.010	12.340	11.700	11.300	11.200	11.200	11.200	11.400	11.600	11.800
31	0.700	0.925	1.080	1.160	1.260	1.140	0.750	0.750	0.750	0.750	0.750	0.750	0.750	0.750
32	13.100	10.725	11.580	12.490	12.900	14.100	10.739	10.029	9.519	9.409	9.300	9.100	8.900	8.600
33XX	20.800	15.350	15.550	16.550	17.550	18.450	16.000	14.895	14.295	13.756	13.600	13.300	13.100	13.100
34	26.750	22.850	22.975	24.350	26.625	27.250	23.100	21.700	21.700	21.800	21.900	22.000	22.100	22.100
35	37.750	38.625	37.525	40.650	43.175	44.900	40.350	39.150	39.050	39.050	39.050	39.950	40.950	41.950
36	22.550	28.875	30.175	28.700	32.325	35.025	31.608	30.618	30.828	31.038	31.150	32.275	33.104	33.825
37	109.450	99.825	118.150	129.500	141.500	142.700	121.148	110.847	100.647	91.535	89.250	84.050	79.250	74.750
38	25.950	25.725	23.320	28.330	27.940	26.850	24.409	23.918	24.028	24.239	24.350	25.425	26.353	27.275
39	7.350	7.400	8.600	10.350	11.900	10.550	8.900	8.050	7.479	7.439	7.400	7.100	6.800	6.500
2421	52.427	44.300	47.250	47.200	47.000	44.900	34.673	32.790	32.028	30.792	30.841	27.899	29.080	29.612
2436	26.582	20.900	21.900	20.900	20.750	19.125	15.493	14.542	14.018	12.929	12.554	9.534	9.295	9.130
24XX	61.066	57.100	60.100	63.400	62.650	59.450	55.829	54.779	53.750	52.739	51.748	47.970	44.436	41.133
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.446	2.394	2.342	2.292	2.242	2.011	1.804	1.618
2621	14.143	13.410	12.650	12.900	13.700	13.700	13.514	13.332	13.149	12.978	12.801	11.993	11.251	10.569
2631	5.037	5.000	4.900	4.850	5.450	5.550	5.457	5.367	5.277	5.189	5.104	4.692	4.316	3.968
26XX	7.896	7.815	8.750	8.500	8.500	8.600	7.979	7.920	7.862	7.804	7.747	7.321	7.207	7.054
2812	0.763	0.700	0.700	0.700	0.600	0.700	0.695	0.691	0.686	0.681	0.676	0.680	0.680	0.644
2819	6.567	8.890	8.780	9.780	9.580	9.980	4.807	4.734	4.662	4.589	4.517	3.977	3.937	3.899
28XX	7.470	7.650	7.650	7.900	8.000	8.600	7.564	7.497	7.427	7.359	7.292	7.051	6.817	6.590
3334	10.350	7.250	5.850	7.300	7.600	7.100	4.050	3.770	3.730	3.690	3.650	3.650	3.650	3.650
SUBTOT	592.100	560.870	591.260	626.670	653.465	657.535	572.644	547.489	531.719	517.828	512.799	495.703	487.455	479.291

NON-MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - REGION 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	179.500	176.500	181.550	187.700	196.700	203.600	200.010	196.002	195.300	196.100	196.800	200.000	202.800	205.400
50-51	194.000	195.700	203.375	213.275	229.000	239.200	233.378	230.918	232.158	234.398	236.739	249.105	261.559	274.190
52,53+	275.100	279.300	300.050	314.100	332.675	346.650	338.429	327.986	330.744	334.602	337.461	354.690	370.825	385.096
54	75.100	92.400	105.125	110.800	117.300	123.900	121.609	121.726	122.244	122.762	123.180	126.611	130.025	133.217
58	195.500	218.400	233.275	241.600	250.100	261.300	259.808	260.717	263.518	266.562	271.001	316.463	361.050	405.864
60-67	188.900	193.400	202.450	205.550	210.750	215.550	208.439	207.899	209.117	211.539	214.761	228.300	240.800	253.102
70	40.200	42.600	45.800	48.850	52.300	55.400	54.100	53.900	54.250	54.607	54.932	59.006	62.900	66.601
72	29.600	35.000	36.075	34.100	35.275	37.150	37.543	37.663	37.901	38.137	38.377	40.813	42.929	44.812
73	89.800	109.800	138.475	123.200	133.650	142.750	143.950	146.400	149.250	152.200	155.650	187.000	218.350	249.747
76	9.800	10.500	11.350	12.750	14.225	14.750	13.609	13.537	13.671	13.804	13.938	14.495	14.912	15.284
80	179.800	212.350	231.100	240.600	252.300	269.000	272.992	280.917	289.244	294.673	300.104	339.848	378.228	415.600
81	17.400	22.700	25.700	26.900	27.925	29.300	29.085	29.373	29.716	30.064	30.469	35.711	40.673	45.441
83	31.800	41.800	47.525	56.500	61.000	63.900	63.800	63.800	64.500	65.300	66.100	73.919	81.629	89.032
89	36.400	36.000	39.100	65.800	71.150	75.300	76.216	77.325	79.133	81.142	83.251	93.607	103.261	111.910
75,78+	122.600	141.125	150.850	158.900	168.500	177.600	177.438	178.467	180.096	182.226	183.856	193.061	201.548	209.508
82	19.800	24.200	27.500	32.800	34.600	35.800	35.300	35.250	35.470	35.500	35.600	36.500	37.500	38.300
941	279.700	280.275	291.400	299.600	306.700	317.900	317.600	318.800	320.179	321.970	323.762	337.888	351.943	365.709
90-99	230.300	236.100	248.300	257.500	266.400	276.300	275.700	275.200	276.200	277.300	279.600	289.500	300.300	311.000
Const	161.300	132.600	140.600	153.750	171.050	184.600	152.600	146.046	148.002	150.974	152.961	164.328	174.698	184.644
Agric	292.200	286.600	286.200	285.055	284.100	280.288	278.211	276.236	274.276	272.330	270.400	260.700	250.900	241.400
Mining	13.300	9.875	9.075	10.075	10.900	11.800	9.700	8.700	8.400	8.400	8.400	8.400	8.400	8.400
Fd Gvt	117.300	116.350	118.300	120.550	122.200	127.200	117.800	114.500	114.000	114.500	115.000	117.700	119.900	122.000
SUBTOT	2779.400	2893.575	3073.175	3199.955	3348.800	3489.239	3417.317	3401.362	3427.369	3459.090	3492.342	3727.645	3955.130	4176.257
TOTAL	3371.500	3454.446	3664.435	3826.625	4002.265	4146.773	3989.961	3948.851	3959.088	3976.918	4005.141	4223.348	4442.585	4655.548

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME   LOW SCENARIO - REGION   2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	2304.022	2428.959	2475.489	2513.748	2559.629	2591.688	2606.216	2614.939	2621.308	2624.187	2632.905	2660.743	2689.617	2709.297
MF	427.732	492.379	528.236	560.778	597.102	626.063	644.096	657.515	669.575	679.088	692.415	751.523	814.844	875.513
MO	230.919	280.062	301.774	321.685	342.460	358.876	367.396	373.226	377.891	380.817	386.111	404.419	421.193	435.109
TOTAL	2962.673	3201.400	3305.500	3396.211	3499.190	3576.626	3617.708	3645.680	3668.774	3684.092	3711.430	3816.684	3925.654	4019.918
POPUL	8003.820	8389.700	8532.000	8668.200	8860.400	9019.000	9121.738	9192.005	9250.031	9288.363	9356.587	9660.864	9976.585	10255.690
HHLDS	2962.673	3201.400	3305.500	3396.210	3499.190	3576.626	3617.708	3645.680	3668.774	3684.092	3711.430	3816.685	3925.654	4019.918
PCI	10360.21	10444.04	10783.52	10964.63	11352.17	11426.33	11602.90	11724.70	11847.46	11969.99	12094.40	12754.33	13450.51	14184.24

MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	31.900	31.100	32.300	34.200	35.500	35.900	33.500	33.000	32.500	32.000	31.500	30.000	29.000	28.000
22	1.000	0.900	1.000	1.200	1.200	1.300	0.900	0.900	0.900	0.900	0.900	0.900	0.900	0.900
23	6.500	6.200	5.700	6.000	6.000	6.200	5.700	5.400	5.200	5.100	5.000	5.000	5.000	5.000
25	3.300	3.800	3.800	4.200	4.000	4.300	3.700	3.600	3.500	3.600	3.650	3.700	3.700	3.700
27	15.800	17.600	20.100	21.400	22.100	22.000	21.000	21.000	21.200	21.300	21.400	22.600	23.800	25.000
29	2.100	1.800	1.800	1.900	1.900	2.200	1.900	1.600	1.500	1.400	1.300	1.200	1.100	1.000
30	3.500	4.500	5.100	5.800	6.200	6.500	6.200	6.200	6.200	6.200	6.200	6.300	6.400	6.500
31	0.400	0.400	0.400	0.500	0.600	0.500	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400
32	6.900	6.400	6.900	7.300	7.500	7.900	6.000	6.000	5.900	5.800	5.700	5.500	5.400	5.200
33XX	9.000	6.900	6.900	7.100	7.300	7.600	6.600	6.295	6.195	6.097	6.000	6.000	6.000	6.000
34	11.800	9.700	10.500	10.900	11.800	12.200	11.000	9.600	9.600	9.700	9.800	9.900	10.000	10.000
35	15.000	17.100	16.200	18.000	19.000	19.500	17.500	17.000	17.000	17.100	17.200	17.600	18.100	18.600
36	11.200	12.100	13.200	10.500	11.700	12.100	11.000	10.500	10.700	10.900	11.000	11.600	12.100	12.600
37	98.350	89.600	106.200	116.200	128.500	128.900	110.000	100.000	90.000	81.087	79.000	74.400	70.200	65.700
38	6.400	10.700	10.800	14.600	14.900	14.700	14.000	13.500	13.500	13.600	13.600	14.000	14.300	14.700
39	4.600	4.500	4.800	5.500	5.900	5.600	5.000	4.600	4.279	4.239	4.200	4.000	3.800	3.600
2421	16.027	13.400	14.500	15.200	15.300	14.700	11.459	10.643	10.258	9.723	9.654	8.370	8.691	8.945
2436	4.982	4.200	3.900	3.600	3.100	3.000	2.336	2.182	2.099	1.932	1.870	1.441	1.430	1.422
24XX	25.991	20.700	22.000	22.800	22.700	21.900	20.024	19.648	19.278	18.916	18.560	17.205	15.938	14.753
2611	2.974	2.100	2.050	2.100	2.500	2.500	2.446	2.394	2.342	2.292	2.242	2.011	1.804	1.618
2621	8.818	9.000	8.400	8.700	9.300	9.300	9.174	9.050	8.926	8.810	8.689	8.142	7.637	7.175
2631	1.637	1.200	1.200	1.200	1.600	1.600	1.574	1.547	1.522	1.497	1.472	1.353	1.245	1.144
26XX	4.171	4.400	4.950	5.100	4.900	5.000	4.780	4.732	4.684	4.637	4.591	4.326	4.306	4.272
2812	0.513	0.500	0.500	0.500	0.400	0.500	0.497	0.493	0.490	0.486	0.483	0.489	0.492	0.460
2819	5.300	7.700	7.700	8.700	8.500	8.900	3.740	3.680	3.620	3.560	3.500	3.000	3.000	3.000
28XX	2.887	3.100	3.300	3.300	3.300	3.500	3.068	3.037	3.007	2.977	2.947	2.856	2.767	2.680
3334	7.700	5.800	4.400	5.600	5.900	5.900	3.200	2.920	2.880	2.840	2.800	2.800	2.800	2.800
SUBTOT	308.750	295.400	318.600	342.100	361.600	364.200	316.697	299.919	287.680	277.093	273.658	265.093	260.310	255.169

NON-MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - WASHINGTON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	91.400	93.600	98.500	101.900	107.900	112.000	111.000	109.000	108.000	108.500	109.000	110.000	111.000	112.000
50-51	100.500	105.700	111.400	116.400	124.600	132.100	130.500	130.500	131.000	132.500	134.000	138.000	142.000	145.900
52,53+	141.000	146.900	161.200	168.800	179.100	189.000	186.000	179.000	180.500	183.000	184.500	194.000	202.362	209.032
54	38.200	49.200	57.400	59.900	62.300	65.400	64.500	65.000	65.300	65.600	65.800	68.000	70.200	72.300
58	101.600	118.900	128.200	132.500	135.000	141.600	142.608	143.017	144.468	145.062	146.501	174.148	202.050	230.751
60-67	91.800	99.600	107.500	109.400	112.300	116.300	113.000	113.000	113.500	115.000	117.000	124.000	130.000	136.400
70	17.800	20.100	21.500	22.900	24.700	26.100	26.000	26.000	26.100	26.200	26.300	28.300	30.200	32.100
72	16.000	19.900	20.800	19.700	20.400	21.500	22.269	22.392	22.517	22.641	22.767	24.400	25.900	27.300
73	52.900	61.000	78.000	70.000	76.500	83.700	84.800	86.400	88.000	89.500	91.000	109.000	127.200	145.400
76	5.500	5.600	5.900	6.900	8.000	8.400	8.000	8.000	8.100	8.200	8.300	8.600	8.800	9.000
80	95.800	117.400	129.300	134.600	140.800	151.200	152.500	156.000	160.000	163.000	166.000	189.148	212.028	233.700
81	9.200	12.400	14.400	15.000	15.600	16.500	16.700	16.800	16.900	17.000	17.100	20.100	22.900	25.500
83	15.600	22.600	25.000	27.200	29.700	31.400	32.000	32.400	32.700	33.000	33.300	37.300	41.200	45.000
89	19.500	21.100	23.100	37.500	40.700	43.000	43.600	44.200	45.500	47.000	48.500	54.500	60.000	65.000
75,78+	66.800	83.500	89.000	95.400	101.100	106.700	107.500	108.500	109.500	111.000	112.000	117.000	121.500	125.500
82	8.900	12.000	13.100	14.700	15.900	16.700	16.600	16.600	16.700	16.700	16.800	17.400	18.000	18.500
941	145.500	143.600	151.100	156.000	160.600	166.300	166.500	167.000	167.500	168.000	168.500	176.100	183.700	191.200
90-99	117.400	129.100	135.500	141.300	146.800	152.100	152.000	152.000	152.300	152.700	153.000	158.000	163.000	168.000
Const	92.600	80.600	88.900	96.600	106.600	115.300	100.000	95.000	96.000	98.000	99.000	105.000	110.000	115.000
Agric	119.300	115.100	114.400	113.300	112.300	110.163	109.591	109.022	108.456	107.892	107.332	103.070	99.438	95.625
Mining	3.200	2.700	3.000	3.300	3.600	4.000	3.500	3.000	2.700	2.700	2.700	2.700	2.700	2.700
Fd Gvt	67.900	70.100	70.600	71.400	72.000	74.500	70.000	68.000	68.500	69.000	69.500	71.000	72.000	73.000
SUBTOT	1418.400	1530.700	1647.800	1714.700	1796.500	1883.963	1859.168	1850.831	1864.241	1882.195	1898.900	2029.766	2156.178	2278.908
TOTAL	1727.150	1826.100	1966.400	2056.800	2158.100	2248.163	2175.865	2150.750	2151.921	2159.287	2172.558	2294.859	2416.488	2534.077

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME LOW SCENARIO - WASHINGTON 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	1193.211	1266.263	1296.121	1318.354	1348.020	1367.485	1378.665	1383.832	1387.676	1387.830	1390.434	1400.914	1411.039	1414.871
MF	250.130	298.560	324.707	346.921	374.775	394.782	408.436	417.508	425.655	431.031	438.424	474.979	513.815	550.173
MO	97.169	126.178	140.172	151.726	166.490	176.657	183.078	186.763	189.797	191.125	193.480	203.236	211.910	218.037
TOTAL	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1970.179	1988.104	2003.128	2009.986	2022.339	2079.129	2136.764	2183.081
POPUL	4132.160	4406.000	4538.000	4619.000	4761.000	4866.700	4945.148	4990.141	5027.852	5045.064	5076.070	5239.404	5406.012	5545.026
HHLDS	1540.510	1691.000	1761.000	1817.000	1889.286	1938.924	1970.179	1988.104	2003.128	2009.986	2022.339	2079.129	2136.764	2183.081
PCI	10725.00	10924.00	11258.00	11383.00	11774.00	11798.00	12031.80	12152.10	12273.60	12396.30	12520.30	13159.00	13830.20	14535.70

MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	24.300	23.800	24.000	23.700	23.600	24.900	23.000	22.800	22.600	22.400	22.200	21.000	20.000	19.000
22	2.000	1.600	1.800	1.800	1.800	2.100	1.279	1.259	1.239	1.219	1.200	1.100	1.000	1.000
23	3.200	2.400	2.500	2.600	2.700	2.900	1.980	1.959	1.939	1.920	1.900	1.800	1.700	1.600
25	2.600	2.700	2.500	2.900	3.000	3.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200
27	10.000	11.500	12.800	13.200	13.500	14.100	13.400	13.000	13.100	13.200	13.300	13.600	13.800	14.000
29	0.600	0.400	0.500	0.500	0.500	0.500	0.378	0.357	0.337	0.318	0.300	0.200	0.200	0.200
30	2.400	3.200	3.800	4.600	4.900	5.000	4.800	4.600	4.600	4.700	4.700	4.800	4.900	5.000
31	0.300	0.400	0.500	0.500	0.500	0.500	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
32	4.500	3.100	3.600	4.000	4.200	4.900	3.800	3.200	2.800	2.800	2.800	2.800	2.700	2.600
33XX	9.600	8.200	8.600	9.300	10.100	10.700	9.300	8.500	8.000	7.559	7.500	7.200	7.000	7.000
34	12.700	11.000	10.200	11.200	12.300	12.400	10.000	10.000	10.000	10.000	10.000	10.000	10.000	10.000
35	17.700	15.500	15.800	16.800	17.600	18.000	16.000	15.500	15.500	15.500	15.500	16.000	16.500	17.000
36	9.800	13.900	13.600	14.100	15.600	17.200	15.500	15.000	15.000	15.000	15.000	15.500	15.800	16.000
37	10.300	9.200	10.800	11.600	11.400	12.200	9.898	9.797	9.697	9.598	9.500	9.000	8.500	8.500
38	19.300	14.600	12.100	13.200	12.500	11.600	10.000	10.000	10.100	10.200	10.300	10.900	11.500	12.000
39	2.200	2.400	3.200	3.800	4.900	3.800	3.000	2.600	2.400	2.400	2.400	2.300	2.200	2.100
2421	23.800	20.500	22.000	21.400	20.800	19.000	14.891	13.812	13.286	12.546	12.444	10.696	11.115	11.401
2436	20.100	15.500	16.800	16.100	16.300	14.900	12.365	11.613	11.164	10.232	9.892	7.265	7.030	6.854
24XX	25.600	27.600	29.200	31.300	29.900	27.300	27.085	26.576	26.077	25.587	25.106	23.273	21.558	19.956
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	5.100	4.160	4.000	3.900	4.100	4.100	4.044	3.991	3.935	3.884	3.832	3.589	3.367	3.163
2631	2.000	2.100	2.000	1.900	2.000	2.000	1.967	1.934	1.901	1.869	1.839	1.690	1.554	1.430
26XX	3.300	2.840	3.200	2.800	3.000	3.000	2.675	2.662	2.648	2.634	2.621	2.526	2.434	2.346
2812	0.250	0.200	0.200	0.200	0.200	0.200	0.199	0.197	0.196	0.195	0.193	0.191	0.188	0.184
2819	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
28XX	2.050	1.900	1.900	1.900	2.000	2.300	1.756	1.741	1.721	1.704	1.687	1.635	1.584	1.534
3334	1.400	0.600	0.700	0.900	0.900	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400	0.400
SUBTOT	215.100	199.300	206.300	214.200	218.300	217.200	190.216	183.998	181.141	178.365	177.114	169.963	167.531	165.768

NON-MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - OREGON 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	60.500	57.300	58.500	60.500	62.800	65.100	63.000	61.000	61.200	61.400	61.600	63.500	65.000	66.400
50-51	67.400	65.800	68.200	72.900	78.200	80.800	77.000	75.000	75.500	76.000	76.500	82.500	88.600	95.000
52,53+	96.200	92.900	98.700	104.200	109.700	112.000	108.000	105.000	106.000	107.000	108.000	114.000	120.100	126.200
54	24.600	29.500	33.800	36.400	39.400	42.000	41.000	41.000	41.100	41.200	41.300	41.900	42.500	43.000
58	67.400	70.400	76.000	78.900	82.300	85.000	84.000	84.500	85.500	87.500	90.000	102.500	114.000	125.000
60-67	70.000	66.800	72.100	73.300	75.300	75.800	73.000	72.430	72.918	73.609	74.500	79.000	83.300	87.202
70	14.800	14.600	15.600	17.100	18.400	19.700	18.800	18.600	18.700	18.800	18.900	20.000	21.000	22.000
72	9.800	10.400	10.800	10.400	10.900	11.600	10.900	10.845	10.905	10.965	11.026	11.497	11.893	12.193
73	24.900	35.000	45.500	43.000	46.700	48.100	48.400	49.000	50.000	51.200	52.800	63.000	73.000	83.000
76	3.000	3.500	4.100	4.400	4.600	4.700	4.200	4.117	4.140	4.163	4.186	4.365	4.515	4.629
80	62.100	69.400	74.400	77.600	82.100	87.200	90.000	94.000	98.000	100.000	102.000	114.000	125.000	136.100
81	5.600	7.300	8.100	8.500	8.700	9.000	9.049	9.218	9.391	9.568	9.800	11.600	13.300	15.000
83	11.400	14.000	16.900	23.300	24.400	25.200	24.800	24.600	24.800	25.100	25.400	28.300	31.200	34.000
89	11.100	10.300	11.300	17.200	19.000	20.500	20.800	21.100	21.400	21.700	22.000	24.500	26.900	29.000
75,78+	42.200	43.500	47.400	47.900	50.800	53.500	52.700	52.500	53.000	53.500	54.000	57.400	60.700	64.000
82	7.100	8.300	10.300	13.800	14.300	14.600	14.300	14.300	14.400	14.400	14.400	14.600	14.800	15.000
941	94.200	94.600	97.400	99.300	101.200	104.100	103.500	104.000	104.500	105.500	106.500	111.700	116.900	122.000
90-99	78.200	73.500	77.700	80.200	81.700	84.300	84.000	83.500	84.000	84.500	86.300	89.900	94.500	99.000
Const	46.500	33.100	35.300	39.900	45.200	47.900	34.000	33.396	34.102	34.824	35.561	39.400	43.200	47.000
Agric	96.300	98.800	99.700	100.300	101.000	100.580	99.781	98.988	98.201	97.421	96.647	93.708	90.121	86.728
Mining	2.300	1.500	1.400	1.300	1.400	1.400	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200
Fd Gvt	30.800	29.600	30.600	31.700	32.200	34.200	31.000	30.000	29.000	29.000	29.000	30.000	31.000	32.000
SUBTOT	926.400	930.100	993.800	1042.100	1090.300	1127.280	1093.430	1088.294	1097.957	1108.550	1121.620	1198.570	1272.729	1345.652
TOTAL	1141.500	1129.400	1200.100	1256.300	1308.600	1344.480	1283.646	1272.292	1279.099	1286.915	1298.734	1368.533	1440.260	1511.420

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME LOW SCENARIO - OREGON 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	766.113	797.066	812.147	825.103	840.326	852.139	855.703	858.599	860.609	863.106	868.900	879.145	890.561	900.054
MF	143.583	154.439	162.893	171.662	179.226	187.320	191.145	194.662	197.759	201.152	206.310	222.922	241.118	259.190
MO	81.898	92.495	98.960	105.235	110.407	115.947	117.901	119.509	120.677	121.992	124.655	129.181	133.571	137.756
TOTAL	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1164.748	1172.770	1179.045	1186.249	1199.865	1231.249	1265.250	1297.000
POPUL	2633.160	2675.800	2690.000	2741.000	2791.000	2842.300	2865.281	2885.015	2900.450	2918.174	2951.668	3041.185	3137.821	3229.531
HHLDS	991.593	1044.000	1074.000	1102.000	1129.959	1155.406	1164.748	1172.770	1179.045	1186.249	1199.865	1231.249	1265.250	1297.000
PCI	9897.80	9845.90	10162.10	10402.20	10731.30	10804.40	10906.10	11037.00	11169.40	11303.50	11439.10	12142.10	12888.30	13680.40

MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	17.000	16.600	16.100	17.100	16.900	17.000	16.000	15.000	14.715	14.557	14.400	13.600	12.800	12.200
22	0.000	0.050	0.100	0.100	0.100	0.100	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
23	0.300	0.250	0.300	0.300	0.300	0.300	0.150	0.100	0.066	0.057	0.050	0.050	0.050	0.050
25	0.250	0.600	0.600	0.700	0.700	0.600	0.500	0.400	0.337	0.318	0.300	0.300	0.300	0.300
27	3.100	4.200	4.300	4.500	4.600	4.800	4.400	4.400	4.500	4.600	4.600	4.800	5.000	5.100
29	0.100	0.025	0.050	0.050	0.050	0.050	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	1.000	0.850	1.100	0.800	0.900	0.800	0.700	0.500	0.400	0.300	0.300	0.300	0.300	0.300
31	0.000	0.100	0.150	0.150	0.150	0.100	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
32	1.300	0.900	0.800	0.900	0.900	1.000	0.700	0.600	0.600	0.600	0.600	0.600	0.600	0.600
33XX	1.200	0.100	0.000	0.100	0.100	0.100	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
34	2.100	1.900	2.000	2.000	2.300	2.400	1.900	1.900	1.900	1.900	1.900	1.900	1.900	1.900
35	5.000	5.800	5.200	5.500	6.200	7.000	6.500	6.300	6.200	6.100	6.000	6.000	6.000	6.000
36	1.500	2.800	3.300	4.000	4.900	5.600	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
37	0.700	0.950	1.100	1.600	1.500	1.500	1.200	1.000	0.900	0.800	0.700	0.600	0.500	0.500
38	0.150	0.300	0.300	0.400	0.400	0.400	0.250	0.250	0.250	0.250	0.250	0.300	0.300	0.300
39	0.400	0.325	0.300	0.400	0.400	0.400	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
2421	8.100	6.400	6.600	6.700	7.000	7.200	5.334	5.343	5.436	5.462	5.603	5.662	5.942	5.938
2436	0.500	0.400	0.400	0.400	0.400	0.400	0.250	0.236	0.238	0.241	0.250	0.261	0.263	0.269
24XX	6.775	6.700	6.400	6.800	7.400	7.600	6.282	6.164	6.048	5.934	5.823	5.398	5.000	4.628
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.225	0.250	0.250	0.300	0.300	0.300	0.296	0.292	0.288	0.284	0.280	0.262	0.246	0.231
2631	0.850	0.950	0.950	1.000	1.100	1.200	1.180	1.161	1.141	1.122	1.104	1.014	0.933	0.858
26XX	0.425	0.575	0.600	0.600	0.600	0.600	0.524	0.527	0.530	0.532	0.535	0.469	0.468	0.435
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	1.067	1.000	0.900	0.900	0.900	0.900	0.889	0.879	0.868	0.858	0.848	0.814	0.781	0.749
28XX	2.433	2.600	2.400	2.600	2.600	2.700	2.641	2.621	2.602	2.582	2.563	2.468	2.377	2.289
3334	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SUBTOT	54.475	54.625	54.200	57.900	60.700	63.050	55.045	53.022	52.369	51.848	51.455	50.149	49.111	47.998

NON-MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - IDAHO 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	20.100	19.200	17.900	18.600	19.100	19.500	19.000	19.000	19.100	19.200	19.200	19.500	19.800	20.000
50-51	22.300	20.800	20.500	20.600	22.700	22.700	22.500	22.000	22.200	22.400	22.700	24.800	26.900	29.000
52,53+	29.900	31.300	31.500	32.400	35.100	36.800	35.800	35.400	35.600	35.900	36.200	37.500	38.800	40.000
54	9.400	10.700	11.100	11.400	12.100	12.700	12.500	12.300	12.400	12.500	12.600	13.100	13.500	13.900
58	19.000	21.600	21.600	22.700	24.400	26.100	24.800	25.000	25.300	25.700	26.100	30.100	34.100	38.000
60-67	23.400	23.600	19.200	19.200	19.300	19.500	19.000	19.000	19.200	19.400	19.700	21.500	23.300	25.000
70	5.100	5.200	5.800	6.000	6.500	6.800	6.500	6.500	6.600	6.700	6.800	7.400	8.000	8.500
72	3.000	3.800	3.600	3.100	3.200	3.300	3.624	3.651	3.679	3.706	3.734	3.933	4.109	4.255
73	11.000	12.100	12.800	8.000	8.800	9.200	9.000	9.200	9.400	9.600	9.900	12.600	15.300	18.000
76	1.000	1.100	1.000	1.100	1.200	1.200	1.107	1.116	1.124	1.132	1.141	1.202	1.255	1.300
80	15.500	17.900	19.100	20.000	20.700	21.800	22.000	22.300	22.500	22.800	23.100	26.800	30.400	34.000
81	2.100	2.400	2.500	2.700	2.900	3.000	2.700	2.706	2.762	2.819	2.878	3.235	3.607	3.985
83	3.400	4.000	4.100	4.500	4.800	5.000	5.000	5.000	5.100	5.200	5.300	5.900	6.500	7.000
89	4.800	3.900	3.900	10.300	10.700	11.000	11.100	11.300	11.500	11.700	12.000	13.800	15.500	17.000
75,78+	10.300	10.800	11.000	12.100	13.100	13.900	13.900	14.100	14.200	14.300	14.400	15.000	15.500	16.000
82	3.800	3.900	4.100	4.300	4.400	4.500	4.400	4.350	4.370	4.400	4.400	4.500	4.700	4.800
941	31.100	32.300	33.400	34.900	35.300	37.700	38.000	38.300	38.600	38.800	39.000	40.000	41.000	42.000
90-99	26.400	26.100	27.700	28.600	29.900	31.700	31.700	31.700	31.800	31.900	32.000	33.000	34.000	35.000
Const	17.400	15.100	13.600	14.200	16.000	18.000	16.000	15.000	15.200	15.400	15.600	16.800	18.000	19.000
Agric	69.100	65.400	64.800	64.155	63.500	62.245	61.684	61.128	60.577	60.031	59.490	57.303	54.884	52.756
Mining	4.700	3.800	2.600	3.300	3.600	3.800	2.800	2.500	2.500	2.500	2.500	2.500	2.500	2.500
Fd Gvt	13.000	11.800	12.200	12.500	12.900	13.300	12.000	11.800	11.900	12.000	12.000	12.200	12.400	12.500
SUBTOT	345.800	346.800	344.000	354.655	370.200	383.745	375.115	373.351	375.612	378.088	380.743	402.673	424.055	444.496
TOTAL	400.275	401.425	398.200	412.555	430.900	446.795	430.160	426.373	427.981	429.936	432.198	452.822	473.166	492.494

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME LOW SCENARIO - IDAHO 2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	262.386	280.726	282.132	285.125	286.174	286.958	286.819	287.624	288.131	288.329	288.680	294.616	300.797	306.094
MF	25.070	29.289	30.147	31.463	32.176	32.816	33.180	33.843	34.422	34.915	35.463	39.615	44.040	48.379
MO	36.714	43.986	44.720	46.412	47.104	47.634	47.666	48.154	48.462	48.584	48.757	51.396	53.853	56.140
TOTAL	324.170	354.000	357.000	363.000	365.455	367.409	367.665	369.621	371.015	371.827	372.900	385.626	398.690	410.613
POPUL	944.000	1004.000	1000.500	1004.400	1005.000	1006.700	1007.401	1012.762	1016.581	1018.806	1021.745	1060.473	1100.385	1137.399
HHLDS	324.170	354.000	357.000	363.000	365.455	367.409	367.665	369.621	371.015	371.827	372.900	385.626	398.690	410.613
PCI	8611.20	8400.50	8573.30	8785.80	9226.40	9457.00	9334.30	9427.70	9521.90	9617.20	9713.30	10208.80	10729.60	11276.90

MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
20	0.700	0.465	0.525	0.550	0.475	0.500	0.445	0.440	0.435	0.430	0.425	0.400	0.400	0.400
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.025	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.075	0.075	0.075
25	0.000	0.140	0.150	0.150	0.150	0.150	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
27	0.750	0.700	0.725	0.750	0.825	0.875	0.800	0.800	0.825	0.850	0.850	0.900	0.900	0.900
29	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30	0.000	0.025	0.025	0.010	0.010	0.040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
31	0.000	0.025	0.030	0.010	0.010	0.040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
32	0.400	0.325	0.280	0.290	0.300	0.300	0.239	0.229	0.219	0.209	0.200	0.200	0.200	0.200
33XX	1.000	0.150	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
34	0.150	0.250	0.275	0.250	0.225	0.250	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
35	0.050	0.225	0.325	0.350	0.375	0.400	0.350	0.350	0.350	0.350	0.350	0.350	0.350	0.350
36	0.050	0.075	0.075	0.100	0.125	0.125	0.108	0.118	0.128	0.138	0.150	0.175	0.204	0.225
37	0.100	0.075	0.050	0.100	0.100	0.100	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
38	0.100	0.125	0.120	0.130	0.140	0.150	0.159	0.168	0.178	0.189	0.200	0.225	0.253	0.275
39	0.150	0.175	0.300	0.650	0.700	0.750	0.700	0.650	0.600	0.600	0.600	0.600	0.600	0.600
2421	4.500	4.000	4.150	3.900	3.900	4.000	2.990	2.993	3.047	3.061	3.141	3.172	3.332	3.328
2436	1.000	0.800	0.800	0.800	0.950	0.825	0.543	0.512	0.517	0.524	0.543	0.567	0.572	0.585
24XX	2.700	2.100	2.500	2.500	2.650	2.650	2.437	2.391	2.346	2.302	2.259	2.094	1.940	1.796
2611	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2621	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2631	0.550	0.750	0.750	0.750	0.750	0.750	0.737	0.725	0.713	0.701	0.690	0.634	0.583	0.536
26XX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2812	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2819	0.200	0.190	0.180	0.180	0.180	0.180	0.178	0.176	0.174	0.172	0.170	0.163	0.156	0.150
28XX	0.100	0.050	0.050	0.100	0.100	0.100	0.099	0.098	0.097	0.096	0.095	0.092	0.089	0.086
3334	1.250	0.850	0.750	0.800	0.800	0.800	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450
SUBTOT	13.775	11.545	12.160	12.470	12.865	13.085	10.685	10.550	10.529	10.522	10.572	10.498	10.504	10.356

NON-MANUFACTURING EMPLOYMENT (1000'S) LOW SCENARIO - WESTERN MONTANA 2/22/91

INDUSTRY	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
40-49	7.500	6.400	6.650	6.700	6.900	7.000	7.010	7.002	7.000	7.000	7.000	7.000	7.000	7.000
50-51	3.800	3.400	3.275	3.375	3.500	3.600	3.378	3.418	3.458	3.498	3.539	3.805	4.059	4.290
52,53+	8.000	8.200	8.650	8.700	8.775	8.850	8.629	8.586	8.644	8.702	8.761	9.190	9.563	9.864
54	2.900	3.000	2.825	3.100	3.500	3.800	3.609	3.426	3.444	3.462	3.480	3.611	3.825	4.017
58	7.500	7.500	7.475	7.500	8.400	8.600	8.400	8.200	8.250	8.300	8.400	9.715	10.900	12.113
60-67	3.700	3.400	3.650	3.650	3.850	3.950	3.439	3.469	3.499	3.530	3.561	3.800	4.200	4.500
70	2.500	2.700	2.900	2.850	2.700	2.800	2.800	2.800	2.850	2.907	2.932	3.306	3.700	4.001
72	0.800	0.900	0.875	0.900	0.775	0.750	0.750	0.775	0.800	0.825	0.850	0.983	1.027	1.064
73	1.000	1.700	2.175	2.200	1.650	1.750	1.750	1.800	1.850	1.900	1.950	2.400	2.850	3.347
76	0.300	0.300	0.350	0.350	0.425	0.450	0.302	0.304	0.307	0.309	0.311	0.328	0.342	0.355
80	6.400	7.650	8.300	8.400	8.700	8.800	8.492	8.617	8.744	8.873	9.004	9.900	10.800	11.800
81	0.500	0.600	0.700	0.700	0.725	0.800	0.636	0.649	0.663	0.677	0.691	0.776	0.866	0.956
83	1.400	1.200	1.525	1.500	2.100	2.300	2.000	1.800	1.900	2.000	2.100	2.419	2.729	3.032
89	1.000	0.700	0.800	0.800	0.750	0.800	0.716	0.725	0.733	0.742	0.751	0.807	0.861	0.910
75,78+	3.300	3.325	3.450	3.500	3.500	3.500	3.338	3.367	3.396	3.426	3.456	3.661	3.848	4.008
82	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
941	8.900	9.775	9.500	9.400	9.600	9.800	9.600	9.500	9.579	9.670	9.762	10.088	10.343	10.509
90-99	8.300	7.400	7.400	7.400	8.000	8.200	8.000	8.000	8.100	8.200	8.300	8.600	8.800	9.000
Const	4.800	3.800	2.800	3.050	3.250	3.400	2.600	2.650	2.700	2.750	2.800	3.128	3.498	3.644
Agric	7.500	7.300	7.300	7.300	7.300	7.300	7.155	7.098	7.042	6.986	6.931	6.619	6.457	6.291
Mining	3.100	1.875	2.075	2.175	2.300	2.600	2.200	2.000	2.000	2.000	2.000	2.000	2.000	2.000
Fd Gvt	5.600	4.850	4.900	4.950	5.100	5.200	4.800	4.700	4.600	4.500	4.500	4.500	4.500	4.500
SUBTOT	88.800	85.975	87.575	88.500	91.800	94.250	89.604	88.886	89.559	90.257	91.079	96.636	102.168	107.201
TOTAL	102.575	97.520	99.735	100.970	104.665	107.335	100.289	99.436	100.088	100.779	101.651	107.134	112.672	117.557

HOUSING, POPULATION, HOUSEHOLDS, AND INCOME   LOW SCENARIO - WESTERN MONTANA   2/22/91

	1980	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
HOUSING														
SF	82.313	84.905	85.088	85.166	85.108	85.105	85.029	84.883	84.892	84.923	84.890	86.068	87.220	88.277
MF	8.950	10.092	10.489	10.732	10.924	11.144	11.336	11.501	11.739	11.991	12.218	14.007	15.871	17.770
MO	15.138	17.403	17.922	18.312	18.459	18.638	18.751	18.800	18.956	19.117	19.219	20.605	21.859	23.176
TOTAL	106.400	112.400	113.500	114.211	114.491	114.886	115.116	115.184	115.586	116.030	116.327	120.680	124.950	129.223
POPUL	294.500	303.900	303.500	303.800	303.400	303.300	303.907	304.086	305.148	306.319	307.103	319.803	332.367	343.734
HHLDS	106.400	112.400	113.500	114.211	114.491	114.886	115.116	115.184	115.586	116.030	116.327	120.680	124.950	129.223
PCI	7793.00	7983.00	8477.00	8595.70	8716.10	8838.10	9474.30	9474.30	9474.30	9474.30	9474.30	10156.30	10887.50	11671.20

CHAPTER 6

FORECAST OF ELECTRICITY USE IN THE PACIFIC NORTHWEST

Introduction

Forecasts of demand for electricity are the foundation of electricity planning. This chapter describes long-term forecasts of electricity needs in the Pacific Northwest region. The forecasts were prepared jointly by the Northwest Power Planning Council and the Bonneville Power Administration.

Demand forecasts play three important roles in the region's power planning process. The first is the traditional role; they are the basis for deciding how much electricity the region will need. The second role is to explore and define the uncertainty surrounding future electrical resource needs. Finally, the demand forecasts are an essential component of conservation assessment. Conservation is identified as the priority resource in the Northwest Power Act. Demand forecasts have a twofold role in conservation planning. First, they determine the conservation potential associated with various levels of demand. Second, they aid in determining the reduction in demand that can be attributed to programs to acquire conservation resources. The role of demand forecasts in resource planning is discussed in more detail in the final section of this chapter.

The use of these demand forecasts in regional planning differs significantly from the traditional role of demand forecasts. The traditional use could be characterized as deterministic. That is, a "best-guess" demand forecast determined the amount of new electricity generation needed. Before the early 1970s, it was generally assumed that demand for electricity would continue to grow at close to historical rates. That growth had been rapid and relatively steady. It was assumed that economies of scale in power generation could be relied on to keep prices for electricity from increasing as new generating plants were added. Planners saw little reason for demand growth to slow down. In fact, it was widely assumed that there would be little or no response to price changes if they did occur.

The dramatic reduction in electricity demand growth that occurred in the rest of the country as electricity prices increased in the early 1970s caught most planners by surprise. The initial response seems to have been to develop much more sophisticated forecasting tools. The forecasting models adopted by the Council and Bonneville represent the results of those efforts. However, it has also been recognized that even with the best available tools, forecasts remain highly uncertain. Forecast ranges have been developed to deal with this uncertainty in planning.

The forecast of demand for electricity encompasses a range of five forecasts: a low, medium-low, medium, medium-high and high forecast. The high-demand forecast is designed to ensure that power supplies never constrain the region's economic growth potential. The high forecast portrays a future in which regional growth achieves record high levels, relative to national growth, combined with less competitive prices for alternative fuels. The likelihood that such rapid growth would occur for a 20-year period is considered very small. The forecast range is bounded on the low side by a forecast that is pessimistic about the regional economy, roughly in proportion to the optimism of the high case.

Inside the bounds of the low and high forecasts is a smaller, most probable range of demands bounded by the medium-low and medium-high forecasts. The medium-low, medium and medium-high forecasts will carry greater weight in the planning of resources than will the high and low extremes. Nevertheless, the possibilities posed by the high-growth forecast must be addressed by appropriate resource options. Similarly, conditions that are implied by the low-demand forecast will be considered within a flexible planning strategy designed to minimize regional electricity costs and risks.

The forecasts of electricity demand are determined by three primary factors: economic growth and its composition, prices of alternative fuels, and the price of electricity. The economic and alternative fuel price assumptions that drive these demand forecasts are described in Chapter 5, "Economic Forecasts for the Pacific Northwest." Forecasts of electricity prices are based on the amount of electricity demand and the cost of generating the electricity needed to meet that demand. At the same time, electricity demand is affected by the price of electricity. Thus, the forecasts must take into account the interaction between electricity prices, as determined by resource choices and their costs, and electricity demand. The interrelationships involved in determining the demand forecasts are illustrated in Figure 6-1. A demand forecasting system captures these relationships in considerable detail.

The Council is required by the Northwest Power Act to produce 20-year forecasts of the demand for electricity in the Pacific Northwest. Bonneville uses long-term forecasts of demand as a basis for determining future federal system loads. Although Bonneville is responsible for meeting federal system loads rather than regional loads, regional load growth is one the the major determinants of federal system loads. Federal system load forecasts combine portions of the regional load forecast and load requirements that retail utilities decide to place on Bonneville.

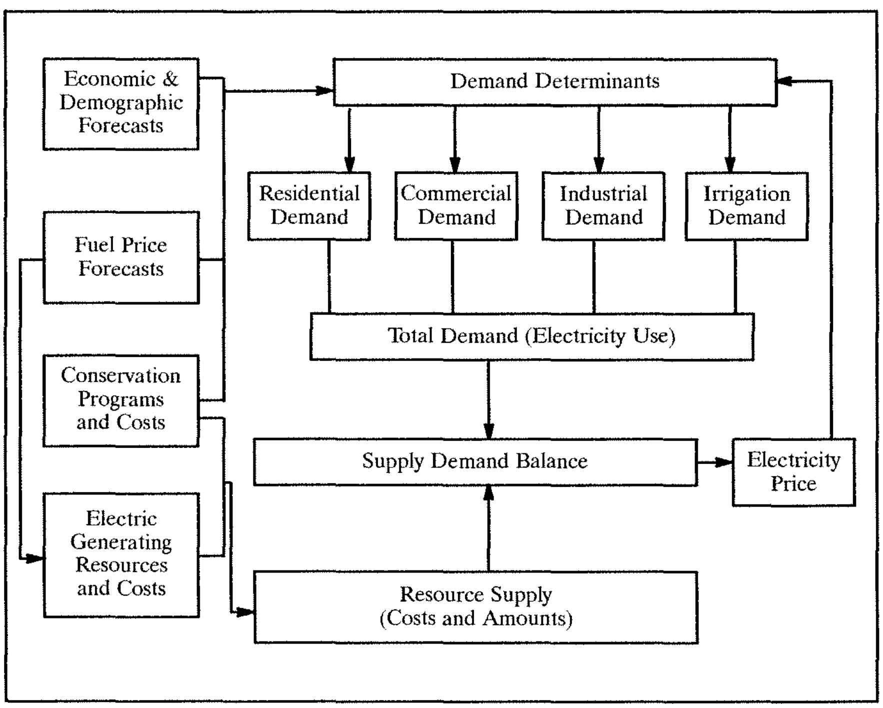
Bonneville also needs near-term forecasts for system operations, rate setting and financial planning. To maintain consistency between near-term forecasts and the long-term forecasts used in the resource planning process, Bonneville typically replaces the near-term loads in the medium forecast with more detailed customer group forecasts that better reflect near-term economic conditions. These near-term forecasts are prepared by Bonneville and regional utilities for the Pacific Northwest Utilities Conference Committee. Only the medium case long-term forecast is merged with near-term customer group specific forecasts. This merging applies only to loads through 1995.

Besides merging medium case forecasts, Bonneville also transforms the forecasts into monthly peak and energy loads, accounts for transmission and distribution losses and compiles calendar, fiscal and operating year load (sales plus losses) forecasts to meet various needs. The discussion and tables of sector sales that follow cover unmerged long-term forecasts; however, tables showing loads forecasts by customer group are attached as Appendix 6-C. They are in a format traditionally presented in Bonneville forecasts.

The demand forecast ranges are constructed by combining economic assumptions, fuel price assumptions and some modeling assumptions. This combination of assumptions is designed to explore a wide range of possible demands without combining assumptions unrealistically. That is, mutually inconsistent assumptions are not combined just to obtain extreme forecasts. In the high forecast, for example, the high economic assumptions are combined with high fuel price assumptions. In addition, for the high forecast, it was assumed large industrial consumers have relatively low price response. Electricity prices, which have a significant effect on demand, are determined for each scenario by an electricity pricing model based on the amount and cost of resources needed to meet demand. Generally, electricity prices are higher with higher demand growth.

Forecast System

Figure 6-1
Structure of the Demand Forecast System



Overview

In 1989, firm sales of electricity to the final consumer in the Pacific Northwest totaled 17,305 average megawatts, when adjusted to reflect normal temperatures. That is 152 billion kilowatt-hours. The high forecast shows this demand could grow to 28,836 average megawatts by 2010, nearly two thirds higher than current electricity requirements. In more graphic terms, the high implies the addition of electricity equivalent to that consumed by nearly 11 cities the size of Seattle by 2010. Under the set of assumptions leading to the low forecast, demand decreases to 15,787 average megawatts, about 9 percent lower than current requirements. This large uncertainty about future needs for electricity resources raises an important challenge for energy planning. The region needs to deal with this uncertainty in a manner that will neither prevent the region from attaining rapid economic growth, nor impose large and unnecessary costs should slower growth occur. Figure 6-2 illustrates the forecast range in the context of historical sales of electricity.

Table 6-1 shows that the rate of growth of demand could be as high as 2.5 percent per year, if the high case were to materialize, or as low as -0.4 if the low case were to occur. A more likely outcome, however, is between the medium-low growth rate of 0.6 percent and the medium-high rate of 1.7 percent. The medium forecast is for a 1.2 percent annual growth rate in demand for electricity. More detailed tables summarizing the five forecasts appear in Appendix 6-A.

Forecast growth rates are higher if direct service industries—industries that buy directly from Bonneville—are excluded. For all but the low case, demand excluding direct service industries demand grows 0.3 percent faster that the total firm demand shown in Table 6-1. For example, the high case growth rate of 2.5 percent per year becomes 2.8 percent if direct service industries are excluded. By excluding direct service industries, the low case growth rate moves from -0.4 percent to 0.1 percent.

It is also important to realize that growth is not forecast to occur at a constant rate each year of the forecast. For example, year-to-year growth in the high case varies from over 4 percent to less than 2 percent, with the most rapid growth occurring in the early 1990s.

The forecasts reflect the robust regional economy over the last four years. As a result, the near-term forecasts are higher than forecasts that were done in 1989 by Bonneville and the Council. This is particularly true for the lower end of the forecast range. The long-term forecasts are also slightly higher. Most of the increases in 2010 are less than 5 percent. Running counter to this pattern are the slight decreases in the high forecast from the forecasts included in Bonneville's 1989 Pacific Northwest Loads and Resources study (white book) and from the Council's 1989 supplement forecast. Table 6-B-1 in Appendix 6-B compares these recent forecasts to those in this plan.

Electricity Sales

Figure 6-2
Sales of Electricity—Historical and Forecast

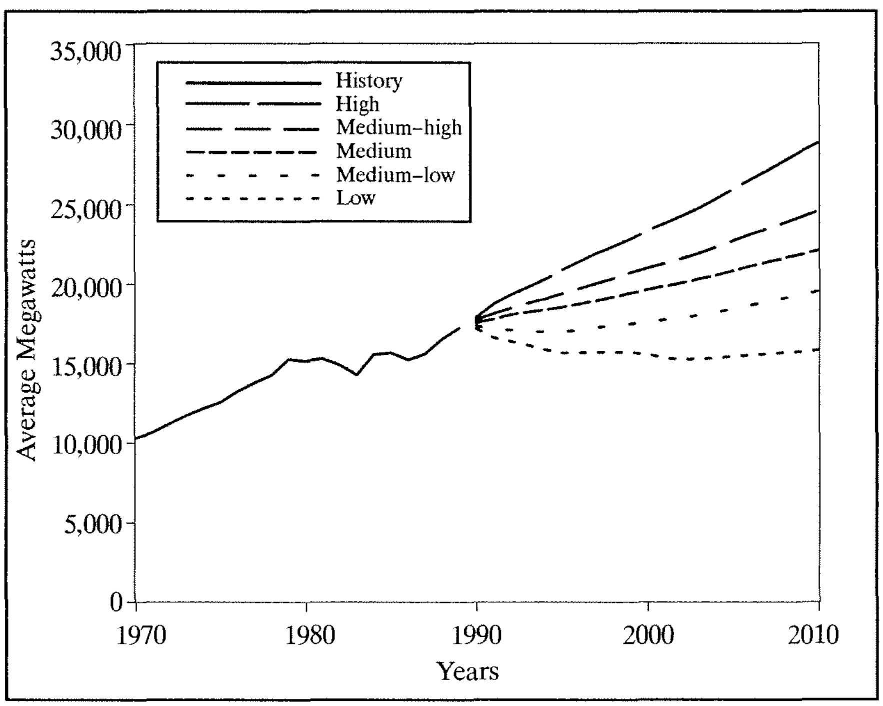


Table 6–1
Firm Sales of Electricity (Average Megawatts)

	Actual 1989	Forecasts 1995	2000	2010	Growth Rate (% per year) 1989–2010
High	17,305	20,826	23,305	28,836	2.5
Medium–High	17,305	19,336	20,935	24,583	1.7
Medium	17,305	18,513	19,587	22,075	1.2
Medium–Low	17,305	16,930	17,566	19,485	0.6
Low	17,305	15,607	15,520	15,787	-0.4

The forecasts for all but the high case have been raised slightly from those included in the draft plan as a result of numerous changes in assumptions. These increases were generally less than 3 percent. The high forecast was not changed significantly. Table 6–B–2 in Appendix 6–B shows the changes to the forecast between the draft and final plan.

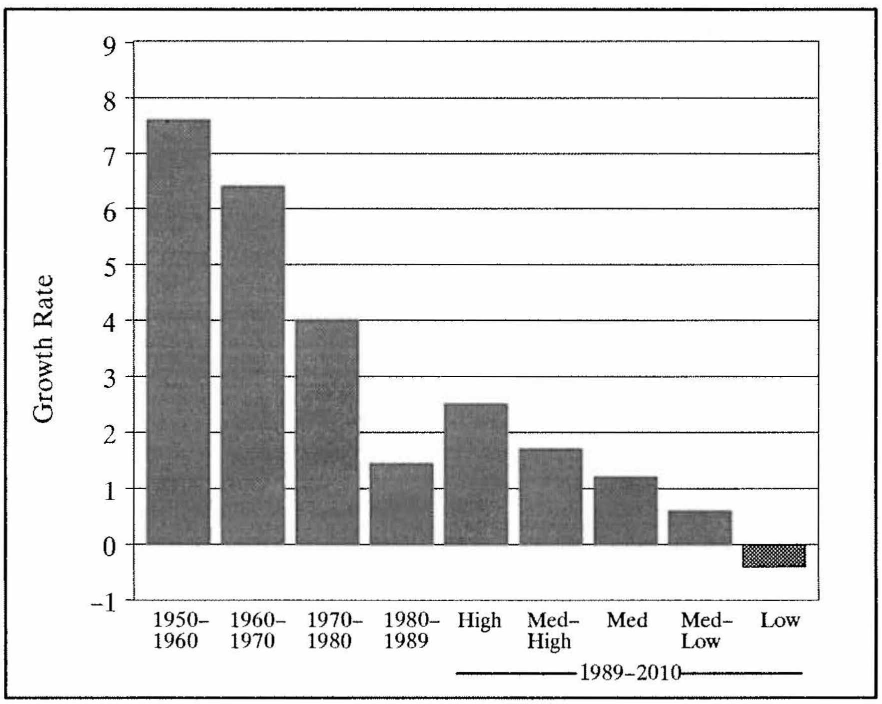
History can provide a useful guide for describing a forecast if the comparison is done carefully. However, year-to-year growth rates are influenced strongly by cycles in economic activity and weather conditions. For this reason, comparing a few years of demand growth with a 20-year forecast is inappropriate. Comparing longer periods or comparing weather-adjusted and cycle-adjusted growth can be useful.

Figure 6–3 compares the projected growth rates of demand to regional growth rates since 1950. Growth of electricity consumption in the Pacific Northwest averaged about 7 percent per year during the 1950s and 1960s. However, even during this time there were years of negative growth. In the 1970s, the region's electricity demand growth fell to a 4 percent rate.

The 1980s are difficult to characterize because of their volatility. However, when two years that are both economic cycle peaks are chosen to compute a growth rate (1979 and 1989), the average demand growth rate is about 1.2 percent per year. Although demand went up and down from 1980 to 1986, demand in 1986 was nearly the same as 1980. Since 1986, demand has been growing strongly, averaging about 3.5 percent per year. The years 1987, 1988 and

Demand Growth

Figure 6–3
Historical and Forecast 1989–2010 Growth



1989 saw an economic boom in the Northwest. This economic prosperity was spread evenly across all sectors of the economy, but was led by dramatic expansion of the Boeing Company. Even the energy-intensive, resource-based industries, such as paper, chemicals, wood products and metals, experienced strong growth. The Northwest economy has benefitted from the earlier decline in the value of the dollar relative to other currencies, making its products more competitive in foreign markets.

All of these factors have contributed to strong growth in demand for electricity. However, a recovery from a recession is not something to be compared to a 20-year trend forecast. The 1979 to 1989 growth rate of 1.2 percent per year is probably a better comparison. The most likely range of the forecast centers around 1 percent, and it falls below the growth rates of the 1950s, 1960s and 1970s.

What are the reasons for expected demand growth being lower than growth rates experienced before 1980? Several factors are listed below.

- The rate of economic growth (employment, population, households and production) is expected to be significantly slower. This is true for the nation as a whole, as well as the region, and is due to basic demographic trends. For example, national forecasts of employment growth over the next 20 years are about half the rate experienced between 1960 and 1980.
- Electricity prices have increased dramatically since the late 1970s, thus decreasing the demand for electricity. This will continue to slow growth during the forecast as buildings and equipment are replaced using more energy-efficient practices. Some of these practices are now mandated by code. For example, buildings being built today use about 30 percent less electricity than the average building in the existing stock. By 2010, nearly half of the building stock will have been built since 1984.
- Oil and natural gas prices have decreased significantly since 1986. These changes, combined with higher electricity prices, make natural gas more attractive as a heating fuel.
- The source of much of the region's electricity demand growth during the earlier decades was in energy-intensive industries, including paper, wood products, aluminum, chemicals and food products. These five industries account for over 90 percent of industrial electricity use. In the future, these are not forecast to grow rapidly, even in the high case. This has a significant effect on expected growth in electricity demand.
- A continuing shift to commercial activities, away from manufacturing, reduces the growth of electricity use. For example, the commercial share of total employment is expected to increase from 73 percent in 1980 to about 82 percent in 2010, but the commercial sector uses only 1 average megawatt of electricity per 1,000 employees compared to 12 average megawatts in the manufacturing sector.

A further caution should be added about comparing historical growth rates to the forecast. Growth rates can vary significantly year to year or with different long-term intervals. However, more importantly for planning, growth rates at different points may have very different resource planning implications. For example, in the high case forecast, which grows at 2.5 percent per year, about 550 average megawatts of new load would be added annually. But in the 1950s and 1960s, with growth at 7 percent per year, only 406 average megawatts per year were added. Thus, a forecast growth rate that is just a little more than one-third of an historical growth rate, implies a need for 35 percent more electricity resources.

This chapter is concerned primarily with forecasts of electricity sales to final consumers. Further, the forecasts throughout this chapter are for average annual energy rather than peak electricity requirements at any particular time. The demand forecast concept presented is a "price effects" forecast. Such a forecast indicates what demand would be if consumers responded to prices and if no new conservation programs were implemented. Other types of forecasts used in the planning process are described in a later section.

The amount of electricity generation required to meet forecast use is called "electricity load." Electricity load is larger than sales to final consumers because of transmission and distribution losses incurred in delivering the electricity from the generator to the consumer. This loss typically amounts to about 8 percent of the generated electricity.

Because electricity loads are needed to determine resource requirements, electricity demand forecasts are converted to loads for resource planning. A brief description of the load forecast follows, but the rest of the chapter focuses on the need for power from the consumer's point of view. This is because the need for power must be analyzed from that view in order to obtain reliable results and understand the role of conservation in power planning.

Regional firm electricity loads, including transmission and distribution losses, are forecast to grow from 18,720 average megawatts in 1989 to between 17,160 and 31,332 average megawatts by 2010. A more probable range is from 21,146 to 26,681 average megawatts, the 2010 forecasts for the medium-low and medium-high cases. The medium forecast is 23,945 average megawatts, which implies an average annual rate of growth of 1.2 percent. The load forecasts are summarized in Table 6-2.

Table 6-2
Electricity Load Forecasts (Average Megawatts)

	Actual 1989	Forecasts 1995	2000	2010	Growth Rate (% per year) 1989-2010
High	18,720	22,569	25,272	31,332	2.5
Medium-High	18,720	20,946	22,685	26,681	1.7
Medium	18,720	20,057	21,222	23,945	1.2
Medium-Low	18,720	18,362	19,047	21,146	0.6
Low	18,720	16,944	16,846	17,160	-0.4

Forecast Detail

Summaries of forecast results tend to obscure important detail. A major dimension of the demand forecasting system is the separate treatment of demand by customers of public utilities and customers of investor-owned utilities. A second major dimension is the separate forecasting of residential, commercial, industrial, and irrigation uses of electricity. Further, most components of demand, such as residential use of electricity in investor-owned utility service areas, are analyzed for specific end-uses as well as other dimensions within the sector forecasting models. The detailed forecast results are described in this section. The forecasts for investor-owned and publicly owned utilities are described first, followed by results for individual consuming sectors.

Utility Type Forecasts

Separate forecasts are done for investor-owned utilities, public utilities and Bonneville direct customers. The economic assumptions driving the forecasts are divided into investor-owned and public utility service areas as described in Chapter 5, "Economic Forecasts for the Pacific Northwest." These economic assumptions, combined with differences in electricity rates and existing conditions, lead to differences in the forecasts for the two customer groups.

Table 6-3 shows the 1989 composition of firm electricity sales and the five forecasts for 2010. In 1989, total regional firm sales of electricity, adjusted for normal temperatures, were 17,305 average megawatts. Investor-owned utilities marketed 8,047 average megawatts or 47 percent of the total. Public utilities marketed 38 percent, and the Bonneville Power Administration directly marketed 16 percent.

Bonneville's direct sales decrease as a share of future regional electricity demand in all five of the forecast cases. Direct service industries accounted for most of Bonneville's direct sales in 1989, but are forecast to decrease in all forecast scenarios. Public utility sales are projected to grow slightly more slowly than investor-owned utility sales in the higher forecasts and slightly faster in the lower forecasts.

In addition to providing electricity directly to some customers, Bonneville is the source for much of the electricity that is sold by public utilities. Although several public utilities generate electricity to serve part of their loads, most public utilities rely entirely on Bonneville. Therefore, the Bonneville administrator's major regional obligations consist of, 1) direct service industrial customers and various federal agencies that are served directly by Bonneville; 2) all loads of publicly owned utilities that have no significant electricity generating resources (non-generating publics); and 3) a part of the loads of publicly owned utilities that do have electricity resources (generating publics). In Figure 6-4, Bonneville-supplied electricity is illustrated by the shaded area. Bonneville was the source for about 40 percent of the firm electricity sales in the region in 1989.

Forecasting the growth of Bonneville's obligations to provide electricity is complicated by uncertainties well beyond the basic uncertainty embodied in forecasts of regional electricity demand. The Northwest Power Act and contracts between Bonneville and the investor-owned utilities allow for the possibility that investor-owned utilities could place loads on Bonneville providing they give seven years' notice. Further, it is not clear to what extent publicly owned utilities will continue to rely on Bonneville to meet their load growth. These uncertainties result in a wide range of possible Bonneville requirements in the future.

Sector Forecasts

Figure 6-5 shows the composition by sector of 1989 electricity sales in the region. The industrial sector accounts for the largest share of electricity sales, followed by the residential sector, and then the commercial sector. The industrial, residential and commercial sectors together account for 95 percent of the region's electricity demand. Irrigation and other miscellaneous uses account for the remainder. Forecasts for each of the demand sectors are discussed in some detail in the sections that follow.

Table 6–3
Firm Sales Forecast by Utility Type (Average Megawatts)

	Total Sales	Investor-Owned Utility Sales	Public Utility Sales	Bonneville Direct Sales
Actual 1989	17,305	8,047	6,542	2,716
Forecast 2010				
▪ High	28,836	14,908	11,314	2,614
▪ Medium-High	24,583	12,437	9,633	2,514
▪ Medium	22,075	11,032	8,693	2,350
▪ Medium-Low	19,485	9,700	7,990	1,795
▪ Low	15,787	8,085	6,838	864
Growth Rates 1989-2010				
▪ High	2.5	3.0	2.6	-0.2
▪ Medium-High	1.7	2.1	1.9	-0.4
▪ Medium	1.2	1.5	1.4	-0.7
▪ Medium-Low	0.6	0.9	1.0	-2.0
▪ Low	-0.4	0.0	0.2	-5.3

Sales by Utility Type

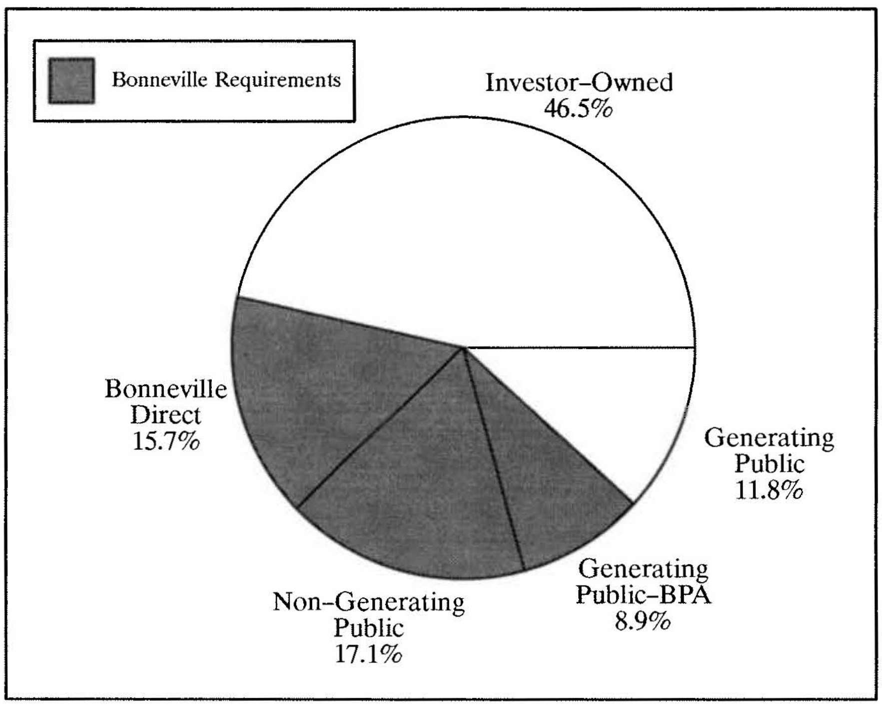


Figure 6–4
1989 Regional Firm Sales by Utility Type (Bonneville's Current Obligation Shaded)

Electricity Use by Sector

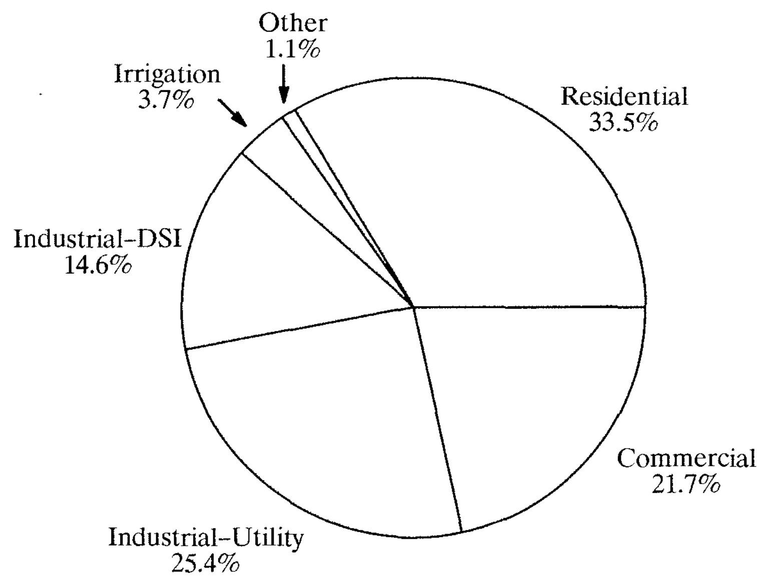


Figure 6-5
1989 Firm Sales Shares

Residential Demand

The residential sector accounted for 34 percent of regional firm sales of electricity in 1989. Residential sector demand is influenced by many social and economic factors, including fuel prices, per capita income, and the choices of efficiency for energy-consuming equipment available to consumers (available technology). The most important factor, however, is the number of households.

The structure of the residential sector demand model reflects this importance by using the individual household as the basic modeling unit. The model projects future demand for electricity, given future growth in households by housing type; by projecting the amount of electricity-using equipment the average household owns; choices of fuel for space heating, water heating; and cooking; the level of energy efficiency chosen; and the energy-using behavior of the household. These choices are influenced in the model by energy prices, equipment costs, average incomes and available technology.

The use of electricity is simulated for each of eight use classifications. Figure 6-6 shows estimated historical shares of these uses in 1989. Space heating and water heating are the two most important end-use categories, accounting for about half of all residential electricity use. The miscellaneous category also includes some back-up space heating in houses that are heated primarily by wood. Note that Figure 6-6 shows end-use shares averaged over all houses, whether they use electricity for a given end use or not. Houses that use electricity for space and water heating will tend to use a larger share for those end uses than is shown in Figure 6-6.

The projections of residential demand for electricity cover a wide range. This range results mostly from variations in projections of the number of households, per capita income and fuel prices in the economic and demographic growth assumptions. Projected demand also varies because of different assumptions regarding use of wood for space heating.

In the absence of new conservation programs, projected residential electricity use in the year 2010 ranges from 9,667 average megawatts in the high case to 5,981 average megawatts in the low case. As shown in Table 6-4, the average annual rate of growth, based on the 1989 weather-adjusted actual of 5,789 average megawatts, varies from 2.5 percent for the high case to 0.2 percent for the low case.

The residential energy demand model is best described as a hybrid of engineering and econometric approaches. It is based on the fundamental idea that residential energy is used by equipment such as furnaces, refrigerators and water heaters to provide amenities to the occupants of residences. Residential energy use, as simulated by the model, is a function of the following factors.

Residential Electricity Uses

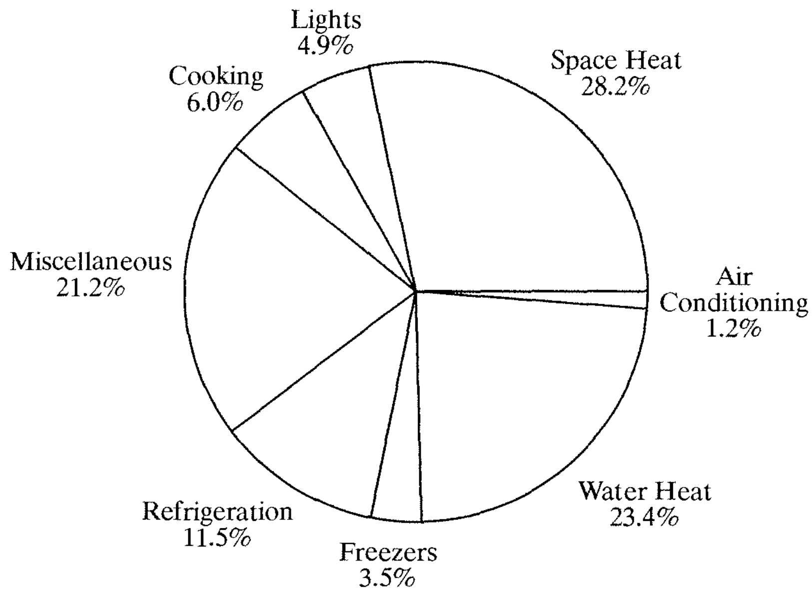


Figure 6–6
1989 Residential Use by Application

Table 6–4
Residential Sector Electricity Demand (Average Megawatts)

	Actual 1989	Forecasts 1995	2000	2010	Growth Rate (% per year) 1989–2010
High	5,789	6,958	7,786	9,667	2.5
Medium–High	5,789	6,523	7,044	8,246	1.7
Medium	5,789	6,346	6,742	7,567	1.3
Medium–Low	5,789	6,129	6,427	7,172	1.0
Low	5,789	5,853	5,833	5,981	0.2

1. ***Total number of residences and the number of new residences constructed.*** The projections for future years are taken from the economic and demographic projections.
2. ***Number of energy–using appliances in the average residence.*** Each year's appliance penetrations, or purchases of appliances per household, are simulated based on econometric analysis of historic sales patterns. Penetrations are influenced by equipment and energy costs and by per capita incomes.
3. ***Efficiencies of these appliances.*** Efficiency choice by consumers is simulated based on engineering analysis of costs of appliances of varying efficiencies and on econometric analysis of observed efficiency choices in the past. Efficiency choices are influenced by energy prices, the cost of more efficient appliances, and the inclination of consumers to invest in conservation (represented by their implicit discount rates). Efficiency choices can also be constrained (e.g., thermal integrity choices will be no worse than some specified level), which provides the means of representing such

conservation programs as building codes and appliance efficiency standards.

4. ***Fuels used by these appliances.*** While some appliances such as air conditioners use electricity exclusively, others such as water heaters can use any of several fuels. Fuel choice is simulated based on the efficiency choices and econometric analysis of past fuel choice behavior. Fuel choices are influenced by relative fuel prices, equipment prices, and relative efficiencies of the appliances using the various fuels.

5. ***Intensity of use of these appliances.*** Intensity of use is varied by such means as thermostat settings and reduced use of hot water for washing clothes. Variation in intensity of use is based on econometric analysis of observed short-run response to fuel prices. Intensity of use is determined in the model by fuel costs, appliance efficiencies and per capita incomes.

Table 6-5 provides a summary of historical and projected values of some of the components that determine total demand for electricity in both public and investor-owned utility (IOU) areas.

The thermal integrity of single-family houses (shown in Table 6-5) improves significantly from 1979 levels. The greater thermal integrity of new houses raises the average thermal integrity in 2010; the higher growth scenarios have a higher proportion of new houses, so the average thermal integrity of the total stock is higher.

Thermal integrity improvements reflect residential weatherization programs throughout the 1980s, more stringent building codes that took effect in Washington and Oregon in 1986, and recent progress toward region-wide adoption of the Council's model conservation standards. These standards have now been adopted in Washington and Oregon, and a building code that obtains 50 to 60 percent of the savings of the model conservation standards has been adopted in Idaho.

In the Draft 1991 Power Plan, the forecast did not assume this recent progress toward the model conservation standards. Taking these developments into account for the final plan reduced projected energy use from what it would be otherwise; in the case of the medium high scenario, the reduction is more than 200 average megawatts in 2010. The Council's estimate of conservation supply still available was reduced accordingly.

The efficiency of refrigerators has improved significantly since the early 1970s and is expected to improve further. In 1972, the average new refrigerator (17 cubic feet, automatic defrost, top-mounted freezer compartment) was estimated to use about 1,600 kilowatt-hours per year. By the early 1980s a comparable new refrigerator was estimated to use about 1,100 kilowatt-hours. The 1990 federal efficiency standard for this average refrigerator is about 900 kilowatt-hours, and the 1993 federal efficiency standard is about 700 kilowatt-hours.

In a change from the Draft 1991 Power Plan, this forecast includes the effects of the 1993 federal standards since these savings are now secured. This change reduces energy use projections from what they would be otherwise; in the medium high scenario the reduction is about 140 average megawatts in 2010. Conservation potential still available has been reduced by corresponding amounts.

As time passes and older, less efficient refrigerators wear out and are replaced, the models that meet the 1990 and 1993 federal standards will make up a bigger share of the population of refrigerators. The average efficiency of refrigerators will therefore improve so that, by the end of the forecast period, it will approach the 1993 efficiency standard. This is an example of the long-term adjustment processes that can be expected in response to changes in energy prices and policy decisions that have already occurred.

Projected improvements in refrigerator efficiencies are shown in Table 6-5. As in the case of thermal integrity, the higher growth scenarios have a higher share of newer, more efficient units, so these scenarios have more efficient stocks of refrigerators.

Fuel choice projections have mixed effects on energy use per household. As shown in Table 6-5, the shares of households with electric water heating are projected to decrease in all forecasts. Electric space heating shares are projected to be higher in higher growth forecasts and lower in lower growth forecasts. Space and water heating saturations are influenced by electricity prices, per capita incomes, and the share of recently constructed houses in the stock. In addition, they are influenced heavily by the relationship of electricity prices to those of competing fuels such as natural gas and oil. As will be described in the section on electricity prices, the higher growth scenarios have higher electricity prices, but *relatively* lower prices of electricity compared to competing fuels. This pattern helps explain the higher saturation of electrical space heating in the higher growth scenarios.

Housing type also influences energy use per household. For all the forecasts, a reduction is projected in the total share of homes that are single-family houses, while an increase in the shares of multifamily units and manufactured homes is projected. Table 6-6 shows the 1980 historical shares of the three building types, along with the projected 2010 shares for each of the forecasts. This trend tends to decrease average use per household, since multifamily units and manufactured homes are smaller and require less energy to heat and cool.

Electricity use per household is the net result of changes in efficiency, housing type, housing size, utilization levels, fuel choice and interaction between end uses (e.g., lower appliance use can increase space heating requirements). The changes in some of these individual components are substantial, but there is a tendency for them to offset one another in their effects on use per household. For example, efficiencies generally improve, tending to reduce use per household, while the sizes of multifamily units and manufactured homes are projected to increase, thereby increasing the per household energy

Table 6–5
Residential Sector Summary Indicators

			Forecast 2010				
		Estimated 1989	High	Medium–High	Medium	Medium–Low	Low
Households (millions)	Public	1.430	2.598	2.205	2.072	1.953	1.648
	IOU[a]	2.069	3.676	3.139	2.959	2.803	2.374
Electricity Prices (1990 cents/kWh)	Public	4.0	4.7	4.2	4.0	3.5	3.3
	IOU	5.2	5.9	5.4	5.6	4.7	4.5
Natural Gas Prices (1990 dollars/million Btu)	Both	5.53	10.24	8.65	7.40	6.30	5.02
Efficiency Measures							
▪ Thermal Integrity (All electrically heated single-family, efficiency relative to regional 1979 stock)	Public	1.26	1.73	1.63	1.57	1.54	1.43
	IOU	1.22	1.75	1.65	1.62	1.57	1.45
▪ Refrigerators (Stock in single-family houses, efficiency relative to regional 1979 stock)	Public	1.15	1.96	1.98	2.00	2.01	2.02
	IOU	1.14	1.95	1.97	1.99	2.01	2.02
Saturations							
▪ Electric Space Heat (% of homes with electric heat)	Public	58	65	62	60	56	56
	IOU	41	48	46	44	43	42
▪ Electric Hot Water (% of homes with electric hot water)	Public	87	81	83	83	83	82
	IOU	80	75	75	75	75	74
Kilowatt–Hours per Household (All homes)		14,493	13,497	13,517	13,176	13,210	13,027
Space Heat kWh per Household (Electrically heated homes)		8,495	7,552	7,909	7,734	7,895	7,875
Non–space–heat kWh per Household (All homes)		10,420	9,341	9,357	9,263	9,394	9,267
Space Heat Sales (MWa)		1,627	2,977	2,538	2,247	2,072	1,726
Total Sales (MWa)		5,789	9,667	8,246	7,567	7,172	5,981

[a] Investor–owned utilities.

Table 6–6
Share of Housing Stock by Building Type 1980–2010 (%)

		2010				
	1980	High	Medium–High	Medium	Medium–Low	Low
Single–Family Dwellings	77.8	77.1	72.4	70.5	69.1	67.4
Multifamily Dwellings	14.4	15.2	17.2	18.5	19.4	21.8
Manufactured Housing	7.8	7.7	10.4	11.0	11.5	10.8

Single–Family Forecast Indicators

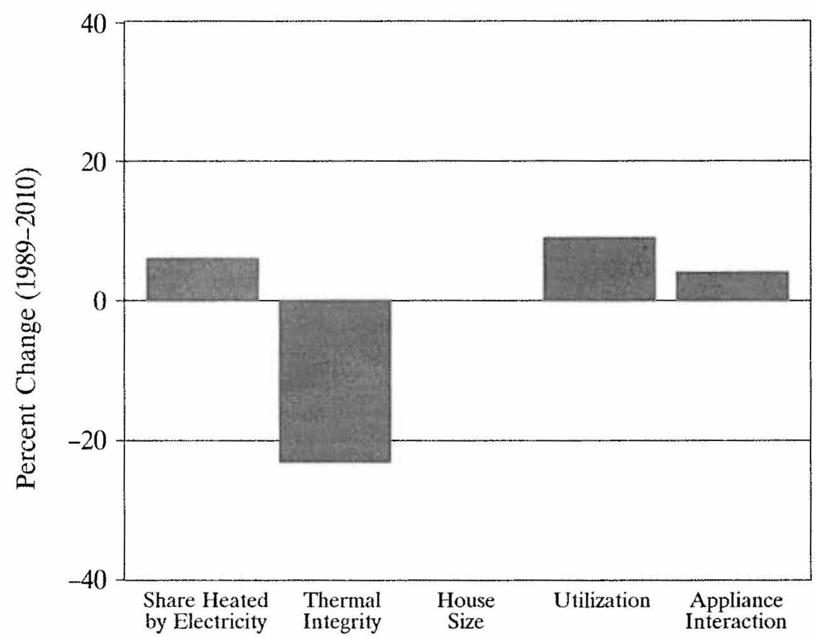


Figure 6–7
Factors Contributing to Change in Electric Space Heating in Public Rate Pool—Medium–High Scenario

requirements for space conditioning. These patterns are illustrated in Figures 6–7 and 6–8. Figure 6–7 shows the impact of the various determinants of electric space heating in single–family houses in the public rate pool. Figure 6–8 shows the same impacts for manufactured homes in the investor–owned utility rate pool.

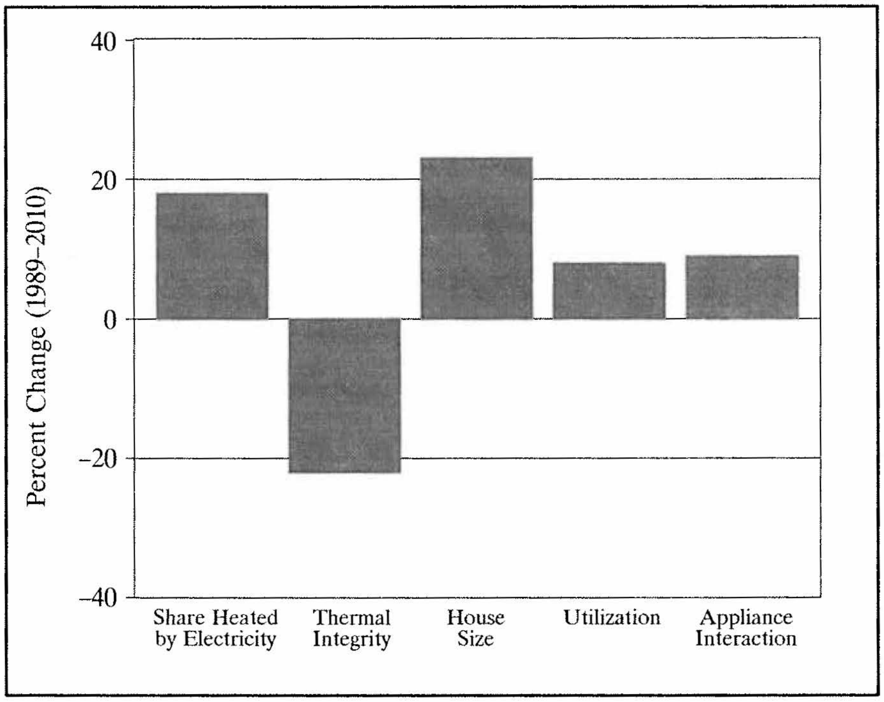
Figure 6–7 shows a decrease in per household use due to improvement in thermal integrity. This is partially balanced by increases in electricity's share of space heating, utilization levels, and the space heating load net of waste heat from appliances. The net change in electric space heating in single–family houses in the public rate pool between 1989 and 2010 in the medium–high scenario is a decrease of 12.8 percent per household.

Figure 6–8 shows an improvement in thermal integrity, that is more than offset by a combination of increases in electricity's share of space heating, utilization levels, house size, and space heating load net of waste heat from appliances. The net change in electric space heating for manufactured homes in the private rate pool is an increase of 13.6 percent per household.

When all the influences just described are combined over all house types, end uses and rate pools, the net effect is the observed pattern of relatively small changes in per household use between scenarios. This means that the variation in total residential demand across the range is due largely to variation in the projected number of households.

Manufactured Home Forecast Indicators

Figure 6–8
Factors Contributing to Change in Electric Space Heating in IOU Rate Pool—Medium–High Scenario



The projection of electrical equipment use is based on demand for electricity before taking into account the Council's proposed conservation programs. The effects of these programs cause sales of electricity to grow at slower rates. In addition, the use of electricity per household would decline because of the increased thermal efficiency of buildings and improved appliance efficiencies. The effects of these efficiency increases would be somewhat diminished, however, by the greater use of energy services due to cost savings from improved efficiency in space and water heating. These effects are reflected in the "sales" forecasts that are the basis of the electricity prices used for the "price effects" forecasts.

Commercial Demand

Although currently the smallest of the major consuming sectors, the commercial sector is the fastest growing, averaging 3.4 percent growth per year since 1980. This rate of growth is more than twice that of total demand by all sectors. The commercial sector has steadily increased its share of regional sales from 16 percent in 1970 to 22 percent in 1989.

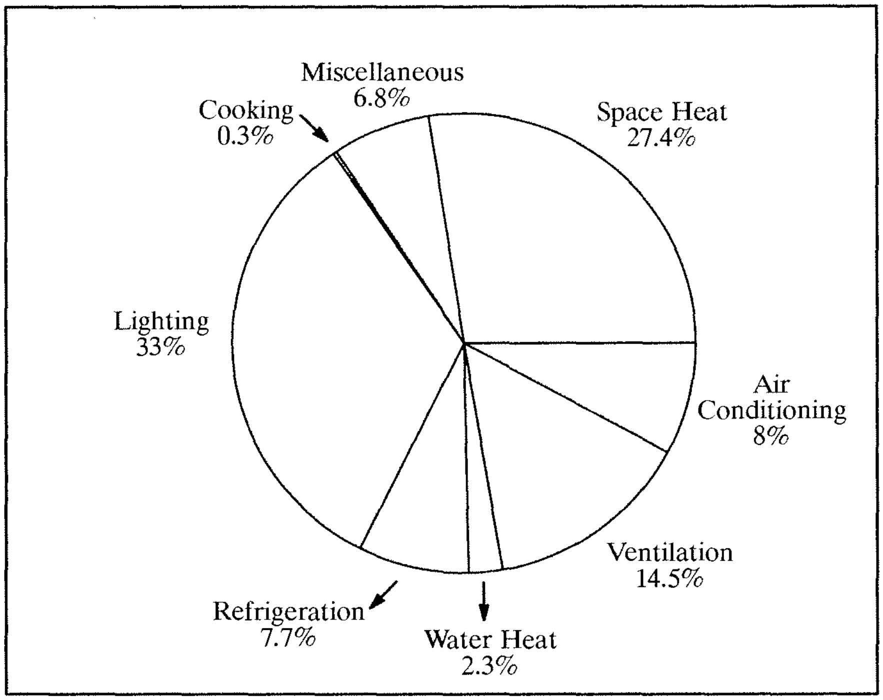
Shares of historical commercial sector demand for electricity for various applications are shown in Figure 6–9. Space heating and lighting make up the largest shares of commercial electricity use. If space heating, ventilation and air conditioning are combined, as they commonly are, into an HVAC category, HVAC and lighting account for more than 80 percent of electricity use in the commercial sector.

Commercial sector electricity use is forecast separately for 10 different building types. The consumption shares of these building types are shown in Figure 6–10. Offices account for more than one-fourth of electricity use by the sector. Retail buildings are the next largest category, followed by miscellaneous buildings and groceries. More than two-thirds of the sector's electricity use is attributed to these four building types.

Commercial sector electricity demand, like that of the residential sector, is influenced by many factors, such as fuel prices and available technology. In particular, one fundamentally important factor used as a basis for energy use projections is the total floor space of the buildings in the commercial sector. The commercial sector demand model projects the amount of commercial floor space and then predicts fuel choice, efficiency choice, and the use of the energy-consuming equipment necessary to service this floor space. These choices are based on investment factors, fuel prices and available technology. Energy-use projections are made separately for different building types, applications and fuel types.

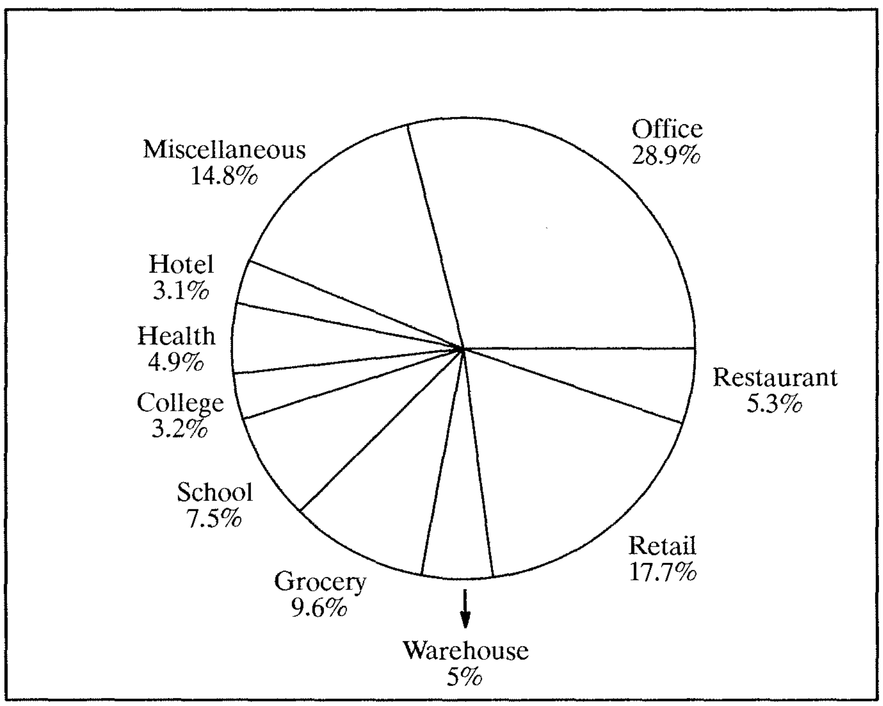
Commercial Electricity Uses

Figure 6–9
1989 Commercial Sector Use by Application



Commercial Use by Building Type

Figure 6–10
1989 Commercial Sector Use by Building Type



Since the 1986 Power Plan, development of the Council's commercial sector energy demand model has concentrated on incorporating recent data on floor space and energy use. Even before 1986, forecasters of commercial sector energy use in many parts of the United States were discovering that they tended to underforecast energy use in the early 1980s. A number of explanations were proposed, including unexpected growth in use of computers and other office machinery, a cyclical boom in construction of office building which exceeded the current requirements for floor space, and unexpected resistance to adoption of more efficient space conditioning and lighting equipment. Since 1986, data has become available which, while it does not eliminate all concern about the problem, does shed some light on its causes.

First, an estimate of the stock of commercial floor space was developed by Baker, Reiter and Associates under contract to the Bonneville Power Administration. This estimate was the result of a widespread sample of commercial buildings in the region and must be regarded as a significant improvement over the estimate previously used in the forecasting model. The estimated floor space of many building types changed substantially.

The estimation effort also resulted in estimates of 1980–1986 construction in the region. The estimated construction is consistent with a boom in office construction that saw estimated office space grow faster than employment of office workers. The differential growth of office space and office workers is also consistent with higher-than-normal vacancy rates (around 20 percent) in the metropolitan centers of the region. The assumption for the Council's forecast is that vacancy rates will gradually decline to around 10 percent, and then office floor space will grow in proportion to employment.

While office floor space appears to have grown faster than office employment, other building types seem to have grown more slowly than relevant employment. Health care buildings are one example. In these cases, the forecast assumes that the 1986 relationship of employment to floor space represents the long-term relationship, and that floor space will grow in proportion to employment growth after 1986.

The re-estimated floor space in the commercial sector made it necessary to re-estimate electricity use per square foot in the model's base year (1979). New energy use data from the End-use Load and Conservation Assessment Program, the Commercial Audit Program and the Seattle City Light Commercial Data Base also contributed to the estimates.

The new energy use data also allowed the examination of the relationship of energy use in buildings built in the early 1980s to that of buildings built earlier. The data indicate that total electricity use in new offices and retail stores is not much different than use in older ones. Further, this relationship seems to hold even when use for heating, ventilation and air conditioning (HVAC) in new buildings is compared to HVAC use in older ones, and when lighting use is compared between new and older buildings.

These results could be interpreted to imply that the energy-efficiency of HVAC and lighting equipment has not improved since 1979. However, there is considerable anecdotal evidence that efficiencies have improved. This evidence suggests that new buildings and equipment are more energy-efficient, but are being used to provide a higher level of service or amenity to the occupants of the buildings. This higher amenity can take a number of forms (more hours of operation, greater control of temperature or humidity, more attractive display lighting, etc.), but the final effect is that energy use per square foot apparently has not declined with improved energy efficiency of buildings or equipment.

Information about changing amenity levels in commercial buildings is mainly anecdotal—new schools tend to be air conditioned, new groceries tend to have delicatessens, and the like. Amenity levels may not increase in all new buildings, but they may increase in some existing buildings as well. The assumption in the commercial forecast is that for five building types (offices, retail, schools, colleges and miscellaneous), buildings built after 1980 provide increased amenities. These increased amenities, together with improved efficiencies, make HVAC and lighting electricity use about the same as the 1979 stock of these buildings types. It is also assumed that the pre-1980 stock of these same building types will provide gradually increasing levels of amenities until they reach the level provided by new buildings.

These assumptions had the effect of raising the forecast and brought the projected electricity use from 1979 to 1989 into much closer agreement with actual commercial sales during that period. This historical agreement is not conclusive proof that the assumptions are accurate, or that the assumptions lead to accurate long run forecasts. Historical agreement could have been obtained with a different combination of assumptions, leading to different long run forecasts. Given that these assumptions are based on the available data, the performance of the model in matching historical experience is some confirmation that the assumptions are reasonable.

Finally, the high scenario assumptions include modifications that bring fuel choices in the investor-owned utilities closer to fuel choice in the public utilities. The intent is to include in the high scenario the possibility that fuel choice is strongly influenced by factors not included in the forecasting model's simulation, and that the net effect of these factors is that electricity is preferred as a heating fuel even when electricity's apparent life-cycle costs are not particularly attractive.

The resulting projections of commercial demand for electricity vary widely. In the low growth forecast, commercial demand for electricity decreases from 3,761 megawatts in 1989 to 4,236 megawatts by 2010. In the high growth forecast, it reaches 7,549 megawatts. As shown in

Table 6-7, the average rate of growth of demand ranges from 0.6 to 3.4 percent per year.

Table 6-8 shows some of the components underlying these totals. Floor space increases in all forecasts, as a result of increased employment in the commercial sector, and is the major driver of growth in demand for electricity. Use of electricity per square foot of floor space of all buildings increases in the higher-growth forecasts and decreases in lower-growth forecasts. The change in use per square foot from 1989 to 2010 is modest for all forecasts, ranging from an increase of 7 percent in the high-growth forecast to a decrease of 10 percent in the low-growth forecast.

Use of electricity per square foot of office floor space, however, is projected to move in different directions depending on utility type. It decreases in the investor-owned utilities for two scenarios, and increases slightly in the other scenario. In the public utilities, it increases for all scenarios. These changes are modest in either direction. The largest projected increase is about 9 percent, and the largest projected decrease is about 6 percent.

Saturation of electric space heating is projected to increase most in the higher growth scenarios and to decrease in the lower scenarios. This pattern holds for offices as well as for commercial buildings generally.

The pattern of projected electric space heat saturations is due partly to the pattern of projected electricity prices. Table 6-8 shows that investor-owned utilities' rate pool prices increase in all growth scenarios, but public rate pool prices decrease or stay constant in the lower-growth scenarios. In addition, projected 2010 prices for investor-owned utilities are at least 65 percent higher than those for the public utilities.

Projected prices of competing fuels also influence space heat saturations. Figure 6-14, in the section on prices, demonstrates that while projected residential electricity prices are lowest in the low scenario, natural gas prices are projected to decline even more, so that electricity prices *relative* to natural gas prices are highest in the low scenario. Fuel prices projected for the commercial sector follow a similar pattern and lead to higher electric space heat saturations in the higher growth scenarios and lower electric space heat saturations in the lower-growth scenarios.

The mixed pattern of projected energy use is due in part to projected electricity prices and in part to conflicting trends in efficiency and amenity levels. As described earlier, new buildings are assumed to provide a higher level of service or amenity to their occupants, which tends to use more electricity. At the same time, new buildings and equipment are projected to be more energy-efficient in providing any specified level of amenity. The net result of these conflicting trends is the observed pattern of small increases and decreases in overall electricity use per square foot.

These projections do not take into account the conservation programs included in the power plan, but are based on existing building codes and market response to increased energy prices. The programs in the plan have been identified as cost-effective resources to meet this demand forecast. The conservation programs will reduce overall demand for electricity, reduce demand per square foot, and improve equipment efficiency.

In general, recent research and trends in commercial electricity use have left a number of unanswered questions. The assumptions made for this forecast seem to be reasonable, but further adjustments will undoubtedly be made as there is more information. Given its increasing share of regional electricity use, the commercial sector will be the subject of continuing research and analysis.

Industrial Demand

The industrial sector is the largest of the four consuming sectors. In 1989, the industrial sector consumed 6,935 average megawatts of firm power, accounting for 40 percent of total firm demand in the region. In addition to the firm power, the industrial sector consumes varying amounts of interruptible power depending on economic and hydroelectric conditions. In 1989, industry consumed 490 average megawatts of interruptible, or nonfirm electricity.

Table 6-7
Commercial Sector Electricity Demand (Average Megawatts)

	Actual 1989	Forecasts 1995	2000	2010	Growth Rate (% per year) 1989-2010
High	3,761	4,948	5,721	7,549	3.4
Medium-High	3,761	4,494	4,993	6,295	2.5
Medium	3,761	4,346	4,676	5,610	1.9
Medium-Low	3,761	4,081	4,210	4,969	1.3
Low	3,761	3,912	3,906	4,236	0.6

Table 6–8
Commercial Sector Summary Indicators

		Estimated 1989	Forecast 2010 High	Medium–High	Medium	Medium–Low	Low
Floor Space (million sq. ft.)	Public	705.3	1,239.6	1,030.8	942.4	892.0	825.7
	IOU[a]	1,331.5	2,586.9	2,190.7	1,991.6	1,876.9	1,733.7
Electricity Prices (1990 cents/kWh)	Public	3.4	4.2	3.7	3.4	3.0	2.7
	IOU	5.3	7.1	6.1	5.9	5.4	5.5
Natural Gas Prices (1990 dollars/ million Btu)	Both	4.80	9.52	7.89	6.64	5.50	4.20
Sales—Kilowatt-hour per Square Foot Floor Space							
▪ Offices							
• Space Heat (offices heated by electricity)	Public	6.4	6.0	6.3	6.5	6.7	6.6
	IOU	6.3	5.4	6.1	6.1	4.8	4.4
• Lighting	Public	8.3	7.8	8.0	8.2	8.3	8.5
	IOU	8.3	8.0	8.0	8.1	8.2	8.2
• Total	Public	25.1	25.4	26.5	27.0	27.3	26.7
	IOU	24.0	24.1	24.9	24.9	23.1	22.5
▪ All Commercial Buildings							
• Space Heat (buildings heated by electricity)		8.9	6.9	8.0	8.5	9.0	10.0
• Lighting		5.3	5.2	5.3	5.3	5.4	5.4
• Total		16.2	17.3	17.1	16.7	15.7	14.5
Saturation of Electric Space Heat (%)							
▪ Offices	Public	73	96	93	88	78	62
	IOU	67	95	85	74	53	42
▪ All Commercial Buildings	Public	60	89	83	76	66	50
	IOU	44	80	58	47	29	13
Total Sales (MWa)							
▪ Space Heat		1,029	2,487	1,950	1,608	1,166	732
▪ Lighting		1,242	2,286	1,934	1,771	1,696	1,572
▪ Total		3,761	7,549	6,295	5,610	4,969	4,236

[a] Investor-owned utilities.

Unlike the residential and commercial sectors where the general uses of electricity are similar in different houses or buildings, the industrial uses of electricity are extremely diverse. It is very difficult to generalize about the end uses of energy or the amounts of energy used in a "typical" industrial plant. For example, the primary metals industry uses about 80 times as much electricity per dollar of output as the apparel industry.

The industrial use of electricity in the Northwest is highly concentrated in a few subsectors. Five industries—

food, chemicals, paper, lumber and metals—account for nearly 90 percent of industrial use of electricity. Figure 6-11 illustrates the composition of total industrial demand for electricity based on the forecast for 1989. Metals production alone accounted for nearly half of total industrial electricity use.

Over 90 percent of electricity use in metals is by Bonneville's direct service industry customers, primarily the region's aluminum smelters. These aluminum smelters also dominate all direct service industry sales, accounting for about 90 percent of that total. Bonneville's direct service industrial customers accounted for 40 percent of total industrial demand for electricity in 1989, or about 17 percent of total regional sales to all sectors. One-fourth of the direct service industry demand is considered nonfirm demand, or interruptible demand. If Bonneville were to have a shortage of energy, for example, due to poor water conditions, it could withhold service for one-fourth of the direct service industry demand. Only the firm portion of direct service industry demands are included in the the Council's forecasts of energy requirements. However, the interruptible portion of direct service industry demand is considered in system operation and electricity pricing analyses.

Forecasts of industrial demand for electricity are based on production forecasts for the various industrial sectors, the amount of energy used per unit of output, and the effects of electricity and other fuel prices on their use of energy. Table 6-9 shows industrial sector firm demand forecasts for selected years for all five forecasts. In the high forecast, consumption of electricity by the industrial sector grows to 10,611 average megawatts by 2010—an average annual growth rate of 2.1 percent per year. In the low forecast, industrial demand decreases at a rate of 1.7 percent per year due to significant reductions in direct service industry sales offsetting modest growth in other industries. The more likely range of industrial demand growth is from -0.2 to 1.3 percent per year with the medium case growth at 0.7 percent per year.

Methods of forecasting the industrial demand for electricity vary substantially among different industrial subsectors. In general, the forecasting methods are most detailed for the activities that consume the greatest amounts of electricity. It is necessary to forecast industrial activity and demand for electricity individually for up to 40 industry components in order to obtain reliable forecasts of total industry demands.

The composition of the industrial forecasting system is shown in Table 6-10. The components are defined using the Standard Industrial Classification (SIC) code. Table 6-10 shows the share of total industrial consumption of electricity estimated to have been consumed by each subsector in 1981. The concentration of demand for electricity that is illustrated in Figure 6-11 is also apparent in Table 6-10.

Industrial Electricity Use

Figure 6-11
Composition of Industry Demand

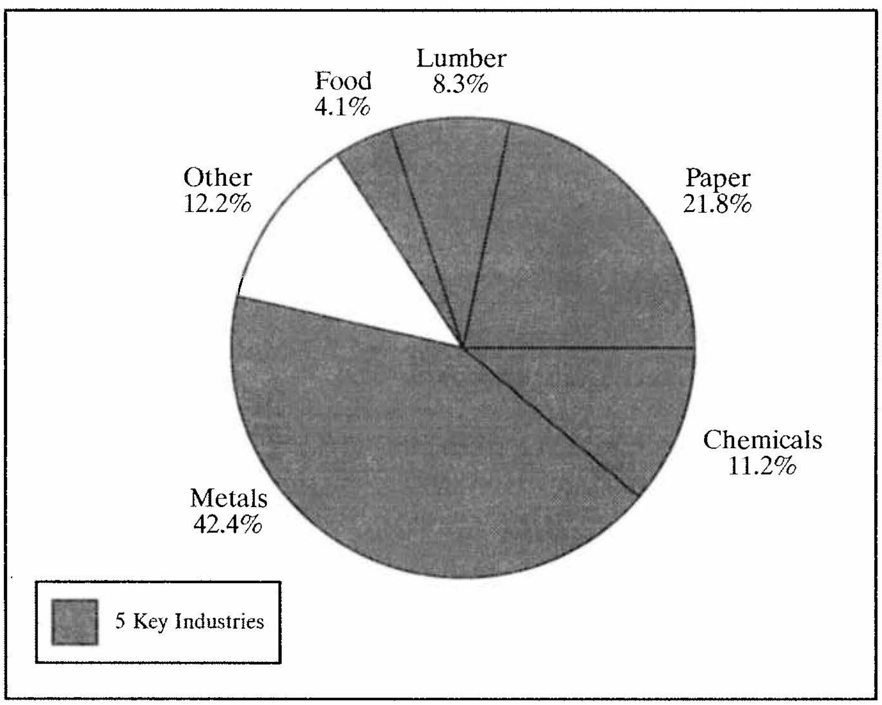


Table 6-9
Industrial Sector Firm Sales (Average Megawatts)

	Actual 1989	Forecasts 1995	2000	2010	Growth Rate (% per year) 1989-2010
High	6,935	8,020	8,852	10,611	2.1
Medium-High	6,935	7,474	8,047	9,143	1.3
Medium	6,935	6,997	7,370	8,082	0.7
Medium-Low	6,935	5,944	6,161	6,601	-0.2
Low	6,935	5,112	5,072	4,885	-1.7

There are four different forecasting methods used for the industrial sector. The methods are referred to as, 1) key industry model, 2) econometric model, 3) simple relationships, and 4) eclectic. The method applied to each industry component is abbreviated in Table 6-10. Most of the forecasting methods are driven primarily by forecasts of industrial production. In addition, each of those methods modifies the relationship between production and electricity use to reflect the effects of changing energy prices and other factors.

The three largest non-direct service industries are forecast using the key industry models. The key industry models are highly detailed approaches to forecasting demand for electricity. The three key industries are lumber and wood products, pulp and paper, and chemicals. First, the industry is divided into the most energy-intensive activities. For those activities, the uses of electricity are divided into several types, such as motors for specific processes, electrolysis or lighting. The fraction of electricity use attributable to each of these end uses is estimated for an average plant. In the case of the chemical production of phosphorus and chlorine, the model is specified separately for each of the relatively few plants in the region.

The forecast requires a specification of how the types of end uses may change their shares over time. In addition, the degree to which electricity for each type of end use could be conserved in response to price changes must be specified. The degree of price response was varied across forecast scenarios, being largest in the low forecast and smallest in the high forecast. Given these specifications, the demand for electricity per unit of production will change from its base year value as production and electricity prices change.

The key industry models require a great deal of data and judgment. This information goes beyond readily available sources of data. For this reason, specification of the key industry models relied heavily on the judgment and advice of industry representatives and trade organizations.

The industrial forecasting system includes a variety of econometric forecasting equations for the remaining non-key and non-direct service industry demands for electricity. Econometric models consist of equations estimated from historical data. The equations attempt to measure the effect of industry production and energy prices on the demands for different types of energy, including electricity.

Alternative econometric estimates are available in the demand forecasting system for most industry components. In Table 6-10, the alternative equation used is specified in parentheses next to the forecasting method. Equations obtained from the Oregon Department of Energy are noted as ODOE. Equations obtained from Bonneville are labeled AEA for the consulting firm that estimated the equations, Applied Economic Associates.[1]

Because historical data is generally of poor quality at the industrial subsector level, it is often difficult to obtain plausible relationships for econometric equations. Where econometric results appeared implausible, simple relationships between output and electricity use were used as a basis for the forecasts. The sectors whose forecasting methods are listed as "simple" are those for which econometric results were unsatisfactory.

In these simple forecasts, demand for electricity is assumed to grow at the same rate as production, but is modified by an assumed trend in electricity use per unit of production. There is substantial agreement, in econometric models and other research on industrial energy demand, that in the absence of other influences, energy demand will grow with production. There is much less agreement about the degree to which price changes influence demand. To reflect this uncertainty, assumptions about changes in demand per unit of production were varied across forecast scenarios. Electricity use per unit of production was assumed constant in the high forecast for industry components that were forecast using the simple method. In the medium-high forecast, the electric intensity was assumed to decrease by 0.5 percent per year; in the medium-low forecast, by 1.5 percent per year; and in the

1. Applied Economic Associates, Inc. *Update and Re-estimation of the Northwest Energy Policy Project Energy Demand Forecasting Model.* Report to Bonneville Power Administration, December 1981.

Table 6–10
Industrial Forecasting Methods

SIC Code	Title	1981 Percent of Manufacturing Electricity		Forecasting Method
Manufacturing				
20	Food and Kindred Products	4.1		Simple
22	Textiles	.1		Econometric Model (AEA)
23	Apparel	.1		Simple
24	Lumber and Wood Products	6.8		Summed
2421	▪ Sawmills and Planing Mills		2.8	Key Industry Model
2436	▪ Softwood Veneer and Plywood		1.5	Key Industry Model
24XX	▪ Rest of SIC 24		2.5	Simple
25	Furniture	.1		Simple
26	Pulp and Paper	21.0		Summed
2611	▪ Pulp Mills		1.6	Key Industry Model
2621	▪ Paper Mills		12.1	Key Industry Model
2621	▪ Paper Mills—Direct Service Industries		.2	Eclectic
	▪ Crown Zellerbach			
2631	▪ Paperboard Mills		4.4	Key Industry Model
26XX	▪ Rest of SIC 26		2.7	Simple
27	Printing and Publishing	.5		Econometric Model (ODOE)
28	Chemicals	11.0		Summed
2812	▪ Chlorine and Alkalies		1.9	Key Industry Model
2812	▪ Chlorine and Alkalies—Direct Service Industries		1.1	Eclectic
	▪ Georgia Pacific			
	▪ Pennwalt			
2819	▪ Elemental Phosphorus		5.0	Key Industry Model
2819	▪ Elemental Phosphorus—Direct Service Industries		.8	Eclectic
	▪ Pacific Carbide			
	▪ DOE Richland			(Included in Federal Agencies)
28XX	Rest of SIC 28		2.2	Econometric Model (ODOE)
29	Petroleum Refining	1.4		Simple
30	Rubber and Plastics	.5		Econometric Model (AEA)
31	Leather and Leather Goods	0.0		Included in Residual
32	Stone, Clay, Glass and Concrete	1.2		Summed
3291	▪ Abrasive Products—Direct Service Industries		.3	Eclectic
	▪ Carborundum			

Table 6-10 (cont.)
Industrial Forecasting Methods

SIC Code	Title	1981 Percent of Manufacturing Electricity	Forecasting Method
Manufacturing (cont.)			
32XX	▪ Rest of SIC 32	.9	Econometric Model (ODOE)
33	Primary Metals	49.0	Summed
3334	▪ Aluminum—Direct Service Industries	43.2	Eclectic
3313	▪ Electrometallurgical—Direct Service Industries	1.3	Eclectic
	▪ Hanna		
	▪ Gilmore		
3339	▪ Non-ferrous n.e.c.—Direct Service Industries	.1	Eclectic
	▪ OREMET		
33XX	▪ Rest of SIC 33	4.4	Econometric Model (ODOE)
34	Fabricated Metals	.8	Simple
35	Machinery Except Electrical	.8	Simple
36	Electrical Machinery	.4	Econometric Model (ODOE)
37	Transportation Equipment	1.9	Simple
38	Professional Instruments	.4	Simple
39	Miscellaneous Manufacturing	.1	Simple
XX	Residual Categories	.4	Simple
Mining			Grows with Employment

low forecast, by 2.0 percent per year. The medium case assumes a reduction of electricity use per unit output of 1.0 percent per year. These assumptions are similar to the range of results from econometric equations that were more acceptable theoretically and behaviorally.

Forecasting methods for the direct service industrial customers of Bonneville are described as eclectic, because they are the results of several types of forecast methods and studies. For example, aluminum industry electricity use was forecast using industry forecasting models, results of various aluminum studies, and external consultants, supplemented by judgment and specific knowledge gained through years of dealing with the industry. The forecasts are done primarily on the basis of the relationship between aluminum prices and production costs. The aluminum price projections are based on forecasts from independent consultants who follow the aluminum industry. Production costs for each smelter are Bonneville estimates. Different model approaches are used in the aluminum load forecasting process for the long term and the short term. In the long-term model, if a plant cannot recover its total production costs over several years, given the long-term aluminum price forecast, then it is assumed to permanently shut down. In the near-term model, if a plant cannot recover its variable costs given the prevailing aluminum prices, then it will temporarily close some production capacity, only to re-open it when the aluminum prices recover enough to exceed the variable production costs. The results are then evaluated with staff judgment to produce the aluminum electricity demand forecast.

Electricity use by non-aluminum direct service industries was forecast by an analysis of each plant and its future markets. Use is determined by general macroeconomic conditions reflected in industry-specific production indices, and the region's relative price of electricity. Variables reflecting national trends were taken from Data Resources Inc. In the case of a few plants, the analysis was supplemented with an assessment of prices and production costs. Projected use is adjusted for these plants based on rough estimates of profits and losses.

The forecast growth rates of industrial demand for electricity are considerably smaller than the projected rates of growth in total industrial production. Production by Northwest manufacturing industries is expected to grow by 4.7 percent per year in the high forecast; 3.7 and 2.1 percent per year in the medium-high and medium-low forecasts, respectively; and by 1.2 percent per year in the low forecast. The medium forecast is 3.0 percent per year.

The relative growth rates of electricity demand and output imply an overall reduction in the electricity intensity of the Northwest industrial sector. The ratios of electricity use to production decline over the forecast period in all five forecasts. The rate of decline in the most probable range is about 2.3 percent per year. Although these rates of decrease are significant, they are lower than recent regional history. Between 1977 and 1986, regional industrial electricity intensity is estimated to have declined by about 3.8 percent per year. Such decreases in energy intensity are not unprecedented. At the national level, for example, total energy use per unit of production in the industrial sector has been estimated to have decreased by 4.5 percent per year between 1970 and 1986.

There are several factors operating to reduce industrial rates of electricity growth relative to production growth. The most important is a change in the mix of industry. Many of the large users of electricity are not expected to grow as fast as industry does on average. This is most notable in the case of the direct service industries, a very large portion of the industrial demand that is contractually limited to current levels and could decline due to economic forces.

During the 1980s, direct service industrial demands for electricity exhibited enormous volatility, primarily reflecting swings in aluminum industry market conditions. This volatility is expected to continue, with the uncertainty for the regional industry compounded by the potential outcomes of major issues. Such issues include the impact of resource strategies taken by the region on availability of power to aluminum smelters, terms and conditions of future direct service industry power sales contracts, the nature and extent of direct service industry contract assignments, and the level of industrial power rates. In general, future direct service industry demand for electricity will be a function of the perceptions of industrial producers about the attractiveness of the region as a place to invest and operate, as well as their ability to maintain competitiveness in product markets.

During the past two years, the competitive position of the region's aluminum smelters has improved. The excess aluminum smelting capacity worldwide in the early 1980s has been reduced through permanent plant closures and delays in announced new capacity in developing countries. Northwest aluminum companies have invested in improved efficiency and benefitted from Bonneville's variable electricity rate structure. In addition, reduced transportation costs to the Pacific rim, combined with a decreased value of the dollar against other world currencies, have made the Northwest smelters more competitive in those markets. Nevertheless, even though regional smelters have reduced their costs considerably, and have benefitted from recent market strength, continued operation of the aluminum smelters will depend, to a great extent, on the outcome of the issues discussed above.

The uncertainty of future direct service industry power sales is reflected in the five forecast scenarios for purposes of defining the full range of electrical resource needs. Figure 6-12 shows the percent of aluminum plant capacity that is assumed to be operating in the region by the end of the forecast period for each of the five forecasts. Capacity is defined as the amount of electricity, in terms of average megawatts, that regional aluminum smelters are expected to consume after efficiency improvements made under Bonneville's Conservation/Modernization program. In the high scenario, it is assumed that the aluminum direct service industries will operate at 100 percent of capacity. Operating rates for the medium-high, medium, and medium-low scenarios are assumed to be 97 percent, 90 percent, and 67 percent, respectively. In the low scenario, the aluminum industry is forecast to operate at about 50 percent of capacity until the year 2001. At that time it is assumed that new contract terms and poor economic conditions could result in a decrease in operating rates to 25 percent of capacity.

The forecast of industrial electricity use is further dampened by the fact that some of the large non-direct service industrial users, such as lumber and wood products, food processing and pulp and paper, are not projected to grow as fast as less energy-intensive industries. As shown in Table 6-11, output growth for the key non-direct service industries combined is expected to be 1.4 percent per year in the medium forecast, compared to 3.0 percent per year for all industrial production. Thus, the two components of the industrial sector that accounted for nearly 90 percent of the sector's electricity demand historically will show relatively weak growth over the next 20 years.

The third major reason for lower electricity growth relative to production is the effect of the large change in the relative price of electricity in the region over the last several years. The effects of price on industrial demand cannot be separated into components as they can for the residential and commercial sectors. But conceptually they include efficiency improvements, fuel switching and product mix changes within individual industrial sectors. The forecasting models embody these changes as general price response.

Irrigation Demand

In 1989, 640 average megawatts of electricity were used for irrigation, less than 4 percent of total regional firm electricity sales. For several decades, Pacific Northwest irrigation sales climbed rapidly and steadily. However, after 1977 they became more erratic, leveled off, and then began to decrease slowly. The average annual rate of growth of on-farm and Bureau of Reclamation irrigation electricity use from 1970 to 1977 was a robust 10 percent. From 1977 to 1989 there was no net growth, reflecting

Aluminum Industry Assumptions

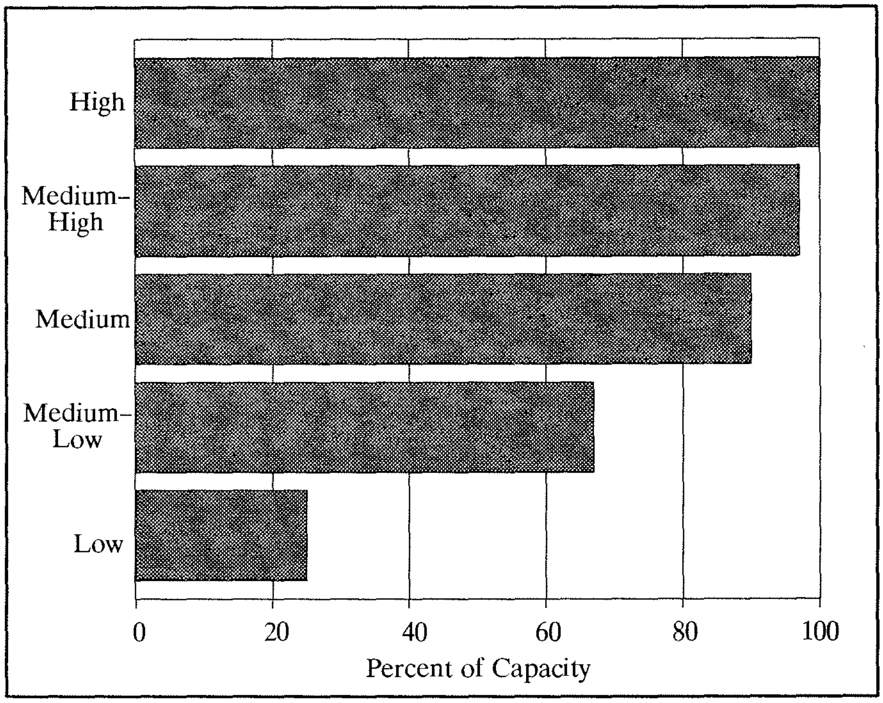


Figure 6–12
Projected Aluminum Operating Rates

Table 6–11
Composition of Industry Growth, 1989–2010: Medium Forecast

	Historical Share of Consumption (%)	Production Growth Rate (% per year)	Demand Growth Rate (% per year)
Direct Service Industries	44	N/A	-0.8
Key Non-Direct Service Industries	43	1.4	0.9
Minor Industries	14	3.9	3.3
Total	100	3.0	0.7

increased electricity and water conservation and a slowing down in the development of new irrigated land.

There are currently about 8.2 million acres of irrigated land in the region. Nearly half of the region's irrigated acres are in Idaho. Oregon and Washington each have a little over one-fifth of the total irrigated acres. Most electricity use in irrigation is associated with sprinkler irrigation. Currently, about 55 percent of the irrigated land in the region is irrigated with sprinkler systems. The distribution of irrigation by state is different for electricity used than for irrigated acres. Washington and Idaho accounted for over 80 percent of irrigation electricity use in 1987 but only 67 percent of sprinkled acres. This difference is due to the high electricity intensity of Washington's irrigated agriculture.

Table 6–12 shows the forecasts of use of electricity for irrigation. The forecast range is quite flat. The high and medium-high forecasts show moderate growth in electricity used for irrigation from its 1989 level. The other cases each show declining amounts of electricity being used for irrigation compared to 1989. All of the growth rates are made lower by the fact that 1989 irrigation electricity sales were high due to dry weather. The irrigation forecast excludes about 100 megawatts of Bureau of Reclamation pumping loads at Grand Coulee and Roza dams. The forecasts shown in Table 6–12 include U.S. Bureau of Reclamation irrigation sales.

The forecasts reflect the expectation that major additions to Northwest irrigated agriculture are unlikely and that additions that do occur are likely to be offset by increased efficiency in the use of electricity and water. Two factors will limit irrigation growth: the depletion of aquifers in some areas, and the lack of additional good land to bring under irrigation.

Increases in the high forecast cases are partly a result of assumed conversions from flood to sprinkled irrigation in areas of Idaho. While sprinkled irrigation requires more electricity, it also uses water more efficiently. The listing of some stocks of salmon as endangered species could further encourage such water conserving practices, which already appear to be attractive for economic and other reasons.

The forecast of irrigation electricity use is based on a range of assumed rates of growth in irrigation sales for five-year increments. The resulting demands are then adjusted for the effects of price changes based on specified price elasticities. The long-term price elasticity was assumed to be -0.4. This price elasticity was jointly specified by the Council and Bonneville. The prices are from the Council's electricity pricing model for all but the medium forecast. The medium prices are from Bonneville's Supply Pricing Model.

Retail Electricity Prices

The forecasts of electricity prices in the Pacific Northwest show relatively stable prices over the next several years. However, the exact price outlook varies substantially in the different forecasts.

Electricity prices are an important determinant of electricity demand. It is also true that electricity demand growth has an important effect on future electricity prices. These mutual dependencies are accounted for in the demand and price forecasts.

Figure 6-13 shows real average retail rates in 1990 dollars for the five forecasts. As can be seen from Figure 6-13, the price outlook varies substantially in the different forecasts, showing substantial increases in the high forecast and declining in real terms in the low forecast. This pattern results because nearly all new resources are more costly than the existing resource base, and the more new resources that need to be added, the greater the cost increase. In the middle range of the forecasts, electricity prices are expected to be generally stable, or increase only moderately, relative to the prices of other goods and services.

It is apparent that the medium forecast prices have a different pattern over time than the other four cases. This is due to the fact that a different pricing model was used for the medium forecast. Bonneville's Supply Pricing Model (SPM) was used for the medium forecast, in order to facilitate use of the medium forecast in other Bonneville processes. In the near term, medium prices dip below the other cases. This is probably due to the fact that Bonneville's SPM is designed to deal with the near term in more detail, and has incorporated updated utility costs using more recent 1990 investor-owned utility and Bonneville cost information. The medium forecast of prices remains below the other forecasts until about 2004, but by 2010 is between the medium-high and high forecasts. The Council and Bonneville staff will continued to explore the differences. However, the difference in prices is not large and has an insignificant effect on forecast demand in the medium case. In addition, since the medium forecast plays no special role in the Council's planning, the differences will not have any significant effect on the plan's resource analysis.

Table 6-13 shows 1989 estimated average electricity prices, forecasts for 2010, and average annual rates of change for three different kinds of rates. The rates include average retail rates paid by all consumers combined, average retail rates paid by customers of public utilities, and average retail rates paid by customers of investor-owned utilities.

Average retail prices in the region are predicted to increase faster than inflation between 1989 and 2010 in the high and medium-high forecasts. In the low and medium-low forecasts, real prices decline. Investor-owned utility prices are projected to increase faster, or decrease less, than the prices for publicly owned utilities. This is because investor-owned utilities need to add new resources sooner than public utilities.

Table 6-12
Irrigation Sector (Average Megawatts)

	Actual 1989	Forecasts 1995	2000	2010	Growth Rate (% per year) 1989-2010
High	640	702	741	791	1.0
Medium-High	640	646	647	680	0.3
Medium	640	626	594	599	-0.3
Medium-Low	640	577	563	525	-0.9
Low	640	532	504	467	-1.5

Electricity Prices

Figure 6–13
Average Retail Electric Rates

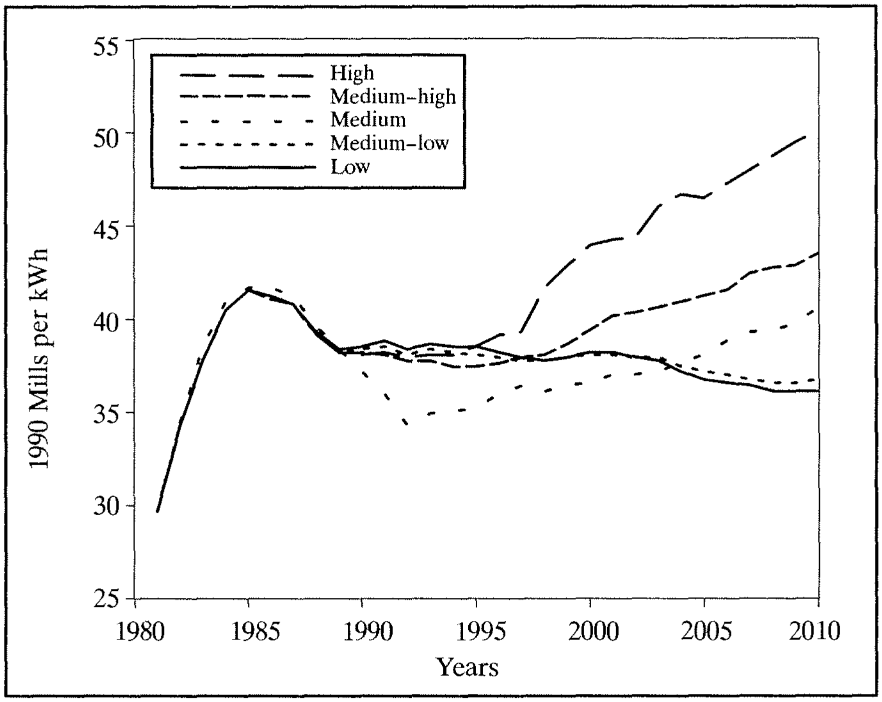


Table 6–13
Electricity Price Forecasts (1990 Cents per Kilowatt–Hour)

	Average Retail All Consumers	Average Retail Public Utilities	Average Retail Investor–Owned Utilities
Estimated 1989 (1990 cents per kWh)	4.1	3.4	4.6
Forecast 2010 (1990 cents per kWh)			
▪ High	5.0	4.1	6.0
▪ Medium–High	4.3	3.6	5.3
▪ Medium	4.1	3.3	5.1
▪ Medium–Low	3.7	2.9	4.6
▪ Low	3.6	2.7	4.6
Growth Rates (1989–2010) (% per year)			
▪ High	1.0	0.9	1.3
▪ Medium–High	0.2	0.3	0.7
▪ Medium	0.0	–0.1	0.5
▪ Medium–Low	–0.5	–0.8	0.0
▪ Low	–0.6	–1.1	0.0

All but the medium case demand forecasts use retail electricity price forecasts produced by an electricity pricing model that is part of the Council's demand forecasting system. The model develops forecasts of retail prices by sector for investor-owned and public utilities. The prices are forecast through a detailed consideration of power system costs, secondary power sales, forecast assumptions, and the provisions of the Pacific Northwest Electric Power Planning and Conservation Act (the Act). Bonneville, as discussed above, has a similar electricity pricing model which was used for the medium case demand forecasts.

The Council's electricity pricing model contains capacity and cost information on both generating and conservation resources. Cost and capacity of the federal base hydroelectric resources are included as a total. However, most other resources are treated on an individual basis. Capability of each resource is specified for critical water conditions and for peak capacity. Capital cost and operating costs are specified for each generation resource. For conservation resources, only those costs that are to be paid through electric rates are included. The effects of conservation programs are generally predicted directly in the various demand models, although in some cases the savings are included as a resource within the pricing model and subtracted from demand there.

The costs of generation and conservation are added up and allocated to the various owners (Bonneville and investor-owned and public utilities). The costs of resources used to provide power to customers of Bonneville, public utilities and investor-owned utilities are combined to reflect contractual agreements among utilities and the exchange and other provisions of the Act. The model develops forecasts of wholesale power costs for three Bonneville rate pools—priority firm, direct service industries and new resources. Similarly, costs are developed for investor-owned and public utilities. Retail markups are added to these costs to obtain estimates of retail rates for each consuming sector of each type of utility.

As demand grows, resources are added to meet demand, and the new resource costs are melded with existing resource costs. The pricing model balances resources and demand based on critical water capacities. However, the effects of different water conditions on secondary energy and electric rates are simulated by the pricing model. The operation of the hydroelectric system on a monthly basis over 40 historical water years is the basis of this simulation. When there is surplus hydroelectric power in any month for a specific water year, the model allocates that secondary power to various uses according to a set of priorities specified in the model assumptions. These uses in the assumed order of priority are, 1) serve the top quartile of direct service industry demand, 2) shut down combustion turbines, 3) sell outside the region, and 4) shut down other thermal generation.

For purposes of the pricing model, firm surpluses are added to secondary power and allocated using the same priorities. If the region is in a deficit situation, instead of surplus, the model will import power at a pre-specified price until additional resources are added to meet demand.

The revenues from sales of secondary power and firm surplus power, or the costs of importing to cover deficits, are averaged over months and water years to obtain estimates of expected prices of power given uncertain water conditions.

These price forecast results depend on several important assumptions. It was assumed that the resource portfolio in the draft power plan would be followed as resources are added to meet growing demand. Therefore, the resource portfolio assumed for these forecasts is similar, but not identical, to the one presented in this plan. The differences are not expected to affect the demand forecast significantly.

Another important assumption is that no dramatically revised repayment requirement will be imposed for the federal debt on the region's hydroelectric system. Some of the more extreme versions of the revised repayment costs would have a significant effect on electricity prices.

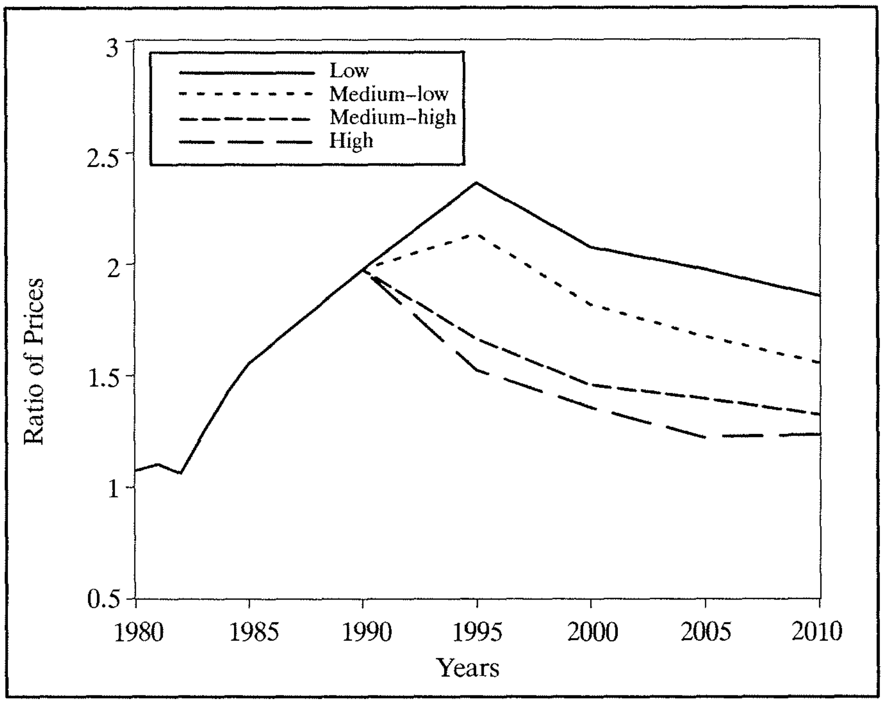
It is assumed that investor-owned utilities do not place significant amounts of load on Bonneville, resources are not built before regional need, and that a constant real price is received for secondary and firm surplus power sales except during times of excess water conditions (spill).

Electricity price forecasts were described above, and fuel price forecasts were described in Chapter 5. However, for most of the demand sectors, the relative price of electricity compared to oil or natural gas is important. It is the relative price that most affects consumers' choice of fuel type. Figure 6-14 shows forecast prices of electricity relative to natural gas for residential customers. Natural gas prices have been divided by 0.8 to adjust for differences in the end-use efficiency of gas and electricity. Thus, the relative prices shown in Figure 6-14 are more appropriate comparisons of the cost of heating than of the cost of buying fuel. Although electricity rates are highest in the high forecast, it is in the high forecast that relative electricity rates are lowest. This stimulates the demand for electricity in the high forecast. The relative fuel price pattern results because the range of uncertainty in future fuel prices is much wider than the range of uncertainty in the electricity prices.

When the ratio in Figure 6-14 is above 1.0, it means electricity is relatively more expensive than natural gas. During most of the 1970s, electricity in the Pacific Northwest was inexpensive relative to natural gas, its main competitor. However, recent large increases in electricity rates, combined with decreases in natural gas prices, have increased the competitiveness of natural gas. This result is only a general tendency, because the relative prices of electricity vary significantly for different utility areas. Further, the attractiveness of electricity or natural gas also can depend on consumer tastes and the relative cost of equipment used to convert energy to a useful service, such as heat. The general conclusion to be drawn from Figure 6-14 is that natural gas and electricity prices could remain competitive within a fairly broad range. However, natural

Natural Gas Price Comparison

Figure 6-14
Relative Residential Energy Prices (Ratio of Electricity to Natural Gas)



gas prices have clearly become more attractive relative to electricity in the early 1980s, and could continue to gain advantage through 1990, particularly in the low and medium-low scenarios.

Demand Forecasts in Resource Planning

The demand forecasts are not simply a preliminary step to resource planning. Instead, the forecasts interact with resource planning in a number of ways, and, as a result, are an integral part of resource planning. Some important dimensions of the use of forecasts in resource planning are described in this section. First, the conceptual roles of forecasts in the planning process are described. Then, some of the practical applications of forecasts to resource planning are also described.

Demand Forecast Roles

The integral planning role of demand forecasts has three major components. First, forecasts of demand define the extent and nature of demand uncertainty that planners must face. Second, the level of demand is not independent of resource choices, but will respond to the costs of resource choices to meet future demands. Finally, sophisticated demand models are needed to assess the potential impacts of choosing conservation programs as alternatives to building new generating resources. These roles are described below.

Defining the Range of Uncertainty

Future demand for electricity has been one of the primary uncertainties addressed in developing a risk-minimizing power plan for the region. The demand forecast range measures this uncertainty. The range of demand forecasts is based primarily on variations in the key assumptions. The forecast range has been described above in terms of five forecasts. However, for resource planning, a probability distribution is assumed to describe the likelihood that any given level of future electricity demand will occur within the range.

Bonneville and the Council currently assume different probability distributions about the forecast range. For planning purposes, the Council has adopted a trapezoidal distribution. The implications of the trapezoidal distribution are, 1) that demands outside the high and low forecasts are judged to be of sufficiently low probability that they are not formally considered in resource planning, and 2) that demands between the medium-high and medium-low forecasts are most likely and are considered equally probable. The probability of future demand being between the medium-low and the medium-high forecasts is about 50 percent. The probability of being between the medium-high and high or between the medium-low and low is about 25 percent.

Bonneville assumes a normal probability distribution around the medium forecast. The implications of this assumption are, 1) the medium forecast is described as the most probable future demand, and 2) future demands can fall outside of the low and high forecasts. Bonneville assumes that there is a 50-percent probability that demand will fall between the medium-low and medium-high cases, that the probabilities of being between the medium-low and low or between the medium-high and high are each 20 percent, and that the probabilities of being either below the low or above the high case are each 5 percent.

Resource portfolio analysis is based on the entire probability distribution of future loads. This is a major change from the Council's first power plan in 1983 and is made possible by an enhanced decision model. The decision model analyzes hundreds of possible load paths that are distributed according to the assumed probability distribution defined over the range of demand forecasts. It is not expected that the specific form of probability distribution used in this analysis would have a significant effect on the results.

Effects of Resource Choices on Price

As discussed in the previous section, there is an electricity pricing model in the demand forecasting system. The pricing model develops forecasts of retail prices for each sector for investor-owned and public utilities. These rates are forecast through a detailed consideration of power system costs, secondary power sales, and the provisions of the Act. This model translates resource decisions into retail prices. The price model ensures that the implications of future resource decisions, including conservation programs, are consistently reflected in future prices and demands.

Conservation Analysis

In addition to defining uncertainty, the demand forecasting models play an important role in defining and evaluating conservation opportunities. This is particularly true for the residential and commercial sectors where the demand models are most detailed and conservation opportunities are best defined.

There are two major roles for the demand models in conservation analysis. The first is to help define the size of the potential conservation resource. The second is to predict the effectiveness of programs designed to achieve some portion of the potential conservation available.

Estimates of the number of energy-using buildings and equipment in the region, including their fuel type and efficiency characteristics, are needed to help determine how much additional efficiency can be achieved to offset the need for new electricity generation. The economic forecasts and the building energy demand models provide the detailed building forecasts necessary to analyze potential conservation. The demand models evaluate the effects of differing regional growth rates on new building construction and the effects of alternative energy prices on fuel choice in those buildings, thus resulting in different amounts of conservation potential for different forecast scenarios.

The effects of conservation programs can be quite complicated, and the demand models are designed to help assess those effects. For example, an energy-efficient building code can affect all three components of a building owner's energy choice: efficiency, fuel type and intensity of use. While the direct impact is on efficiency choice, there are also likely to be unintended effects on fuel choice and intensity of use. For example, a more stringent code for residential electrical efficiency will tend to increase the construction cost of electrically heated homes. This relative increase in the initial cost, if borne by homebuyers, may cause some increase in the number of homes heated by natural gas or oil, even though the operating cost of the electrically heated homes would be reduced.

When cost-effective conservation actions are taken, the cost of providing an end-use service, such as space heating, will decrease. With the decrease in cost, the consumer's intensity of use may increase. Another important complication is that appliances give off waste heat that affects the heating and cooling requirements in buildings. Since more efficient appliances give off less waste heat, more heating and less cooling will be needed than with less efficient appliances. These secondary effects are evaluated in the detailed building models to give a more accurate assessment of the actual effects of conservation programs on demand for electricity.

Forecast Concepts

Treating conservation as a resource creates interactions among demand forecasts and resource choices that complicate analysis. For example, conservation actions that planners think are available resource choices may also be taken by consumers in response to increasing electricity prices. Double counting of this conservation must be avoided in planning. In order to avoid such problems, some innovative analytical methods have been developed.

For example, three different demand forecast concepts are used in resource planning. Most presentations and publications, including this chapter, describe "price effects" forecasts. Price-effects forecasts show what the demand for electricity would be if customers were to respond to price, but no new conservation programs were implemented. Price-effects forecasts reflect current state building codes as of 1991 and federal appliance efficiency standards, but do not assume further adoption of the Council's model conservation standards.

An important factor affecting price-effects forecasts is what resource mix is assumed in developing the electricity price that is provided to the demand models. The electricity prices that determine the price-effects forecast are based on a second concept of demand—a "sales" forecast. A "sales" forecast is a forecast of the demand for electricity after the effects of the model conservation standards and other conservation programs have been taken into account. This is the amount of electricity that would actually be sold by utilities if conservation programs were implemented and savings realized.

The third demand concept, the "frozen-efficiency" forecast, attempts to eliminate double counting of conservation actions that are taken by consumers in response to price, but which could also be achieved through the proposed conservation programs. Frozen-efficiency forecasts, as the name implies, hold the technical efficiency of energy use constant at current levels for uses where conservation programs are proposed. This eliminates the part of consumer price response that could potentially be double counted as conservation program savings.

The three forecasts for the high scenario are illustrated in Figure 6-15. Table 6-14 shows the growth rates for the three forecast concepts for each of the forecast scenarios. The price-effects growth rates are the same as those shown in Table 6-1 and Figure 6-3. The frozen-efficiency growth rates are slightly higher because part of the demand decreases due to price response have been eliminated. The differences between price-effects and frozen-efficiency forecasts are relatively small because prices are not forecast to increase much in most forecast scenarios. Demand growth is significantly lower for the sales forecasts than for the other two forecasts, reflecting potential conservation savings from the Council's programs. The differences between the frozen-efficiency and sales forecasts are smallest in the low case because only new building standards savings are acquired and relatively few new buildings are constructed.

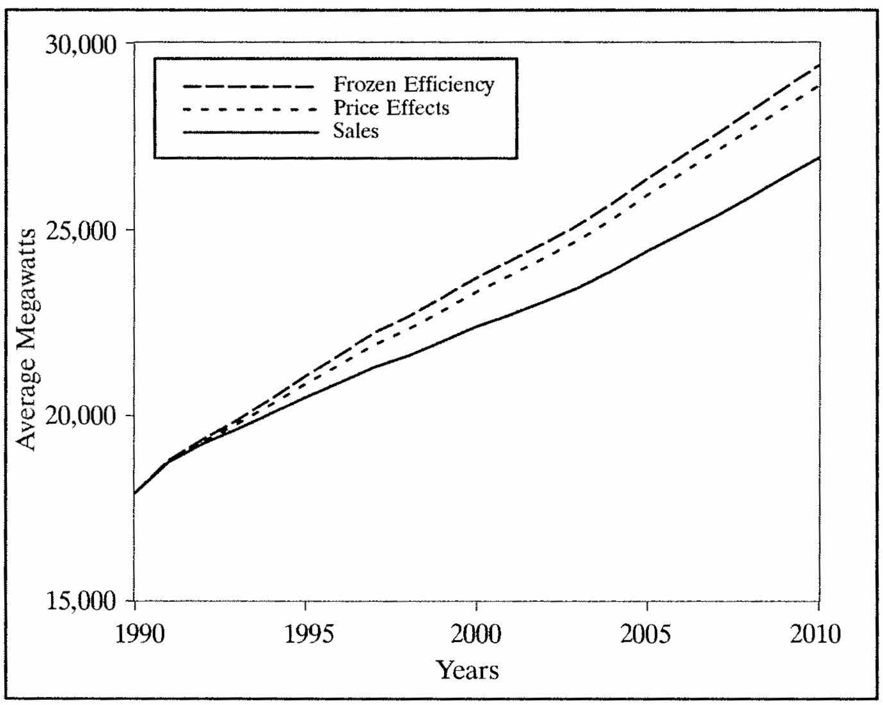
The difference between the highest forecast (the frozen-efficiency forecast) and the lowest (the sales forecast) is the total effect on electricity demand of conservation resources. The price-effects forecast divides that total effect into two parts, that which would result from price response and the incremental effect of conservation programs. The difference between the frozen-efficiency and price-effects forecasts represents the price response portion. The difference between the price-effects and the sales forecasts represents the incremental program impacts. The results of the forecast indicate that very little of the cost-effective conservation would be achieved, under current regional electricity pricing practices, without a strong conservation program effort.

Electrical Loads for Resource Planning

Demand forecasts serve as the basis for resource portfolio analysis. This section describes what forecast concepts are used and how they are modified for resource planning analysis.

Forecast Concepts

Figure 6-15
Comparison of High Forecast Concepts



For resource portfolio analysis, the decision analysis model (ISAAC) uses frozen-efficiency forecasts of demand in order to avoid counting conservation potential twice.[2] However, several adjustments are made to these forecasts before they are used for resource planning.

First, demand forecasts are converted to load forecasts by adding transmission and distribution losses. The demand forecasts are for consumption of electricity at the point of use, while loads are the amount of electricity that needs to be generated. More electricity has to be generated than is actually consumed by utility customers, because some electricity is used or lost in the transmission and distribution of power. The demand forecasts are converted to loads based on historical average losses. These losses are about 8 percent.

Second, resource analysis is done on an operating year basis. Since the demand forecasts are done on a calendar year basis, the demands must be converted from a year that begins in January to a year that begins the previous September. (Note that the operating years described in Appendix 6-C are from July 1 through June 30.) This is done by calculating a weighted average of the previous and current calendar years. The previous year receives a one-third weight, and the current year a two-thirds weight. In addition, for resource planning, the forecasts were set to actual values for operating year 1989.

In the demand-forecast range, the forecasts of direct service industry demand for electricity are shown as a range of demand levels associated with specific forecast scenarios. The direct service industry loads are treated differently, however, for resource planning. The decision analysis model (ISAAC) embodies an aluminum forecasting submodel. This model forecasts levels of aluminum demand that depend on a randomly selected level of aluminum prices, as well as electricity prices and other costs of production. Aluminum prices are not assumed to be correlated to general economic conditions. As a result, levels of aluminum demand, instead of being associated with particular demand scenarios as they are in the demand forecast ranges described here, are independent of demand scenarios. The aluminum model was calibrated to result in the same range of aluminum loads as those in the demand forecasts, but they are not associated with particular demand conditions. This better reflects the various counterbalancing influences that are likely to affect the aluminum industry under specific scenarios.

Federal agency and non-aluminum direct service industry loads are entered into the decision model separately from other loads, and do not vary by scenario. The operating year, frozen-efficiency, non-direct service industry and non-federal agency loads that are provided to the decision model are shown for selected years in Table 6-15.

2. ISAAC is an acronym for Integrated System for Analysis of Acquisitions. For a description of the ISAAC model, see Volume II, Chapter 15.

Table 6-14
Growth Rates for Different Forecast Concepts (Average Annual Rate of Change, 1989-2010)

	Sales	Price Effects	Frozen Efficiency
High	2.1	2.5	2.6
Medium-High	1.4	1.7	1.8
Medium	0.8	1.2	1.2
Medium-Low	0.2	0.6	0.6
Low	-0.8	-0.4	-0.4

Table 6-15
Decision Model Loads (Average Megawatts by Operating Year)

	Estimated 1989	Forecasts 1995	Forecasts 2000	Forecasts 2010	Growth Rate (% per year) 1989-2010
High	15,700	19,806	22,738	29.017	3.0
Medium-High	15,700	18,324	20,190	24,356	2.1
Medium-Low	15,700	16,551	17,284	19,364	1.0
Low	15,700	15,626	15,693	16,268	0.2

and other conservation programs have been taken into account. This is the amount of electricity that would actually be sold by utilities if conservation programs were implemented and savings realized.

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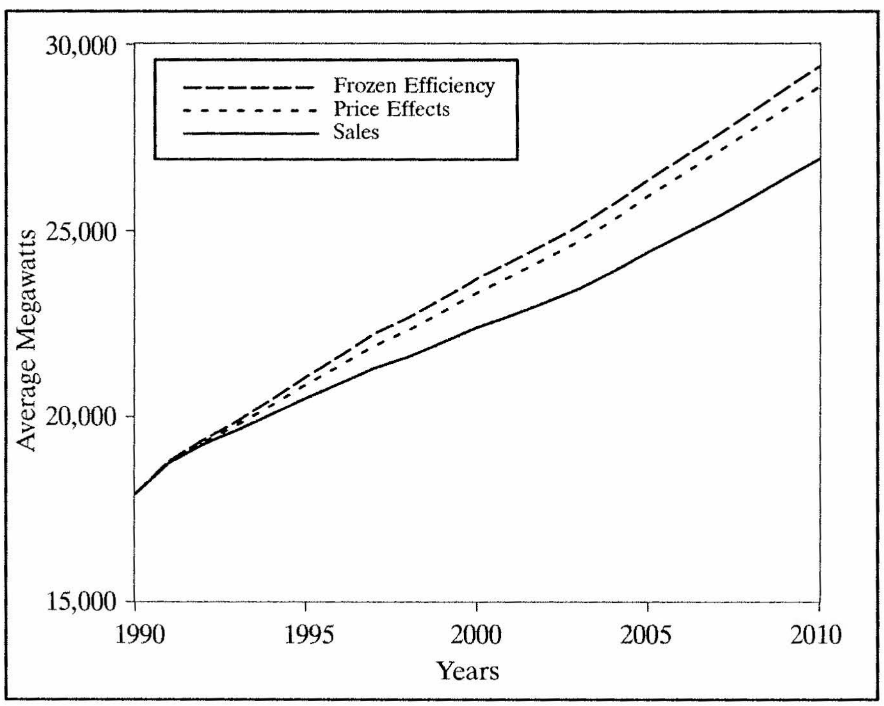

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APPENDIX 6-A

FORECAST SUMMARY TABLES

1. Price Effects Forecasts
2. Sales Forecasts
3. Frozen–Efficiency Forecasts

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1LP - 1991 FINAL PLAN 1 LOW - PRICE

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	3912.	3906.	4033.	4236.	0.66	0.53	0.57
RESIDENTIAL	5586.	5789.	5839.	5853.	5833.	5883.	5981.	0.18	0.14	0.16
INDUSTRIAL FIRM (1)	6646.	6935.	6591.	5112.	5072.	4787.	4885.	-4.96	-0.30	-1.65
DSI FIRM	2435.	2531.	2284.	1129.	1002.	651.	651.	-12.59	-3.60	-6.26
NON-DSI FIRM	4211.	4404.	4307.	3983.	4070.	4136.	4234.	-1.66	0.41	-0.19
IRRIGATION (2)	649.	640.	547.	532.	504.	471.	467.	-3.03	-0.87	-1.49
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17135.	15607.	15520.	15386.	15787.	-1.71	0.08	-0.44
TOTAL NON-DSI SALES	14231.	14774.	14850.	14478.	14519.	14735.	15136.	-0.34	0.30	0.12
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1667.	1698.	1724.	1784.	1885.	1.54	0.70	0.94
RESIDENTIAL	2485.	2596.	2631.	2632.	2614.	2633.	2671.	0.23	0.10	0.14
INDUSTRIAL FIRM (1)	4449.	4639.	4343.	3068.	2989.	2681.	2725.	-6.66	-0.79	-2.50
DSI FIRM	2435.	2531.	2284.	1129.	1002.	651.	651.	-12.59	-3.60	-6.26
NON-DSI FIRM	2014.	2108.	2058.	1939.	1988.	2030.	2074.	-1.38	0.45	-0.08
IRRIGATION (2)	327.	324.	271.	264.	253.	239.	239.	-3.33	-0.68	-1.44
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9076.	7830.	7755.	7516.	7702.	-2.75	-0.11	-0.87
TOTAL NON-DSI SALES	6467.	6727.	6792.	6701.	6753.	6865.	7051.	-0.06	0.34	0.22
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2298.	2214.	2182.	2249.	2351.	0.02	0.40	0.29
RESIDENTIAL	3101.	3193.	3208.	3221.	3218.	3250.	3309.	0.15	0.18	0.17
INDUSTRIAL FIRM (1)	2197.	2296.	2249.	2044.	2083.	2106.	2160.	-1.92	0.37	-0.29
IRRIGATION	322.	316.	276.	268.	251.	231.	228.	-2.73	-1.06	-1.54
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8058.	7777.	7766.	7870.	8085.	-0.57	0.26	0.02

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1MLP - 1991 FINAL 1 MEDIUM LOW - PRICE

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3965.	4081.	4210.	4505.	4969.	1.37	1.32	1.33
RESIDENTIAL	5586.	5789.	5849.	6129.	6427.	6803.	7172.	0.96	1.05	1.03
INDUSTRIAL FIRM (1)	6646.	6935.	6757.	5944.	6161.	6337.	6601.	-2.54	0.70	-0.24
DSI FIRM	2435.	2531.	2368.	1580.	1582.	1582.	1582.	-7.56	0.01	-2.21
NON-DSI FIRM	4211.	4404.	4389.	4365.	4580.	4756.	5019.	-0.15	0.94	0.62
IRRIGATION (2)	649.	640.	579.	577.	563.	537.	525.	-1.71	-0.63	-0.94
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17344.	16930.	17566.	18395.	19485.	-0.36	0.94	0.57
TOTAL NON-DSI SALES	14231.	14774.	14976.	15351.	15985.	16814.	17904.	0.64	1.03	0.92
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1666.	1780.	1873.	1983.	2159.	2.35	1.29	1.59
RESIDENTIAL	2485.	2596.	2637.	2752.	2868.	3023.	3176.	0.98	0.96	0.96
INDUSTRIAL FIRM (1)	4449.	4639.	4482.	3706.	3804.	3887.	4004.	-3.67	0.52	-0.70
DSI FIRM	2435.	2531.	2368.	1580.	1582.	1582.	1582.	-7.56	0.01	-2.21
NON-DSI FIRM	2014.	2108.	2114.	2126.	2223.	2305.	2423.	0.14	0.87	0.67
IRRIGATION (2)	327.	324.	286.	284.	278.	267.	263.	-2.19	-0.51	-0.99
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9235.	8689.	8997.	9339.	9785.	-1.05	0.79	0.26
TOTAL NON-DSI SALES	6467.	6727.	6868.	7110.	7416.	7757.	8203.	0.93	0.96	0.95
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2299.	2300.	2337.	2522.	2810.	0.65	1.34	1.15
RESIDENTIAL	3101.	3193.	3212.	3378.	3559.	3780.	3996.	0.94	1.13	1.07
INDUSTRIAL FIRM (1)	2197.	2296.	2275.	2239.	2357.	2450.	2596.	-0.42	0.99	0.59
IRRIGATION	322.	316.	294.	294.	285.	270.	263.	-1.22	-0.74	-0.88
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8109.	8241.	8569.	9056.	9700.	0.40	1.09	0.89

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F2MP - 1991 FINAL PLAN 2 MEDIUM - PRICE W/ BPA'S SPM

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3976.	4346.	4676.	5128.	5610.	2.44	1.72	1.92
RESIDENTIAL	5586.	5789.	5860.	6346.	6742.	7180.	7567.	1.54	1.18	1.28
INDUSTRIAL FIRM (1)	6646.	6935.	6905.	6997.	7370.	7684.	8082.	0.15	0.97	0.73
DSI FIRM	2435.	2531.	2446.	2152.	2136.	2136.	2137.	-2.67	-0.05	-0.80
NON-DSI FIRM	4211.	4404.	4459.	4845.	5234.	5548.	5945.	1.60	1.37	1.44
IRRIGATION (2)	649.	640.	617.	626.	594.	581.	599.	-0.37	-0.30	-0.32
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17552.	18513.	19587.	20786.	22075.	1.13	1.18	1.17
TOTAL NON-DSI SALES	14231.	14774.	15106.	16361.	17451.	18650.	19938.	1.72	1.33	1.44
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1664.	1860.	1997.	2148.	2313.	3.10	1.46	1.93
RESIDENTIAL	2485.	2596.	2638.	2841.	2999.	3179.	3344.	1.51	1.09	1.21
INDUSTRIAL FIRM (1)	4449.	4639.	4591.	4455.	4596.	4735.	4902.	-0.67	0.64	0.26
DSI FIRM	2435.	2531.	2446.	2152.	2136.	2136.	2137.	-2.67	-0.05	-0.80
NON-DSI FIRM	2014.	2108.	2145.	2303.	2460.	2600.	2765.	1.49	1.23	1.30
IRRIGATION (2)	327.	324.	304.	309.	296.	291.	301.	-0.80	-0.17	-0.35
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9362.	9633.	10062.	10532.	11043.	0.66	0.91	0.84
TOTAL NON-DSI SALES	6467.	6727.	6916.	7481.	7926.	8396.	8906.	1.79	1.17	1.35
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2312.	2486.	2678.	2980.	3297.	1.96	1.90	1.92
RESIDENTIAL	3101.	3193.	3222.	3505.	3742.	4001.	4223.	1.57	1.25	1.34
INDUSTRIAL FIRM (1)	2197.	2296.	2314.	2542.	2774.	2949.	3180.	1.71	1.50	1.56
IRRIGATION	322.	316.	313.	317.	298.	290.	297.	0.05	-0.43	-0.29
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8190.	8881.	9525.	10254.	11032.	1.66	1.46	1.51

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1MHP - 1991 FINAL PLAN 1 MEDIUM HIGH - PRICE

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	4494.	4993.	5583.	6295.	3.01	2.27	2.48
RESIDENTIAL	5586.	5789.	5854.	6523.	7044.	7667.	8246.	2.01	1.58	1.70
INDUSTRIAL FIRM (1)	6646.	6935.	7036.	7474.	8047.	8526.	9143.	1.26	1.35	1.32
DSI FIRM	2435.	2531.	2503.	2336.	2338.	2300.	2301.	-1.33	-0.10	-0.45
NON-DSI FIRM	4211.	4404.	4533.	5139.	5709.	6226.	6842.	2.60	1.93	2.12
IRRIGATION (2)	649.	640.	650.	646.	647.	656.	680.	0.16	0.34	0.29
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17697.	19336.	20935.	22644.	24583.	1.87	1.61	1.69
TOTAL NON-DSI SALES	14231.	14774.	15194.	17001.	18598.	20344.	22282.	2.37	1.82	1.98
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1665.	1918.	2127.	2312.	2541.	3.62	1.89	2.38
RESIDENTIAL	2485.	2596.	2640.	2918.	3131.	3397.	3646.	1.97	1.50	1.63
INDUSTRIAL FIRM (1)	4449.	4639.	4690.	4780.	5023.	5207.	5461.	0.50	0.89	0.78
DSI FIRM	2435.	2531.	2503.	2336.	2338.	2300.	2301.	-1.33	-0.10	-0.45
NON-DSI FIRM	2014.	2108.	2187.	2445.	2685.	2907.	3160.	2.50	1.73	1.95
IRRIGATION (2)	327.	324.	316.	313.	311.	314.	316.	-0.59	0.06	-0.12
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9476.	10097.	10766.	11408.	12146.	1.46	1.24	1.30
TOTAL NON-DSI SALES	6467.	6727.	6973.	7762.	8428.	9108.	9846.	2.41	1.60	1.83
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2299.	2577.	2866.	3271.	3754.	2.58	2.54	2.55
RESIDENTIAL	3101.	3193.	3214.	3605.	3913.	4270.	4600.	2.04	1.64	1.75
INDUSTRIAL FIRM (1)	2197.	2296.	2346.	2694.	3023.	3319.	3682.	2.70	2.11	2.27
IRRIGATION	322.	316.	334.	333.	336.	342.	364.	0.90	0.59	0.68
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8221.	9239.	10169.	11237.	12437.	2.33	2.00	2.09

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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1HP - 1991 PLAN FINAL 1 HIGH - PRICE

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3994.	4948.	5721.	6569.	7549.	4.68	2.86	3.37
RESIDENTIAL	5586.	5789.	5851.	6958.	7786.	8759.	9667.	3.11	2.22	2.47
INDUSTRIAL FIRM (1)	6646.	6935.	7148.	8020.	8852.	9593.	10611.	2.45	1.88	2.05
DSI FIRM	2435.	2531.	2538.	2476.	2476.	2401.	2401.	-0.36	-0.20	-0.25
NON-DSI FIRM	4211.	4404.	4611.	5544.	6376.	7191.	8210.	3.91	2.65	3.01
IRRIGATION (2)	649.	640.	686.	702.	741.	780.	791.	1.55	0.80	1.02
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17872.	20826.	23305.	25914.	28836.	3.13	2.19	2.46
TOTAL NON-DSI SALES	14231.	14774.	15335.	18350.	20829.	23513.	26435.	3.68	2.46	2.81
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1665.	2097.	2395.	2676.	3014.	5.18	2.45	3.22
RESIDENTIAL	2485.	2596.	2639.	3100.	3444.	3857.	4244.	3.00	2.12	2.37
INDUSTRIAL FIRM (1)	4449.	4639.	4771.	5089.	5439.	5722.	6145.	1.56	1.26	1.35
DSI FIRM	2435.	2531.	2538.	2476.	2476.	2401.	2401.	-0.36	-0.20	-0.25
NON-DSI FIRM	2014.	2108.	2233.	2613.	2963.	3320.	3744.	3.65	2.43	2.77
IRRIGATION (2)	327.	324.	332.	335.	339.	342.	342.	0.55	0.13	0.25
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9571.	10789.	11791.	12776.	13928.	2.58	1.72	1.96
TOTAL NON-DSI SALES	6467.	6727.	7033.	8313.	9315.	10375.	11527.	3.59	2.20	2.60
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2329.	2850.	3326.	3893.	4535.	4.32	3.14	3.48
RESIDENTIAL	3101.	3193.	3212.	3858.	4342.	4902.	5422.	3.21	2.29	2.55
INDUSTRIAL FIRM (1)	2197.	2296.	2378.	2931.	3413.	3871.	4466.	4.15	2.85	3.22
IRRIGATION	322.	316.	354.	367.	402.	438.	450.	2.53	1.36	1.69
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8301.	10037.	11514.	13138.	14908.	3.75	2.67	2.98

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1L - 1991 FINAL PLAN 1 LOW - SALES

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	3798.	3582.	3616.	3716.	0.17	-0.15	-0.06
RESIDENTIAL	5586.	5789.	5838.	5739.	5478.	5376.	5391.	-0.14	-0.42	-0.34
INDUSTRIAL FIRM (1)	6646.	6935.	6591.	5096.	5030.	4744.	4843.	-5.01	-0.34	-1.70
DSI FIRM	2435.	2531.	2284.	1129.	1002.	651.	651.	-12.59	-3.60	-6.26
NON-DSI FIRM	4211.	4404.	4307.	3967.	4028.	4093.	4192.	-1.73	0.37	-0.23
IRRIGATION (2)	649.	640.	547.	517.	462.	429.	425.	-3.51	-1.29	-1.93
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17134.	15349.	14758.	14378.	14593.	-1.98	-0.34	-0.81
TOTAL NON-DSI SALES	14231.	14774.	14849.	14220.	13756.	13727.	13942.	-0.64	-0.13	-0.28
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1667.	1649.	1578.	1594.	1642.	1.05	-0.03	0.28
RESIDENTIAL	2485.	2596.	2631.	2586.	2464.	2408.	2406.	-0.06	-0.48	-0.36
INDUSTRIAL FIRM (1)	4449.	4639.	4343.	3063.	2976.	2668.	2711.	-6.69	-0.81	-2.52
DSI FIRM	2435.	2531.	2284.	1129.	1002.	651.	651.	-12.59	-3.60	-6.26
NON-DSI FIRM	2014.	2108.	2058.	1934.	1974.	2017.	2060.	-1.43	0.42	-0.11
IRRIGATION (2)	327.	324.	271.	264.	250.	236.	236.	-3.38	-0.74	-1.50
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9076.	7730.	7442.	7085.	7179.	-2.96	-0.49	-1.20
TOTAL NON-DSI SALES	6467.	6727.	6791.	6601.	6441.	6434.	6528.	-0.31	-0.07	-0.14
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2298.	2149.	2003.	2022.	2074.	-0.48	-0.24	-0.31
RESIDENTIAL	3101.	3193.	3207.	3154.	3014.	2968.	2985.	-0.21	-0.37	-0.32
INDUSTRIAL FIRM (1)	2197.	2296.	2249.	2033.	2054.	2077.	2132.	-2.01	0.32	-0.35
IRRIGATION	322.	316.	276.	253.	212.	193.	189.	-3.64	-1.92	-2.41
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8058.	7619.	7315.	7293.	7415.	-0.91	-0.18	-0.39

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1ML - 1991 FINAL 1 MEDIUM LOW - SALES

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	3956.	3884.	4024.	4369.	0.85	0.66	0.72
RESIDENTIAL	5586.	5789.	5848.	6004.	6034.	6224.	6478.	0.61	0.51	0.54
INDUSTRIAL FIRM (1)	6646.	6935.	6757.	5917.	6091.	6244.	6507.	-2.61	0.64	-0.30
DSI FIRM	2435.	2531.	2368.	1580.	1582.	1582.	1582.	-7.56	0.01	-2.21
NON-DSI FIRM	4211.	4404.	4389.	4338.	4509.	4662.	4925.	-0.25	0.85	0.53
IRRIGATION (2)	649.	640.	579.	562.	521.	487.	476.	-2.15	-1.10	-1.40
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17342.	16637.	16735.	17192.	18047.	-0.65	0.54	0.20
TOTAL NON-DSI SALES	14231.	14774.	14975.	15058.	15154.	15610.	16466.	0.32	0.60	0.52
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1666.	1726.	1730.	1793.	1917.	1.82	0.70	1.02
RESIDENTIAL	2485.	2596.	2636.	2700.	2701.	2767.	2866.	0.66	0.40	0.47
INDUSTRIAL FIRM (1)	4449.	4639.	4482.	3700.	3791.	3873.	3991.	-3.70	0.51	-0.71
DSI FIRM	2435.	2531.	2368.	1580.	1582.	1582.	1582.	-7.56	0.01	-2.21
NON-DSI FIRM	2014.	2108.	2114.	2121.	2209.	2291.	2409.	0.10	0.85	0.64
IRRIGATION (2)	327.	324.	286.	283.	275.	264.	260.	-2.25	-0.57	-1.05
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9235.	8578.	8670.	8875.	9215.	-1.26	0.48	-0.02
TOTAL NON-DSI SALES	6467.	6727.	6867.	6998.	7088.	7294.	7634.	0.66	0.58	0.60
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2298.	2229.	2154.	2231.	2452.	0.13	0.64	0.49
RESIDENTIAL	3101.	3193.	3211.	3304.	3333.	3458.	3612.	0.57	0.60	0.59
INDUSTRIAL FIRM (1)	2197.	2296.	2275.	2217.	2300.	2371.	2516.	-0.58	0.85	0.44
IRRIGATION	322.	316.	294.	279.	246.	223.	216.	-2.05	-1.69	-1.79
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8107.	8060.	8065.	8316.	8832.	0.03	0.61	0.44

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F2M - 1991 FINAL PLAN 2 MEDIUM - SALES W/ BPA'S SPM

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3976.	4209.	4323.	4533.	4906.	1.89	1.03	1.27
RESIDENTIAL	5586.	5789.	5859.	6215.	6340.	6553.	6830.	1.19	0.63	0.79
INDUSTRIAL FIRM (1)	6646.	6935.	6905.	6952.	7250.	7490.	7885.	0.04	0.84	0.61
DSI FIRM	2435.	2531.	2446.	2152.	2136.	2136.	2137.	-2.67	-0.05	-0.80
NON-DSI FIRM	4211.	4404.	4459.	4800.	5114.	5354.	5748.	1.45	1.21	1.28
IRRIGATION (2)	649.	640.	617.	611.	552.	525.	527.	-0.78	-0.98	-0.93
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17551.	18186.	18671.	19314.	20365.	0.83	0.76	0.78
TOTAL NON-DSI SALES	14231.	14774.	15105.	16034.	16535.	17178.	18229.	1.37	0.86	1.01
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1664.	1804.	1855.	1896.	2015.	2.57	0.74	1.26
RESIDENTIAL	2485.	2596.	2638.	2789.	2831.	2885.	2997.	1.20	0.48	0.69
INDUSTRIAL FIRM (1)	4449.	4639.	4591.	4433.	4540.	4640.	4804.	-0.75	0.54	0.17
DSI FIRM	2435.	2531.	2446.	2152.	2136.	2136.	2137.	-2.67	-0.05	-0.80
NON-DSI FIRM	2014.	2108.	2145.	2281.	2404.	2504.	2667.	1.33	1.05	1.13
IRRIGATION (2)	327.	324.	304.	308.	292.	282.	276.	-0.84	-0.74	-0.77
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9362.	9502.	9691.	9881.	10274.	0.44	0.52	0.50
TOTAL NON-DSI SALES	6467.	6727.	6916.	7350.	7556.	7745.	8137.	1.49	0.68	0.91
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2312.	2405.	2469.	2637.	2891.	1.41	1.23	1.28
RESIDENTIAL	3101.	3193.	3221.	3426.	3509.	3668.	3833.	1.18	0.75	0.87
INDUSTRIAL FIRM (1)	2197.	2296.	2314.	2519.	2710.	2850.	3081.	1.55	1.35	1.41
IRRIGATION	322.	316.	313.	303.	259.	244.	251.	-0.72	-1.24	-1.09
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8189.	8683.	8979.	9433.	10092.	1.28	1.01	1.08

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1MH - 1991 FINAL PLAN 1 MEDIUM HIGH - SALES

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	4357.	4654.	5026.	5560.	2.48	1.64	1.88
RESIDENTIAL	5586.	5789.	5853.	6383.	6620.	7000.	7448.	1.64	1.03	1.21
INDUSTRIAL FIRM (1)	6646.	6935.	7036.	7465.	8024.	8490.	9101.	1.24	1.33	1.30
DSI FIRM	2435.	2531.	2503.	2336.	2338.	2300.	2301.	-1.33	-0.10	-0.45
NON-DSI FIRM	4211.	4404.	4533.	5130.	5686.	6190.	6800.	2.57	1.90	2.09
IRRIGATION (2)	649.	640.	650.	631.	605.	600.	608.	-0.24	-0.25	-0.24
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17697.	19035.	20108.	21329.	22935.	1.60	1.25	1.35
TOTAL NON-DSI SALES	14231.	14774.	15194.	16699.	17770.	19029.	20635.	2.06	1.42	1.60
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1665.	1863.	1991.	2092.	2235.	3.12	1.22	1.76
RESIDENTIAL	2485.	2596.	2640.	2860.	2950.	3082.	3268.	1.63	0.89	1.10
INDUSTRIAL FIRM (1)	4449.	4639.	4690.	4776.	5012.	5191.	5440.	0.49	0.87	0.76
DSI FIRM	2435.	2531.	2503.	2336.	2338.	2300.	2301.	-1.33	-0.10	-0.45
NON-DSI FIRM	2014.	2108.	2187.	2441.	2675.	2891.	3139.	2.47	1.69	1.91
IRRIGATION (2)	327.	324.	316.	312.	308.	304.	290.	-0.63	-0.48	-0.52
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9476.	9979.	10436.	10848.	11416.	1.26	0.90	1.00
TOTAL NON-DSI SALES	6467.	6727.	6973.	7644.	8098.	8548.	9115.	2.15	1.18	1.46
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2299.	2494.	2662.	2934.	3325.	2.02	1.94	1.96
RESIDENTIAL	3101.	3193.	3213.	3522.	3670.	3918.	4179.	1.65	1.15	1.29
INDUSTRIAL FIRM (1)	2197.	2296.	2346.	2689.	3011.	3299.	3661.	2.67	2.08	2.25
IRRIGATION	322.	316.	334.	319.	297.	296.	318.	0.16	-0.02	0.03
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8221.	9055.	9672.	10481.	11520.	1.99	1.62	1.72

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1H - 1991 PLAN FINAL 1 HIGH - SALES

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3994.	4774.	5330.	5949.	6713.	4.06	2.30	2.80
RESIDENTIAL	5586.	5789.	5850.	6809.	7343.	8050.	8807.	2.74	1.73	2.02
INDUSTRIAL FIRM (1)	6646.	6935.	7148.	7994.	8783.	9478.	10452.	2.40	1.80	1.97
DSI FIRM	2435.	2531.	2538.	2476.	2476.	2401.	2401.	-0.36	-0.20	-0.25
NON-DSI FIRM	4211.	4404.	4611.	5518.	6307.	7077.	8050.	3.83	2.55	2.91
IRRIGATION (2)	649.	640.	686.	687.	698.	718.	714.	1.18	0.26	0.52
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17871.	20462.	22360.	24407.	26904.	2.83	1.84	2.12
TOTAL NON-DSI SALES	14231.	14774.	15334.	17986.	19884.	22006.	24503.	3.33	2.08	2.44
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1665.	2026.	2236.	2421.	2667.	4.58	1.85	2.62
RESIDENTIAL	2485.	2596.	2638.	3038.	3253.	3521.	3838.	2.65	1.57	1.88
INDUSTRIAL FIRM (1)	4449.	4639.	4771.	5078.	5409.	5670.	6072.	1.52	1.20	1.29
DSI FIRM	2435.	2531.	2538.	2476.	2476.	2401.	2401.	-0.36	-0.20	-0.25
NON-DSI FIRM	2014.	2108.	2233.	2601.	2933.	3269.	3671.	3.57	2.32	2.68
IRRIGATION (2)	327.	324.	332.	334.	336.	326.	311.	0.50	-0.48	-0.20
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9571.	10643.	11407.	12117.	13070.	2.35	1.38	1.66
TOTAL NON-DSI SALES	6467.	6727.	7033.	8167.	8931.	9716.	10669.	3.29	1.80	2.22
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2329.	2748.	3094.	3528.	4046.	3.68	2.61	2.92
RESIDENTIAL	3101.	3193.	3212.	3771.	4090.	4529.	4969.	2.81	1.86	2.13
INDUSTRIAL FIRM (1)	2197.	2296.	2378.	2916.	3374.	3808.	4380.	4.07	2.75	3.12
IRRIGATION	322.	316.	354.	353.	363.	392.	403.	1.84	0.90	1.17
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8301.	9819.	10952.	12291.	13834.	3.37	2.31	2.61

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1LF - 1991 FINAL PLAN 1 LOW - FROZEN EFF.

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	3957.	3967.	4055.	4227.	0.85	0.44	0.56
RESIDENTIAL	5586.	5789.	5839.	5853.	5835.	5892.	6004.	0.18	0.17	0.17
INDUSTRIAL FIRM (1)	6646.	6935.	6591.	5112.	5072.	4787.	4885.	-4.96	-0.30	-1.65
DSI FIRM	2435.	2531.	2284.	1129.	1002.	651.	651.	-12.59	-3.60	-6.26
NON-DSI FIRM	4211.	4404.	4307.	3983.	4070.	4136.	4234.	-1.66	0.41	-0.19
IRRIGATION (2)	649.	640.	547.	532.	504.	471.	467.	-3.03	-0.87	-1.49
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17135.	15653.	15583.	15416.	15801.	-1.66	0.06	-0.43
TOTAL NON-DSI SALES	14231.	14774.	14850.	14524.	14582.	14765.	15150.	-0.28	0.28	0.12
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1667.	1702.	1722.	1757.	1837.	1.59	0.51	0.81
RESIDENTIAL	2485.	2596.	2631.	2632.	2615.	2636.	2677.	0.23	0.11	0.15
INDUSTRIAL FIRM (1)	4449.	4639.	4343.	3068.	2989.	2681.	2725.	-6.66	-0.79	-2.50
DSI FIRM	2435.	2531.	2284.	1129.	1002.	651.	651.	-12.59	-3.60	-6.26
NON-DSI FIRM	2014.	2108.	2058.	1939.	1988.	2030.	2074.	-1.38	0.45	-0.08
IRRIGATION (2)	327.	324.	271.	264.	253.	239.	239.	-3.33	-0.68	-1.44
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9076.	7835.	7753.	7492.	7660.	-2.74	-0.15	-0.90
TOTAL NON-DSI SALES	6467.	6727.	6792.	6706.	6752.	6841.	7009.	-0.05	0.30	0.20
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2298.	2255.	2245.	2298.	2391.	0.32	0.39	0.37
RESIDENTIAL	3101.	3193.	3208.	3221.	3220.	3256.	3326.	0.15	0.21	0.20
INDUSTRIAL FIRM (1)	2197.	2296.	2249.	2044.	2083.	2106.	2160.	-1.92	0.37	-0.29
IRRIGATION	322.	316.	276.	268.	251.	231.	228.	-2.73	-1.06	-1.54
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8058.	7818.	7830.	7924.	8141.	-0.48	0.27	0.06

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1MLF - 1991 FINAL 1 MEDIUM LOW - FROZEN EFF.

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3965.	4137.	4301.	4565.	5030.	1.60	1.31	1.39
RESIDENTIAL	5586.	5789.	5849.	6130.	6434.	6839.	7241.	0.96	1.12	1.07
INDUSTRIAL FIRM (1)	6646.	6935.	6757.	5944.	6161.	6337.	6601.	-2.54	0.70	-0.24
DSI FIRM	2435.	2531.	2368.	1580.	1582.	1582.	1582.	-7.56	0.01	-2.21
NON-DSI FIRM	4211.	4404.	4389.	4365.	4580.	4756.	5019.	-0.15	0.94	0.62
IRRIGATION (2)	649.	640.	579.	577.	563.	537.	525.	-1.71	-0.63	-0.94
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17344.	16987.	17664.	18491.	19615.	-0.31	0.96	0.60
TOTAL NON-DSI SALES	14231.	14774.	14976.	15408.	16083.	16910.	18033.	0.70	1.05	0.95
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1666.	1794.	1890.	1980.	2147.	2.47	1.21	1.57
RESIDENTIAL	2485.	2596.	2637.	2752.	2872.	3047.	3216.	0.98	1.04	1.02
INDUSTRIAL FIRM (1)	4449.	4639.	4482.	3706.	3804.	3887.	4004.	-3.67	0.52	-0.70
DSI FIRM	2435.	2531.	2368.	1580.	1582.	1582.	1582.	-7.56	0.01	-2.21
NON-DSI FIRM	2014.	2108.	2114.	2126.	2223.	2305.	2423.	0.14	0.87	0.67
IRRIGATION (2)	327.	324.	286.	284.	278.	267.	263.	-2.19	-0.51	-0.99
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9235.	8703.	9018.	9359.	9813.	-1.03	0.80	0.28
TOTAL NON-DSI SALES	6467.	6727.	6868.	7123.	7437.	7778.	8231.	0.96	0.97	0.97
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2299.	2344.	2411.	2585.	2882.	0.97	1.39	1.27
RESIDENTIAL	3101.	3193.	3212.	3378.	3561.	3793.	4025.	0.94	1.17	1.11
INDUSTRIAL FIRM (1)	2197.	2296.	2275.	2239.	2357.	2450.	2596.	-0.42	0.99	0.59
IRRIGATION	322.	316.	294.	294.	285.	270.	263.	-1.22	-0.74	-0.88
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8109.	8284.	8646.	9132.	9802.	0.49	1.13	0.94

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F2MF - 1991 FINAL PLAN 2 MEDIUM - FROZEN EFF. W/ BPA'S SPM

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3976.	4396.	4761.	5190.	5740.	2.63	1.79	2.03
RESIDENTIAL	5586.	5789.	5860.	6348.	6753.	7214.	7639.	1.55	1.24	1.33
INDUSTRIAL FIRM (1)	6646.	6935.	6905.	6997.	7370.	7684.	8082.	0.15	0.97	0.73
DSI FIRM	2435.	2531.	2446.	2152.	2136.	2136.	2137.	-2.67	-0.05	-0.80
NON-DSI FIRM	4211.	4404.	4459.	4845.	5234.	5548.	5945.	1.60	1.37	1.44
IRRIGATION (2)	649.	640.	617.	626.	594.	581.	599.	-0.37	-0.30	-0.32
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17552.	18566.	19684.	20882.	22278.	1.18	1.22	1.21
TOTAL NON-DSI SALES	14231.	14774.	15106.	16414.	17548.	18746.	20141.	1.77	1.37	1.49
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1664.	1874.	2026.	2166.	2347.	3.23	1.51	2.00
RESIDENTIAL	2485.	2596.	2638.	2842.	3005.	3195.	3370.	1.52	1.14	1.25
INDUSTRIAL FIRM (1)	4449.	4639.	4591.	4455.	4596.	4735.	4902.	-0.67	0.64	0.26
DSI FIRM	2435.	2531.	2446.	2152.	2136.	2136.	2137.	-2.67	-0.05	-0.80
NON-DSI FIRM	2014.	2108.	2145.	2303.	2460.	2600.	2765.	1.49	1.23	1.30
IRRIGATION (2)	327.	324.	304.	309.	296.	291.	301.	-0.80	-0.17	-0.35
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9362.	9648.	10096.	10567.	11104.	0.69	0.94	0.87
TOTAL NON-DSI SALES	6467.	6727.	6916.	7496.	7960.	8431.	8967.	1.82	1.20	1.38
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2312.	2522.	2735.	3023.	3393.	2.21	2.00	2.06
RESIDENTIAL	3101.	3193.	3222.	3506.	3748.	4019.	4269.	1.57	1.32	1.39
INDUSTRIAL FIRM (1)	2197.	2296.	2314.	2542.	2774.	2949.	3180.	1.71	1.50	1.56
IRRIGATION	322.	316.	313.	317.	298.	290.	297.	0.05	-0.43	-0.29
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8190.	8918.	9588.	10315.	11174.	1.73	1.52	1.58

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
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(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1MHF - 1991 FINAL PLAN 1 MEDIUM HIGH - FROZEN EFF.

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3964.	4595.	5182.	5789.	6613.	3.39	2.46	2.72
RESIDENTIAL	5586.	5789.	5854.	6530.	7060.	7703.	8300.	2.03	1.61	1.73
INDUSTRIAL FIRM (1)	6646.	6935.	7036.	7474.	8047.	8526.	9143.	1.26	1.35	1.32
DSI FIRM	2435.	2531.	2503.	2336.	2338.	2300.	2301.	-1.33	-0.10	-0.45
NON-DSI FIRM	4211.	4404.	4533.	5139.	5709.	6226.	6842.	2.60	1.93	2.12
IRRIGATION (2)	649.	640.	650.	646.	647.	656.	680.	0.16	0.34	0.29
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17697.	19444.	21142.	22886.	24955.	1.96	1.68	1.76
TOTAL NON-DSI SALES	14231.	14774.	15194.	17108.	18804.	20586.	22654.	2.48	1.89	2.06
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1665.	1951.	2191.	2376.	2632.	3.92	2.02	2.56
RESIDENTIAL	2485.	2596.	2640.	2921.	3139.	3413.	3666.	1.98	1.53	1.66
INDUSTRIAL FIRM (1)	4449.	4639.	4690.	4780.	5023.	5207.	5461.	0.50	0.89	0.78
DSI FIRM	2435.	2531.	2503.	2336.	2338.	2300.	2301.	-1.33	-0.10	-0.45
NON-DSI FIRM	2014.	2108.	2187.	2445.	2685.	2907.	3160.	2.50	1.73	1.95
IRRIGATION (2)	327.	324.	316.	313.	311.	314.	316.	-0.59	0.06	-0.12
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9476.	10133.	10837.	11488.	12258.	1.52	1.28	1.35
TOTAL NON-DSI SALES	6467.	6727.	6973.	7798.	8500.	9188.	9957.	2.49	1.64	1.88
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2299.	2644.	2991.	3413.	3981.	3.02	2.77	2.84
RESIDENTIAL	3101.	3193.	3214.	3609.	3922.	4290.	4635.	2.06	1.68	1.79
INDUSTRIAL FIRM (1)	2197.	2296.	2346.	2694.	3023.	3319.	3682.	2.70	2.11	2.27
IRRIGATION	322.	316.	334.	333.	336.	342.	364.	0.90	0.59	0.68
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8221.	9311.	10304.	11398.	12697.	2.46	2.09	2.20

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

PACIFIC NORTHWEST ELECTRICITY LOAD FORECASTING SYSTEM

SUMMARY OF REGIONAL DEMAND AND GROWTH RATES

91F1HF - 1991 PLAN FINAL 1 HIGH - FROZEN

	DEMAND IN AVERAGE MEGAWATTS							DEMAND GROWTH RATES		
	1988	1989	1990	1995	2000	2005	2010	1989-1995	1995-2010	1989-2010
TOTAL:	(ACTUAL)	(ACTUAL)								
COMMERCIAL	3603.	3761.	3994.	5120.	6050.	6917.	8009.	5.28	3.03	3.66
RESIDENTIAL	5586.	5789.	5851.	6982.	7835.	8841.	9765.	3.17	2.26	2.52
INDUSTRIAL FIRM (1)	6646.	6935.	7148.	8020.	8852.	9593.	10611.	2.45	1.88	2.05
DSI FIRM	2435.	2531.	2538.	2476.	2476.	2401.	2401.	-0.36	-0.20	-0.25
NON-DSI FIRM	4211.	4404.	4611.	5544.	6376.	7191.	8210.	3.91	2.65	3.01
IRRIGATION (2)	649.	640.	686.	702.	741.	780.	791.	1.55	0.80	1.02
OTHER (3)	182.	180.	194.	199.	206.	212.	218.	1.64	0.64	0.92
TOTAL FIRM SALES	16666.	17305.	17872.	21022.	23683.	26343.	29394.	3.30	2.26	2.55
TOTAL NON-DSI SALES	14231.	14774.	15335.	18546.	21207.	23942.	26992.	3.86	2.53	2.91
PUBLIC CUSTOMER POOL:										
COMMERCIAL	1488.	1549.	1665.	2143.	2493.	2797.	3192.	5.56	2.69	3.50
RESIDENTIAL	2485.	2596.	2639.	3110.	3467.	3894.	4282.	3.06	2.15	2.41
INDUSTRIAL FIRM (1)	4449.	4639.	4771.	5089.	5439.	5722.	6145.	1.56	1.26	1.35
DSI FIRM	2435.	2531.	2538.	2476.	2476.	2401.	2401.	-0.36	-0.20	-0.25
NON-DSI FIRM	2014.	2108.	2233.	2613.	2963.	3320.	3744.	3.65	2.43	2.77
IRRIGATION (2)	327.	324.	332.	335.	339.	342.	342.	0.55	0.13	0.25
OTHER (3)	153.	150.	165.	168.	174.	179.	183.	1.91	0.57	0.95
TOTAL FIRM SALES	8902.	9258.	9571.	10844.	11912.	12933.	14143.	2.67	1.79	2.04
TOTAL NON-DSI SALES	6467.	6727.	7033.	8368.	9436.	10532.	11742.	3.71	2.28	2.69
PRIVATE CUSTOMER POOL:										
COMMERCIAL	2115.	2212.	2329.	2978.	3556.	4120.	4817.	5.08	3.26	3.78
RESIDENTIAL	3101.	3193.	3212.	3872.	4368.	4947.	5483.	3.27	2.35	2.61
INDUSTRIAL FIRM (1)	2197.	2296.	2378.	2931.	3413.	3871.	4466.	4.15	2.85	3.22
IRRIGATION	322.	316.	354.	367.	402.	438.	450.	2.53	1.36	1.69
OTHER (3)	29.	30.	29.	31.	32.	34.	35.	0.28	1.00	0.79
TOTAL FIRM SALES	7764.	8047.	8301.	10178.	11771.	13410.	15251.	3.99	2.73	3.09

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(1) INCLUDES COLOCKUM, MINING, AND NON-BPA INTERRUPTIBLE
(2) INCLUDES USBR, EXCLUDES GRAND COULEE AND ROZA PUMPING
(3) FEDERAL AGENCIES AND STREET LIGHTING

APPENDIX 6-B

FORECAST CHANGES FROM 1989

Table 6–B–1
*Demand Forecast Changes from Previous Forecasts (91F1*P, 91F2MP)*

Year/Scenario	1989 Supplement[a]	1989 White Book[b]	1991 Power Plan	Change from 1989 Supplement	Change from 1989 White Book
1995					
▪ Low	14,322	14,738	15,607	+1,284	+855
▪ Medium–Low	15,998	16,393	16,930	+932	+523
▪ Medium	17,162	17,588	18,276	+1,115	+674
▪ Medium–High	18,333	18,728	19,335	+1,003	+594
▪ High	20,439	20,885	20,826	+387	-73
2000					
▪ Low	14,414	14,501	15,520	+1,106	+1,008
▪ Medium–Low	16,721	16,847	17,566	+845	+708
▪ Medium	18,372	18,559	19,345	+973	+774
▪ Medium–High	19,933	20,263	20,935	+1,002	+661
▪ High	22,976	23,386	23,305	+329	-92
2005					
▪ Low	14,913	14,669	15,386	+473	+717
▪ Medium–Low	17,897	17,641	18,395	+498	+754
▪ Medium	19,852	19,775	20,599	+747	+824
▪ Medium–High	21,915	21,956	22,644	+729	+688
▪ High	25,979	26,290	25,914	-65	-376
2010					
▪ Low	15,442	14,963	15,787	+346	+817
▪ Medium–Low	19,124	18,621	19,485	+361	+857
▪ Medium	21,344	21,146	22,129	+785	+977
▪ Medium–High	24,026	23,942	24,583	+557	+635
▪ High	29,223	29,537	28,836	-387	-707

[a] Northwest Power Planning Council. *1989 Supplement to the 1986 Northwest Conservation and Electric Power Plan*, Volume II, Appendix 2–A. Spring 1989.

[b] *Forecast of Electricity Use in the Pacific Northwest*, Appendix A. August 1989.

Table 6-B-2
*Demand Forecast Changes from Draft Plan (91F1*P, 91F2MP)*

Year/Scenario	1991 Draft Plan	1991 Power Plan	Change from Draft Plan
1995			
▪ Low	15,136	15,607	+471
▪ Medium-Low	16,668	16,930	+262
▪ Medium	18,224	18,276	+52
▪ Medium-High	19,258	19,335	+78
▪ High	20,888	20,826	-62
2000			
▪ Low	15,147	15,520	+373
▪ Medium-Low	17,375	17,566	+191
▪ Medium	19,178	19,345	+167
▪ Medium-High	20,863	20,935	+72
▪ High	23,280	23,305	+25
2005			
▪ Low	14,992	15,386	+394
▪ Medium-Low	18,114	18,395	+281
▪ Medium	20,339	20,599	+260
▪ Medium-High	22,437	22,644	+207
▪ High	25,855	25,914	+59
2010			
▪ Low	15,317	15,787	+470
▪ Medium-Low	19,130	19,485	+355
▪ Medium	21,419	22,129	+710
▪ Medium-High	24,316	24,583	+267
▪ High	28,859	28,836	-23

APPENDIX 6-C

DETAILED FORECAST TABLES

1. Calendar Year Forecasts
2. Operating Year Forecasts
3. Fiscal Year Forecasts

1991 FINAL COUNCIL PLAN -- LOW CASE -- (91F1LP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	2968.2	2964.8	2960.4	2956.4	2960.8	2969.3	2982.2	2984.3	2984.9	2982.9	2986.3	2993.0
2 DISTRIBUTION LOSSES	124.7	124.5	124.3	124.2	124.4	124.7	125.3	125.3	125.4	125.3	125.4	125.7
3 SYSTEM LOAD	3092.9	3089.3	3084.7	3080.6	3085.2	3094.0	3107.5	3109.7	3110.2	3108.1	3111.7	3118.7
4 DSI ALUM FIRM LOAD	1876.5	1700.6	1485.0	1256.6	1027.0	1027.0	1027.0	1027.0	1027.0	899.7	624.9	549.0
5 DSI NON-ALUM FIRM LOAD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	1976.5	1800.6	1585.0	1356.6	1127.0	1127.0	1127.0	1127.0	1127.0	999.7	724.9	649.0
8 TOT DSI FIRM TRANS LOSSES	51.5	47.0	41.4	35.4	29.4	29.4	29.4	29.4	29.4	26.1	19.0	16.9
9 BPA FEDERAL AGENCIES	144.6	143.1	141.6	142.7	143.8	144.8	145.7	146.5	147.4	148.3	149.1	149.9
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	138.2	133.5	127.8	121.7	115.9	116.1	116.5	116.6	116.6	113.3	106.3	104.4
12 ADDTL FEDERAL TRAN LOSSES	60.1	61.6	59.6	56.8	56.8	52.8	49.5	49.5	48.0	47.8	47.7	47.8
13 TOTAL FEDERAL FIRM LOAD	5479.5	5295.5	5065.8	4825.7	4595.9	4602.0	4613.6	4616.8	4616.8	4484.8	4207.4	4137.6
GENERATING PUBLIC UTILITIES												
14 SALES	3367.5	3363.7	3358.7	3354.2	3359.2	3368.7	3383.4	3385.9	3386.5	3384.2	3388.0	3395.6
15 TRANSMIS & DISTRIB LOSSES	215.5	215.3	215.0	214.7	215.0	215.6	216.5	216.7	216.7	216.6	216.8	217.3
16 SYSTEM LOAD	3583.1	3579.0	3573.6	3568.8	3574.1	3584.3	3600.0	3602.5	3603.2	3600.7	3604.9	3612.9
17 PUB RESIDENTL EXCHG--RPSA	313.2	314.4	311.0	305.4	304.1	304.7	304.1	302.5	302.6	303.0	304.0	304.5
18 PUB RESIDENTL EXCHG--ETCA	10.3	10.2	10.0	9.8	9.7	9.6	9.6	9.4	9.4	9.4	9.4	9.3
19 TOTAL PUBLIC SALES	6335.7	6328.5	6319.1	6310.6	6320.0	6338.0	6365.6	6370.2	6371.3	6367.0	6374.3	6388.6
INVESTOR-OWNED UTILITIES												
20 SALES	7893.1	7842.2	7811.4	7778.8	7777.4	7767.4	7763.9	7766.0	7769.4	7765.8	7770.2	7784.6
21 TRANSMIS & DISTRIB LOSSES	828.8	823.4	820.2	816.8	816.6	815.6	815.2	815.4	815.8	815.4	815.9	817.4
22 SYSTEM LOAD	8721.9	8665.7	8631.6	8595.5	8594.0	8582.9	8579.1	8581.4	8585.2	8581.2	8586.1	8602.0
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	16597.3	16361.8	16104.3	15836.0	15615.5	15624.5	15649.7	15657.2	15662.7	15528.3	15266.2	15219.8
26 TOTAL REGIONAL FIRM LOAD	17964.5	17720.1	17451.1	17170.1	16944.1	16949.3	16972.7	16980.7	16985.2	16846.6	16578.3	16532.5
27 DSI ALUM TQ LOAD	625.7	566.9	495.0	419.1	342.0	342.0	342.0	342.0	342.0	300.0	208.3	183.0
28 DSI NON-ALUM TQ LOAD	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	658.7	599.9	528.0	452.1	375.0	375.0	375.0	375.0	375.0	333.0	241.3	216.0
31 TOT DSI T Q TRANS LOSSES	17.2	15.6	13.8	11.8	9.8	9.8	9.8	9.8	9.8	8.7	6.3	5.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	18640.4	18335.7	17992.9	17634.0	17328.9	17334.0	17357.5	17365.5	17370.0	17188.4	16825.9	16754.1

1991 FINAL COUNCIL PLAN -- LOW CASE -- (91F1LP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2003	2004	2005	2006	2007	2008	2009	2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	2998.8	3015.2	3033.7	3051.2	3065.5	3081.7	3098.5	3119.3
2 DISTRIBUTION LOSSES	126.0	126.6	127.4	128.1	128.7	129.4	130.1	131.0
3 SYSTEM LOAD	3124.8	3141.8	3161.1	3179.3	3194.2	3211.1	3228.6	3250.3
4 DSI ALUM FIRM LOAD	549.0	549.0	549.0	549.0	549.0	549.0	549.0	549.0
5 DSI NON-ALUM FIRM LOAD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	649.0	649.0	649.0	649.0	649.0	649.0	649.0	649.0
8 TOT DSI FIRM TRANS LOSSES	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
9 BPA FEDERAL AGENCIES	150.5	151.1	151.8	152.5	153.0	153.7	154.2	154.8
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	104.6	105.1	105.6	106.1	106.5	107.0	107.5	108.0
12 ADDTL FEDERAL TRAN LOSSES	46.7	47.0	48.2	49.8	50.3	49.6	49.8	50.4
13 TOTAL FEDERAL FIRM LOAD	4143.4	4161.8	4183.6	4204.7	4221.1	4238.4	4257.1	4280.7
GENERATING PUBLIC UTILITIES								
14 SALES	3402.3	3420.8	3441.8	3461.7	3477.9	3496.3	3515.3	3539.0
15 TRANSMIS & DISTRIB LOSSES	217.7	218.9	220.3	221.5	222.6	223.8	225.0	226.5
16 SYSTEM LOAD	3620.0	3639.7	3662.1	3683.2	3700.5	3720.0	3740.3	3765.5
17 PUB RESIDENTL EXCHG--RPSA	304.9	306.3	307.8	309.5	310.5	311.7	313.0	315.3
18 PUB RESIDENTL EXCHG--ETCA	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
19 TOTAL PUBLIC SALES	6401.1	6436.0	6475.4	6512.9	6543.4	6578.0	6613.8	6658.3
INVESTOR-OWNED UTILITIES								
20 SALES	7795.2	7827.4	7870.0	7910.3	7948.6	7989.2	8035.4	8084.7
21 TRANSMIS & DISTRIB LOSSES	818.5	821.9	826.3	830.6	834.6	838.9	843.7	848.9
22 SYSTEM LOAD	8613.7	8649.3	8696.3	8740.8	8783.2	8828.0	8879.1	8933.6
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	15243.6	15311.3	15394.2	15472.6	15542.1	15617.8	15700.5	15795.0
26 TOTAL REGIONAL FIRM LOAD	16557.1	16630.8	16722.0	16808.8	16884.8	16966.4	17056.6	17159.8
27 DSI ALUM TQ LOAD	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
28 DSI NON-ALUM TQ LOAD	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
31 TOT DSI T Q TRANS LOSSES	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	16778.8	16852.5	16943.6	17030.4	17106.5	17188.0	17278.2	17381.5

1991 FINAL COUNCIL PLAN -- MEDIUM LOW CASE -- (91F1MLP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3046.7	3073.3	3095.2	3121.9	3152.3	3185.3	3222.7	3246.6	3271.8	3293.4	3318.0	3345.1
2 DISTRIBUTION LOSSES	128.0	129.1	130.0	131.1	132.4	133.8	135.4	136.4	137.4	138.3	139.4	140.5
3 SYSTEM LOAD	3174.7	3202.4	3225.2	3253.0	3284.7	3319.1	3358.0	3382.9	3409.2	3431.7	3457.3	3485.6
4 DSI ALUM FIRM LOAD	1929.7	1864.6	1722.9	1581.5	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0
5 DSI NON-ALUM FIRM LOAD	166.0	157.5	139.3	139.3	139.7	140.1	140.6	141.1	141.3	141.8	142.1	142.1
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2095.7	2022.1	1862.2	1720.8	1578.7	1579.1	1579.6	1580.1	1580.3	1580.8	1581.1	1581.1
8 TOT DSI FIRM TRANS LOSSES	54.7	52.7	48.6	44.9	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2
9 BPA FEDERAL AGENCIES	144.6	143.1	141.6	142.7	143.8	144.8	145.7	146.5	147.4	148.3	149.1	149.9
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	143.5	142.3	138.6	135.7	132.9	133.8	134.9	135.6	136.3	136.9	137.6	138.4
12 ADDTL FEDERAL TRAN LOSSES	63.2	65.7	64.5	62.5	63.2	59.9	57.2	57.8	56.9	57.3	57.7	58.4
13 TOTAL FEDERAL FIRM LOAD	5688.9	5642.8	5499.2	5382.1	5270.6	5304.0	5342.8	5370.3	5397.7	5422.6	5450.4	5481.1
GENERATING PUBLIC UTILITIES												
14 SALES	3456.6	3486.8	3511.6	3541.9	3576.4	3613.9	3656.2	3683.3	3712.0	3736.4	3764.3	3795.1
15 TRANSMIS & DISTRIB LOSSES	221.2	223.1	224.7	226.7	228.9	231.3	234.0	235.7	237.6	239.1	240.9	242.9
16 SYSTEM LOAD	3677.8	3709.9	3736.3	3768.6	3805.3	3845.2	3890.2	3919.1	3949.5	3975.6	4005.3	4038.0
17 PUB RESIDENTL EXCHG--RPSA	321.5	325.9	325.2	322.5	323.8	326.9	328.6	329.1	331.6	334.6	337.7	340.3
18 PUB RESIDENTL EXCHG--ETCA	10.5	10.5	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.4	10.4	10.4
19 TOTAL PUBLIC SALES	6503.3	6560.0	6606.7	6663.8	6728.8	6799.2	6878.9	6929.9	6983.8	7029.8	7082.3	7140.2
INVESTOR-OWNED UTILITIES												
20 SALES	8076.6	8099.9	8146.3	8191.8	8240.7	8296.6	8358.9	8425.9	8498.9	8569.2	8641.7	8724.7
21 TRANSMIS & DISTRIB LOSSES	848.0	850.5	855.4	860.1	865.3	871.1	877.7	884.7	892.4	899.8	907.4	916.1
22 SYSTEM LOAD	8924.6	8950.4	9001.7	9051.9	9106.0	9167.7	9236.6	9310.6	9391.2	9468.9	9549.0	9640.7
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17067.4	17072.5	17004.0	16966.5	16939.3	17067.0	17210.5	17329.9	17457.9	17575.6	17701.8	17843.6
26 TOTAL REGIONAL FIRM LOAD	18471.4	18483.1	18417.2	18382.6	18361.9	18496.9	18649.6	18780.0	18918.5	19047.1	19184.7	19339.9
27 DSI ALUM TQ LOAD	643.4	621.5	574.3	527.5	480.0	480.0	480.0	480.0	480.0	480.0	480.0	480.0
28 DSI NON-ALUM TQ LOAD	55.4	52.5	46.3	46.3	46.5	46.7	47.2	47.2	47.2	47.3	47.3	47.3
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	698.8	674.0	620.7	573.8	526.5	526.7	527.2	527.2	527.2	527.3	527.3	527.3
31 TOT DSI T Q TRANS LOSSES	18.2	17.6	16.2	15.0	13.7	13.7	13.7	13.7	13.7	13.8	13.8	13.8
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19188.4	19174.7	19054.1	18971.4	18902.2	19037.3	19190.5	19321.0	19459.4	19588.1	19725.7	19880.9

1991 FINAL COUNCIL PLAN -- MEDIUM LOW CASE -- (91F1MLP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2003	2004	2005	2006	2007	2008	2009	2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	3371.0	3409.1	3451.6	3493.5	3533.9	3575.4	3614.9	3659.0
2 DISTRIBUTION LOSSES	141.6	143.2	145.0	146.7	148.4	150.2	151.8	153.7
3 SYSTEM LOAD	3512.6	3552.3	3596.6	3640.3	3682.3	3725.5	3766.7	3812.7
4 DSI ALUM FIRM LOAD	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0
5 DSI NON-ALUM FIRM LOAD	142.1	142.2	142.3	142.3	142.3	142.6	142.8	142.8
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	1581.1	1581.2	1581.3	1581.3	1581.3	1581.6	1581.8	1581.8
8 TOT DSI FIRM TRANS LOSSES	41.2	41.2	41.2	41.2	41.2	41.2	41.3	41.3
9 BPA FEDERAL AGENCIES	150.5	151.1	151.8	152.5	153.0	153.7	154.2	154.8
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	139.1	140.2	141.4	142.5	143.7	144.8	145.9	147.1
12 ADDTL FEDERAL TRAN LOSSES	57.8	58.7	60.2	62.8	63.8	63.8	64.8	65.8
13 TOTAL FEDERAL FIRM LOAD	5508.9	5551.3	5599.1	5647.3	5692.0	5737.4	5781.5	5830.4
GENERATING PUBLIC UTILITIES								
14 SALES	3824.5	3867.8	3916.0	3963.5	4009.3	4056.4	4101.2	4151.3
15 TRANSMIS & DISTRIB LOSSES	244.8	247.5	250.6	253.7	256.6	259.6	262.5	265.7
16 SYSTEM LOAD	4069.3	4115.3	4166.6	4217.2	4265.9	4316.0	4363.7	4416.9
17 PUB RESIDENTL EXCHG--RPSA	342.7	346.3	350.2	354.4	357.9	361.7	365.1	369.8
18 PUB RESIDENTL EXCHG--ETCA	10.5	10.5	10.6	10.7	10.7	10.8	10.8	10.9
19 TOTAL PUBLIC SALES	7195.5	7276.9	7367.6	7457.1	7543.1	7631.7	7716.1	7810.3
INVESTOR-OWNED UTILITIES								
20 SALES	8807.6	8921.7	9056.5	9183.0	9309.8	9442.2	9566.8	9700.5
21 TRANSMIS & DISTRIB LOSSES	924.8	936.8	950.9	964.2	977.5	991.4	1004.5	1018.5
22 SYSTEM LOAD	9732.4	9858.5	10007.4	10147.2	10287.3	10433.7	10571.3	10719.0
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17982.5	18178.7	18405.1	18621.7	18835.3	19057.2	19267.0	19495.5
26 TOTAL REGIONAL FIRM LOAD	19490.6	19705.1	19953.1	20191.7	20425.2	20667.1	20896.5	21146.4
27 DSI ALUM TQ LOAD	480.0	480.0	480.0	480.0	480.0	480.0	480.0	480.0
28 DSI NON-ALUM TQ LOAD	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	527.3	527.3	527.3	527.3	527.3	527.3	527.3	527.3
31 TOT DSI T Q TRANS LOSSES	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20031.6	20246.2	20494.2	20732.8	20966.3	21208.2	21437.6	21687.5

1991 FINAL COUNCIL PLAN -- MEDIUM CASE -- (91F2MP) (M-TERM MRG=1/95)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3137.4	3168.7	3206.2	3252.3	3291.5	3334.7	3375.8	3416.6	3457.1	3495.7	3532.3	3574.7
2 DISTRIBUTION LOSSES	131.8	133.1	134.7	136.6	138.2	140.1	141.8	143.5	145.2	146.8	148.4	150.1
3 SYSTEM LOAD	3269.2	3301.8	3340.8	3388.9	3429.7	3474.8	3517.6	3560.1	3602.3	3642.5	3680.7	3724.8
4 DSI ALUM FIRM LOAD	2161.0	2105.0	2053.1	1986.3	1972.2	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0
5 DSI NON-ALUM FIRM LOAD	219.8	214.8	179.2	179.3	179.5	180.7	181.3	181.9	182.9	183.8	183.9	183.9
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2380.8	2319.8	2232.3	2165.5	2151.7	2131.7	2132.3	2132.9	2133.9	2134.8	2134.9	2134.9
8 TOT DSI FIRM TRANS LOSSES	62.1	60.5	58.2	56.5	56.1	55.6	55.6	55.6	55.6	55.7	55.7	55.7
9 BPA FEDERAL AGENCIES	144.6	143.1	141.6	142.7	143.8	144.8	145.7	146.5	147.4	148.3	149.1	149.9
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	153.4	152.7	151.3	150.9	151.6	152.3	153.5	154.6	155.8	156.9	157.9	159.1
12 ADDTL FEDERAL TRAN LOSSES	66.2	69.4	68.4	66.9	67.8	64.7	62.6	63.7	62.5	63.0	64.1	65.2
13 TOTAL FEDERAL FIRM LOAD	6081.5	6054.0	6001.6	5982.2	6012.0	6035.6	6079.0	6125.3	6169.5	6213.1	6254.4	6301.7
GENERATING PUBLIC UTILITIES												
14 SALES	3611.6	3691.1	3731.8	3771.9	3808.2	3858.2	3905.7	3952.9	3999.8	4044.5	4086.8	4135.8
15 TRANSMIS & DISTRIB LOSSES	231.1	236.2	238.8	241.4	243.7	246.9	250.0	253.0	256.0	258.8	261.6	264.7
16 SYSTEM LOAD	3842.7	3927.3	3970.7	4013.3	4051.9	4105.1	4155.7	4205.9	4255.8	4303.3	4348.4	4400.5
17 PUB RESIDENTL EXCHG--RPSA	331.0	336.0	336.9	336.0	338.1	342.2	344.2	346.3	350.4	355.1	359.5	363.7
18 PUB RESIDENTL EXCHG--ETCA	10.8	10.9	10.8	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.1	11.2
19 TOTAL PUBLIC SALES	6749.0	6859.8	6938.0	7024.2	7099.7	7192.9	7281.5	7369.5	7457.0	7540.2	7619.2	7710.5
INVESTOR-OWNED UTILITIES												
20 SALES	8332.5	8509.2	8652.7	8761.8	8880.7	8987.8	9107.0	9244.7	9385.8	9525.5	9645.0	9790.2
21 TRANSMIS & DISTRIB LOSSES	874.9	893.5	908.5	920.0	932.5	943.7	956.2	970.7	985.5	1000.2	1012.7	1028.0
22 SYSTEM LOAD	9207.5	9402.6	9561.2	9681.8	9813.2	9931.5	10063.2	10215.4	10371.4	10525.6	10657.7	10818.1
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17854.2	18079.2	18211.7	18341.5	18523.2	18704.5	18913.8	19141.2	19371.6	19596.2	19795.8	20033.3
26 TOTAL REGIONAL FIRM LOAD	19311.7	19564.0	19713.4	19857.2	20057.0	20252.2	20477.9	20726.6	20976.7	21222.0	21440.5	21700.4
27 DSI ALUM TQ LOAD	720.0	702.0	684.1	661.9	657.4	650.0	650.0	650.0	650.0	650.0	650.0	650.0
28 DSI NON-ALUM TQ LOAD	89.9	71.7	59.8	59.8	59.8	60.4	60.4	60.6	61.0	61.4	61.4	61.4
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	809.9	773.7	743.9	721.8	717.3	710.4	710.4	710.6	711.0	711.4	711.4	711.4
31 TOT DSI T Q TRANS LOSSES	21.1	20.2	19.4	18.8	18.7	18.5	18.5	18.5	18.5	18.6	18.6	18.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20142.7	20357.8	20476.8	20597.8	20793.0	20981.2	21206.9	21455.8	21706.2	21952.0	22170.5	22430.3

1991 FINAL COUNCIL PLAN -- MEDIUM CASE -- (91F2MP) (M-TERM MRG=1/95)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2003	2004	2005	2006	2007	2008	2009	2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	3615.0	3660.9	3711.8	3762.0	3808.5	3856.9	3901.4	3946.7
2 DISTRIBUTION LOSSES	151.8	153.8	155.9	158.0	160.0	162.0	163.9	165.8
3 SYSTEM LOAD	3766.8	3814.7	3867.7	3920.0	3968.5	4018.9	4065.2	4112.4
4 DSI ALUM FIRM LOAD	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0
5 DSI NON-ALUM FIRM LOAD	184.2	184.2	184.5	184.5	184.8	185.1	185.1	185.1
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2135.2	2135.2	2135.5	2135.5	2135.8	2136.1	2136.1	2136.1
8 TOT DSI FIRM TRANS LOSSES	55.7	55.7	55.7	55.7	55.7	55.7	55.7	55.7
9 BPA FEDERAL AGENCIES	150.5	151.1	151.8	152.5	153.0	153.7	154.2	154.8
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	160.2	161.5	162.9	164.3	165.6	167.0	168.2	169.5
12 ADDTL FEDERAL TRAN LOSSES	65.0	66.1	68.0	70.8	72.0	72.2	73.1	74.4
13 TOTAL FEDERAL FIRM LOAD	6345.6	6396.5	6453.8	6511.0	6563.0	6615.8	6664.9	6715.3
GENERATING PUBLIC UTILITIES								
14 SALES	4182.5	4235.6	4294.5	4352.5	4406.4	4462.3	4513.8	4566.2
15 TRANSMIS & DISTRIB LOSSES	267.7	271.1	274.8	278.6	282.0	285.6	288.9	292.2
16 SYSTEM LOAD	4450.2	4506.7	4569.3	4631.1	4688.4	4747.9	4802.7	4858.4
17 PUB RESIDENTL EXCHG--RPSA	367.5	371.9	376.6	381.6	385.7	390.1	394.1	398.9
18 PUB RESIDENTL EXCHG--ETCA	11.2	11.3	11.4	11.5	11.6	11.6	11.7	11.8
19 TOTAL PUBLIC SALES	7797.5	7896.6	8006.3	8114.5	8214.9	8319.2	8415.2	8512.9
INVESTOR-OWNED UTILITIES								
20 SALES	9931.5	10083.2	10254.3	10407.8	10561.2	10733.8	10889.4	11032.4
21 TRANSMIS & DISTRIB LOSSES	1042.8	1058.7	1076.7	1092.8	1108.9	1127.0	1143.4	1158.4
22 SYSTEM LOAD	10974.3	11142.0	11331.0	11500.6	11670.1	11860.8	12032.8	12190.8
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	20262.4	20513.9	20795.8	21058.2	21313.0	21590.7	21843.0	22084.3
26 TOTAL REGIONAL FIRM LOAD	21950.0	22225.1	22534.2	22822.7	23101.5	23404.5	23680.4	23944.6
27 DSI ALUM TQ LOAD	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
28 DSI NON-ALUM TQ LOAD	61.4	61.5	61.5	61.5	61.5	61.5	61.5	61.5
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	711.4	711.5	711.5	711.5	711.5	711.5	711.5	711.5
31 TOT DSI T Q TRANS LOSSES	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	22680.0	22955.2	23264.2	23552.7	23831.5	24134.6	24410.4	24674.6

1991 FINAL COUNCIL PLAN -- MEDIUM HIGH CASE -- (91F1MHP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3189.4	3255.8	3320.8	3387.1	3457.6	3525.8	3594.3	3655.5	3713.0	3767.8	3824.1	3885.9
2 DISTRIBUTION LOSSES	134.0	136.7	139.5	142.3	145.2	148.1	151.0	153.5	155.9	158.2	160.6	163.2
3 SYSTEM LOAD	3323.4	3392.6	3460.3	3529.4	3602.8	3673.9	3745.3	3809.1	3869.0	3926.0	3984.7	4049.1
4 DSI ALUM FIRM LOAD	2161.0	2123.0	2123.0	2115.5	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0
5 DSI NON-ALUM FIRM LOAD	274.4	264.9	247.2	247.3	247.5	248.1	248.4	249.1	249.2	249.8	231.0	212.3
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2435.4	2387.9	2370.2	2362.8	2334.5	2335.1	2335.4	2336.1	2336.2	2336.8	2318.0	2299.3
8 TOT DSI FIRM TRANS LOSSES	63.5	62.3	61.8	61.6	60.9	60.9	60.9	60.9	60.9	60.9	60.5	60.0
9 BPA FEDERAL AGENCIES	144.6	143.1	141.6	142.7	143.8	144.8	145.7	146.5	147.4	148.3	149.1	149.9
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	156.3	156.8	158.1	159.7	161.0	162.9	164.8	166.5	168.1	169.6	170.7	171.9
12 ADDTL FEDERAL TRAN LOSSES	69.2	72.8	72.7	72.0	73.3	70.6	68.9	70.5	70.3	71.5	73.0	74.8
13 TOTAL FEDERAL FIRM LOAD	6196.1	6220.5	6270.1	6333.8	6382.7	6454.6	6527.5	6596.1	6658.4	6719.7	6763.2	6812.8
GENERATING PUBLIC UTILITIES												
14 SALES	3618.5	3693.8	3767.6	3842.8	3922.8	4000.2	4077.9	4147.3	4212.6	4274.7	4338.6	4408.7
15 TRANSMIS & DISTRIB LOSSES	231.6	236.4	241.1	245.9	251.1	256.0	261.0	265.4	269.6	273.6	277.7	282.2
16 SYSTEM LOAD	3850.1	3930.2	4008.7	4088.7	4173.8	4256.2	4338.9	4412.8	4482.2	4548.3	4616.2	4690.9
17 PUB RESIDENTL EXCHG--RPSA	336.5	345.3	348.9	349.9	355.1	361.8	366.5	370.5	376.4	382.8	389.2	395.3
18 PUB RESIDENTL EXCHG--ETCA	11.0	11.2	11.2	11.2	11.3	11.4	11.5	11.6	11.7	11.8	12.0	12.1
19 TOTAL PUBLIC SALES	6808.0	6949.7	7088.5	7229.9	7380.4	7526.0	7672.3	7802.8	7925.6	8042.5	8162.7	8294.6
INVESTOR-OWNED UTILITIES												
20 SALES	8518.5	8700.5	8888.0	9056.8	9239.0	9413.7	9593.1	9785.8	9983.4	10169.3	10343.1	10546.7
21 TRANSMIS & DISTRIB LOSSES	894.4	913.5	933.2	951.0	970.1	988.4	1007.3	1027.5	1048.3	1067.8	1086.0	1107.4
22 SYSTEM LOAD	9412.9	9614.0	9821.2	10007.8	10209.1	10402.1	10600.4	10813.4	11031.7	11237.1	11429.2	11654.1
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	18153.8	18428.5	18735.4	19039.5	19345.0	19667.0	19993.9	20318.8	20640.1	20944.3	21220.6	21538.3
26 TOTAL REGIONAL FIRM LOAD	19639.2	19944.8	20280.1	20610.4	20945.6	21293.0	21646.8	22002.3	22352.3	22685.0	22988.6	23337.8
27 DSI ALUM TQ LOAD	720.0	708.0	708.0	705.5	696.0	696.0	696.0	696.0	696.0	696.0	696.0	696.0
28 DSI NON-ALUM TQ LOAD	91.3	88.3	82.3	82.3	82.3	82.7	83.0	83.2	83.2	83.3	77.0	70.8
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	811.3	796.3	790.3	787.8	778.3	778.7	779.0	779.2	779.2	779.3	773.0	766.8
31 TOT DSI T Q TRANS LOSSES	21.2	20.8	20.6	20.5	20.3	20.3	20.3	20.3	20.3	20.3	20.2	20.0
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20471.7	20761.8	21090.9	21418.8	21744.2	22091.9	22446.2	22801.7	23151.8	23484.6	23781.7	24124.6

1991 FINAL COUNCIL PLAN -- MEDIUM HIGH CASE -- (91F1MHP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2003	2004	2005	2006	2007	2008	2009	2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	3947.1	4015.2	4084.4	4156.0	4221.2	4287.1	4357.3	4428.4
2 DISTRIBUTION LOSSES	165.8	168.6	171.5	174.6	177.3	180.1	183.0	186.0
3 SYSTEM LOAD	4112.9	4183.9	4255.9	4330.6	4398.5	4467.1	4540.3	4614.4
4 DSI ALUM FIRM LOAD	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0
5 DSI NON-ALUM FIRM LOAD	212.4	212.3	212.6	212.7	212.7	213.3	213.3	213.3
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2299.4	2299.3	2299.6	2299.7	2299.7	2300.3	2300.3	2300.3
8 TOT DSI FIRM TRANS LOSSES	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
9 BPA FEDERAL AGENCIES	150.5	151.1	151.8	152.5	153.0	153.7	154.2	154.8
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	173.6	175.5	177.4	179.4	181.2	183.0	185.0	186.9
12 ADDTL FEDERAL TRAN LOSSES	75.0	76.6	79.1	82.3	84.0	84.7	86.4	88.0
13 TOTAL FEDERAL FIRM LOAD	6879.2	6954.3	7031.8	7112.4	7184.4	7256.8	7334.2	7412.6
GENERATING PUBLIC UTILITIES								
14 SALES	4478.1	4555.4	4633.9	4715.2	4789.1	4863.8	4943.5	5024.2
15 TRANSMIS & DISTRIB LOSSES	286.6	291.5	296.6	301.8	306.5	311.3	316.4	321.5
16 SYSTEM LOAD	4764.7	4847.0	4930.4	5017.0	5095.6	5175.1	5259.9	5345.7
17 PUB RESIDENTL EXCHG--RPSA	401.3	407.9	414.4	421.6	427.5	433.7	440.1	447.6
18 PUB RESIDENTL EXCHG--ETCA	12.3	12.4	12.6	12.7	12.8	12.9	13.1	13.3
19 TOTAL PUBLIC SALES	8425.2	8570.7	8718.3	8871.2	9010.4	9150.9	9300.8	9452.6
INVESTOR-OWNED UTILITIES								
20 SALES	10746.6	10983.1	11236.6	11483.9	11704.9	11951.4	12204.7	12436.8
21 TRANSMIS & DISTRIB LOSSES	1128.4	1153.2	1179.8	1205.8	1229.0	1254.9	1281.5	1305.9
22 SYSTEM LOAD	11875.0	12136.3	12416.5	12689.7	12933.9	13206.3	13486.2	13742.6
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	21869.5	22252.1	22654.2	23055.2	23416.0	23804.2	24208.1	24592.6
26 TOTAL REGIONAL FIRM LOAD	23698.9	24117.6	24558.7	24999.0	25394.0	25818.2	26260.3	26680.9
27 DSI ALUM TQ LOAD	696.0	696.0	696.0	696.0	696.0	696.0	696.0	696.0
28 DSI NON-ALUM TQ LOAD	70.9	70.8	71.1	71.2	71.2	71.2	71.2	71.2
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	766.9	766.8	767.1	767.2	767.2	767.2	767.2	767.2
31 TOT DSI T Q TRANS LOSSES	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	24485.8	24904.4	25345.8	25786.2	26181.1	26605.4	27047.5	27468.1

1991 FINAL COUNCIL PLAN -- HIGH CASE -- (91F1HP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3298.2	3405.9	3499.3	3605.5	3716.0	3816.0	3920.9	4005.5	4091.6	4183.0	4272.8	4366.6
2 DISTRIBUTION LOSSES	138.5	143.0	147.0	151.4	156.1	160.3	164.7	168.2	171.8	175.7	179.5	183.4
3 SYSTEM LOAD	3436.7	3549.0	3646.3	3756.9	3872.1	3976.3	4085.6	4173.7	4263.4	4358.7	4452.3	4550.0
4 DSI ALUM FIRM LOAD	2160.5	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0
5 DSI NON-ALUM FIRM LOAD	316.8	315.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	278.5	241.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2477.3	2475.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2438.5	2401.0
8 TOT DSI FIRM TRANS LOSSES	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.6	63.6	62.6
9 BPA FEDERAL AGENCIES	144.6	143.1	141.6	142.7	143.8	144.8	145.7	146.5	147.4	148.3	149.1	149.9
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	160.3	163.2	165.7	168.7	171.7	174.5	177.4	179.7	182.1	184.6	186.2	187.7
12 ADDTL FEDERAL TRAN LOSSES	72.8	77.8	78.8	79.0	81.4	79.3	78.4	80.8	81.7	83.8	86.1	88.8
13 TOTAL FEDERAL FIRM LOAD	6359.0	6475.4	6575.6	6690.7	6812.3	6918.2	7030.5	7124.3	7218.1	7319.0	7379.8	7445.3
GENERATING PUBLIC UTILITIES												
14 SALES	3742.0	3864.2	3970.1	4090.6	4215.9	4329.4	4448.5	4544.4	4642.1	4745.8	4847.7	4954.1
15 TRANSMIS & DISTRIB LOSSES	239.5	247.3	254.1	261.8	269.8	277.1	284.7	290.8	297.1	303.7	310.2	317.1
16 SYSTEM LOAD	3981.4	4111.5	4224.2	4352.4	4485.8	4606.5	4733.2	4835.2	4939.2	5049.6	5157.9	5271.2
17 PUB RESIDENTL EXCHG--RPSA	348.0	361.2	367.7	372.4	381.7	391.6	399.8	406.0	414.7	425.0	434.9	444.2
18 PUB RESIDENTL EXCHG--ETCA	11.4	11.7	11.8	11.9	12.2	12.4	12.6	12.7	12.9	13.2	13.4	13.6
19 TOTAL PUBLIC SALES	7040.2	7270.1	7469.4	7696.1	7932.0	8145.4	8369.4	8549.9	8733.7	8928.9	9120.5	9320.8
INVESTOR-OWNED UTILITIES												
20 SALES	8821.0	9137.7	9422.8	9720.0	10036.8	10328.0	10633.7	10891.8	11200.9	11514.3	11811.3	12128.0
21 TRANSMIS & DISTRIB LOSSES	926.2	959.5	989.4	1020.6	1053.9	1084.4	1116.5	1143.6	1176.1	1209.0	1240.2	1273.4
22 SYSTEM LOAD	9747.2	10097.1	10412.2	10740.6	11090.6	11412.4	11750.2	12035.4	12377.0	12723.3	13051.5	13401.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	18730.3	19273.2	19757.0	20282.1	20835.9	21341.6	21872.2	22311.6	22805.5	23315.0	23767.1	24247.4
26 TOTAL REGIONAL FIRM LOAD	20267.6	20863.9	21392.0	21963.7	22568.7	23117.1	23693.9	24174.9	24714.3	25271.8	25769.3	26297.9
27 DSI ALUM TQ LOAD	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
28 DSI NON-ALUM TQ LOAD	105.8	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	92.5	80.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	825.8	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	812.5	800.0
31 TOT DSI T Q TRANS LOSSES	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.2	20.9
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	21114.9	21710.5	22238.5	22810.2	23415.2	23963.6	24540.4	25021.4	25560.8	26118.3	26603.0	27118.7

1991 FINAL COUNCIL PLAN -- HIGH CASE -- (91F1HP)
CALENDAR YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2003	2004	2005	2006	2007	2008	2009	2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	4457.5	4564.7	4677.8	4785.2	4890.1	4997.4	5105.2	5216.2
2 DISTRIBUTION LOSSES	187.2	191.7	196.5	201.0	205.4	209.9	214.4	219.1
3 SYSTEM LOAD	4644.7	4756.5	4874.3	4986.2	5095.5	5207.3	5319.6	5435.3
4 DSI ALUM FIRM LOAD	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0
5 DSI NON-ALUM FIRM LOAD	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0
8 TOT DSI FIRM TRANS LOSSES	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
9 BPA FEDERAL AGENCIES	150.5	151.1	151.8	152.5	153.0	153.7	154.2	154.8
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	190.2	193.2	196.3	199.3	202.2	205.1	208.1	211.1
12 ADDTL FEDERAL TRAN LOSSES	90.1	92.9	96.6	101.1	104.0	106.1	108.8	111.1
13 TOTAL FEDERAL FIRM LOAD	7544.3	7662.5	7787.9	7908.0	8023.7	8141.2	8259.9	8381.5
GENERATING PUBLIC UTILITIES								
14 SALES	5057.1	5178.9	5307.1	5429.0	5548.0	5669.7	5792.0	5918.0
15 TRANSMIS & DISTRIB LOSSES	323.7	331.4	339.7	347.5	355.1	362.9	370.7	378.7
16 SYSTEM LOAD	5380.8	5510.3	5646.8	5776.5	5903.1	6032.6	6162.7	6296.8
17 PUB RESIDENTL EXCHG--RPSA	453.2	463.7	474.6	485.5	495.3	505.5	515.7	527.2
18 PUB RESIDENTL EXCHG--ETCA	13.8	14.1	14.4	14.6	14.9	15.1	15.3	15.6
19 TOTAL PUBLIC SALES	9514.6	9743.6	9984.9	10214.3	10438.1	10667.1	10897.3	11134.2
INVESTOR-OWNED UTILITIES								
20 SALES	12413.0	12751.5	13138.0	13489.5	13839.8	14197.4	14555.4	14908.1
21 TRANSMIS & DISTRIB LOSSES	1303.4	1338.9	1379.5	1416.4	1453.2	1490.7	1528.3	1565.3
22 SYSTEM LOAD	13716.4	14090.4	14517.5	14905.9	15293.0	15688.1	16083.7	16473.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	24726.9	25295.0	25923.7	26505.2	27080.0	27667.2	28256.0	28846.3
26 TOTAL REGIONAL FIRM LOAD	26821.5	27443.2	28132.2	28770.4	29399.8	30041.8	30686.3	31331.7
27 DSI ALUM TQ LOAD	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
28 DSI NON-ALUM TQ LOAD	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
31 TOT DSI T Q TRANS LOSSES	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	27642.4	28264.1	28953.1	29591.3	30220.7	30862.7	31507.2	32152.6

1991 FINAL COUNCIL PLAN -- LOW CASE -- (91F1LP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	2986.0	2966.5	2962.6	2958.4	2958.7	2965.1	2975.8	2983.3	2984.6	2983.8	2984.6	2989.7
2 DISTRIBUTION LOSSES	125.4	124.6	124.4	124.3	124.3	124.5	125.0	125.3	125.4	125.3	125.4	125.6
3 SYSTEM LOAD	3111.5	3091.1	3087.0	3082.6	3082.9	3089.6	3100.8	3108.6	3110.0	3109.2	3109.9	3115.2
4 DSI ALUM FIRM LOAD	2055.5	1795.3	1596.8	1379.0	1107.6	1027.0	1027.0	1027.0	1027.0	992.9	770.7	549.0
5 DSI NON-ALUM FIRM LOAD	151.5	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2207.0	1895.3	1696.8	1479.0	1207.6	1127.0	1127.0	1127.0	1127.0	1092.9	870.7	649.0
8 TOT DSI FIRM TRANS LOSSES	57.4	49.4	44.2	38.5	31.4	29.4	29.4	29.4	29.4	28.5	22.7	16.9
9 BPA FEDERAL AGENCIES	143.8	144.5	141.7	142.1	143.3	144.3	145.2	146.1	147.0	147.8	148.7	149.5
10 USBR	67.2	67.3	67.3	67.2	67.3	67.3	67.4	67.5	67.5	67.5	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	144.6	136.0	130.6	124.9	117.8	116.0	116.3	116.5	116.6	115.7	110.0	104.3
12 ADDTL FEDERAL TRAN LOSSES	59.1	61.8	61.7	57.0	56.7	57.1	49.3	49.7	48.9	47.8	47.7	47.8
13 TOTAL FEDERAL FIRM LOAD	5733.1	5396.0	5185.1	4952.8	4675.5	4601.4	4606.1	4615.4	4616.9	4581.0	4354.6	4133.6
GENERATING PUBLIC UTILITIES												
14 SALES	3387.5	3365.6	3361.1	3356.4	3356.7	3364.1	3376.3	3384.7	3386.2	3385.3	3386.2	3391.9
15 TRANSMIS & DISTRIB LOSSES	216.8	215.4	215.1	214.8	214.8	215.3	216.1	216.6	216.7	216.7	216.7	217.1
16 SYSTEM LOAD	3604.3	3581.0	3576.2	3571.2	3571.6	3579.4	3592.4	3601.3	3602.9	3601.9	3602.9	3609.0
17 PUB RESIDENTL EXCHG--RPSA	316.3	313.8	314.4	306.6	304.8	304.5	304.8	303.0	302.5	302.5	304.0	304.3
18 PUB RESIDENTL EXCHG--ETCA	10.5	10.2	10.1	9.9	9.7	9.7	9.6	9.5	9.4	9.4	9.4	9.4
19 TOTAL PUBLIC SALES	6373.6	6332.0	6323.7	6314.7	6315.4	6329.2	6352.2	6368.0	6370.8	6369.1	6370.7	6381.6
INVESTOR-OWNED UTILITIES												
20 SALES	7973.1	7809.9	7834.2	7791.2	7781.3	7777.6	7760.1	7766.1	7772.9	7759.9	7768.2	7775.4
21 TRANSMIS & DISTRIB LOSSES	837.2	820.0	822.6	818.1	817.0	816.6	814.8	815.4	816.2	814.8	815.7	816.4
22 SYSTEM LOAD	8810.3	8629.9	8656.8	8609.2	8598.3	8594.3	8574.9	8581.5	8589.1	8574.7	8583.8	8591.8
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	16944.6	16429.1	16243.7	15974.3	15694.9	15625.5	15631.9	15654.6	15665.1	15617.3	15405.9	15203.2
26 TOTAL REGIONAL FIRM LOAD	18327.7	17786.9	17598.1	17313.2	17025.4	16955.0	16953.4	16978.2	16988.8	16937.6	16721.3	16514.5
27 DSI ALUM TQ LOAD	655.4	598.5	532.3	459.8	369.1	342.0	342.0	342.0	342.0	330.8	257.0	183.0
28 DSI NON-ALUM TQ LOAD	49.7	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	705.1	631.5	565.3	492.8	402.1	375.0	375.0	375.0	375.0	363.8	290.0	216.0
31 TOT DSI T Q TRANS LOSSES	18.4	16.4	14.7	12.8	10.4	9.8	9.8	9.8	9.8	9.5	7.6	5.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19051.1	18434.9	18178.1	17818.9	17437.9	17339.8	17338.2	17363.0	17373.6	17310.8	17018.8	16736.1

1991 FINAL COUNCIL PLAN -- LOW CASE -- (91F1LP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011
SMALL & NONGEN PUBLIC UTILS									
1 SALES	2995.9	3007.1	3024.6	3042.6	3058.5	3073.7	3090.2	3109.1	3119.3
2 DISTRIBUTION LOSSES	125.8	126.3	127.0	127.8	128.5	129.1	129.8	130.6	131.0
3 SYSTEM LOAD	3121.8	3133.4	3151.6	3170.4	3186.9	3202.8	3220.0	3239.7	3250.3
4 DSI ALUM FIRM LOAD	549.0	549.0	549.0	549.0	549.0	549.0	549.0	549.0	549.0
5 DSI NON-ALUM FIRM LOAD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	649.0	649.0	649.0	649.0	649.0	649.0	649.0	649.0	649.0
8 TOT DSI FIRM TRANS LOSSES	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
9 BPA FEDERAL AGENCIES	150.2	150.8	151.5	152.2	152.8	153.4	153.9	154.5	155.1
10 USBR	67.7	67.8	67.9	67.9	68.0	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	104.5	104.9	105.4	105.9	106.3	106.8	107.2	107.8	108.1
12 ADDTL FEDERAL TRAN LOSSES	47.3	46.8	47.2	49.3	50.4	50.0	49.3	50.4	50.4
13 TOTAL FEDERAL FIRM LOAD	4140.6	4152.7	4172.5	4194.7	4213.4	4229.9	4247.6	4269.5	4281.0
GENERATING PUBLIC UTILITIES									
14 SALES	3399.1	3411.8	3431.6	3452.0	3470.0	3487.4	3506.1	3527.5	3539.0
15 TRANSMIS & DISTRIB LOSSES	217.5	218.4	219.6	220.9	222.1	223.2	224.4	225.8	226.5
16 SYSTEM LOAD	3616.6	3630.2	3651.2	3673.0	3692.1	3710.6	3730.5	3753.3	3765.5
17 PUB RESIDENTL EXCHG--RPSA	304.7	305.6	307.0	308.7	310.0	311.1	312.4	313.9	315.6
18 PUB RESIDENTL EXCHG--ETCA	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
19 TOTAL PUBLIC SALES	6395.0	6419.0	6456.2	6494.6	6528.5	6561.1	6596.3	6636.6	6658.3
INVESTOR-OWNED UTILITIES									
20 SALES	7792.8	7813.2	7851.2	7891.0	7929.8	7964.7	8018.1	8060.8	8118.2
21 TRANSMIS & DISTRIB LOSSES	818.2	820.4	824.4	828.6	832.6	836.3	841.9	846.4	852.4
22 SYSTEM LOAD	8611.1	8633.5	8675.6	8719.6	8762.5	8800.9	8860.0	8907.2	8970.7
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	15234.8	15279.7	15355.8	15434.7	15508.1	15576.1	15665.4	15749.0	15828.8
26 TOTAL REGIONAL FIRM LOAD	16548.2	16596.4	16679.3	16767.2	16848.0	16921.4	17018.0	17109.9	17197.2
27 DSI ALUM TQ LOAD	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
28 DSI NON-ALUM TQ LOAD	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
31 TOT DSI T Q TRANS LOSSES	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	16769.9	16818.0	16901.0	16988.9	17069.6	17143.1	17239.6	17331.5	17418.8

1991 FINAL COUNCIL PLAN -- MEDIUM LOW CASE -- (91F1MLP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3043.4	3060.2	3084.4	3108.8	3137.4	3169.1	3204.3	3234.8	3259.4	3282.8	3305.9	3331.7
2 DISTRIBUTION LOSSES	127.8	128.5	129.5	130.6	131.8	133.1	134.6	135.9	136.9	137.9	138.8	139.9
3 SYSTEM LOAD	3171.2	3188.7	3213.9	3239.3	3269.1	3302.2	3338.9	3370.7	3396.3	3420.6	3444.7	3471.7
4 DSI ALUM FIRM LOAD	2072.0	1904.7	1797.8	1654.3	1491.5	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0
5 DSI NON-ALUM FIRM LOAD	184.7	171.3	139.0	139.3	139.4	140.1	140.3	140.9	141.1	141.6	142.1	142.1
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2256.7	2075.9	1936.8	1793.5	1630.9	1579.1	1579.3	1579.9	1580.1	1580.6	1581.1	1581.1
8 TOT DSI FIRM TRANS LOSSES	58.7	54.1	50.5	46.7	42.4	41.2	41.2	41.2	41.2	41.2	41.2	41.2
9 BPA FEDERAL AGENCIES	143.8	144.5	141.7	142.1	143.3	144.3	145.2	146.1	147.0	147.8	148.7	149.5
10 USBR	67.2	67.3	67.3	67.2	67.3	67.3	67.4	67.5	67.5	67.5	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	147.5	143.3	140.3	137.2	133.7	133.4	134.4	135.2	135.9	136.6	137.3	138.0
12 ADDTL FEDERAL TRAN LOSSES	61.7	65.4	66.3	62.2	62.8	63.9	56.7	57.7	57.3	57.0	57.5	58.1
13 TOTAL FEDERAL FIRM LOAD	5848.1	5685.2	5566.3	5441.6	5307.2	5290.2	5321.9	5357.1	5384.1	5410.2	5436.9	5466.1
GENERATING PUBLIC UTILITIES												
14 SALES	3452.9	3472.1	3499.5	3527.2	3559.7	3595.7	3635.7	3670.2	3698.1	3724.6	3750.8	3780.2
15 TRANSMIS & DISTRIB LOSSES	221.0	222.2	224.0	225.7	227.8	230.1	232.7	234.9	236.7	238.4	240.0	241.9
16 SYSTEM LOAD	3673.9	3694.3	3723.5	3752.9	3787.5	3825.8	3868.4	3905.1	3934.8	3962.9	3990.9	4022.1
17 PUB RESIDENTL EXCHG--RPSA	322.3	323.7	327.4	322.2	323.2	325.4	328.2	328.5	330.3	332.8	336.7	339.1
18 PUB RESIDENTL EXCHG--ETCA	10.6	10.5	10.5	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.4	10.4
19 TOTAL PUBLIC SALES	6496.3	6532.4	6583.9	6636.0	6697.1	6764.8	6840.0	6905.0	6957.5	7007.3	7056.7	7111.9
INVESTOR-OWNED UTILITIES												
20 SALES	8092.1	8029.8	8131.6	8165.7	8220.1	8274.9	8322.5	8394.3	8468.8	8526.3	8606.3	8681.6
21 TRANSMIS & DISTRIB LOSSES	849.7	843.1	853.8	857.4	863.1	868.9	873.9	881.4	889.2	895.3	903.7	911.6
22 SYSTEM LOAD	8941.7	8872.9	8985.4	9023.1	9083.2	9143.8	9196.4	9275.7	9358.0	9421.6	9509.9	9593.2
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17236.0	17029.8	17041.3	16984.6	16938.7	17010.5	17134.4	17272.8	17400.8	17509.6	17640.3	17771.8
26 TOTAL REGIONAL FIRM LOAD	18643.7	18432.5	18455.1	18397.7	18357.9	18439.8	18566.6	18717.9	18856.9	18974.8	19117.7	19261.3
27 DSI ALUM TQ LOAD	660.9	634.9	599.3	551.6	497.5	480.0	480.0	480.0	480.0	480.0	480.0	480.0
28 DSI NON-ALUM TQ LOAD	60.9	57.2	46.3	46.3	46.4	46.7	46.8	47.2	47.2	47.3	47.3	47.3
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	721.8	692.1	645.5	597.9	543.9	526.7	526.8	527.2	527.2	527.3	527.3	527.3
31 TOT DSI T Q TRANS LOSSES	18.8	18.0	16.8	15.6	14.2	13.7	13.7	13.7	13.7	13.8	13.8	13.8
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19384.3	19142.6	19117.5	19011.2	18916.0	18980.2	19107.2	19258.8	19397.8	19515.8	19658.7	19802.3

1991 FINAL COUNCIL PLAN -- MEDIUM LOW CASE -- (91F1MLP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011
SMALL & NONGEN PUBLIC UTILS									
1 SALES	3358.3	3390.4	3430.7	3472.9	3514.0	3555.0	3595.4	3637.3	3659.0
2 DISTRIBUTION LOSSES	141.0	142.4	144.1	145.9	147.6	149.3	151.0	152.8	153.7
3 SYSTEM LOAD	3499.3	3532.8	3574.8	3618.8	3661.6	3704.3	3746.5	3790.1	3812.7
4 DSI ALUM FIRM LOAD	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0
5 DSI NON-ALUM FIRM LOAD	142.1	142.1	142.2	142.3	142.3	142.3	142.8	142.8	142.8
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	1581.1	1581.1	1581.2	1581.3	1581.3	1581.3	1581.8	1581.8	1581.8
8 TOT DSI FIRM TRANS LOSSES	41.2	41.2	41.2	41.2	41.2	41.2	41.3	41.3	41.3
9 BPA FEDERAL AGENCIES	150.2	150.8	151.5	152.2	152.8	153.4	153.9	154.5	155.1
10 USBR	67.7	67.8	67.9	67.9	68.0	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	138.8	139.7	140.8	142.0	143.1	144.3	145.4	146.6	147.2
12 ADDTL FEDERAL TRAN LOSSES	58.1	58.2	59.0	62.0	63.6	63.9	63.8	65.8	65.8
13 TOTAL FEDERAL FIRM LOAD	5495.3	5530.3	5575.1	5624.1	5670.3	5715.0	5759.5	5806.9	5830.7
GENERATING PUBLIC UTILITIES									
14 SALES	3810.3	3846.8	3892.6	3940.5	3987.1	4033.5	4079.5	4127.0	4151.3
15 TRANSMIS & DISTRIB LOSSES	243.9	246.2	249.1	252.2	255.2	258.1	261.1	264.1	265.7
16 SYSTEM LOAD	4054.1	4093.0	4141.7	4192.7	4242.3	4291.7	4340.6	4391.1	4416.9
17 PUB RESIDENTL EXCHG--RPSA	341.5	344.6	348.3	352.4	356.2	359.8	363.4	367.2	370.3
18 PUB RESIDENTL EXCHG--ETCA	10.5	10.5	10.6	10.6	10.7	10.8	10.8	10.9	10.9
19 TOTAL PUBLIC SALES	7168.5	7237.2	7323.3	7413.4	7501.1	7588.5	7674.9	7764.3	7810.3
INVESTOR-OWNED UTILITIES									
20 SALES	8770.2	8867.6	8992.9	9121.6	9247.7	9371.9	9512.1	9635.3	9740.7
21 TRANSMIS & DISTRIB LOSSES	920.9	931.1	944.2	957.8	971.0	984.0	998.8	1011.7	1022.8
22 SYSTEM LOAD	9691.0	9798.6	9937.1	10079.4	10218.7	10356.0	10510.9	10647.0	10763.5
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17917.8	18084.5	18296.8	18516.4	18730.9	18943.0	19170.9	19384.1	19536.0
26 TOTAL REGIONAL FIRM LOAD	19420.4	19602.0	19834.0	20076.2	20311.3	20542.7	20790.9	21025.0	21191.1
27 DSI ALUM TQ LOAD	480.0	480.0	480.0	480.0	480.0	480.0	480.0	480.0	480.0
28 DSI NON-ALUM TQ LOAD	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	527.3	527.3	527.3	527.3	527.3	527.3	527.3	527.3	527.3
31 TOT DSI T Q TRANS LOSSES	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19961.4	20143.0	20375.1	20617.2	20852.4	21083.8	21332.0	21566.1	21732.2

1991 FINAL COUNCIL PLAN -- MEDIUM CASE -- (91F2MP) (M-TERM MRG=1/95)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3099.0	3149.5	3186.7	3230.4	3273.7	3313.5	3355.6	3396.5	3437.2	3476.7	3514.3	3553.9
2 DISTRIBUTION LOSSES	130.2	132.3	133.8	135.7	137.5	139.2	140.9	142.7	144.4	146.0	147.6	149.3
3 SYSTEM LOAD	3229.2	3281.8	3320.5	3366.1	3411.2	3452.6	3496.5	3539.2	3581.6	3622.8	3661.9	3703.1
4 DSI ALUM FIRM LOAD	2182.5	2142.0	2079.1	2016.3	1975.9	1959.3	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0
5 DSI NON-ALUM FIRM LOAD	205.3	242.3	178.8	179.2	179.3	180.2	181.0	181.5	182.4	183.3	183.8	183.9
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2387.8	2384.3	2257.8	2195.4	2155.2	2139.4	2132.0	2132.5	2133.4	2134.3	2134.8	2134.9
8 TOT DSI FIRM TRANS LOSSES	62.3	62.2	58.9	57.2	56.2	55.8	55.6	55.6	55.6	55.7	55.7	55.7
9 BPA FEDERAL AGENCIES	143.8	144.5	141.7	142.1	143.3	144.3	145.2	146.1	147.0	147.8	148.7	149.5
10 USBR	67.2	67.3	67.3	67.2	67.3	67.3	67.4	67.5	67.5	67.5	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	152.6	153.8	151.5	151.0	151.2	151.9	152.9	154.1	155.2	156.4	157.4	158.5
12 ADDTL FEDERAL TRAN LOSSES	64.3	68.9	70.0	66.5	67.2	68.6	61.7	63.4	63.4	62.5	63.5	65.0
13 TOTAL FEDERAL FIRM LOAD	6044.9	6100.5	6008.9	5988.4	5995.4	6024.2	6055.8	6102.7	6148.1	6191.4	6234.0	6278.7
GENERATING PUBLIC UTILITIES												
14 SALES	3560.1	3651.1	3710.3	3754.7	3793.4	3833.9	3882.7	3930.0	3977.1	4022.8	4066.3	4112.1
15 TRANSMIS & DISTRIB LOSSES	227.8	233.7	237.5	240.3	242.8	245.4	248.5	251.5	254.5	257.5	260.2	263.2
16 SYSTEM LOAD	3787.9	3884.8	3947.8	3995.0	4036.1	4079.3	4131.2	4181.5	4231.6	4280.3	4326.5	4375.2
17 PUB RESIDENTL EXCHG--RPSA	328.1	333.2	338.2	334.9	337.3	340.3	343.6	345.0	348.4	352.4	357.9	361.7
18 PUB RESIDENTL EXCHG--ETCA	10.8	10.8	10.9	10.8	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.1
19 TOTAL PUBLIC SALES	6659.1	6800.7	6897.0	6985.1	7067.1	7147.4	7238.3	7326.6	7414.3	7499.6	7580.6	7665.9
INVESTOR-OWNED UTILITIES												
20 SALES	8263.4	8361.8	8590.6	8703.9	8826.9	8941.5	9042.2	9178.6	9323.0	9447.8	9586.6	9716.3
21 TRANSMIS & DISTRIB LOSSES	867.7	878.0	902.0	913.9	926.8	938.9	949.4	963.7	978.9	992.0	1006.6	1020.2
22 SYSTEM LOAD	9131.1	9239.8	9492.6	9617.8	9753.7	9880.4	9991.7	10142.3	10301.9	10439.8	10593.1	10736.5
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17701.3	17938.5	18134.4	18273.8	18439.7	18620.0	18805.2	19031.2	19265.1	19477.0	19698.3	19914.4
26 TOTAL REGIONAL FIRM LOAD	19143.9	19405.2	19629.2	19781.2	19965.2	20163.9	20358.7	20606.6	20861.6	21091.5	21333.6	21570.5
27 DSI ALUM TQ LOAD	697.4	714.0	693.1	671.9	658.5	652.9	650.0	650.0	650.0	650.0	650.0	650.0
28 DSI NON-ALUM TQ LOAD	84.4	80.8	59.7	59.8	59.8	60.1	60.4	60.4	60.9	61.2	61.4	61.4
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	781.8	794.8	752.8	731.8	718.3	713.0	710.4	710.4	710.9	711.2	711.4	711.4
31 TOT DSI T Q TRANS LOSSES	20.4	20.7	19.6	19.1	18.7	18.6	18.5	18.5	18.5	18.5	18.6	18.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19946.2	20220.7	20401.6	20532.0	20702.2	20895.5	21087.6	21335.6	21591.0	21821.2	22063.6	22300.5

1991 FINAL COUNCIL PLAN -- MEDIUM CASE -- (91F2MP) (M-TERM MRG=1/95)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011
SMALL & NONGEN PUBLIC UTILS									
1 SALES	3595.2	3638.4	3686.8	3737.3	3785.7	3833.1	3879.5	3924.4	3946.7
2 DISTRIBUTION LOSSES	151.0	152.8	154.8	157.0	159.0	161.0	162.9	164.8	165.8
3 SYSTEM LOAD	3746.2	3791.2	3841.6	3894.3	3944.6	3994.1	4042.4	4089.2	4112.4
4 DSI ALUM FIRM LOAD	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0
5 DSI NON-ALUM FIRM LOAD	184.1	184.1	184.3	184.5	184.6	185.0	185.1	185.1	185.1
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2135.1	2135.1	2135.3	2135.5	2135.6	2136.0	2136.1	2136.1	2136.1
8 TOT DSI FIRM TRANS LOSSES	55.7	55.7	55.7	55.7	55.7	55.7	55.7	55.7	55.7
9 BPA FEDERAL AGENCIES	150.2	150.8	151.5	152.2	152.8	153.4	153.9	154.5	155.1
10 USBR	67.7	67.8	67.9	67.9	68.0	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	159.7	160.9	162.3	163.7	165.0	166.3	167.6	168.9	169.5
12 ADDTL FEDERAL TRAN LOSSES	65.0	65.5	66.7	69.7	71.7	72.1	72.3	74.4	74.4
13 TOTAL FEDERAL FIRM LOAD	6324.0	6371.3	6425.3	6483.2	6537.7	6589.9	6640.5	6691.2	6715.6
GENERATING PUBLIC UTILITIES									
14 SALES	4159.9	4209.9	4265.9	4324.4	4380.3	4435.2	4488.8	4540.8	4566.2
15 TRANSMIS & DISTRIB LOSSES	266.2	269.4	273.0	276.8	280.3	283.8	287.3	290.6	292.2
16 SYSTEM LOAD	4426.1	4479.3	4539.0	4601.1	4660.6	4719.0	4776.1	4831.4	4858.4
17 PUB RESIDENTL EXCHG--RPSA	365.6	369.8	374.3	379.2	383.7	388.0	392.1	396.2	399.4
18 PUB RESIDENTL EXCHG--ETCA	11.2	11.3	11.4	11.5	11.5	11.6	11.7	11.7	11.8
19 TOTAL PUBLIC SALES	7755.0	7848.2	7952.7	8061.7	8165.9	8268.3	8368.3	8465.2	8512.9
INVESTOR-OWNED UTILITIES									
20 SALES	9865.8	10010.9	10173.3	10333.3	10486.1	10643.0	10820.4	10962.7	11078.2
21 TRANSMIS & DISTRIB LOSSES	1035.9	1051.1	1068.2	1085.0	1101.0	1117.5	1136.1	1151.1	1163.2
22 SYSTEM LOAD	10901.7	11062.0	11241.4	11418.3	11587.1	11760.5	11956.5	12113.8	12241.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	20153.9	20392.8	20660.7	20930.6	21188.3	21448.7	21726.8	21966.6	22130.4
26 TOTAL REGIONAL FIRM LOAD	21831.8	22092.6	22385.7	22682.6	22965.4	23249.5	23553.1	23316.4	23995.4
27 DSI ALUM TQ LOAD	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
28 DSI NON-ALUM TQ LOAD	61.4	61.4	61.5	61.5	61.5	61.5	61.5	61.5	61.5
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	711.4	711.4	711.5	711.5	711.5	711.5	711.5	711.5	711.5
31 TOT DSI T Q TRANS LOSSES	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	22561.8	22822.5	23115.8	23412.7	23695.5	23979.6	24283.1	24546.4	24725.5

1991 FINAL COUNCIL PLAN -- MEDIUM HIGH CASE -- (91F1MHP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3140.3	3223.2	3288.9	3354.5	3422.9	3492.3	3560.7	3625.4	3684.8	3740.9	3796.4	3855.5
2 DISTRIBUTION LOSSES	131.9	135.4	138.1	140.9	143.8	146.7	149.5	152.3	154.8	157.1	159.4	161.9
3 SYSTEM LOAD	3272.2	3358.6	3427.0	3495.4	3566.7	3639.0	3710.2	3777.7	3839.5	3898.0	3955.9	4017.5
4 DSI ALUM FIRM LOAD	2182.5	2142.0	2123.0	2123.0	2097.5	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0
5 DSI NON-ALUM FIRM LOAD	239.5	278.3	246.9	247.2	247.3	248.0	248.3	248.8	249.1	249.4	249.8	212.2
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2422.0	2420.3	2369.9	2370.2	2344.8	2335.0	2335.3	2335.8	2336.1	2336.4	2336.8	2299.2
8 TOT DSI FIRM TRANS LOSSES	63.2	63.1	61.8	61.8	61.1	60.9	60.9	60.9	60.9	60.9	60.9	60.0
9 BPA FEDERAL AGENCIES	143.8	144.5	141.7	142.1	143.3	144.3	145.2	146.1	147.0	147.8	148.7	149.5
10 USBR	67.2	67.3	67.3	67.2	67.3	67.3	67.4	67.5	67.5	67.5	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	154.6	156.8	157.2	159.0	160.3	162.0	163.9	165.7	167.3	168.9	170.4	171.1
12 ADDTL FEDERAL TRAN LOSSES	66.8	72.1	73.9	71.3	72.7	74.1	67.9	70.1	70.4	70.8	72.2	74.1
13 TOTAL FEDERAL FIRM LOAD	6126.6	6219.6	6237.0	6305.3	6355.0	6421.7	6489.9	6562.8	6627.7	6689.4	6751.6	6779.0
GENERATING PUBLIC UTILITIES												
14 SALES	3563.6	3657.3	3731.8	3806.3	3884.0	3962.7	4040.2	4113.7	4180.9	4244.6	4307.6	4374.7
15 TRANSMIS & DISTRIB LOSSES	228.1	234.1	238.8	243.6	248.6	253.6	258.6	263.3	267.6	271.6	275.7	280.0
16 SYSTEM LOAD	3791.7	3891.4	3970.7	4050.0	4132.6	4216.3	4298.8	4376.9	4448.5	4516.2	4583.3	4654.7
17 PUB RESIDENTL EXCHG--RPSA	332.5	341.0	349.1	347.7	352.6	358.6	364.6	368.2	373.5	379.2	386.6	392.4
18 PUB RESIDENTL EXCHG--ETCA	10.9	11.1	11.2	11.2	11.2	11.4	11.5	11.6	11.6	11.7	11.9	12.1
19 TOTAL PUBLIC SALES	6703.9	6880.5	7020.7	7160.9	7306.9	7454.9	7600.9	7739.1	7865.7	7985.4	8104.0	8230.2
INVESTOR-OWNED UTILITIES												
20 SALES	8374.6	8549.3	8804.7	8969.9	9153.5	9334.6	9498.6	9692.9	9893.3	10068.4	10258.1	10444.0
21 TRANSMIS & DISTRIB LOSSES	879.3	897.7	924.5	941.8	961.1	980.1	997.3	1017.7	1038.8	1057.2	1077.1	1096.6
22 SYSTEM LOAD	9253.9	9446.9	9729.2	9911.8	10114.6	10314.7	10495.9	10710.6	10932.1	11125.5	11335.2	11540.7
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17891.5	18241.9	18584.4	18890.4	19195.8	19516.2	19827.4	20161.3	20489.5	20785.6	21095.3	21370.6
26 TOTAL REGIONAL FIRM LOAD	19352.2	19737.9	20116.9	20447.0	20782.2	21132.7	21464.6	21830.3	22188.4	22511.2	22850.1	23154.4
27 DSI ALUM TQ LOAD	697.4	714.0	708.0	708.0	699.5	696.0	696.0	696.0	696.0	696.0	696.0	696.0
28 DSI NON-ALUM TQ LOAD	79.2	92.6	82.3	82.3	82.3	82.6	82.8	83.0	83.2	83.3	83.3	70.8
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	776.6	806.6	790.3	790.3	781.8	778.6	778.8	779.0	779.2	779.3	779.3	766.8
31 TOT DSI T Q TRANS LOSSES	20.3	21.0	20.6	20.6	20.4	20.3	20.3	20.3	20.3	20.3	20.3	20.0
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20149.1	20565.6	20927.8	21257.9	21584.4	21931.6	22263.8	22629.7	22987.8	23310.8	23649.7	23941.1

1991 FINAL COUNCIL PLAN -- MEDIUM HIGH CASE -- (91F1MHP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011
SMALL & NONGEN PUBLIC UTILS									
1 SALES	3917.0	3981.7	4050.4	4120.8	4189.2	4254.7	4322.8	4393.4	4428.4
2 DISTRIBUTION LOSSES	164.5	167.2	170.1	173.1	175.9	178.7	181.6	184.5	186.0
3 SYSTEM LOAD	4081.5	4149.0	4220.5	4293.9	4365.1	4433.4	4504.3	4578.0	4614.4
4 DSI ALUM FIRM LOAD	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0
5 DSI NON-ALUM FIRM LOAD	212.4	212.3	212.5	212.6	212.7	213.0	213.3	213.3	213.3
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2299.4	2299.3	2299.5	2299.6	2299.7	2300.0	2300.3	2300.3	2300.3
8 TOT DSI FIRM TRANS LOSSES	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
9 BPA FEDERAL AGENCIES	150.2	150.8	151.5	152.2	152.8	153.4	153.9	154.5	155.1
10 USBR	67.7	67.8	67.9	67.9	68.0	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	172.8	174.6	176.5	178.5	180.3	182.2	184.1	186.0	187.0
12 ADDTL FEDERAL TRAN LOSSES	74.9	75.7	77.5	81.1	83.5	84.4	85.2	88.0	88.0
13 TOTAL FEDERAL FIRM LOAD	6846.7	6917.2	6993.4	7073.2	7149.3	7221.3	7295.8	7374.9	7412.9
GENERATING PUBLIC UTILITIES									
14 SALES	4444.5	4517.9	4595.8	4675.8	4753.3	4827.6	4904.9	4985.1	5024.2
15 TRANSMIS & DISTRIB LOSSES	284.4	289.1	294.1	299.2	304.2	309.0	313.9	319.0	321.5
16 SYSTEM LOAD	4728.9	4807.1	4890.0	4975.0	5057.5	5136.6	5218.8	5304.1	5345.7
17 PUB RESIDENTL EXCHG--RPSA	398.4	404.7	411.2	418.2	424.6	430.6	437.0	443.5	448.1
18 PUB RESIDENTL EXCHG--ETCA	12.2	12.3	12.5	12.6	12.8	12.9	13.0	13.1	13.3
19 TOTAL PUBLIC SALES	8361.5	8499.7	8646.2	8796.6	8942.5	9082.3	9227.6	9378.5	9452.6
INVESTOR-OWNED UTILITIES									
20 SALES	10652.5	10869.4	11115.5	11363.5	11596.7	11823.7	12088.7	12323.5	12488.3
21 TRANSMIS & DISTRIB LOSSES	1118.5	1141.3	1167.1	1193.2	1217.6	1241.5	1269.3	1294.0	1311.3
22 SYSTEM LOAD	11771.0	12010.6	12282.6	12556.7	12814.4	13065.2	13358.0	13617.5	13799.6
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	21711.4	22067.0	22460.5	22859.8	23239.6	23607.4	24018.5	24404.9	24644.5
26 TOTAL REGIONAL FIRM LOAD	23526.6	23914.9	24346.0	24784.9	25201.2	25603.1	26052.6	26476.5	26738.3
27 DSI ALUM TQ LOAD	696.0	696.0	696.0	696.0	696.0	696.0	696.0	696.0	696.0
28 DSI NON-ALUM TQ LOAD	70.9	70.8	71.0	71.1	71.2	71.2	71.2	71.2	71.2
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	766.9	766.8	767.0	767.1	767.2	767.2	767.2	767.2	767.2
31 TOT DSI T Q TRANS LOSSES	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	24313.5	24701.8	25133.0	25572.0	25988.4	26390.3	26839.7	27263.6	27525.4

1991 FINAL COUNCIL PLAN -- HIGH CASE -- (91F1HP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3209.5	3353.0	3453.4	3553.3	3661.7	3766.9	3869.4	3963.9	4049.3	4138.1	4228.7	4320.5
2 DISTRIBUTION LOSSES	134.8	140.8	145.0	149.2	153.8	158.2	162.5	166.5	170.1	173.8	177.6	181.5
3 SYSTEM LOAD	3344.3	3493.8	3598.4	3702.5	3815.5	3925.1	4031.9	4130.4	4219.3	4311.9	4406.3	4502.0
4 DSI ALUM FIRM LOAD	2182.5	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0
5 DSI NON-ALUM FIRM LOAD	261.3	314.3	315.8	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	241.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2443.8	2474.3	2475.8	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2401.0
8 TOT DSI FIRM TRANS LOSSES	63.8	64.5	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.6	62.6
9 BPA FEDERAL AGENCIES	143.8	144.5	141.7	142.1	143.3	144.3	145.2	146.1	147.0	147.8	148.7	149.5
10 USBR	67.2	67.3	67.3	67.2	67.3	67.3	67.4	67.5	67.5	67.5	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	157.1	161.8	164.5	167.3	170.3	173.2	176.0	178.6	181.0	183.4	185.9	186.5
12 ADDTL FEDERAL TRAN LOSSES	70.1	76.3	79.5	77.9	80.5	82.5	76.9	80.0	81.3	82.7	84.9	87.8
13 TOTAL FEDERAL FIRM LOAD	6226.2	6418.0	6527.2	6633.1	6752.8	6868.3	6973.4	7078.6	7172.1	7269.4	7369.4	7394.4
GENERATING PUBLIC UTILITIES												
14 SALES	3642.6	3804.9	3918.7	4032.2	4155.2	4274.4	4390.7	4497.9	4594.7	4695.5	4798.3	4902.5
15 TRANSMIS & DISTRIB LOSSES	233.1	243.5	250.8	258.1	265.9	273.6	281.0	287.9	294.1	300.5	307.1	313.8
16 SYSTEM LOAD	3875.8	4048.4	4169.5	4290.2	4421.1	4548.0	4671.7	4785.7	4888.8	4996.0	5105.4	5216.3
17 PUB RESIDENTL EXCHG--RPSA	339.8	354.7	366.5	368.3	377.2	386.8	396.3	402.6	410.4	419.5	430.7	439.7
18 PUB RESIDENTL EXCHG--ETCA	11.1	11.5	11.7	11.8	12.0	12.3	12.5	12.6	12.8	13.0	13.3	13.5
19 TOTAL PUBLIC SALES	6852.1	7157.9	7372.1	7585.5	7816.9	8041.3	8260.1	8461.8	8644.0	8833.6	9027.0	9223.1
INVESTOR-OWNED UTILITIES												
20 SALES	8569.6	8918.2	9292.1	9569.9	9885.6	10192.4	10476.6	10766.9	11057.0	11349.6	11665.9	11969.4
21 TRANSMIS & DISTRIB LOSSES	899.8	936.4	975.7	1004.8	1038.0	1070.2	1100.0	1130.5	1161.0	1191.7	1224.9	1256.8
22 SYSTEM LOAD	9469.4	9854.6	10267.8	10574.7	10923.5	11262.6	11576.6	11897.4	12217.9	12541.4	12890.8	13226.2
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	18256.4	18942.1	19529.0	20020.8	20569.0	21101.3	21605.4	22098.3	22571.4	23054.6	23565.2	23990.7
26 TOTAL REGIONAL FIRM LOAD	19751.4	20500.9	21144.5	21678.0	22277.4	22858.9	23401.8	23941.7	24458.8	24986.8	25545.6	26016.9
27 DSI ALUM TQ LOAD	697.4	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
28 DSI NON-ALUM TQ LOAD	86.4	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	80.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	783.8	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	800.0
31 TOT DSI T Q TRANS LOSSES	20.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	20.9
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20555.7	21347.5	21991.0	22524.5	23124.0	23705.4	24248.3	24788.2	25305.3	25833.3	26392.2	26837.8

1991 FINAL COUNCIL PLAN -- HIGH CASE -- (91F1HP)
OPERATING YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011
SMALL & NONGEN PUBLIC UTILS									
1 SALES	4412.8	4512.0	4622.2	4732.4	4838.6	4944.7	5052.2	5161.6	5216.2
2 DISTRIBUTION LOSSES	185.3	189.5	194.1	198.8	203.2	207.7	212.2	216.8	219.1
3 SYSTEM LOAD	4598.1	4701.5	4816.3	4931.2	5041.8	5152.3	5264.4	5378.4	5435.3
4 DSI ALUM FIRM LOAD	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0
5 DSI NON-ALUM FIRM LOAD	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0
8 TOT DSI FIRM TRANS LOSSES	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
9 BPA FEDERAL AGENCIES	150.2	150.8	151.5	152.2	152.8	153.4	153.9	154.5	155.1
10 USBR	67.7	67.8	67.9	67.9	68.0	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	189.1	191.8	194.8	197.9	200.8	203.7	206.7	209.7	211.2
12 ADDTL FEDERAL TRAN LOSSES	89.5	91.5	94.5	99.3	102.9	105.1	107.2	111.1	111.1
13 TOTAL FEDERAL FIRM LOAD	7495.7	7604.4	7726.0	7849.4	7967.2	8083.5	8201.2	8322.9	8381.8
GENERATING PUBLIC UTILITIES									
14 SALES	5007.2	5119.9	5244.9	5369.9	5490.3	5610.7	5732.7	5856.9	5918.0
15 TRANSMIS & DISTRIB LOSSES	320.5	327.7	335.7	343.7	351.4	359.1	366.9	374.8	378.7
16 SYSTEM LOAD	5327.7	5447.5	5580.6	5713.6	5841.7	5969.8	6099.6	6231.8	6296.8
17 PUB RESIDENTL EXCHG--RPSA	448.8	458.6	469.2	480.2	490.5	500.5	510.7	521.1	527.8
18 PUB RESIDENTL EXCHG--ETCA	13.7	13.9	14.2	14.5	14.7	14.9	15.2	15.4	15.6
19 TOTAL PUBLIC SALES	9420.0	9631.8	9867.2	10102.3	10328.9	10555.4	10784.9	11018.6	11134.2
INVESTOR-OWNED UTILITIES									
20 SALES	12277.8	12588.1	12952.2	13318.2	13668.3	14014.1	14389.6	14735.9	14969.9
21 TRANSMIS & DISTRIB LOSSES	1289.2	1321.7	1360.0	1398.4	1435.2	1471.5	1510.9	1547.3	1571.8
22 SYSTEM LOAD	13566.9	13909.9	14312.2	14716.6	15103.5	15485.5	15900.5	16283.1	16541.8
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	24496.8	25019.6	25619.7	26221.7	26798.9	27371.8	27977.5	28558.1	28908.4
26 TOTAL REGIONAL FIRM LOAD	26570.2	27141.8	27798.8	28459.7	29092.4	29718.8	30381.4	31017.8	31400.4
27 DSI ALUM TQ LOAD	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
28 DSI NON-ALUM TQ LOAD	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
31 TOT DSI T Q TRANS LOSSES	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	27391.1	27962.6	28619.6	29280.5	29913.3	30539.7	31202.2	31838.6	32221.2

1991 FINAL COUNCIL PLAN -- LOW CASE -- (91F1LP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	2977.6	2965.7	2961.5	2957.5	2959.7	2967.1	2978.9	2983.8	2984.7	2983.4	2985.4	2991.2
2 DISTRIBUTION LOSSES	125.1	124.6	124.4	124.2	124.3	124.6	125.1	125.3	125.4	125.3	125.4	125.6
3 SYSTEM LOAD	3102.7	3090.3	3085.9	3081.7	3084.0	3091.7	3104.0	3109.1	3110.1	3108.7	3110.8	3116.9
4 DSI ALUM FIRM LOAD	1975.8	1748.8	1540.8	1325.2	1050.0	1027.0	1027.0	1027.0	1027.0	949.7	694.4	549.0
5 DSI NON-ALUM FIRM LOAD	124.8	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2100.6	1848.8	1640.8	1425.2	1150.0	1127.0	1127.0	1127.0	1127.0	1049.7	794.4	649.0
8 TOT DSI FIRM TRANS LOSSES	54.9	48.3	42.9	37.2	30.0	29.4	29.4	29.4	29.4	27.5	20.9	16.9
9 BPA FEDERAL AGENCIES	144.1	144.2	141.3	142.4	143.5	144.5	145.4	146.3	147.2	148.0	148.9	149.7
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	141.8	134.9	129.3	123.6	116.4	116.1	116.4	116.6	116.6	114.7	108.2	104.4
12 ADDTL FEDERAL TRAN LOSSES	59.1	61.8	60.8	57.0	56.7	55.0	49.3	49.6	48.5	47.8	47.9	47.8
13 TOTAL FEDERAL FIRM LOAD	5615.6	5347.2	5125.4	4897.1	4617.9	4601.6	4609.6	4616.1	4616.9	4536.4	4277.8	4135.5
GENERATING PUBLIC UTILITIES												
14 SALES	3378.6	3364.7	3360.0	3355.4	3357.8	3366.2	3379.5	3385.2	3386.3	3384.8	3387.0	3393.6
15 TRANSMIS & DISTRIB LOSSES	216.2	215.3	215.0	214.7	214.9	215.4	216.3	216.7	216.7	216.6	216.8	217.2
16 SYSTEM LOAD	3594.8	3580.1	3575.1	3570.1	3572.7	3581.6	3595.8	3601.9	3603.0	3601.4	3603.8	3610.8
17 PUB RESIDENTL EXCHG--RPSA	314.6	314.0	312.9	305.4	304.3	304.6	304.4	302.4	302.5	302.7	303.9	304.3
18 PUB RESIDENTL EXCHG--ETCA	10.3	10.2	10.0	9.8	9.7	9.6	9.6	9.5	9.4	9.4	9.4	9.4
19 TOTAL PUBLIC SALES	6356.2	6330.4	6321.6	6312.8	6317.5	6333.2	6358.3	6369.0	6371.0	6368.1	6372.4	6384.8
INVESTOR-OWNED UTILITIES												
20 SALES	7935.7	7825.1	7826.3	7790.3	7776.6	7776.8	7761.5	7765.6	7770.7	7761.9	7768.0	7781.6
21 TRANSMIS & DISTRIB LOSSES	833.2	821.6	821.8	818.0	816.5	816.6	815.0	815.4	815.9	815.0	815.6	817.1
22 SYSTEM LOAD	8769.0	8646.7	8648.1	8608.3	8593.1	8593.3	8576.5	8581.0	8586.6	8576.9	8583.6	8598.6
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	16783.9	16395.7	16177.2	15918.0	15634.9	15628.9	15639.7	15655.4	15663.4	15575.3	15331.3	15212.8
26 TOTAL REGIONAL FIRM LOAD	18159.4	17754.0	17528.5	17255.5	16963.8	16956.6	16961.8	16978.9	16986.5	16894.8	16645.2	16524.9
27 DSI ALUM TQ LOAD	645.8	582.9	513.7	441.9	349.8	342.0	342.0	342.0	342.0	316.5	231.5	183.0
28 DSI NON-ALUM TQ LOAD	42.7	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	688.5	615.9	546.7	474.9	382.8	375.0	375.0	375.0	375.0	349.5	264.5	216.0
31 TOT DSI T Q TRANS LOSSES	18.0	16.1	14.3	12.4	10.0	9.8	9.8	9.8	9.8	9.2	7.0	5.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	18865.8	18386.0	18089.5	17742.8	17356.5	17341.4	17346.6	17363.7	17371.2	17253.4	16916.7	16746.5

1991 FINAL COUNCIL PLAN -- LOW CASE -- (91F1LP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	2997.3	3010.9	3028.9	3046.7	3061.8	3077.5	3094.1	3113.9
2 DISTRIBUTION LOSSES	125.9	126.5	127.2	128.0	128.6	129.3	130.0	130.8
3 SYSTEM LOAD	3123.2	3137.4	3156.1	3174.6	3190.4	3206.7	3224.1	3244.7
4 DSI ALUM FIRM LOAD	549.0	549.0	549.0	549.0	549.0	549.0	549.0	549.0
5 DSI NON-ALUM FIRM LOAD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	649.0	649.0	649.0	649.0	649.0	649.0	649.0	649.0
8 TOT DSI FIRM TRANS LOSSES	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
9 BPA FEDERAL AGENCIES	150.3	150.9	151.6	152.3	152.9	153.5	154.1	154.7
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	104.6	105.0	105.5	106.0	106.4	106.9	107.3	107.9
12 ADDTL FEDERAL TRAN LOSSES	47.0	46.8	47.6	49.6	50.5	50.1	49.5	50.4
13 TOTAL FEDERAL FIRM LOAD	4141.9	4156.9	4177.7	4199.4	4217.2	4234.2	4252.1	4274.8
GENERATING PUBLIC UTILITIES								
14 SALES	3400.5	3415.8	3436.2	3456.4	3473.6	3491.4	3510.2	3532.7
15 TRANSMIS & DISTRIB LOSSES	217.6	218.6	219.9	221.2	222.3	223.4	224.7	226.1
16 SYSTEM LOAD	3618.1	3634.5	3656.1	3677.6	3695.9	3714.8	3734.9	3758.7
17 PUB RESIDENTL EXCHG--RPSA	304.7	305.9	307.4	309.2	310.2	311.4	312.7	314.6
18 PUB RESIDENTL EXCHG--ETCA	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
19 TOTAL PUBLIC SALES	6397.8	6426.8	6465.0	6503.0	6535.3	6568.8	6604.3	6646.6
INVESTOR-OWNED UTILITIES								
20 SALES	7790.6	7818.1	7858.9	7899.9	7937.7	7978.5	8022.8	8071.0
21 TRANSMIS & DISTRIB LOSSES	818.0	820.9	825.2	829.5	833.5	837.7	842.4	847.5
22 SYSTEM LOAD	8608.6	8639.0	8684.1	8729.4	8771.2	8816.2	8865.2	8918.5
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	15235.6	15292.6	15372.5	15452.2	15522.9	15597.8	15678.3	15769.4
26 TOTAL REGIONAL FIRM LOAD	16548.6	16610.4	16697.9	16786.4	16864.2	16945.2	17032.1	17132.0
27 DSI ALUM TQ LOAD	183.0	183.0	183.0	183.0	183.0	183.0	183.0	183.0
28 DSI NON-ALUM TQ LOAD	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
31 TOT DSI T Q TRANS LOSSES	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	16770.3	16832.0	16919.5	17008.0	17085.9	17166.8	17253.8	17353.7

1991 FINAL COUNCIL PLAN -- MEDIUM LOW CASE -- (91F1MLP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3045.0	3066.4	3089.5	3115.0	3144.4	3176.8	3213.0	3240.4	3265.3	3287.8	3311.6	3338.0
2 DISTRIBUTION LOSSES	127.9	128.8	129.8	130.8	132.1	133.4	134.9	136.1	137.1	138.1	139.1	140.2
3 SYSTEM LOAD	3172.8	3195.2	3219.2	3245.8	3276.5	3310.2	3347.9	3376.5	3402.4	3425.9	3450.7	3478.2
4 DSI ALUM FIRM LOAD	2004.6	1889.1	1760.3	1621.5	1454.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0
5 DSI NON-ALUM FIRM LOAD	174.4	164.8	139.2	139.3	139.5	140.1	140.4	141.0	141.3	141.7	142.1	142.1
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2179.0	2053.9	1899.5	1760.8	1593.5	1579.1	1579.4	1580.0	1580.3	1580.7	1581.1	1581.1
8 TOT DSI FIRM TRANS LOSSES	56.9	53.6	49.6	45.9	41.6	41.2	41.2	41.2	41.2	41.2	41.2	41.2
9 BPA FEDERAL AGENCIES	144.1	144.2	141.3	142.4	143.5	144.5	145.4	146.3	147.2	148.0	148.9	149.7
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	145.7	143.0	139.5	136.6	133.0	133.6	134.6	135.4	136.1	136.8	137.4	138.2
12 ADDTL FEDERAL TRAN LOSSES	62.0	65.7	65.5	62.3	63.0	62.0	56.9	57.7	57.1	57.2	57.7	58.3
13 TOTAL FEDERAL FIRM LOAD	5770.9	5669.2	5532.3	5415.2	5276.9	5296.7	5331.7	5363.3	5390.5	5416.1	5443.4	5473.2
GENERATING PUBLIC UTILITIES												
14 SALES	3454.6	3478.7	3504.9	3533.8	3567.2	3603.8	3644.9	3676.1	3704.3	3729.9	3756.9	3786.9
15 TRANSMIS & DISTRIB LOSSES	221.1	222.6	224.3	226.2	228.3	230.6	233.3	235.3	237.1	238.7	240.4	242.4
16 SYSTEM LOAD	3675.6	3701.3	3729.2	3759.9	3795.5	3834.5	3878.1	3911.3	3941.4	3968.6	3997.3	4029.2
17 PUB RESIDENTL EXCHG--RPSA	321.8	324.8	326.5	321.8	323.4	326.2	328.4	328.5	331.0	333.6	337.2	339.7
18 PUB RESIDENTL EXCHG--ETCA	10.6	10.5	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.4	10.4
19 TOTAL PUBLIC SALES	6499.5	6545.1	6594.4	6648.7	6711.6	6780.6	6857.8	6916.4	6969.6	7017.6	7068.4	7124.9
INVESTOR-OWNED UTILITIES												
20 SALES	8084.8	8062.6	8141.4	8183.2	8226.8	8289.3	8339.2	8408.7	8482.3	8545.7	8621.7	8703.9
21 TRANSMIS & DISTRIB LOSSES	848.9	846.6	854.8	859.2	863.8	870.4	875.6	882.9	890.6	897.3	905.3	913.9
22 SYSTEM LOAD	8933.7	8909.2	8996.2	9042.4	9090.6	9159.7	9214.8	9291.6	9372.9	9443.0	9526.9	9617.8
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17154.8	17053.1	17023.8	16982.5	16922.7	17040.9	17169.3	17298.9	17426.8	17539.6	17667.7	17807.3
26 TOTAL REGIONAL FIRM LOAD	18560.3	18459.7	18437.7	18397.5	18342.9	18470.9	18604.6	18746.3	18884.8	19007.6	19147.6	19300.1
27 DSI ALUM TQ LOAD	655.4	629.7	586.8	540.8	485.0	480.0	480.0	480.0	480.0	480.0	480.0	480.0
28 DSI NON-ALUM TQ LOAD	59.5	55.0	46.3	46.3	46.5	46.7	47.0	47.2	47.2	47.3	47.3	47.3
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	714.9	684.7	633.1	587.1	531.5	526.7	527.0	527.2	527.2	527.3	527.3	527.3
31 TOT DSI T Q TRANS LOSSES	18.7	17.9	16.5	15.3	13.9	13.7	13.7	13.7	13.7	13.8	13.8	13.8
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19293.9	19162.2	19087.3	18999.9	18888.3	19011.3	19145.4	19287.2	19425.7	19548.6	19688.6	19841.1

1991 FINAL COUNCIL PLAN -- MEDIUM LOW CASE -- (91F1MLP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	3364.3	3399.3	3440.6	3482.7	3523.4	3564.6	3604.6	3647.6
2 DISTRIBUTION LOSSES	141.3	142.8	144.5	146.3	148.0	149.7	151.4	153.2
3 SYSTEM LOAD	3505.6	3542.0	3585.1	3628.9	3671.4	3714.3	3756.0	3800.8
4 DSI ALUM FIRM LOAD	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0	1439.0
5 DSI NON-ALUM FIRM LOAD	142.1	142.1	142.3	142.3	142.3	142.3	142.8	142.8
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	1581.1	1581.1	1581.3	1581.3	1581.3	1581.3	1581.8	1581.8
8 TOT DSI FIRM TRANS LOSSES	41.2	41.2	41.2	41.2	41.2	41.2	41.3	41.3
9 BPA FEDERAL AGENCIES	150.3	150.9	151.6	152.3	152.9	153.5	154.1	154.7
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	138.9	139.9	141.0	142.2	143.4	144.5	145.6	146.8
12 ADDTL FEDERAL TRAN LOSSES	57.9	58.4	59.5	62.3	63.8	64.1	64.3	65.8
13 TOTAL FEDERAL FIRM LOAD	5501.6	5540.2	5586.4	5635.0	5680.7	5725.7	5769.9	5818.0
GENERATING PUBLIC UTILITIES								
14 SALES	3816.6	3856.2	3903.1	3950.8	3997.0	4043.7	4089.2	4137.8
15 TRANSMIS & DISTRIB LOSSES	244.3	246.8	249.8	252.8	255.8	258.8	261.7	264.8
16 SYSTEM LOAD	4060.9	4103.0	4152.8	4203.6	4252.8	4302.5	4350.9	4402.7
17 PUB RESIDENTL EXCHG--RPSA	342.1	345.5	349.2	353.5	357.1	360.8	364.3	368.6
18 PUB RESIDENTL EXCHG--ETCA	10.5	10.5	10.6	10.7	10.7	10.8	10.8	10.9
19 TOTAL PUBLIC SALES	7180.9	7255.4	7343.6	7433.4	7520.4	7608.3	7693.8	7785.4
INVESTOR-OWNED UTILITIES								
20 SALES	8784.0	8891.0	9021.4	9150.2	9275.7	9407.6	9533.7	9664.6
21 TRANSMIS & DISTRIB LOSSES	922.3	933.5	947.2	960.8	973.9	987.8	1001.0	1014.8
22 SYSTEM LOAD	9706.3	9824.5	9968.7	10110.9	10249.7	10395.4	10534.7	10679.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17944.1	18126.3	18345.9	18565.1	18778.3	18998.8	19211.5	19434.7
26 TOTAL REGIONAL FIRM LOAD	19448.8	19647.7	19887.9	20129.6	20363.2	20603.7	20835.5	21080.1
27 DSI ALUM TQ LOAD	480.0	480.0	480.0	480.0	480.0	480.0	480.0	480.0
28 DSI NON-ALUM TQ LOAD	47.3	47.3	47.3	47.3	47.3	47.3	47.3	47.3
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	527.3	527.3	527.3	527.3	527.3	527.3	527.3	527.3
31 TOT DSI T Q TRANS LOSSES	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	19989.8	20188.7	20429.0	20670.6	20904.3	21144.8	21376.6	21621.2

1991 FINAL COUNCIL PLAN -- MEDIUM CASE -- (91F2MP) (M-TERM MRG=1/95)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3123.0	3160.0	3198.2	3242.3	3278.1	3323.5	3365.1	3406.0	3446.6	3485.7	3522.8	3563.7
2 DISTRIBUTION LOSSES	131.2	132.7	134.3	136.2	137.7	139.6	141.3	143.1	144.8	146.4	148.0	149.7
3 SYSTEM LOAD	3254.1	3292.7	3332.5	3378.5	3415.8	3463.1	3506.5	3549.1	3591.4	3632.1	3670.8	3713.4
4 DSI ALUM FIRM LOAD	2172.3	2123.5	2068.3	1999.0	1975.8	1953.3	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0
5 DSI NON-ALUM FIRM LOAD	211.7	229.3	179.2	179.3	179.3	180.4	181.2	181.7	182.7	183.5	183.9	183.9
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2384.0	2352.8	2247.5	2178.3	2155.2	2133.8	2132.2	2132.7	2133.7	2134.5	2134.9	2134.9
8 TOT DSI FIRM TRANS LOSSES	62.2	61.4	58.6	56.8	56.2	55.6	55.6	55.6	55.6	55.7	55.7	55.7
9 BPA FEDERAL AGENCIES	144.1	144.2	141.3	142.4	143.5	144.5	145.4	146.3	147.2	148.0	148.9	149.7
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	153.1	153.3	151.5	150.9	151.3	152.0	153.2	154.3	155.5	156.6	157.7	158.8
12 ADDTL FEDERAL TRAN LOSSES	64.7	69.2	69.4	66.6	67.5	66.7	62.2	63.4	63.1	62.8	63.7	65.0
13 TOTAL FEDERAL FIRM LOAD	6067.4	6079.5	6009.4	5984.0	6000.6	6027.5	6066.9	6113.2	6158.3	6201.6	6243.6	6289.5
GENERATING PUBLIC UTILITIES												
14 SALES	3592.6	3673.7	3722.5	3765.1	3792.7	3844.8	3893.0	3940.3	3987.2	4032.5	4075.5	4122.7
15 TRANSMIS & DISTRIB LOSSES	229.9	235.1	238.2	241.0	242.7	246.1	249.1	252.2	255.2	258.1	260.8	263.8
16 SYSTEM LOAD	3822.6	3908.8	3960.7	4006.1	4035.4	4090.8	4142.1	4192.4	4242.4	4290.6	4336.3	4386.5
17 PUB RESIDENTL EXCHG--RPSA	330.1	334.7	338.1	335.1	337.2	341.3	344.0	345.3	349.4	353.7	358.7	362.7
18 PUB RESIDENTL EXCHG--ETCA	10.8	10.9	10.8	10.8	10.8	10.8	10.8	10.8	10.9	11.0	11.1	11.2
19 TOTAL PUBLIC SALES	6715.6	6833.7	6920.7	7007.4	7070.9	7168.3	7258.1	7346.3	7433.9	7518.2	7598.3	7686.4
INVESTOR-OWNED UTILITIES												
20 SALES	8296.0	8431.0	8623.0	8737.2	8847.6	8967.8	9072.2	9209.2	9351.8	9483.4	9612.6	9753.3
21 TRANSMIS & DISTRIB LOSSES	871.1	885.2	905.4	917.4	929.0	941.6	952.6	967.0	981.9	995.8	1009.3	1024.1
22 SYSTEM LOAD	9167.0	9316.2	9528.4	9654.5	9776.6	9909.4	10024.8	10176.1	10333.7	10479.1	10621.9	10777.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	17787.0	18008.9	18179.6	18312.5	18464.5	18661.7	18855.3	19081.9	19314.0	19531.7	19742.4	19972.0
26 TOTAL REGIONAL FIRM LOAD	19237.0	19484.5	19678.5	19824.6	19992.7	20207.8	20413.8	20661.8	20914.5	21151.3	21381.8	21633.4
27 DSI ALUM TQ LOAD	710.9	708.0	689.3	666.2	658.6	650.8	650.0	650.0	650.0	650.0	650.0	650.0
28 DSI NON-ALUM TQ LOAD	88.5	76.5	59.8	59.8	59.8	60.3	60.4	60.5	61.0	61.3	61.4	61.4
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	799.4	784.5	749.2	726.0	718.4	711.1	710.4	710.5	711.0	711.3	711.4	711.4
31 TOT DSI T Q TRANS LOSSES	20.8	20.5	19.5	18.9	18.7	18.5	18.5	18.5	18.5	18.5	18.6	18.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20057.3	20289.5	20447.2	20569.6	20729.9	20937.4	21142.7	21390.8	21644.0	21881.1	22111.8	22363.3

1991 FINAL COUNCIL PLAN -- MEDIUM CASE -- (91F2MP) (M-TERM MRG=1/95)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	3604.6	3649.0	3698.6	3749.0	3796.5	3844.3	3889.8	3934.9
2 DISTRIBUTION LOSSES	151.4	153.3	155.3	157.5	159.5	161.5	163.4	165.3
3 SYSTEM LOAD	3755.9	3802.3	3854.0	3906.4	3955.9	4005.8	4053.2	4100.2
4 DSI ALUM FIRM LOAD	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0	1951.0
5 DSI NON-ALUM FIRM LOAD	184.2	184.1	184.5	184.5	184.6	185.0	185.1	185.1
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2135.2	2135.1	2135.5	2135.5	2135.6	2136.0	2136.1	2136.1
8 TOT DSI FIRM TRANS LOSSES	55.7	55.7	55.7	55.7	55.7	55.7	55.7	55.7
9 BPA FEDERAL AGENCIES	150.3	150.9	151.6	152.3	152.9	153.5	154.1	154.7
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	159.9	161.2	162.6	164.0	165.3	166.6	167.9	169.1
12 ADDTL FEDERAL TRAN LOSSES	65.0	65.8	67.2	70.2	72.0	72.4	72.7	74.4
13 TOTAL FEDERAL FIRM LOAD	6334.2	6383.1	6438.8	6496.4	6549.6	6602.3	6652.0	6702.6
GENERATING PUBLIC UTILITIES								
14 SALES	4170.0	4221.4	4278.7	4337.0	4392.0	4447.3	4500.0	4552.2
15 TRANSMIS & DISTRIB LOSSES	266.9	270.2	273.8	277.6	281.1	284.6	288.0	291.3
16 SYSTEM LOAD	4436.8	4491.5	4552.5	4614.5	4673.0	4731.9	4788.0	4843.5
17 PUB RESIDENTL EXCHG--RPSA	366.6	370.8	375.4	380.5	384.8	389.1	393.1	397.6
18 PUB RESIDENTL EXCHG--ETCA	11.2	11.3	11.4	11.5	11.6	11.6	11.7	11.8
19 TOTAL PUBLIC SALES	7774.5	7870.4	7977.3	8085.9	8188.4	8291.7	8389.8	8487.1
INVESTOR-OWNED UTILITIES								
20 SALES	9892.4	10042.6	10209.8	10367.9	10520.0	10688.7	10848.1	10994.0
21 TRANSMIS & DISTRIB LOSSES	1038.7	1054.5	1072.0	1088.6	1104.6	1122.3	1139.0	1154.4
22 SYSTEM LOAD	10931.1	11097.0	11281.8	11456.6	11624.6	11811.0	11987.2	12148.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	20200.2	20446.8	20722.2	20989.6	21244.9	21517.8	21776.2	22020.0
26 TOTAL REGIONAL FIRM LOAD	21882.2	22151.7	22453.1	22747.4	23027.3	23325.2	23607.2	23874.5
27 DSI ALUM TQ LOAD	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
28 DSI NON-ALUM TQ LOAD	61.4	61.4	61.5	61.5	61.5	61.5	61.5	61.5
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	711.4	711.4	711.5	711.5	711.5	711.5	711.5	711.5
31 TOT DSI T Q TRANS LOSSES	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	22612.1	22881.6	23183.2	23477.5	23757.3	24055.3	24337.2	24604.5

1991 FINAL COUNCIL PLAN -- MEDIUM HIGH CASE -- (91F1MHP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3163.5	3238.6	3304.0	3369.9	3439.3	3508.1	3576.6	3639.7	3698.1	3753.6	3809.5	3869.9
2 DISTRIBUTION LOSSES	132.9	136.0	138.8	141.5	144.5	147.3	150.2	152.9	155.3	157.6	160.0	162.5
3 SYSTEM LOAD	3296.4	3374.6	3442.8	3511.5	3583.8	3655.5	3726.8	3792.5	3853.4	3911.2	3969.5	4032.4
4 DSI ALUM FIRM LOAD	2172.3	2132.5	2123.0	2121.5	2090.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0
5 DSI NON-ALUM FIRM LOAD	256.0	272.1	247.2	247.2	247.3	248.1	248.3	248.9	249.2	249.5	240.5	212.3
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2428.3	2404.6	2370.2	2368.7	2337.3	2335.1	2335.3	2335.9	2336.2	2336.5	2327.5	2299.3
8 TOT DSI FIRM TRANS LOSSES	63.3	62.7	61.8	61.8	61.0	60.9	60.9	60.9	60.9	60.9	60.7	60.0
9 BPA FEDERAL AGENCIES	144.1	144.2	141.3	142.4	143.5	144.5	145.4	146.3	147.2	148.0	148.9	149.7
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	155.3	156.8	157.6	159.4	160.5	162.4	164.3	166.0	167.7	169.2	170.6	171.5
12 ADDTL FEDERAL TRAN LOSSES	67.4	72.6	73.4	71.5	73.0	72.5	68.3	70.3	70.3	71.0	72.5	74.5
13 TOTAL FEDERAL FIRM LOAD	6158.9	6220.1	6252.4	6320.8	6365.5	6437.4	6507.5	6578.5	6642.2	6703.6	6756.6	6795.0
GENERATING PUBLIC UTILITIES												
14 SALES	3588.1	3673.6	3747.8	3822.6	3901.3	3979.4	4057.1	4128.7	4195.1	4258.0	4321.4	4389.9
15 TRANSMIS & DISTRIB LOSSES	229.6	235.1	239.9	244.6	249.7	254.7	259.6	264.2	268.5	272.5	276.6	281.0
16 SYSTEM LOAD	3817.8	3908.8	3987.7	4067.3	4151.0	4234.1	4316.7	4392.9	4463.5	4530.5	4598.0	4670.9
17 PUB RESIDENTL EXCHG--RPSA	334.6	343.1	349.3	348.2	353.8	360.3	365.6	369.0	374.9	381.0	388.0	393.9
18 PUB RESIDENTL EXCHG--ETCA	11.0	11.2	11.2	11.2	11.3	11.4	11.5	11.6	11.7	11.8	12.0	12.1
19 TOTAL PUBLIC SALES	6751.7	6912.3	7051.8	7192.6	7340.6	7487.6	7633.7	7768.4	7893.2	8011.6	8130.9	8259.8
INVESTOR-OWNED UTILITIES												
20 SALES	8441.9	8620.0	8846.8	9016.4	9190.2	9376.5	9542.5	9736.0	9934.9	10114.8	10296.5	10494.7
21 TRANSMIS & DISTRIB LOSSES	886.4	905.1	928.9	946.7	965.0	984.5	1002.0	1022.3	1043.2	1062.1	1081.1	1101.9
22 SYSTEM LOAD	9328.3	9525.1	9775.7	9963.2	10155.2	10361.0	10544.5	10758.3	10978.0	11176.9	11377.7	11596.6
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	18013.3	18328.3	18657.3	18967.4	19259.1	19591.0	19904.4	20234.1	20558.9	20858.5	21151.5	21451.1
26 TOTAL REGIONAL FIRM LOAD	19485.0	19834.0	20195.8	20531.2	20851.7	21212.5	21548.7	21909.8	22263.8	22591.0	22912.3	23242.5
27 DSI ALUM TQ LOAD	710.9	711.0	708.0	707.5	697.0	696.0	696.0	696.0	696.0	696.0	696.0	696.0
28 DSI NON-ALUM TQ LOAD	86.6	90.6	82.3	82.3	82.3	82.7	82.9	83.1	83.2	83.3	80.2	70.8
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	797.5	801.6	790.3	789.8	779.3	778.7	778.9	779.1	779.2	779.3	776.2	766.8
31 TOT DSI T Q TRANS LOSSES	20.8	20.9	20.6	20.6	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.0
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20303.3	20656.5	21006.7	21341.6	21651.4	22011.5	22348.0	22709.2	23063.3	23390.6	23708.7	24029.3

1991 FINAL COUNCIL PLAN -- MEDIUM HIGH CASE -- (91F1MHP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	3931.2	3997.6	4066.5	4137.5	4204.3	4270.0	4339.1	4410.0
2 DISTRIBUTION LOSSES	165.1	167.9	170.8	173.8	176.6	179.3	182.2	185.2
3 SYSTEM LOAD	4096.3	4165.5	4237.2	4311.2	4380.9	4449.3	4521.3	4595.2
4 DSI ALUM FIRM LOAD	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0	2087.0
5 DSI NON-ALUM FIRM LOAD	212.4	212.3	212.5	212.6	212.7	213.2	213.3	213.3
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2299.4	2299.3	2299.5	2299.6	2299.7	2300.2	2300.3	2300.3
8 TOT DSI FIRM TRANS LOSSES	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
9 BPA FEDERAL AGENCIES	150.3	150.9	151.6	152.3	152.9	153.5	154.1	154.7
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	173.2	175.0	176.9	178.9	180.7	182.6	184.5	186.4
12 ADDTL FEDERAL TRAN LOSSES	74.8	76.1	78.2	81.6	83.8	84.8	85.7	88.0
13 TOTAL FEDERAL FIRM LOAD	6861.9	6934.7	7011.4	7091.6	7166.0	7238.4	7313.9	7392.7
GENERATING PUBLIC UTILITIES								
14 SALES	4459.5	4534.7	4612.8	4693.4	4769.3	4843.8	4922.1	5002.6
15 TRANSMIS & DISTRIB LOSSES	285.4	290.2	295.2	300.4	305.2	310.0	315.0	320.2
16 SYSTEM LOAD	4744.9	4824.9	4908.1	4993.8	5074.5	5153.8	5237.2	5322.7
17 PUB RESIDENTL EXCHG--RPSA	399.8	406.3	412.8	420.0	426.1	432.2	438.6	445.7
18 PUB RESIDENTL EXCHG--ETCA	12.2	12.4	12.5	12.7	12.8	12.9	13.1	13.2
19 TOTAL PUBLIC SALES	8390.7	8532.3	8679.3	8830.8	8973.6	9113.8	9261.2	9412.5
INVESTOR-OWNED UTILITIES								
20 SALES	10692.0	10920.3	11170.7	11419.6	11646.0	11887.0	12137.9	12375.0
21 TRANSMIS & DISTRIB LOSSES	1122.7	1146.6	1172.9	1199.1	1222.8	1248.1	1274.5	1299.4
22 SYSTEM LOAD	11814.7	12066.9	12343.6	12618.7	12868.8	13135.1	13412.3	13674.4
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	21780.3	22150.6	22549.0	22950.3	23320.2	23702.5	24101.5	24490.6
26 TOTAL REGIONAL FIRM LOAD	23601.5	24006.5	24443.0	24884.0	25289.4	25707.3	26143.4	26569.8
27 DSI ALUM TQ LOAD	696.0	696.0	696.0	696.0	696.0	696.0	696.0	696.0
28 DSI NON-ALUM TQ LOAD	70.9	70.8	71.0	71.1	71.2	71.2	71.2	71.2
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	766.9	766.8	767.0	767.1	767.2	767.2	767.2	767.2
31 TOT DSI T Q TRANS LOSSES	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	24388.4	24793.3	25230.0	25671.1	26076.5	26494.5	26930.6	27357.0

1991 FINAL COUNCIL PLAN -- HIGH CASE -- (91F1HP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	1990-1991	1991-1992	1992-1993	1993-1994	1994-1995	1995-1996	1996-1997	1997-1998	1998-1999	1999-2000	2000-2001	2001-2002
SMALL & NONGEN PUBLIC UTILS												
1 SALES	3251.4	3378.0	3475.1	3578.0	3687.4	3790.1	3893.7	3983.6	4069.3	4159.3	4249.6	4342.3
2 DISTRIBUTION LOSSES	136.6	141.9	146.0	150.3	154.9	159.2	163.5	167.3	170.9	174.7	178.5	182.4
3 SYSTEM LOAD	3388.0	3519.9	3621.1	3728.3	3842.2	3949.3	4057.3	4150.9	4240.2	4334.0	4428.0	4524.7
4 DSI ALUM FIRM LOAD	2172.1	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0
5 DSI NON-ALUM FIRM LOAD	288.1	314.5	316.0	316.0	316.0	316.0	316.0	316.0	316.0	316.0	297.3	241.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2460.2	2474.5	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2476.0	2457.3	2401.0
8 TOT DSI FIRM TRANS LOSSES	64.2	64.5	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.6	64.1	62.6
9 BPA FEDERAL AGENCIES	144.1	144.2	141.3	142.4	143.5	144.5	145.4	146.3	147.2	148.0	148.9	149.7
10 USBR	67.3	67.3	67.2	67.3	67.3	67.4	67.4	67.5	67.5	67.6	67.6	67.7
11 FEDERAL TRANSMIS LOSSES	158.5	162.4	165.0	167.9	170.9	173.7	176.6	179.1	181.5	184.0	186.0	187.1
12 ADDTL FEDERAL TRAN LOSSES	70.9	77.1	79.2	78.4	81.0	81.0	77.5	80.3	81.4	83.1	85.5	88.2
13 TOTAL FEDERAL FIRM LOAD	6289.0	6445.3	6549.8	6660.2	6781.0	6891.9	7000.2	7100.1	7193.8	7292.7	7373.3	7418.3
GENERATING PUBLIC UTILITIES												
14 SALES	3687.0	3831.4	3941.7	4058.3	4182.3	4299.0	4416.5	4518.7	4615.9	4718.0	4820.4	4925.6
15 TRANSMIS & DISTRIB LOSSES	236.0	245.2	252.3	259.7	267.7	275.1	282.7	289.2	295.4	301.9	308.5	315.2
16 SYSTEM LOAD	3923.0	4076.6	4193.9	4318.0	4450.0	4574.1	4699.2	4807.8	4911.3	5019.9	5128.9	5240.8
17 PUB RESIDENTL EXCHG--RPSA	344.1	358.0	367.4	369.8	379.4	389.4	398.1	403.9	412.6	422.2	432.8	442.0
18 PUB RESIDENTL EXCHG--ETCA	11.4	11.7	11.8	11.9	12.1	12.4	12.6	12.7	12.9	13.1	13.4	13.6
19 TOTAL PUBLIC SALES	6938.4	7209.4	7416.8	7636.3	7869.7	8089.1	8310.3	8502.2	8685.2	8877.3	9069.9	9267.9
INVESTOR-OWNED UTILITIES												
20 SALES	8687.1	9020.9	9356.6	9646.4	9952.8	10261.2	10549.9	10825.0	11123.7	11425.9	11732.5	12046.7
21 TRANSMIS & DISTRIB LOSSES	912.1	947.2	982.4	1012.9	1045.0	1077.4	1107.7	1136.6	1168.0	1199.7	1231.9	1264.9
22 SYSTEM LOAD	9599.3	9968.1	10339.0	10659.3	10997.9	11338.6	11657.6	11961.6	12291.7	12625.6	12964.4	13311.6
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	18477.2	19096.2	19637.9	20148.4	20689.4	21218.2	21729.0	22197.0	22679.5	23174.8	23656.2	24113.0
26 TOTAL REGIONAL FIRM LOAD	19991.2	20670.0	21262.8	21817.5	22408.8	22984.6	23537.0	24049.5	24576.7	25118.3	25646.6	26150.7
27 DSI ALUM TQ LOAD	710.9	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
28 DSI NON-ALUM TQ LOAD	97.4	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	98.8	80.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	808.3	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	825.0	818.8	800.0
31 TOT DSI T Q TRANS LOSSES	21.1	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.4	20.9
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	20820.6	21516.5	22109.3	22664.0	23255.4	23831.2	24383.5	24896.1	25423.3	25964.8	26486.7	26971.6

1991 FINAL COUNCIL PLAN -- HIGH CASE -- (91F1HP)
FISCAL YEAR MEANS FOR AVERAGE REGIONAL FORECAST

	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010
SMALL & NONGEN PUBLIC UTILS								
1 SALES	4433.9	4536.9	4648.5	4757.4	4862.9	4969.6	5077.3	5187.5
2 DISTRIBUTION LOSSES	186.2	190.6	195.2	199.8	204.2	208.7	213.2	217.9
3 SYSTEM LOAD	4620.1	4727.5	4843.7	4957.2	5067.2	5178.3	5290.5	5405.3
4 DSI ALUM FIRM LOAD	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0	2160.0
5 DSI NON-ALUM FIRM LOAD	241.0	241.0	241.0	241.0	241.0	241.0	241.0	241.0
6 DSI HANNA FIRM LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 TOTAL DSI FIRM LOAD	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0	2401.0
8 TOT DSI FIRM TRANS LOSSES	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
9 BPA FEDERAL AGENCIES	150.3	150.9	151.6	152.3	152.9	153.5	154.1	154.7
10 USBR	67.8	67.8	67.9	67.9	68.0	68.0	68.1	68.1
11 FEDERAL TRANSMIS LOSSES	189.6	192.4	195.5	198.5	201.4	204.3	207.3	210.3
12 ADDTL FEDERAL TRAN LOSSES	89.7	92.1	95.5	100.0	103.4	105.8	107.8	111.1
13 TOTAL FEDERAL FIRM LOAD	7518.6	7631.7	7755.2	7877.0	7993.9	8111.0	8228.8	8350.5
GENERATING PUBLIC UTILITIES								
14 SALES	5029.5	5146.2	5272.7	5396.3	5516.1	5637.1	5759.2	5884.2
15 TRANSMIS & DISTRIB LOSSES	321.9	329.4	337.5	345.4	353.0	360.8	368.6	376.6
16 SYSTEM LOAD	5351.4	5475.6	5610.2	5741.7	5869.1	5997.9	6127.8	6260.8
17 PUB RESIDENTL EXCHG--RPSA	451.0	461.2	471.9	483.0	493.0	503.1	513.3	524.3
18 PUB RESIDENTL EXCHG--ETCA	13.8	14.1	14.4	14.6	14.8	15.1	15.3	15.6
19 TOTAL PUBLIC SALES	9463.4	9683.2	9921.2	10153.7	10379.0	10606.7	10836.5	11071.7
INVESTOR-OWNED UTILITIES								
20 SALES	12335.9	12661.9	13037.4	13398.1	13747.0	14104.0	14461.1	14814.7
21 TRANSMIS & DISTRIB LOSSES	1295.3	1329.5	1368.9	1406.8	1443.4	1480.9	1518.4	1555.5
22 SYSTEM LOAD	13631.2	13991.4	14406.3	14804.9	15190.4	15584.9	15979.5	16370.2
23 IOU RESIDENTIAL EXCHANGE	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0	-999.0
24 COLOCKUM	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
25 TOTAL REGIONAL FIRM SALES	24598.5	25144.8	25759.2	26353.1	26927.9	27513.2	28100.8	28690.1
26 TOTAL REGIONAL FIRM LOAD	26681.2	27278.7	27951.7	28603.6	29233.4	29873.8	30516.2	31161.6
27 DSI ALUM TQ LOAD	720.0	720.0	720.0	720.0	720.0	720.0	720.0	720.0
28 DSI NON-ALUM TQ LOAD	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
29 DSI HANNA TQ LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30 TOTAL DSI TOP QTL LOAD	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
31 TOT DSI T Q TRANS LOSSES	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
32 OTHER INTERRUPTIBLE LOAD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33 TOTAL REGIONAL LOAD	27502.0	28099.6	28772.6	29424.5	30054.3	30694.6	31337.0	31982.4

CHAPTER 7

CONSERVATION RESOURCES

Overview

Conservation is a key ingredient in the Council's resource portfolio for meeting future electrical energy needs. Each megawatt of electricity conserved is one less megawatt that needs to be generated. The Council has identified over 4,100 average megawatts of technical conservation in the high demand forecast, available at an average cost of about 5 cents per kilowatt-hour.[1] In this package, no individual measure exceeds 11 cents per kilowatt-hour. This is enough energy to replace the output of about 10 coal plants, at about half the cost. In addition, the Council has identified a second block of generally more expensive conservation with individual measure costs just over 11 cents and up to 15 cents per kilowatt-hour. These resources represent an additional 845 average megawatts.

While much has been accomplished in acquiring conservation since the conservation estimates were first done by the Council, the remaining conservation is still an extraordinarily cost-effective resource for the region to acquire. This chapter provides an overview of the procedures and major assumptions used to derive the Council's estimates of conservation resources in both the public and private utility service territories.

In the Council's plan, conservation is defined as the more efficient use of electricity. This means that less electricity is used to produce a given service at a given amenity level. Conservation resources are measures that ensure the efficient use of electricity for new and existing residential buildings, household appliances, new and existing commercial buildings, and industrial and irrigation processes. For example, buildings in which heat loss is reduced through insulating and tightening require less electricity for heating. These electricity savings mean that fewer power plants are needed to meet growing demand. Conservation also includes measures to reduce electrical losses in the region's generation, transmission and distribution system. These latter conservation resources are discussed in Chapter 8, Generating Resources.

Progress in Conservation Acquisition and Its Effects on Conservation Resource Estimates

The current estimate of technical conservation potential is about 4,100[2] average megawatts in the high demand forecast with no individual measure exceeding 11 cents per kilowatt-hour, as displayed in Table 7-1. In lower demand forecasts, less conservation is available from many sectors, because the economy is not growing as rapidly, and there are fewer new houses, businesses and appliances that can supply energy savings. Table 7-1 shows that about 3,000 average megawatts are available in the medium forecast. In addition, Table 7-2 shows about 845 average megawatts of technical conservation potential in a second, generally more expensive block of conservation. Typically, this resource consists of measures that cost between 11 and 15 cents per kilowatt-hour or are considered more advanced than those in the first group. This second block of conservation was identified because there are generating resources, such as wind, with equivalent costs, which also play a role in the resource portfolio under certain conditions.

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1. This average cost includes administration, transmission and distribution adjustments. All costs are in 1990 dollars. Levelized cost calculations are performed using a nominal discount rate. See Chapter 13 for a discussion of how the Council calculates nominal 1990 dollars. Earlier Council analyses were conducted using a real discount rate. In real terms, the average cost of all conservation is about half the 5 cents per kilowatt-hour nominal number.

2. This value is technical potential and has not been increased to reflect conservation's benefit of avoiding line losses when compared to generating resources, nor decreased to reflect expected market penetration rates.

Table 7–1
Comparison of Conservation Savings and Costs Technical Potential—Block 1

	High Forecast (MWa)	Medium Forecast (MWa)	Nominal[a] Levelized Cost (cents/kWh)
Residential Sector			
Space Heating			
▪ Existing Single-Family Dwellings	135	135	7
▪ Existing Multifamily Dwellings	60	60	6
▪ New Single-Family Dwellings	270	120	6
▪ New Multifamily Dwellings	30	20	7
▪ New Manufactured Housing	165	175	7
Water Heating	700	560	4
Heat Pump Heat-Recovery Ventilators	190	100	8
Refrigerators	0	0	—
Freezers	0	0	—
Lighting	115	80	8
Commercial Sector			
▪ Existing	800	630	5
▪ New	710	440	4
▪ Renovation and Remodel	350	335	4
Industrial Sector			
▪ Existing	265	265	3
▪ New	275	75	3
Irrigation	50	50	5
Total	4,115	3,045	

[a] Real levelized costs (at a 3-percent discount rate) are about 50 percent of nominal costs reported here.

Table 7–2
Comparison of Conservation Savings and Costs Technical Potential—Block 2

	High Forecast (MWa)
Residential Sector	
Space Heating	
▪ Existing Single–Family Dwellings	0
▪ Existing Multifamily Dwellings	0
▪ New Single–Family Dwellings	35
▪ New Multifamily Dwellings	5
▪ New Manufactured Housing	10
Water Heating	85
Heat Pump Heat–Recovery Ventilators	0
Refrigerators	75
Freezers	40
Lighting	0
Commercial Sector	
▪ Existing	120
▪ New	70
▪ Renovation and Remodel	60
Industrial Sector	
▪ Existing	165
▪ New	170
Irrigation	10
Total	845

The size of the conservation resource yet to be acquired has typically been reduced over the last few years compared to prior estimates. This is due primarily to significant actions taken by various jurisdictions in the region, and in some cases by the federal government, that have already set in motion mechanisms to acquire a large portion of the conservation resource. For example, the states of Oregon and Washington passed building codes that will, as construction occurs over time, capture a good part of the residential space heating conservation resource identified in earlier estimates. This chapter estimates conservation resources based on savings beyond codes and standards that were enacted before 1991.

The estimate of the conservation resource in this chapter assumes that building codes and appliance standards will continue to be implemented over the planning period. Each of these codes means that there is less of the conservation resource left to acquire in the future, because it will be secured through fairly stable mechanisms: building and appliance codes. The energy reductions secured through codes reduce demand in the load forecasts.

Legislation that mandates implementation of conservation, such as building codes and appliance standards, reduces the forecast of electric loads, which—in turn—automatically reduces the amount of conservation potential remaining to be secured. Figure 7–1 depicts the effect on forecast loads and conservation resources of adopting conservation codes and standards. Forecast loads without building and appliance codes result in the highest electricity consumption over the 20–year horizon along "Pathway A." "Pathway C" represents electricity loads if all new houses and appliances purchased were to install all cost–effective conservation.

Once building codes and appliance standards are adopted, each new building or appliance is mandated to be more efficient. This results in an intermediate load forecast, because each new unit will consume less electricity than in Pathway A. This intermediate step is depicted as Pathway B in Figure 7-1. The difference between Pathway A and B is the conservation secured through the codes and standards. But often there are still cost-effective conservation measures not included in all of the codes and standards, and many end uses for which there are no codes or standards. The difference between B and C is the remaining conservation potential identified in this plan that still needs to be secured to fill electricity needs. This conservation resource remains a significant and cost-effective resource for the region. Actions to secure this resource are highlighted in the Action Plan.

While these new codes and standards tend to reduce the amount of future conservation available, new information on more conservation measures increased the potential in the final plan. For example, this chapter estimates savings from such measures as heat pump heat recovery ventilators, and residential lighting improvements, which were not included in the draft plan.

Estimating the Conservation Resource

The following section summarizes the Council's estimates of conservation resources available to the region. The narrative is based on calculations from the Council's high demand forecast. Results for the medium forecast are summarized at the end of each sector. Similar calculations were done for the low, medium-low and medium-high forecasts.

The evaluation of conservation resources involves three major steps. The first step is to develop conservation supply curves based on engineering analysis. This step entails evaluating the levelized life-cycle cost[3] of all conservation measures and ranking them with the least-cost measure first.

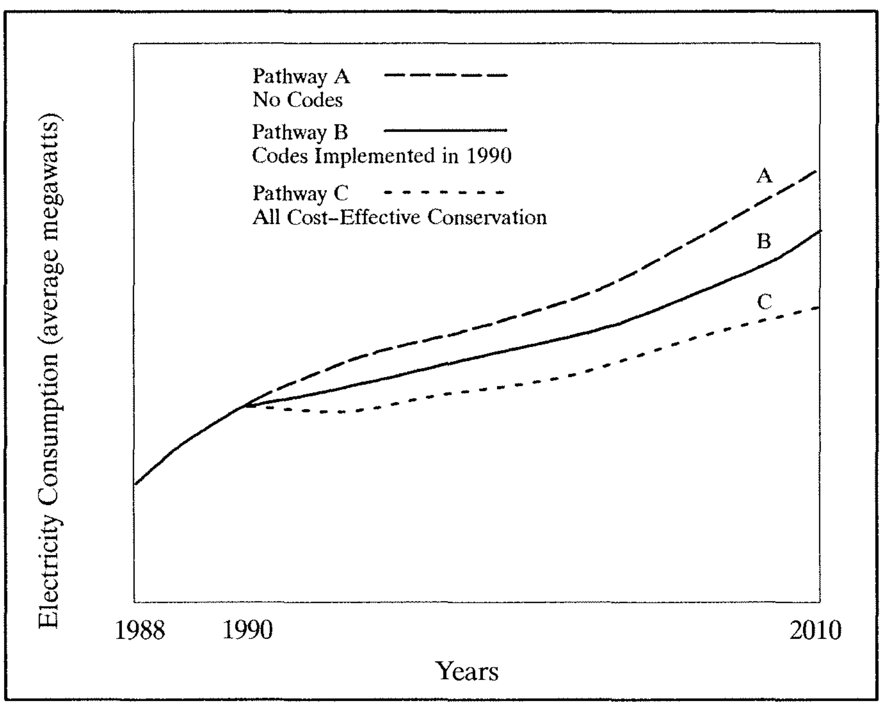
The second step is to group all measures into programs[4] with levelized costs up to a given avoided cost, in this case 11 cents per kilowatt-hour for the first block of conservation and typically 12 to 15 cents per kilowatt-hour for the second block, and to evaluate savings from these programs in the context of the Council's forecasting model. The program groupings are thus consistent with the assumptions in the Council's forecast. As part of this step, the measures grouped as programs are compared to any evaluation data available from the field that apply to similar end uses and are comparable in other characteristics.

3. Levelized life-cycle cost is the present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments; unit levelized life-cycle costs (cents per kilowatt-hour) are obtained by dividing this payment by the annual kilowatt-hours saved or produced.

4. The term program is used loosely here to mean the grouping of identified measures into an end use. For example, all the measures that can save hot water are identified and then grouped into the hot water end use. This grouping is called a "program," even though it may take various program delivery mechanisms to secure all the measures.

Load Effects

Figure 7-1
Effect on Loads and Conservation of Building and Appliance Codes



The third step involves using the cost and savings characteristics of each program to evaluate the conservation resource's cost-effectiveness and compatibility with the existing power system. Cost-effectiveness is determined by comparing each program against other resources to find which resource provides electric service at the lowest cost. This process is discussed further in Chapter 10.

These three steps are illustrated in Figure 7-2. Typically, information on measure costs and, to the extent possible, savings comes from programs operated in the region. This may mean actual weatherization costs incurred over the last few years in the weatherization program, or end use metered water heating consumption data from the End-Use Load and Conservation Assessment Program (ELCAP). Whenever possible, actual metered or field data are used. This information is combined in an economic analysis to select a group of measures that represent cost-effective efficiency improvements. The economic analysis requires data such as the discount rate and measure life. The economic analysis is described in another chapter of this plan.

Once the package of representative measures is selected, there is a calibration to the demand forecast to ensure that savings are not counted twice (once as a reduction of demand in the forecast and again as a conservation measure) or undercounted. In addition, consumer behavior, such as changing wood heating use in response to changes in electricity prices, are incorporated into the savings estimates. This results in average savings and costs for each end use that are calibrated to the forecast and that incorporate expected long-term consumer behavior.

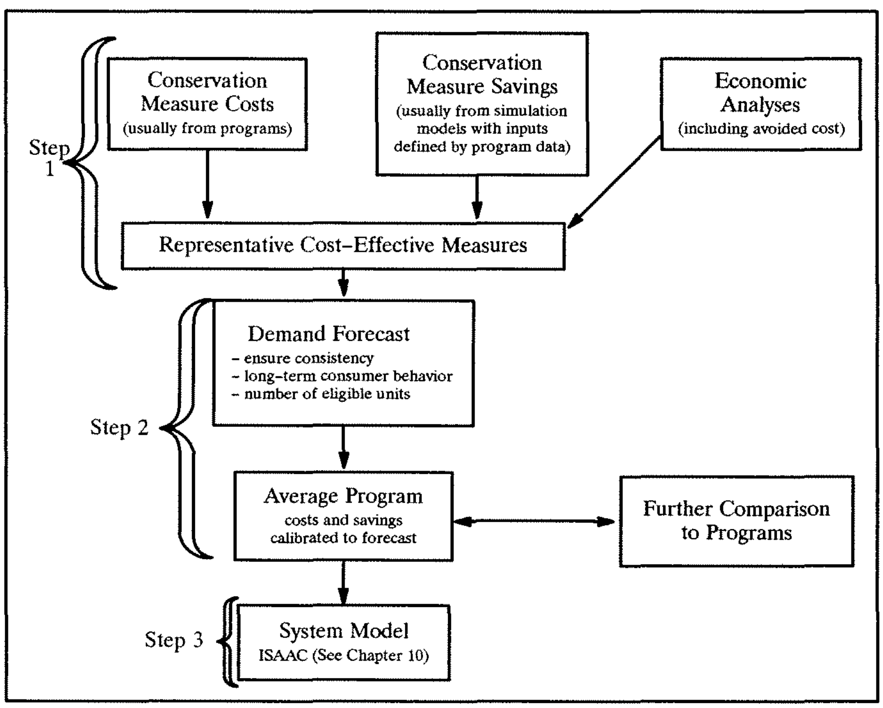
After the savings are calibrated to the forecast, the package of measures in each end use is compared to any evaluation data available from the field for comparable programs. This gives an indication of how well the results compare to evaluation data. Both the derived results here and the evaluation data can have problems, and in many cases they are not directly comparable, but each estimate helps assess the reliability and robustness of the other.

The cost and savings data, calibrated to the forecast, along with other characteristics of the end use savings (such as their seasonal distribution) are used in the system model, called the Integrated System for Analysis of Acquisitions (ISAAC), to be valued in comparison with other electricity options in the development of the resource portfolio. The system model is described in Chapter 10.

The bulk of this chapter deals with steps one and two, which are preliminary cost-effectiveness screens to size the conservation resource used in the resource portfolio. Since the collection of data to be used in deriving the costs and savings of conservation measures is very important, a table appears at the beginning of each end use section to summarize the key data sets used in the conservation estimates.

Key Analysis Steps

Figure 7-2
Key Steps in Conservation Analysis



Supply Curves

Conservation supply curves are used to determine the amount of conservation available at given costs. A supply curve is an economic tool that depicts the amount of a product available across a range of prices. In the case of conservation, this translates into the number of average megawatts that can be conserved (and made available for others to use) at various costs. For example, an industrial customer may be able to recover waste heat from a process and conserve 3 average megawatts at a cost of 2 cents per kilowatt-hour. This same customer may conserve 5, 7 and 8 average megawatts of electricity for the respective costs of 3, 4 and 5 cents per kilowatt-hour. These figures represent the conservation supply curve for this particular customer. Individual conservation estimates for end uses in each sector are merged to arrive at the regional supply curve for that sector.

The supply curves used in this plan do not distinguish between conservation resulting from specific programs or from rising prices of electricity. Whether the consumer or the utility invests in a conservation measure, the region is purchasing those savings at a particular price, and the money is not available for investment in other resources and goods. However, if a customer contributes to the purchase of conservation resources, then the cost to the electricity system will be less than the costs developed in this chapter.

Conservation supply curves are primarily a function of the conservation measure's savings and cost. Each measure's savings and cost are used to derive a levelized cost, expressed in cents per kilowatt-hour, for that measure. The absolute value (in terms of kilowatt-hours per year) of the savings produced by adding a conservation measure is a function of the existing level of efficiency. The less efficient the existing structure or equipment, the greater the savings obtained from installing the measure. In order to minimize the costs of efficiency improvements, conservation measures are applied with the least costly measure first,[5] until all measures are evaluated.

The levelized costs used to generate the supply curves are based on the calculations described in Volume II, Chapter 13. To ensure consistency between the conservation supply curves and the system models,[6] financial factors used in the levelized cost calculation are the same ones used in the system models. This means that the tax benefits, rate requirements and other financial considerations specific to the developer of the resource are accounted for in the levelized cost of the conservation resource.

The models assume that conservation will be financed for 20 years by the Bonneville Power Administration and for 20 years or the life of the conservation measures, whichever is shorter, by the investor-owned utilities. It was assumed that Bonneville would sponsor 40 percent of the conservation acquisition costs, and the investor-owned utilities would sponsor 60 percent, based on their share of total loads.

Conservation Programs for the Resource Portfolio Analysis

After the supply curves are generated for each end use or sector, the amount of conservation to be used in the resource portfolio analysis is first sized by cutting off the supply curve at a specific point. That is the point at which the levelized cost of the last measure included is equal to or just slightly less than the avoided cost. This is called the "technical" conservation potential. The technical potential is then reduced by the portion of the conservation resource that is considered not practically achievable. The remainder, termed "achievable conservation," is defined as the net energy savings the Council anticipates after taking into account factors such as consumer resistance, quality control and unforeseen technical problems. Historically, the Council has used high achievable conservation rates because it believes that the wide assortment of incentives and regulatory measures provided by the Northwest Power Act can persuade the region's electricity consumers to install a large percentage of the technically available conservation. These same rates were used in this chapter, and are described for each sector or end use at the end of the detailed section on that sector or end use.

Each conservation program consists of the package of measures that cost less than the avoided cost. Costs and savings for this package are taken from the supply curves described in this chapter. The present-value costs of the achievable savings for each program are adjusted in the following manner before they are used in the system models to determine compatibility with the existing power system and to derive a least-cost resource portfolio.

First, since the system models use conservation programs instead of measures in the resource portfolio, capital replacement costs have to be added to those measures with lifetimes shorter than the lifetime of the major measure in the program. For example, caulking and weatherstripping have shorter lifetimes than insulation; therefore, replacement costs are incurred over the expected lifetime of the insulation to maintain the benefits of caulking and weatherstripping.

Second, in addition to the direct capital and replacement costs of the conservation measures, administrative costs to run the program must be included in the overall cost. Administrative costs can vary significantly among programs and are usually ongoing annual costs. In the 1983 and 1986 Power Plans, the Council used 20 percent

5. Least costly is defined in terms of a measure's levelized life-cycle cost, stated in terms of cents per kilowatt-hour.

6. The system models are the Integrated System for Analysis of Acquisitions and the System Analysis Model.

of the capital costs of a conservation program to represent administrative costs. This figure is an oversimplification of a complex situation.

Several factors can affect the level of administrative costs needed to run a program. First, programs with different desired rates of acquisition will require different levels of administrative costs, especially for such things as marketing, advertising and contract management.

Furthermore, it is likely that the administrative costs will increase as the megawatts from a discretionary resource decrease. The first megawatts likely will be acquired from willing homeowners or businesses most interested in energy conservation. Alternatively, the last few megawatts may be very hard to identify and secure.

Finally, administrative costs likely will decrease as the portion of the total cost of conservation that a utility pays increases. Higher payments to individuals and businesses probably will result in lower administrative costs, because customers will require less of a "sales pitch" to participate.

The Council believes that the administrative cost of a given program is largely independent of the number of measures installed in a house or building. While some additional measures may increase the number of inspections, the administrative expense of requiring an insulation contractor to install full levels of cost-effective ceiling insulation is generally no greater than if the contractor were only required to install half the cost-effective amount. Processing of contracts, quality checks and other administrative actions still be needed, regardless of the number of measures installed.

Some evidence suggests that administrative costs in the commercial sector might exceed those in the residential sector, for several reasons. First, the commercial sector is far more diverse than the residential sector; therefore, much more difficult to target and work with. Furthermore, there are probably more barriers to adopting energy conservation measures in the commercial sector. These barriers include such things as absentee landlords. Administrative costs of convincing owners to participate in a program could be considerable, particularly in the existing commercial sector where daily business activities might have to be interrupted to install all cost-effective energy conservation measures. The perception of lost productivity or business may prevent businesses from taking cost-effective energy actions.

Countering some of these barriers is the fact that the Northwest Power Act provided significant mechanisms and incentives for this region to promote conservation. For example, the Council was authorized to develop model conservation standards for multiple end uses and to recommend that Bonneville assess a surcharge if those standards are not adopted. Bonneville can acquire the electrical output of conservation measures through an array of activities. These include direct purchases, authorizing loans and grants to consumers, providing technical and financial assistance, aiding in the implementation of the model conservation standards, and funding demonstration projects to determine the cost-effectiveness of conservation measures. In terms of administrative costs, the region still has little experience with programs that fall within the range of options authorized by the Act.

The data concerning administrative costs, even for currently operated programs, is still scarce. Puget Sound Power and Light provided the Council with two estimates of administrative costs: 5 percent of capital costs for its commercial lighting program[7] and 30 percent for its Audit Incentive Program. The Oregon Department of Energy found about a 25 percent administrative cost for its business energy tax credits program. Bonneville has found 25 percent administrative costs in its commercial Purchase of Energy Savings (PES) program and Commercial Incentive Pilot Program (CIPP). The Energy Edge Program, which has a significant research component, incurred 37 percent administrative costs.

Other programs with some data on administrative costs were reviewed when the Council's made its five-year report on progress with conservation.[8] These were primarily residential sector programs, and their administrative costs ranged from 15 percent to 28 percent. Oak Ridge National Laboratory recently conducted a review of administrative costs. It concluded that administrative costs for residential weatherization programs ran about 20 percent. Commercial audit and incentive programs had costs of 25 to 35 percent and commercial lighting about 10 to 15 percent.

The Council's current estimate of 20 percent falls within the range of costs experienced in the region to date. At this time, there is no evidence that argues strongly for a different estimate of administrative costs. Therefore, the average cost of the conservation programs is increased 20 percent before the conservation is compared to generating resources to determine which is more cost-effective. The Council is committed to continued monitoring of the administrative costs of regional conservation programs to see if this estimate can be refined.

A third factor that must be accounted for when comparing conservation programs with generating resources is the 10 percent credit given to conservation in the Northwest Power Act and continued by Bonneville in response to the Council's five-year review of conservation. This credit means that conservation can cost 10 percent more than the next lowest-cost resource and still be considered cost-effective under the Act.

Finally, to ensure that conservation and generating resources are compared fairly, the costs and savings of both types of resources must be evaluated at the same

7. In this program, which was operated through contractors, there were some questions regarding the allocation of program costs between the measures and administrative requirements.

8. Northwest Power Planning Council. *A Review of Conservation Costs and Benefits—Five Years of Experience under the Northwest Power Act.* October 1, 1987. (Order publication number 87-6.)

point of distribution in the electrical grid. Conservation savings and costs are evaluated at the point of use, such as in the house. In contrast, the costs and generation from a power plant are evaluated at the generator (busbar) itself. Thus, to make conservation and the traditional forms of generation comparable, the costs of the generation plant must be adjusted to include transmission system losses (7.5 percent) and transmission costs (2.5 percent).

The net effect of all these adjustments for the marginal conservation measure differs from the average program, because administrative costs are assessed on the average program and not the marginal measure. As mentioned above, the Council determined that the administrative cost of a given program depends largely on the number or amount of measures installed.

Compatibility with the Power System

After these adjustments are made, each conservation program is evaluated in terms of its compatibility with the existing power system. Comparisons are made to the cost and savings characteristics of other electricity resources. To assess compatibility, and ultimately the cost-effectiveness of the conservation programs, the Council used two complex computer programs, called the Integrated Systems for Analysis of Acquisitions (ISAAC) and the System Analysis Model (SAM). These models served as a final screen for judging whether a conservation program is regionally cost-effective.

As with the previous Decision Analysis Model, the ISAAC model determines how many resources are needed to serve the loads described by each of the Council's forecasts. This model includes several variables that describe the characteristics of different resources, including generating and conservation resources. The key conservation variables are program ramp rates, program type, conservation ownership assumptions, seasonal distribution of savings and percent payments for conservation acquisition. These variables are described next.

Ramp Rates

The discretionary conservation resources that the model secures in any one year to meet energy needs depend on how fast a program can become operational and on the ultimate amount of cost-effective conservation available. The rate at which a program can be brought online is sometimes known as the program ramp rate. If the region has surplus power for a long time, but a conservation program is already operating, the rate at which the program can slow down and the minimum level at which that program can remain viable are also important. The minimum viable level of the program, if above zero, determines the amount of savings that would accrue even though the region would prefer to delay purchase of the resource during the surplus period. These ramp rates are discussed in Volume II, Chapter 10.

Program Type

The Integrated Systems for Analysis of Acquisitions models four types of conservation programs. The first one, called non-discretionary programs, is modeled as savings that are secured automatically, regardless of the status of the power system. This is exemplified by conservation that is secured through codes. The second program type is very similar to the first, because the conservation is secured as new end uses of electricity are purchased, but the savings may be the result of programs rather than codes. This second program type is known as voluntary programs that operate on newly purchased appliances, houses and businesses. The third program type is a discretionary program that secures savings from existing end uses, such as residential weatherization. The fourth program type is a mixture of two programs. The conservation is initially secured without a program or code by homeowners or business managers on their own, but the end use is transitioned later into a particular program to secure the remaining conservation.

Resource Ownership

In addition to program types, the model needs to know the distribution of the ownership of the conservation savings among various parties in the region, particularly the investor-owned utilities, generating public utilities and non-generating public utilities. Ownership splits are based on the estimated number of customers in each electricity-consuming sector in these utilities' service territories.

Seasonal Distribution of Savings

The model also uses the seasonal distribution of the savings over the months of the year when assessing compatibility. In general, end use monitored data from the End-Use Load and Conservation Assessment Program is used to model the seasonal distribution of savings from residential space heating and appliances. For lack of data, commercial and industrial savings are assumed to be evenly distributed throughout the year. Finally, agricultural savings are modeled as being highest in April, May and June, with a smaller peak in September, and as non-existent at other times of the year.

Payments

Finally, the model can accommodate different levels of incentive payments for the acquisition of different types of conservation programs. These vary depending on the types of studies being conducted, and are used to primarily model rate impacts.

The technical discussion that follows describes the evaluation of conservation resources conducted by the Council. The narrative is illustrated with calculations from the high demand forecast, and the summary includes the results from the medium forecast. Similar calculations were conducted for all of the Council's forecasts. All costs are in 1990 dollars. This discussion, and the technical exhibits listed at the end of each sector, display the capital costs, energy savings and measure life used by the Council. Bonneville is expected to use comparable assumptions and procedures in any calculation of cost-effectiveness.

Residential Sector

In 1989, the region's residential sector consumed 5,790 average megawatts of electricity when adjusted for weather, which is about 34 percent of the region's total firm electrical consumption. Space heating is the largest single category of consumption in the residential sector; water heating is second.

Space Heating Conservation in Existing Residential Buildings

Figure 7-3 shows the estimated space heating savings available from existing residences at various electricity prices. The technical conservation potential, with no single measure exceeding 11 cents per kilowatt-hour, is approximately 200 average megawatts. The estimated average cost of insulating and weatherizing existing residences is about 7 cents per kilowatt-hour for single-family and multifamily houses. These values escalate to about 8 cents per kilowatt-hour if administrative costs and transmission and distribution adjustments are incorporated.

The Council's assessment of the conservation potential for existing space heating involved four steps. These steps were to:

1. estimate cost-effective thermal integrity changes that are available from insulating existing electrically heated dwellings;
2. develop savings estimates and conservation supply functions consistent with the Council's forecasting model, and incorporate the forecasting model's estimates of the effect of consumer behavior on savings using the thermal integrity changes identified in Step 1;
3. compare projected cost and savings estimates with historically observed cost and savings data; and,
4. estimate realizable conservation potential.

The key data sources used in this analysis come from the diverse programs operated in the region. These sources are summarized in Table 7-3.

Space Heating Potential

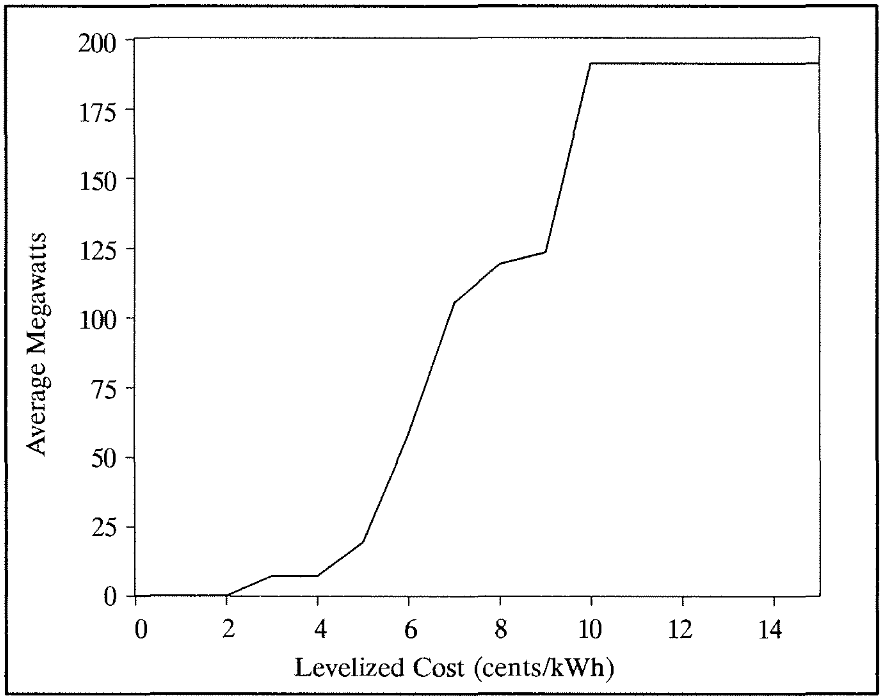


Figure 7-3
Technical Conservation Potential from Space Heating Measures in Existing Residences

Table 7–3
Key Data Sources for Existing Space Heating Measures

Costs	
Puget Power's Weatherization Program	Measure costs
Bonneville's Weatherization Program (Data Gathering Project)	Measure costs
Eugene Water and Electric Board's Weatherization Program	Time series of measure costs
Hood River Program	Measure costs
Consumption and Savings	
End–Use Load and Conservation Assessment Program (ELCAP)	Insulation levels of households remaining to be fully weatherized, space heating consumption
Residential Standards Demonstration Program	Test of simulation model
Evaluation Reports from Weatherization Programs	Use and savings comparison test of simulation inputs
1987 Oregon Survey	Insulation levels of houses remaining to weatherize
Pacific Northwest Residential Energy Surveys	Wood heat/electric splits, house size, unweatherized energy use

Step 1. Estimate Cost–Effective Thermal Integrity Improvements from Conservation Measures

The costs and savings of conservation measures are the primary determinants of the amount of conservation that is available from the supply curves. The Council's estimates of single–family home weatherization costs are based on information provided by Bonneville and utilities on the costs they have incurred in recent years to weatherize single–family residences. The actual costs of measures installed by the programs are shown in Table 7–4. Costs in the Hood River Conservation Project[9] are typically higher than costs experienced in regionwide, longer running programs. Information from Hood River was used for those measures not widely used in the regionwide weatherization program. This included the costs of insulating floors to R–30 where additional joist space had to be added to accommodate the depth of the insulation, and for a double–glazed storm window added to an existing window. As can be seen from the table, the region currently has a large data base of costs for common weatherization measures.

The costs of installing windows in existing houses were investigated as a separate item. Utility programs provided costs on adding storm windows and on replacing prime windows with somewhat better double–glazed windows. These programs do not include information on the costs of going to much more efficient windows at the time the existing prime window is replaced. Such an analysis requires separating the cost of labor to install a prime replacement window, which would be virtually the same regardless of the efficiency of the replacement window, from the cost of the physical window itself.

The labor costs of replacing an existing window were derived from phone conversations with window contractors. Some contractors pay their installers $35 per window for wood windows and $45 per window for aluminum or vinyl windows if the window size is 20 square feet or less, and an additional $10 for each additional 10 square feet. With the 1,350–square–foot prototype building, an assumption of half wood and half aluminum windows, and a 25 percent general contractor mark–up, this translates into labor costs of about $3.25 per square foot of window.

The next question is what are the materials costs of more efficient windows? This was addressed by looking at data from the residential standards demonstration program for new manufactured homes and the Competitek service from Rocky Mountain Institute. These costs are summarized in Table 7–4. None of these costs include the labor cost described above, although in the analysis, the labor cost was added to the replacement cost of the window.

9. The Hood River Conservation Project was an attempt to determine how much conservation could be acquired by weatherizing an entire community. The project provided unique and valuable experience in mobilizing the community resources. However, since it was testing how much could be installed, it included some measures that were not necessarily cost–effective at the time.

The manner in which the information was collected from the weatherization projects is not completely compatible with the prototype analysis required here. Consequently, the data was put in a format that reflected incremental steps. For example, instead of from R-0 to R-38 in one step, it went from R-0 to R-19 ceiling insulation and then from R-19 to R-30 and R-30 to R-38. This required making an estimate of the cost that is incurred to initially set up an insulation job, compared to the cost of adding additional insulation once the contractor is already incurring the labor to get to the house and set up. The costs from Puget Power and Bonneville are averaged together using the estimated proportion of houses in private and public service territories still eligible for a weatherization program. These costs are then allocated between job set-up costs and add-on costs for each measure. The results are displayed in Table 7-5 for those measures where costs had to be constructed from the actual measure data.

The costs of weatherizing multifamily units are based on costs reported by Bonneville and Puget Power to weatherize multifamily buildings in their service territories. While the data base for the multifamily weatherization measures is not as large as that for single-family weatherization, it is still quite large. The costs as reported by Bonneville and Puget are shown in Table 7-6. As with single-family costs, this information had to be summarized in a manner that was compatible with the prototype analysis. This information, after Bonneville and Puget costs were weighted together, is displayed in Table 7-7 for ceiling insulation. The costs for insulating floors from R-19 to R-30 and window costs are taken from information on single-family buildings, described above.

No savings or costs were estimated for weatherizing or insulating existing manufactured homes since there were significant questions surrounding the feasibility of such efforts. Bonneville is currently involved in collecting data on the costs and savings potential from existing manufactured homes. This effort will be reflected in the revision to the power plan following the completion of Bonneville's efforts.

It is useful to distinguish between set-up and add-on costs to answer two different questions. Set-up costs are included when determining whether any insulation should be added to a building component, given that a certain level already exists. For example, if a ceiling is already insulated to R-30, it turns out that it is not cost-effective to the region to pay for a contractor to come to the house and increase the ceiling insulation level to R-38. Add-on costs determine how far a building component should be insulated, assuming the contractor is already set up and has installed some base insulation. If the contractor is already there, for example, it is cost-effective to increase ceiling insulation to R-38 from a base of R-19, and it is also cost-effective to continue adding insulation to R-49. Thus, the regional cost-effectiveness limit is R-49 in the ceiling, if anything less than about R-30 exists before weatherization.

In an ideal situation, where all measures can be installed in the building and no lost-opportunity measure has already been created, the following measures would be recommended for installation in single-family houses: R-49 ceiling insulation, if the house has less than R-30; R-11 wall insulation, if no insulation currently exists; R-30 underfloor insulation if less than R-19 currently exists and there is space in the joist for the insulation; and either double paned thermally-broken storm windows or effective R-2.6 prime replacement windows, if single panes are present, but not if the windows are already double paned. The current analysis indicates that it is not cost-effective to weatherize these individual components further if the house is already at R-30 in the ceiling, has some wall insulation, has R-19 or more in the floor and double pane windows. Since there is some uncertainty regarding the labor costs of prime replacement windows, the Council conducted a sensitivity analysis to see how high labor costs could go and still keep R-2.6 replacement windows cost-effective. A sensitivity done on the 1,350-square-foot prototype in Seattle indicated that the labor costs could more than double, and moving from an R-1.2 to an R-2.6 window would still be cost-effective.

These results have important implications for the design of weatherization programs. For example, if a utility runs a weatherization program that takes the ceiling insulation to R-30 only, the savings from going beyond R-30 are lost to the region, even though it would have been cost-effective to go further at the time the house was weatherized. Additionally, these results lead to a weatherization program design that could be modeled after the oil dipstick in a car. If an audit shows that the house already has R-30 in the ceiling, it is only half a quart low and no oil—that is, insulation—should be added. On the other hand, if the audit shows that the ceiling is only at R-19, it is a full quart low, and insulation should be added to the full cost-effectiveness level (R-49), or as close as structural barriers permit.

Three typical building designs were used to estimate the retrofit potential for single-family houses in the region. The first is an 850-square-foot, single-story house built over an unheated basement. The second is a 1,350-square-foot house over a vented crawl space. The third is a 2,100-square-foot, two-story house with a heated basement. The multifamily design is a three-story apartment house with four 840-square-foot units on each floor.

Table 7–4
Cost to Weatherize Single–Family Dwellings—Actual Program Data Where Available[a] (N = sample size)

	Puget Power		Bonneville Data Gathering Project		Other Source	
	($/sq. ft.)	(N)	($/sq. ft.)	(N)	($/sq. ft.)	(N)
Ceiling Insulation						
▪ R–0 to R–38	0.59	1,761	0.69	778		
▪ R–11 to R–38	0.47	6,513	0.48	1,951		
▪ R–19 to R–38	0.40	2,379	0.42	881		
▪ R–30 to R–38	0.40	79	0.61	149		
Wall Insulation						
▪ R–0 to R–11	0.44	3,075	0.72	1,296		
▪ R–0 to R–19			0.72	184		
Floor Insulation						
▪ R–0 to R–11	0.65	9,117	0.71	2,081		
▪ R–0 to R–30	—	—	0.80	9		
Doors					12.85[b]	
Caulking and Weatherstripping		1991 house	1,600[c]			
Glass						
▪ Storm Windows—Single to Double	6.75	10,763	7.50	2,624		
▪ Prime Replacement Windows[e]						
• R–2.6					15.94	
• R–5					23.13	

[a] These costs were incurred over a three– to five–year period. Analysis of Eugene Water and Electric Board's weatherization data, collected by year since 1983, showed that the costs of weatherization measures have remained constant over this period. Costs are therefore in 1990 dollars.

[b] Taken from the 1983 Power Plan, and escalated to 1990 dollars.

[c] Approximate sample size.

[d] Approximate sample size. These costs are from the Hood River Conservation Project.

[e] Materials only. Labor is an additional $3.25 per square foot.

Table 7–5
Individual Measure Costs to Weatherize Single–Family Dwellings from Actual Program Data (1990 Dollars)

	Set–up[a] Costs ($/sq. ft.)	Add–on[b] Costs ($/sq. ft.)
Ceiling Insulation		
▪ R–0 to R–19	0.44	—
▪ R–19 to R–30	0.33	0.15
▪ R–30 to R–38	0.29	0.11
▪ R–38 to R–49	—	0.15[c]
Floor Insulation		
▪ R–0 to R–19	0.74	—
▪ R–19 to R–30	—	0.14
▪ R–19 to R–30 with added joist	0.64[d]	—

[a] Set–up costs are the costs of installing insulation, assuming the contractor has to be called to the site.

[b] Add–on costs represent the incremental cost of adding insulation assuming the contractor is already installing insulation for that building component.

[c] Costs taken from the 1986 Power Plan.

[d] Estimated cost for the measure if additional joist space must be added to accommodate the R–30 insulation.

Table 7-6
Costs to Weatherize Multifamily Dwellings—Actual Program Data Where Available[a] (N = sample size)

	Puget Power		Bonneville Data Gathering Project		Other Source	
	($/sq. ft.)	(N)	($/sq. ft.)	(N)	($/sq. ft.)	(N)
Ceiling Insulation						
▪ R-0 to R-38	0.45	933	0.76	62		
▪ R-11 to R-38	0.45	2,079	0.42	159		
▪ R-19 to R-38	0.37	1,199	0.48	50		
▪ R-30 to R-38	0.43	23	0.26	10		
Wall Insulation						
▪ R-0 to R-11	0.56	184	0.70	42		
▪ R-0 to R-19			0.54	12		
Floor Insulation						
▪ R-0 to R-19	0.62	2,717	0.69	145		
Doors					12.84[b]	
Caulking and Weatherstripping			118/ dwelling unit	115[c]		
Glass						
▪ Storm Window—Single to Double	6.30	4,395	6.00	217		
▪ Prime Replacement Window[d]						
• R-2.6					15.94	
• R-5					23.13	

[a] These costs were incurred over a three- to five-year period. Analysis of Eugene Water and Electric Board's weatherization costs, collected by year since 1983, showed that the costs of weatherization measures have remained constant over this period. Costs are therefore represented in 1990 dollars.

[b] Taken from the 1983 Power Plan.

[c] Approximate sample size.

[d] Materials only. Labor is an additional $3.25 per square foot.

Table 7–7
Individual Measure Costs to Weatherize Multifamily Dwellings from Actual Program Data (1990 Dollars)

	Set-up[a] Costs ($/sq. ft.)	Add-on[b] Costs ($/sq. ft.)
Ceiling Insulation		
▪ R–0 to R–19	0.46	—
▪ R–19 to R–30	0.42	0.08
▪ R–30 to R–38	0.40	0.04

[a] Set-up costs are the costs of adding insulation, assuming the contractor has not been called to the site already.

[b] Add-on costs represent the incremental cost of adding insulation, assuming the contractor is already installing insulation for that building component.

There are limitations on the number of houses that can reach full cost-effective weatherization levels. For example, if the house does not have room in the joist system to accommodate R–30 insulation, then given current data, it does not appear cost-effective to add the increased joist space to accommodate the thicker insulation. Given this limitation, the current analysis of single-family residential weatherization savings uses R–30 floors on only one of the three prototypes. Less information is known about multifamily buildings. As a consequence, the multifamily prototypes were modeled with floors that could go to R–30 insulation without the increased joist cost. In addition, recent draft information on air change rates in multifamily units indicates that these dwellings have less air exchange with the outside air than single-family houses. The base case air change rate for multifamily dwellings is 0.4 air changes per hour in the current analysis. For single-family houses, the initial air change rate is assumed to be 0.6 air changes per hour. When some air infiltration reduction measures are taken, this is assumed to drop to 0.5 air changes per hour. This is a fairly small drop in infiltration, because costs taken from current programs represent only fairly small amount of air infiltration reduction measures.

Savings from weatherization measures installed in all four house designs were estimated using a two-step process. This first step assesses the savings from each measure holding constant other determinants of space heating consumption, such as thermostat settings and room closure behavior. The second step is to take the aggregate efficiency improvement that is identified as cost-effective compared to a house with average insulation, and run it through the forecast to incorporate consumer behavior changes into the estimate of aggregate savings.

In the first step, the SUNDAY computer model,[10] which simulates a building's daily space heating energy needs, is used to evaluate a base case and the savings attributable to each conservation measure, holding behavior constant. This step determines which of the representative measures applied to the prototypes are cost-effective. At this stage, savings are evaluated using an average indoor temperature setting of 65°F, internal gains consistent with the efficient appliances included in the Council's resource portfolio (2,000 British thermal units per hour), and no reduction in use from room closure and wood heat. This set of assumptions is often called the "standard operating conditions" of a residential building.

These values were selected based on analysis and judgment. They represent a house used at levels that are reasonable if efficiency measures are installed. Curtailment activities, such as room closure and reduced temperature settings, are less likely to continue after efficiency measures are installed since these measures significantly lower utility bills. If the house ends up being operated in the long run at reduced amenity, then potentially a measure was included in the program that should not have been there. However, if less than full amenity were assumed in this step of the analysis, then measures that might have been cost-effective would be lost. The Council has selected the former condition as preferable to the latter, partially to protect against the high load growth scenarios, where every conservation measure is important.

It is important to emphasize here that the SUNDAY model is used to determine which representative measures should be incorporated into a program, while holding behavior at pre-determined amenity levels. Once the relative efficiency change is determined, savings are re-estimated using the forecasting model to incorporate behavioral changes in response to price. In addition, because the forecast implicitly incorporates an estimate of wood heat and room closure, these are also accounted for in the average estimate of savings from weatherizing houses.

10. The SUNDAY model simulates space heating needs based on heat loss rate, daily access to solar energy, daily inside and outside temperatures, thermal mass, and the amount of heat given off by lights, people and appliances.

Tables 7–8 through 7–10 for single-family and Table 7–11 for multifamily houses show the costs, levelized in mills (tenths of a cent) per kilowatt-hour, and the engineering savings assuming standard operating conditions from weatherizing the typical prototype houses in three representative climate zones in the region. The purpose of these tables is to show the expected reduction in space heating use as weatherization measures are installed. The precise order of the measures, and their location in the list is a function of which one has the least expected cost per savings. Since people often install measures out of order, the listings here must be considered as simply representative of the type of expected energy savings that would be secured as insulation is added.

Each measure has its own average or expected lifetime, which is used in generating the levelized cost. The levelized costs displayed in these tables reflect financing costs and replacement costs for short-lived measures. Insulation and prime replacement windows last the lifetime of the residence, which for existing stock is expected to be an average of about 60 years or more. This was reduced to 50 years. Replacement doors are assumed to last an average of about 30 years. Infiltration reduction measures were assumed to last 10 years.

Table 7-8
Representative Thermal Integrity Curve for Single-Family Dwelling Weatherization Measures, Zone 1—Seattle

Measures	UA	Capital Cost		Annual Use		Present Value Cost	Levelized Cost (mills/kWh)
		Total	($/sq. ft.)	(kWh/yr.)	(kWh/sq. ft.)		
House Size—850 Square Feet							
Base Case	669	$0	0.00	18,869	22.20	$0	0
Ceiling R-0 to R-19	478	$374	0.44	11,795	13.88	$418	4
Walls R-0 to R-11	393	$978	1.15	8,735	10.28	$1,094	16
Crawl Space R-0 to R-19	316	$1,607	1.89	6,079	7.15	$1,798	20
Ceiling R-19 to R-30	302	$1,735	2.04	5,594	6.58	$1,941	22
Crawl Space R-19 to R-30	295	$1,854	2.18	5,369	6.32	$2,074	45
ACH .6 to .5	283	$1,954	2.30	4,966	5.84	$2,412	64
Ceiling R-30 to R-38	279	$2,047	2.41	4,854	5.71	$2,516	71
Windows R-3	274	$2,218	2.61	4,669	5.49	$2,707	78
Windows R-2.6	231	$3,545	4.17	3,335	3.92	$4,192	85
Windows R-5	220	$4,221	4.97	2,991	3.52	$4,948	168
Wood to Metal Door	209	$4,783	5.63	2,659	3.13	$5,804	197
House Size—1,350 Square Feet							
Base Case	1,025	$0	0.00	30,440	22.55	$0	0
Ceiling R-0 to R-19	721	$594	0.44	19,144	14.18	$665	4
Walls R-0 to R-11	589	$1,362	1.01	14,323	10.61	$1,524	13
Crawl Space R-0 to R-19	467	$2,361	1.75	10,036	7.43	$2,642	19
Ceiling R-19 to R-30	444	$2,564	1.90	9,249	6.85	$2,868	22
ACH .6 to .5	425	$2,664	1.97	8,587	6.36	$3,206	39
Ceiling R-30 to R-38	419	$2,812	2.08	8,406	6.23	$3,372	70
Windows R-3	410	$3,082	2.28	8,107	6.01	$3,674	77
Windows R-2.6	343	$5,187	3.84	5,907	4.38	$6,029	81
Windows R-5	325	$6,258	4.64	5,338	3.95	$7,227	161
Wood to Metal Door	314	$6,819	5.05	4,991	3.70	$8,082	188
Crawl Space R-19 to R-30[a]	303	$7,683	5.69	4,657	3.45	$9,049	221
House Size—2,100 Square Feet							
Base Case	1,140	$0	0.00	31,231	14.87	$0	0
Ceiling R-0 to R-19	982	$308	0.15	25,466	12.13	$345	4
Walls R-0 to R-11	783	$1,505	0.72	18,360	8.74	$1,684	14
Ceiling R-19 to R-30	771	$1,610	0.77	17,943	8.54	$1,801	21
ACH .6 to .5	739	$1,710	0.81	16,802	8.00	$2,139	22
Ceiling R-30 to R-38	736	$1,787	0.85	16,706	7.96	$2,225	68

Table 7–8 (cont.)
Representative Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures, Zone 1—Seattle

Measures	UA	Capital Cost Total	Capital Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Present Value Cost	Levelized Cost (mills/kWh)
House Size—2,100 Square Feet (cont.)							
Windows R-3	717	$2,358	1.12	16,054	7.64	$2,864	75
Windows R-2.6	575	$6,807	3.24	11,270	5.37	$7,842	79
Windows R-5	537	$9,071	4.32	10,049	4.79	$10,375	158
Wood to Metal Door	526	$9,633	4.59	9,692	4.62	$11,231	183

[a] The costs of this measure include an estimate for extending the joist to accommodate R-30 insulation.

Table 7–9
Representative Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures, Zone 2—Spokane

Measures	UA	Capital Cost Total	Capital Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Present Value Cost	Levelized Cost (mills/kWh)
House Size—850 Square Feet							
Base Case	669	$0	$0.00	25,536	30.04	$0	0
Ceiling R-0 to R-19	478	$374	$0.44	16,582	19.51	$418	3
Walls R-0 to R-11	393	$978	$1.15	12,678	14.92	$1,094	13
Crawl Space R-0 to R-19	316	$1,607	$1.89	9,247	10.88	$1,798	15
Ceiling R-19 to R-30	302	$1,735	$2.04	8,609	10.13	$1,941	17
Crawl Space R-19 to R-30	295	$1,854	$2.18	8,311	9.78	$2,074	34
ACH .6 to .5	283	$1,954	$2.30	7,775	9.15	$2,412	48
Ceiling R-30 to R-38	279	$2,047	$2.41	7,626	8.97	$2,516	53
Windows R-3	274	$2,218	$2.61	7,380	8.68	$2,707	59
Windows R-2.6	231	$3,545	$4.17	5,567	6.55	$4,192	62
Windows R-5	220	$4,221	$4.97	5,094	5.99	$4,948	122
Wood to Metal Door	209	$4,783	$5.63	4,633	5.45	$5,804	141
House Size—1,350 Square Feet							
Base Case	1,025	$0	$0.00	40,342	29.88	$0	0
Ceiling R-0 to R-19	721	$594	$0.44	26,081	19.32	$665	3
Walls R-0 to R-11	589	$1,362	$1.01	19,988	14.81	$1,524	10
Crawl Space R-0 to R-19	467	$2,361	$1.75	14,517	10.75	$2,642	15
Ceiling R-19 to R-30	444	$2,564	$1.90	13,496	10.00	$2,868	16
ACH .6 to .5	425	$2,664	$1.97	12,636	9.36	$3,206	30

Table 7–9 (cont.)
Representative Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures, Zone 2—Spokane

Measures	UA	Capital Cost Total	Capital Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Present Value Cost	Levelized Cost (mills/kWh)
House Size—1,350 Square Feet (cont.)							
Ceiling R–30 to R–38	419	$2,812	$2.08	12,398	9.18	$3,372	53
Windows R–3	410	$3,082	$2.28	12,004	8.89	$3,674	58
Windows R–2.6	343	$5,187	$3.84	9,083	6.73	$6,029	61
Windows R–5	325	$6,258	$4.64	8,321	6.16	$7,227	120
Wood to Metal Door	314	$6,819	$5.05	7,852	5.82	$8,082	139
Crawl Space R–19 to R–30[a]	303	$7,683	$5.69	7,401	5.48	$9,049	163
House Size—2,100 Square Feet							
Base Case	1,140	$0	$0.00	41,942	19.97	$0	0
Ceiling R–0 to R–19	982	$308	$0.15	34,672	16.51	$345	3
Walls R–0 to R–11	783	$1,505	$0.72	25,629	12.20	$1,684	11
Ceiling R–19 to R–30	771	$1,610	$0.77	25,093	11.95	$1,801	16
ACH .6 to .5	739	$1,710	$0.81	23,625	11.25	$2,139	17
Ceiling R–30 to R–38	736	$1,787	$0.85	23,500	11.19	$2,225	52
Windows R–3	717	$2,358	$1.12	22,657	10.79	$2,864	57
Windows R–2.6	575	$6,807	$3.24	16,397	7.81	$7,842	60
Windows R–5	537	$9,071	$4.32	14,778	7.04	$10,375	119
Wood to Metal Door	526	$9,633	$4.59	14,301	6.81	$11,231	137

[a] The costs of this measure include an estimate for extending the joist to accommodate R–30 insulation.

Table 7–10
Representative Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures, Zone 3—Missoula

Measures	UA	Capital Cost Total	Capital Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Present Value Cost	Levelized Cost (mills/kWh)
House Size—850 Square Feet							
Base Case	669	$0	$0.00	29,675	34.91	$0	0
Ceiling R–0 to R–19	478	$374	$0.44	19,418	22.84	$418	3
Walls R–0 to R–11	393	$978	$1.15	14,902	17.53	$1,094	11
Crawl Space R–0 to R–19	316	$1,607	$1.89	10,904	12.83	$1,798	13
Ceiling R–19 to R–30	302	$1,735	$2.04	10,160	11.95	$1,941	14
Crawl Space R–19 to R–30	295	$1,854	$2.18	9,814	11.55	$2,074	29

Table 7–10 (cont.)
Representative Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures, Zone 3—Missoula

Measures	UA	Capital Cost Total	Capital Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Present Value Cost	Levelized Cost (mills/kWh)
House Size—850 Square Feet (cont.)							
ACH .6 to .5	283	$1,954	$2.30	9,194	10.82	$2,412	41
Ceiling R–30 to R–38	279	$2,047	$2.41	9,022	10.61	$2,516	46
Windows R–3	274	$2,218	$2.61	8,736	10.28	$2,707	51
Windows R–2.6	231	$3,545	$4.17	6,638	7.81	$4,192	54
Windows R–5	220	$4,221	$4.97	6,091	7.17	$4,948	105
Wood to Metal Door	209	$4,783	$5.63	5,556	6.54	$5,804	122
House Size—1,350 Square Feet							
Base Case	1,025	$0	$0.00	46,836	34.69	$0	0
Ceiling R–0 to R–19	721	$594	$0.44	30,499	22.59	$665	3
Walls R–0 to R–11	589	$1,362	$1.01	23,435	17.36	$1,524	9
Crawl Space R–0 to R–19	46	$2,361	$1.75	17,058	12.64	$2,642	13
Ceiling R–19 to R–30	444	$2,564	$1.90	15,876	11.76	$2,868	14
ACH .6 to .5	425	$2,664	$1.97	14,882	11.02	$3,206	25
Ceiling R–30 to R–38	419	$2,812	$2.08	14,607	10.82	$3,372	46
Windows R–3	410	$3,082	$2.28	14,154	10.48	$3,674	50
Windows R–2.6	343	$5,187	$3.84	10,788	7.99	$6,029	53
Windows R–5	325	$6,258	$4.64	9,906	7.34	$7,227	103
Wood to Metal Door	314	$6,819	$5.05	9,362	6.93	$8,082	120
Crawl Space R–19 to R–30[a]	303	$7,683	$5.69	8,838	6.55	$9,049	141
House Size—2,100 Square Feet							
Base Case	1,140	$0	$0.00	48,918	23.29	$0	0
Ceiling R–0 to R–19	982	$308	$0.15	40,513	19.29	$345	3
Walls R–0 to R–11	783	$1,505	$0.72	30,039	14.30	$1,684	9
Ceiling R–19 to R–30	771	$1,610	$0.77	29,417	14.01	$1,801	14
ACH .6 to .5	739	$1,710	$0.81	27,711	13.20	$2,139	15
Ceiling R–30 to R–38	736	$1,787	$0.85	27,566	13.13	$2,225	45
Windows R–3	717	$2,358	$1.12	26,585	12.66	$2,864	49
Windows R–2.6	575	$6,807	$3.24	19,372	9.22	$7,842	52
Windows R–5	537	$9,071	$4.32	17,505	8.34	$10,375	103
Wood to Metal Door	526	$9,633	$4.59	16,956	8.07	$11,231	119

[a] The costs of this measure include an estimate for extending the joist to accommodate R–30 insulation.

Table 7–11
Representative Thermal Integrity Curve for Multifamily Dwelling Weatherization Measures

Measure	UA (per unit)	Incremental Capital Cost	Cumulative Capital Cost	Cumulative Present Value Cost	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Levelized Cost (mills/kWh)
Zone 1—Seattle							
Base Case	345	0	0	0	7,841	9.3	0
Ceiling R–0 to R–19	276	$140	$140	$156	5,470	6.5	5.0
Ceiling R–19 to R–30	271	$21	$161	$180	5,297	6.3	10.5
Walls R–0 to R–11	228	$301	$462	$517	3,874	4.6	18.1
Crawl Space R–0 to R–19	203	$215	$677	$758	3,082	3.7	23.3
Ceiling R–30 to R–38	202	$15	$693	$775	3,044	3.6	34.8
Crawl Space R–19 to R–30	199	$42	$735	$823	2,961	3.5	43.5
ACH .4 to .3	185	$129	$864	$1,258	2,532	3.0	77.8
Windows R–3	179	$172	$1,036	$1,451	2,363	2.8	87.4
Windows R–2.6	136	$1,342	$2,378	$2,952	1,169	1.4	96.2
Windows R–5	125	$683	$3,061	$3,716	887	1.1	207.5
Wood to Metal Door	122	$140	$3,201	$3,929	823	1.0	256.9
Zone 2—Spokane							
Base Case	345	0	0	0	11,237	13.4	0
Ceiling R–0 to R–19	276	$140	$140	$156	8,173	9.7	3.9
Ceiling R–19 to R–30	271	$21	$161	$180	7,945	9.5	8.0
Walls R–0 to R–11	228	$301	$462	$517	6,054	7.2	13.7
Crawl Space R–0 to R–19	203	$215	$677	$758	4,982	5.9	17.2
Ceiling R–30 to R–38	202	$15	$693	$775	4,931	5.9	25.5
Crawl Space R–19 to R–30	199	$42	$735	$823	4,816	5.7	31.8
ACH .4 to .3	185	$129	$864	$1,258	4,227	5.0	56.6
Windows R–3	179	$172	$1,036	$1,451	3,993	4.8	62.9
Windows R–2.6	136	$1,342	$2,378	$2,952	2,297	2.7	67.8
Windows R–5	125	$683	$3,061	$3,716	1,877	2.2	139.1
Wood to Metal Door	122	$140	$3,201	$3,929	1,779	2.1	166.1
Zone 3—Missoula							
Base Case	345	0	0	0	13,186	15.7	0
Ceiling R–0 to R–19	276	$140	$140	$156	9,624	11.5	3.4
Ceiling R–19 to R–30	271	$21	$161	$180	9,359	11.1	6.9
Walls R–0 to R–11	228	$301	$462	$517	7,172	8.5	11.8

Table 7–11 (cont.)
Representative Thermal Integrity Curve for Multifamily Dwelling Weatherization Measures

Measure	UA (per unit)	Incremental Capital Cost	Cumulative Capital Cost	Cumulative Present Value Cost	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Levelized Cost (mills/kWh)
Zone 3—Missoula (cont.)							
Crawl Space R-0 to R-19	203	$215	$677	$758	5,934	7.1	14.9
Ceiling R-30 to R-38	202	$15	$693	$775	5,875	7.0	22.0
Crawl Space R-19 to R-30	199	$42	$735	$823	5,742	6.8	27.5
ACH .4 to .3	185	$129	$864	$1,258	5,063	6.0	49.1
Windows R-3	179	$172	$1,036	$1,451	4,795	5.7	55.0
Windows R-2.6	136	$1,342	$2,378	$2,952	2,848	3.4	59.1
Windows R-5	125	$683	$3,061	$3,716	2,355	2.8	118.5
Wood to Metal Door	122	$140	$3,201	$3,929	2,237	2.7	138.8

Since each representative measure saves a different amount of energy in each house design and location, an aggregate supply curve must be developed to represent the weighted average efficiency change for all representative measures in the dwelling types. The use and cost from each climate zone were combined according to percentages listed in Table 7-12. The regional average thermal integrity curves for each typical house design appear in Tables 7-13 and 7-14.

Table 7–12
Weights Used to Reflect Regional Weather for Existing Space Heating

	Climate Zone 1	Climate Zone 2	Climate Zone 3
Single-Family Dwellings	84%	11%	5%
Multifamily Dwellings	73.1%	22.1%	4.8%

Table 7–13
Regionally Weighted Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures

	Levelized Cost (mills/kWh)	Capital Cost ($/sq. ft.)	Use/sq.ft. (kWh/yr.)	Present–Value Cost	UA
House Size—850 Square Feet					
Base Case	0	$0.00	23.70	$0	669
Ceiling R–0 to R–19	4	$0.44	14.94	$418	478
Walls R–0 to R–11	16	$1.15	11.15	$1,094	393
Crawl Space R–0 to R–19	19	$1.89	7.85	$1,798	316
Ceiling R–19 to R–30	21	$2.04	7.24	$1,941	302
Crawl Space R–19 to R–30	43	$2.18	6.96	$2,074	295
ACH .6 to .5	61	$2.30	6.45	$2,412	283
Ceiling R–30 to R–38	68	$2.41	6.31	$2,516	279
Windows R–3	75	$2.61	6.08	$2,707	274
Windows R–2.6	81	$4.17	4.41	$4,192	231
Windows R–5	160	$4.97	3.97	$4,948	220
Wood to Metal Door	187	$5.63	3.55	$5,804	209
House Size—1,350 Square Feet					
Base Case	0	$0.00	23.96	$0	1,025
Ceiling R–0 to R–19	4	$0.44	15.17	$665	721
Walls R–0 to R–11	13	$1.01	11.41	$1,524	589
Crawl Space R–0 to R–19	19	$1.75	8.06	$2,642	467
Ceiling R–19 to R–30	21	$1.90	7.44	$2,868	444
ACH .6 to .5	37	$1.97	6.92	$3,206	425
Ceiling R–30 to R–38	67	$2.08	6.78	$3,372	419
Windows R–3	73	$2.28	6.55	$3,674	410
Windows R–2.6	78	$3.84	4.82	$6,029	343
Windows R–5	153	$4.64	4.37	$7,227	325
Wood to Metal Door	179	$5.05	4.09	$8,082	314
Crawl Space R–19 to R–30[a]	211	$5.69	3.83	$9,049	303
House Size—2,100 Square Feet					
Base Case	0	$0.00	15.85	$0	1,140
Ceiling R–0 to R–19	4	$0.15	12.97	$345	982
Walls R–0 to R–11	13	$0.72	9.40	$1,684	783
Ceiling R–19 to R–30	20	$0.77	9.19	$1,801	771
ACH .6 to .5	21	$0.81	8.62	$2,139	739
Ceiling R–30 to R–38	65	$0.85	8.57	$2,225	736

Table 7–13 (cont.)
Regionally Weighted Thermal Integrity Curve for Single–Family Dwelling Weatherization Measures

	Levelized Cost (mills/kWh)	Capital Cost ($/sq. ft.)	Use/sq. ft. (kWh/yr.)	Present–Value Cost	UA
House Size—2,100 Square Feet (cont.)					
Windows R-3	71	$1.12	8.24	$2,864	717
Windows R-2.6	76	$3.24	5.83	$7,842	575
Windows R-5	151	$4.32	5.21	$10,375	537
Wood to Metal Door	174	$4.59	5.03	$11,231	526

[a] The costs of this measure include an estimate for extending the joist to accommodate R-30 insulation.

Table 7–14
Regionally Weighted Thermal Integrity Curve for Multifamily Dwelling Weatherization Measures (per unit)

Measure	UA	Incremental Capital Cost	Cumulative Capital Cost	Cumulative Present Value Cost	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Levelized Cost (mills/kWh)
Base Case	345	$0	$0	$0	8,856	10.5	0.0
Ceiling R-0 to R-19	276	$140	$140	$156	6,273	7.5	4.7
Ceiling R-19 to R-30	271	$21	$161	$180	6,083	7.2	9.8
Walls R-0 to R-11	228	$301	$462	$517	4,518	5.4	16.8
Crawl Space R-0 to R-19	203	$215	$677	$758	3,642	4.3	21.5
Ceiling R-30 to R-38	202	$15	$693	$775	3,601	4.3	32.1
Crawl Space R-19 to R-30	199	$42	$735	$823	3,508	4.2	40.1
ACH .4 to .3	185	$129	$864	$1,258	3,032	3.6	71.7
Windows R-3	179	$172	$1,036	$1,451	2,843	3.4	80.4
Windows R-2.6	136	$1,342	$2,378	$2,952	1,501	1.8	88.1
Windows R-5	125	$683	$3,061	$3,716	1,178	1.4	188.0
Wood to Metal Door	122	$140	$3,201	$3,929	1,104	1.3	231.0

The cost and use for each of the three single–family houses were merged to estimate regional space heating consumption by cents per kilowatt–hour. The 1979 Pacific Northwest survey indicated that the average pre–1980 house was approximately 1,350 square feet. The 2,100–square–foot, 1,350–square–foot, and 850–square–foot houses were weighted to represent approximately 22, 46 and 32 percent, respectively, of the regional stock to achieve the appropriate average house size. These weights result in an average house size of 1,355 square feet. Tables 7–15 and 7–16 show the curve of regionally weighted costs and space heating use for single–family and multifamily houses.

The information from Table 7–15 is displayed graphically in Figure 7–4. The curve represents thermal integrity improvements starting with an uninsulated house. Space heating use is reduced and present–value costs increase from adding more insulation to the house. The space heating use of the solid line is based on the SUNDAY model with the assumed standard operating conditions described above. If, for example, a reduced thermostat set point were used instead of the currently assumed standard operating conditions, the curve would be displaced to a lower use for a given amount of conservation investment. The level of use that is predicted at the 11 cent cost-effectiveness cut-off, labeled point C, is also identified in Figure 7-4. The forecasting model predicts a lower usage in the pre-weatherization condition than standard operating conditions. This is illustrated by point B. This put the houses on a lower amenity curve, below the one depicted. However, after weatherization, the forecast predicts that space heat use is fairly close to the line represented by standard operating conditions, depicted by point D. This means that behavior has changed, and the occupants now operate the house at an energy use that is closer to those assumed in standard operating conditions.

The purpose of the thermal integrity curve is to identify the relative efficiency level that is cost-effective, holding amenities constant. That efficiency level is the ratio of the use at the 11 cent cut-off divided by the estimated base case use of a house. This is consumption at point C divided by consumption at point A. As noted earlier, these curves start with an uninsulated house, while the vast majority of houses in the region, even those that are not retrofitted, already have some insulation. Therefore, the base case use on which a relative efficiency change is calculated cannot be taken from the uninsulated case, but must be estimated based on the average energy consumption or average existing insulation levels in the eligible stock.

Savings for the residential weatherization program after calibration to the forecast are the difference in usage between point B and point D. The costs between A and C are a conservative estimate of average costs, because they include only the most expensive measures. Generally, consumers do not install just the cheapest measures first, leaving only the most expensive remaining.

The data used in the development of the relative efficiency level is described for multifamily buildings first. The Council used work done for the Bonneville Power Administration by ICF, Inc., and others, to determine the base case insulation values for multifamily units. These base case values for pre-1979 unweatherized stock translated into a heat loss rate per unit of 247 UA.[11] Under standard operating conditions, this implies a use of 5,191 kilowatt-hours per year. If all cost-effective measures are added to the structure, the use under standard operating conditions drops to 1,500 kilowatt-hours per year.

The relative use, after all cost-effective measures are installed, with amenity and behavior held constant, is 0.29 (1,500/5,191). As described in the next section, this efficiency improvement will be used in the forecasting model to incorporate behavioral changes into the estimate of average savings. The method to determine a relative efficiency level is quite similar for single-family houses.

Some information is available on the average insulation level in pre-1979 vintage unweatherized single-family houses. The best estimate that could be found is from a sample of 228 pre-1979 single-family houses in the End-Use Load and Conservation Assessment Program (ELCAP) where the average heat loss rate (specified in terms of UA) was determined from on-site surveys of the houses.[12] The UA value, after normalizing for the regional average square footage of existing houses used in this analysis and including the heat loss effect of infiltration, is approximately 550. If a house with a 550 UA were operated assuming standard operating conditions, it would consume approximately 13,696 kilowatt-hours per year for space heating. If this is the base case, and 6,649 kilowatt-hours per year is the predicted consumption if all cost-effective measures are installed, then the relative electric energy use of the weatherized houses is 0.49. This estimate is for efficiency changes only, and does not incorporate behavioral changes, since amenity and behavior were held constant as insulation was added. However, behavioral impacts on the estimate of savings are incorporated when the new thermal efficiency level is used in the forecasting model.

11. UA is the heat loss rate of a building (expressed as a U-value) times the area of the component. A U-value has units of Btu per Fahrenheit degree per square foot.

12. Only about 13 percent of the houses on which the estimate is based participated in a weatherization program and took at least one major measure. If these houses were removed, the probable effect would be to raise the average UA. On the other hand, some self-weatherization has most likely occurred since the time the ELCAP houses were audited. The size of this action is unknown, but it would act to lower the UA. The judgment was to consider these as offsetting effects.

Table 7–15
Regionally Weighted Single–Family Dwelling Thermal Integrity Curve by Levelized Cost Category

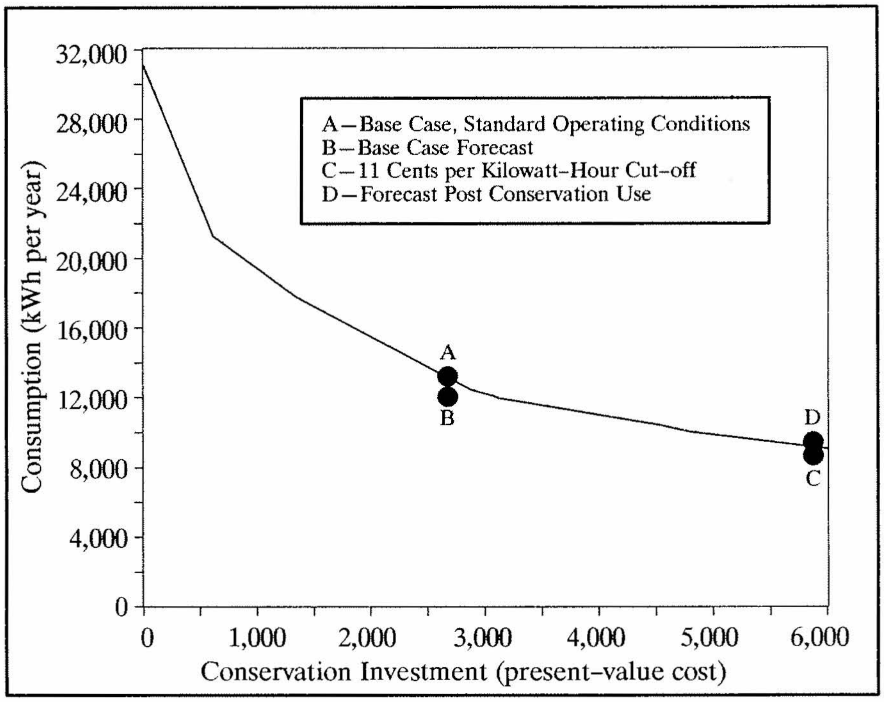
Levelized Cost (mills/kWh) Nominal	Capital Cost ($/sq. ft.)	Use/sq. ft. (kWh/yr.)	Present Value Cost	UA	Use (kWh/yr.)	Capital Cost
0	$0.00	22.09	$0	936	29,937	$0
10	$0.38	14.61	$515	701	19,799	$509
20	$1.57	8.29	$2,161	488	11,228	$2,124
30	$1.71	7.64	$2,411	463	10,347	$2,311
40	$1.74	7.40	$2,566	454	10,024	$2,357
50	$1.78	7.31	$2,609	452	9,902	$2,418
60	$1.78	7.31	$2,609	452	9,902	$2,418
70	$1.92	7.03	$2,846	444	9,520	$2,596
80	$3.32	5.44	$5,365	372	7,376	$4,492
90	$3.82	4.91	$5,840	359	6,649	$5,170
100	$3.82	4.91	$5,840	359	6,649	$5,170
110	$3.82	4.91	$5,840	359	6,649	$5,170
120	$3.82	4.91	$5,840	359	6,649	$5,170
130	$3.82	4.91	$5,840	359	6,649	$5,170
140	$3.82	4.91	$5,840	359	6,649	$5,170
150	$3.82	4.91	$5,840	359	6,649	$5,170
160	$4.42	4.56	$6,949	342	6,186	$5,985
170	$4.67	4.43	$7,191	338	5,998	$6,330
180	$4.92	4.26	$7,772	331	5,773	$6,669
190	$5.13	4.13	$8,046	327	5,591	$6,956
200	$5.13	4.13	$8,046	327	5,591	$6,956

Table 7-16
Regionally Weighted Multifamily Dwelling Thermal Integrity Curve by Levelized Cost Category

Levelized Cost	Capital Cost	Present Value Cost	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)
0	$0.00	$0	8,856	10.5
10	$0.19	$180	6,083	7.2
20	$0.55	$517	4,518	5.4
30	$0.81	$758	3,642	4.3
40	$0.82	$775	3,601	4.3
50	$0.88	$823	3,508	4.2
60	$0.88	$823	3,508	4.2
70	$0.88	$823	3,508	4.2
80	$1.03	$1,258	3,032	3.6
90	$2.83	$2,952	1,501	1.8
100	$2.83	$2,952	1,501	1.8
110	$2.83	$2,952	1,501	1.8
120	$2.83	$2,952	1,501	1.8
130	$2.83	$2,952	1,501	1.8
140	$2.83	$2,952	1,501	1.8
150	$2.83	$2,952	1,501	1.8
160	$2.83	$2,952	1,501	1.8
170	$2.83	$2,952	1,501	1.8
180	$2.83	$2,952	1,501	1.8
190	$3.64	$3,716	1,178	1.4
200	$3.64	$3,716	1,178	1.4

Thermal Integrity

Figure 7–4
Existing Single–Family Dwelling Thermal Integrity Curve



Step 2. Develop Conservation Savings Estimates that are Consistent with the Council's Forecast and Incorporate Behavioral Impacts

The Council's supply function for the total amount of conservation available in existing residential buildings was developed for the year 2010. This was done for three reasons. First, the supply of energy available through conservation in existing buildings is constrained by the rates at which measures can be implemented. Second, these rates are constrained by the need for additional energy supplies. Third, some existing houses will be torn down by the year 2010, and others may change their primary heating fuel. As a result, the conservation savings from existing buildings diminish with time because of removal and can also change due to altered selections of heating fuel. By developing its retrofit supply function for the year 2010, the Council was able to account for demolitions and set deployment schedules based on the need for additional supplies, which is done in the Integrated Systems for Analysis of Acquisitions model, described in Chapter 10.

The estimates are based on the size of the existing housing stock and savings per house that will be expected in the year 2010. These estimates will vary from savings expected in the near term, not only because electricity prices change over this time period, but also because of expected equipment changes in residential households. For example, over this period, it is expected that residential appliances, such as refrigerators and freezers, will become much more efficient. During cold periods, the space heating equipment must then make up for the lack of heat that was once given off by the less efficient appliance. For residential space heating, these factors act to make savings look larger at the end of the forecast period. However, the magnitude of this effect is small. In addition, the savings expected in the year 2010 are consistent with the pre–conservation consumption used in the forecast.

The forecast model, combined with information from utility weatherization programs, was used to determine the number of electrically heated houses built before 1979 that would survive to 2010 and could still be retrofitted. Houses built after 1979 are not included as weatherization potential. These houses represent a lost–opportunity for conservation because they are insulated well enough that additional weatherization is generally not cost–effective, yet they are not insulated to the full level that is cost–effective for new homes. Houses that have electric heating systems, but heat primarily with wood, are also not included in the stock remaining to be weatherized. The retrofit savings in this chapter are based only on houses primarily heated with electricity.

In 1979, the stock of primarily electric space heated single–family houses amounted to 871,600 houses. The same value for multifamily units was 322,300. The existing housing stock is estimated to have an average lifetime of approximately 80 years. Today, the average age of the existing stock is approximately 20 years. By the year 2010, a number of these existing houses will have been removed from the housing stock because of such things as fire and decay. In addition, some houses may have changed their primary heating fuel either into, or away from, electricity over this period, as modeled in the forecast. Consequently, the remaining pre-1980 vintage stock in 2010, given the Council's average lifetime estimates and fuel choice, is approximately 552,560 single-family houses and 246,070 multifamily units.

One of the assumptions in this method of counting is that highly weatherized houses are not as likely to be removed from the housing stock between now and 2010 as units that are not weatherized. It seems likely that houses that are considered valuable enough to invest in for weatherization are probably not the houses that will decay out of the housing stock first.

A number of the houses that will survive to 2010 have already been weatherized through either utility-sponsored weatherization programs or by their owners. Therefore, the remaining conservation potential consists only of those houses that have not been fully weatherized. A study conducted for the Pacific Northwest Utilities Conference Committee indicated that the public utilities have weatherized approximately 184,237 single-family houses and approximately 28,845 multifamily houses. The private utilities in the region have completed approximately 139,759 single-family and 38,555 multifamily weatherization jobs.

Not all of these houses use electricity as the primary fuel for space heating, but all of them had electric space heating installed. The number of houses that were weatherized through a utility program because they had electric space heating equipment installed but used primarily wood heat was estimated using the forecast. It was assumed that the same proportion of wood heaters were weatherized by utility programs as the proportion of primary wood heated houses with electricity as backup that were represented in the forecast. This means that approximately 85 percent of single-family weatherizations accomplished by utilities were primarily electric space heaters, and the other 15 percent used primarily wood with electricity as backup. These wood-heated houses were subtracted from the utility weatherizations for single-family houses. For multifamily houses, the wood heating portion was estimated to be negligible.

In addition, there is initial indication from the 1987 Oregon Weatherization Study that some homeowners have done some weatherization on their own. This data indicates that for every 100 single-family houses that went through a significant utility weatherization program, an additional 25 single-family households have done something on their own. If this assumption proved to be closer to zero households that weatherized on their own, the supply curve would have an additional approximately 10-20 average megawatts. Zero would be a lower bound, and given information from the Oregon Weatherization Study, an assumption of 25 percent seems prudent. In multifamily dwellings, the number that have done significant weatherization on their own is assumed to be zero.

The next question is whether every household that participated in a program, or weatherized significantly on its own, secured the majority of conservation measures. If they had done many of the major measures, but not all, it would not only be extremely difficult to locate them, but also additional measures might not be cost-effective due to additional administration and set-up costs. Information collected by Bonneville in the Data Gathering Project for the public service territory indicates that the public utilities achieve approximately 85 percent of the measures recommended in the audit and about 90 percent of the savings identified in the audit for single-family households. Furthermore, Bonneville staff has indicated that the audits generally approximate measures that are missing from a full cost-effectiveness package that would be something like R-38 ceiling insulation, R-11 or R-19 wall insulation, R-19 floor insulation, double glazing, caulking and weatherstripping. A house that achieved even 85 percent of this level of weatherization would likely not have any further potential. Consequently, this analysis assumes that single-family houses already weatherized under the public utilities' programs achieved approximately 90 percent of all cost-effective savings, and that the remaining 10 percent savings per house cannot be secured through future programs.

Less information is available from the private utilities on the levels of weatherization secured by their programs. Initial information from Puget Power indicates that it appears to have weatherization patterns similar to Bonneville's, which would indicate little, if no, further potential to secure. However, most of the other private utilities appear to have spent fewer dollars per weatherized house, and probably installed fewer measures. For Pacific Power and Light's territory in Oregon and Portland General Electric, the 1987 Oregon Survey supports preliminary indications that about one-third of the houses that went through the utilities' weatherization programs still have a number of major measures remaining to be secured. The Council is currently assuming that half of the houses weatherized under the private utilities' programs only went half of the way to the full cost-effectiveness level. This means that approximately half of the houses already counted in a private utility weatherization program still have half of the savings left to acquire. Since it is quite possible that some lost opportunities were created when the house was initially weatherized, the analysis assumes that these houses, which have already secured 50 percent of the cost-effective savings, can only secure 40 percent more, which ultimately would put them at a level that is being achieved by Bonneville's program.

Finally, there was very little information on how much insulation was installed by single-family homeowners who weatherized on their own. It was assumed that these homeowners went half way on their own, and still have 40 percent of the cost-effective savings remaining to secure.

For multifamily units, it was assumed that if the unit was weatherized under any utility program there was nothing remaining to be secured.

For single-family houses, the above discussion results in a total of 342,896 primarily electrically heated houses either being weatherized in a program or taking some action on their own. This leaves a potential of 209,664[13] households that can still secure the full savings. In addition, the houses that went part way on their own, combined with houses weatherized only part way in the private utilities' territories, leaves 127,070 houses that still have an assumed 40 percent of the total savings remaining. For multifamily houses, the potential is 246,070 electrically heated units surviving until 2010, minus 67,400 units already weatherized through a program. Therefore, the potential is 178,670 multifamily units still to weatherize to the full potential.

The cost-effective efficiency levels derived for single-family and for multifamily houses are installed in the forecasting model, and the model modifies electricity intensity due to behavioral responses. These are responses to the effect of lower bills now that the house is weatherized, and to changing electricity prices and incomes. The cost-effective efficiency levels resulted in a consumption of electric space heating use from the forecast in 2010 of 7,842 kilowatt-hours per year for a fully retrofitted single-family house and 2,089 kilowatt-hours per year for multifamily houses. Overall savings for the efficiency improvements are derived by subtracting 2010 consumption, including behavior as predicted in the forecast with the efficiency improvements installed, from consumption in 2010 with efficiency held frozen at the pre-conservation level. The values from the forecast for the pre-conservation, frozen-efficiency level are 12,477 and 5,145 kilowatt-hours per year, respectively. The total technical potential of average megawatt savings for all forecasts can then be calculated:

SFS_f	=	$HH_f \times S_f \div C$
	=	209,664 x (12,477-7,842) ÷ 8,760,000
	=	111 average megawatts
SFS_p	=	$HH_p \times S_p \div C$
	=	127,070 x (9,728-8,020) ÷ 8,760,000
	=	25 average megawatts
MFS	=	$HH \times S \div C$
	=	178,670 x (5,145-2,089) ÷ 8,760,000
	=	62 average megawatts
TWxS	=	$SFS_f + SFS_p + MFS$
	=	111 + 25 + 62
	=	198 average megawatts

13. This equals 552,560 electrically heated houses left in 2010, minus 342,896 with some weatherization, which equals 209,664 houses left with full potential.

Where:		
SFS_f	=	single-family savings from houses with full weatherization potential, expressed in average megawatts
HH_f	=	number of households with full weatherization potential
S_f	=	savings per house from houses with full weatherization potential, expressed in kilowatt-hours (pre-weatherization use minus post-weatherization use)
C	=	conversion factor from kilowatt-hours to average megawatts (8,760,000 kilowatt-hours per average megawatts)
SFS_p	=	single-family savings from houses with partial weatherization potential, expressed in average megawatts
HH_p	=	number of households with partial weatherization potential
S_p	=	savings per house from houses with partial weatherization potential, expressed in kilowatt-hours
MFS	=	multifamily savings, expressed in average megawatts
HH	=	number of multifamily households
S	=	savings per multifamily house, expressed in kilowatt-hours
TWxS	=	total weatherization savings, expressed in average megawatts

The supply curve shown in Table 7-17 reflects the distribution of savings that is expected, given the thermal integrity curve from the engineering model. The cheapest measures were assumed to be used to reduce consumption from the uninsulated house to the base case level used in the forecast.

Step 3. Compare Cost and Savings Estimates with Observed Costs and Savings

This section compares measured end use of electricity and other estimates of residential space heating consumption to that projected by the engineering model (SUNDAY) used by the Council. Two questions are addressed:

1. Does the space heating energy use projected by the engineering model agree with measured usage for homes with a wide range of energy efficiency?
2. Do the Council's estimates of single-family weatherization savings agree with savings estimates obtained from the evaluation of regional weatherization programs?

1. Engineering Use Estimates versus Measured Use

The annual space and water heating requirements of over 800 houses were measured in the Residential Standards Demonstration Program (RSDP). Houses that were built to the prevailing building practice between 1979 and 1983, as well as houses that met the Council's model conservation standards, were monitored. Houses that were built to the prevailing building codes and practices between 1979 and 1983 are referred to as "control" dwellings. These houses spanned a wide range of efficiencies and sizes. Some control houses in the RSDP, due to their size and overall insulation levels, had heat loss rates similar to the Council's estimate of a house that has not been through a weatherization program (approximate UA of 550). Other control houses in the RSDP, either due to their small size or insulation levels, were representative of fully weatherized residences and were as efficient as the Council's model conservation standards.

Staff from the Council's Montana office, using a data base prepared by Lawrence Berkeley Laboratories for Bonneville, developed the estimates shown in Table 7-18 of actual space heating demand for 422 houses in the RSDP. Houses that were built at least as efficiently as the Council's residential model conservation standards (MCS) are referred to as "RSDP/MCS" dwellings. These houses all had at least 300 days of measured electricity used for space heating.

In its evaluation of the cost-effectiveness of the model conservation standards, Bonneville also developed an estimate of the measured space heating use observed in the RSDP. These estimates, shown in Table 7-19, were based on a sample of 233 houses for which had at least 330 days of measured electricity used for space heating.

The Council's and Bonneville's estimates of measured use agree closely for Zones 1 and 2, although they vary significantly for Zone 3. This may be due to differences in the size of the sample and the number of days of measured data. However, both the Council's and Bonneville's estimates of the regionally weighted average are within 0.1 kilowatt-hours per square foot, per year, for both RSDP/MCS and control dwellings. Furthermore, the Council's and Bonneville's estimates of the average difference in space heating use observed between the RSDP/MCS and control dwellings are identical and are equal to 2.5 kilowatt-hours per square foot, per year.

The SUNDAY thermal simulation was run using weather data from Seattle, Spokane and Missoula to represent the three climate zones found in the region. Three combinations of inputs to SUNDAY were tested. These input sets varied in their assumptions regarding thermostat set point and the amount of heat loss caused by infiltration. Two thermostat set points were tested, a 65°F constant set point, as had been assumed by the Council and by Bonneville in its cost-effectiveness analysis, and the set points reported by the occupants. Three levels of infiltration losses were tested. The first level was equivalent to that calculated from fan pressurization (blower door) test results using the Lawrence Berkeley Laboratory's infiltration prediction model. These averaged 0.32 air changes per hour for the RSDP/MCS houses and 0.54 air changes per hour for the control houses. The second level of infiltration losses assumed was a constant 0.35 air changes per hour. This level was adopted by Bonneville in its cost-effectiveness analysis for both control and RSDP/MCS houses. The third infiltration level tested was derived from a weather adjustment made to the Lawrence Berkeley Laboratory's model's predictions based on blower test results. This level assumed that control houses had 0.5 air changes per hour and that RSDP/MCS had 0.3 air changes per hour. The conductance heat loss rates (UAs) assumed for all three sets of infiltration inputs were calculated as they were by the Council in its 1986 plan.

Table 7–17
Technical Conservation from Existing Space Heating

Levelized Cost (cents/kWh)		Cumulative Technical Potential (Average Megawatts)		
Nominal	Real	Single–Family Dwellings	Multifamily Dwellings	Total
0	0	0	0	0
1	0.5	0	0	0
2	1	19	10	29
3	1.5	33	25	58
4	2	40	26	66
5	2.5	43	28	71
6	3	43	28	71
7	3.5	54	28	82
8	4	115	36	151
9	4.5	135	62	197
10	5	135	62	197
11	5.5	135	62	197
12	6	135	62	197
13	6.5	135	62	197
14	7	135	62	197
15	7.5	135	62	197
16	8	148	62	210
17	8.5	154	62	216
18	9	160	62	222
19	9.5	165	67	232
20	10	165	67	232

Table 7–18
Measured Space Heating Demand for RSDP Houses—300 Days Measured Use

House Type	Number	Annual Use (kWh/sq. ft.) Zone 1	Zone 2	Zone 3	Regional Average
Control	244	5.8	5.9	6.4	5.8
RSDP/MCS	178	3.3	3.7	2.9	3.3
Difference		2.5	2.2	3.5	2.5

Table 7–19
Measured Space Heating Demand for RSDP Houses—330 Days Measured Use

House Type	Number	Annual Use (kWh/sq. ft.) Zone 1	Zone 2	Zone 3	Regional Average
Control	126	5.8	6.1	7.0	5.9
RSDP/MCS	107	3.4	3.7	3.6	3.4
Difference		2.4	2.4	3.5	2.5

Table 7-20 shows the space heating demand predicted by SUNDAY when thermostat set points are equivalent to those reported by the occupant.[14] These reported set points are 63.7°F for control houses and 67.3°F for RSDP/MCS houses. Infiltration losses underlying the calculations in Table 7-20 are estimated from blower door tests. Table 7-21 shows the space heating use predicted by SUNDAY when thermostat set points are 65°F and infiltration losses are 0.35 air changes per hour for both control and RSDP/MCS houses. Conductance losses, except for differential air change rates and internal gains assumptions, are the same in both cases.

Table 7-22 shows the space heating use predicted by SUNDAY when the thermostat set points are equivalent to those reported by the occupants, and heat loss rates from infiltration are based on an average 0.5 air changes per hour for the control houses and 0.3 air changes per hour for the RSDP/MCS dwellings. These infiltration rates are slightly lower than those actually measured because the winter of 1985/1986 was slightly warmer and less windy than the 30-year average, which is used in the Lawrence Berkeley Laboratory model. This adjustment was estimated by comparing the weather from 1985/1986 to the 30-year average.

A comparison of Table 7-20 and Table 7-21 shows that very similar SUNDAY results for annual space heating demand are obtained from the two different sets of inputs. The lower set points reported by homeowners are offset by the higher infiltration rate of .54 air changes per hour underlying the calculations in Table 7-20. On a regional average basis, both sets of model inputs produce an identical estimate of the expected difference in annual space heating needs of the control and RSDP/MCS houses. The differences estimated for any of the three climate zones do not exceed 0.1 kilowatt-hours per square foot, per year. Also, both sets of input assumptions produce results that agree closely with the measured space heating use shown in Tables 7-18 and 7-19.

As shown in Table 7-22, once the infiltration rates have been adjusted to reflect the milder winter of 1985/1986, the agreement between the SUNDAY predictions and the measured space heating use improves for both the control and RSDP/MCS houses. While there is some variance between measured and predicted use within individual climate zones, the regional average predictions of SUNDAY are within 0.2 kilowatt-hours per square foot, per year, of the monitored space heating use for both the RSDP/MCS houses and control houses. This is remarkably good agreement given how little is known about the accuracy of the inputs.

14. Thermostat set points used are the average, wintertime temperature settings considering the occupants daytime and weekend activities. This temperature setting was chosen because the SUNDAY model uses the mean thermostat set point for all hours during the heating season to compute space heating use.

Table 7–20
SUNDAY Predicted Space Heating Use with Occupant–Reported Thermostat Setting,
3,000 Btu per hour Internal Gains, and Blower Door Derived Infiltration Rate

House Type	Annual Use (kWh/sq. ft.) Zone 1	Zone 2	Zone 3	Regional Average
Control	5.8	7.8	6.7	6.1
RSDP	2.8	3.7	4.3	3.0
Difference	3.0	4.1	2.4	3.1

Table 7–21
SUNDAY Predicted Space Heating Use with 65°F Thermostat Set Point, 3,000 Btu per hour Internal Gains and Infiltration Losses Based on 0.35 ach

	Annual Space Heating Use (kWh/sq. ft.)			
House Type	Zone 1	Zone 2	Zone 3	Regional Average
Control	5.4	7.8	6.6	5.8
RSDP/MCS	2.5	3.5	4.1	2.7
Difference	2.9	4.2	2.5	3.1

Table 7–22
SUNDAY Predicted Space Heating Use with Occupant Reported Thermostat Set Points, 3,000 Btu per hour Internal Gains and Infiltration Losses for Control of 0.5 ach and for RSDP/MCS of 0.3 ach

	Annual Space Heating Use (kWh/sq. ft./yr.)			
House Type	Zone 1	Zone 2	Zone 3	Regional Average
Control	5.6	6.4	7.6	5.8
RSDP/MCS	3.0	3.9	4.7	3.2
Difference	2.5	2.3	3.5	2.6

NOTE: Numbers may not add, due to rounding.

SUNDAY space heating predictions for RSDP houses in Washington state were found to agree very well with measured use when input assumptions were estimated for the actual efficiency of the building, weather conditions on the building site and known occupant behavior. Figure 7-5 shows the measured annual space heating consumption of 278 RSDP houses located in Washington as a function of their estimated heat loss rate, or UA. Also shown in Figure 7-5 is the predicted space heating consumption from SUNDAY for these same houses. Over the range of heat loss rates exhibited by these houses, there is very good agreement between the predicted space heating use and the monitored use.[15] For all houses, the average difference between the measured and simulated space heating use was approximately 8 percent.

The SUNDAY simulation model has also been compared to measured space heating consumption in a small sample of houses (20 houses) in Hood River, Oregon, before the houses were weatherized in the Hood River Conservation Project. This analysis found that room closure patterns and temperature setbacks had to be modeled in the inputs before SUNDAY, which represents a house as a single temperature zone, matched the monitored space heating use.

2. Weatherization Program Costs and Savings versus Engineering Estimates

The Bonneville residential weatherization program has operated in various forms since 1980. Oak Ridge National Laboratory (ORNL), under contract to Bonneville, has evaluated this program's costs and savings. It assessed the effect of the installation of conservation measures on the amount of electricity used for space heating. Oak Ridge National Laboratory used a statistical regression technique (called PRISM)[16] to estimate space heating use from known total electric consumption. For each participating house, annual electricity use, normalized to long-term weather conditions, was compared to its pre-weatherization use. Table 7-23 shows the average estimated use for space heating for pre- and post-retrofit conditions for the four different phases of the Bonneville residential weatherization program. This table also shows the average weatherization package cost of each program phase converted to 1990 dollars.

15. The range of heat loss rates shown in Figure 7-5 encompasses the range being analyzed by the Council for both new and existing residential space heating conservation programs.

16. PRISM is the Princeton Scorekeeping Model.

Space Heating Use

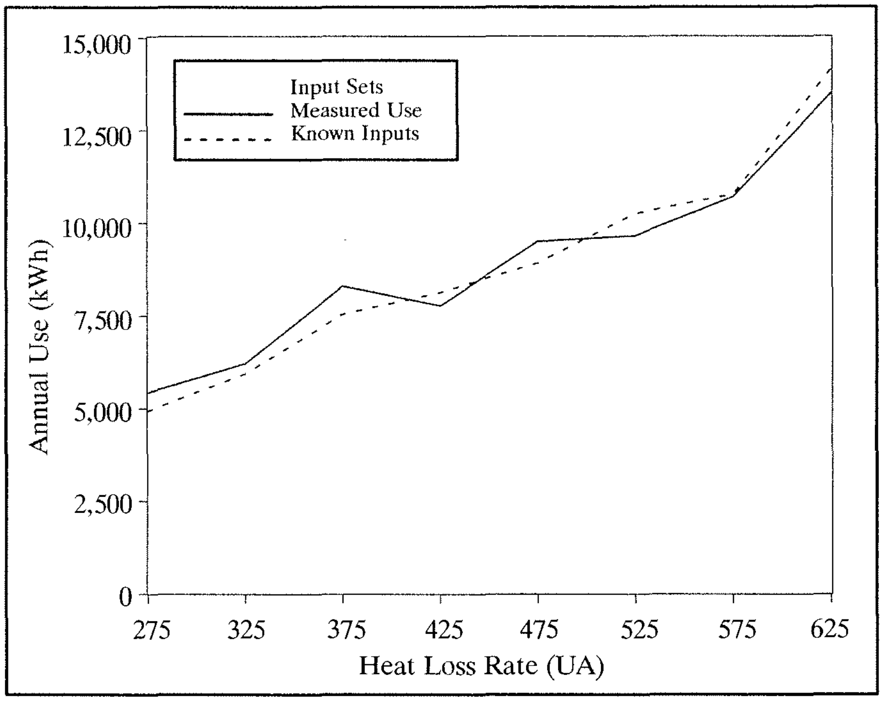


Figure 7-5
SUNDAY Predicted versus Monitored Space Heating Use in Washington RSDP Houses

Table 7-23
Estimated Pre- and Post-Program Participation Energy Use and Retrofit Cost in Bonneville Residential Weatherization Programs

Program Phase Year Participating	Pre-Program Use (kWh/sq. ft.)	Post-Program Use (kWh/sq. ft.)	Savings	Cost ($/sq. ft.) (1990 $)
Pilot/1981	12.1	7.7	4.4	$2.07
Interim/1982	8.9	6.6	2.3	$1.32
Interim/1983	8.0	5.9	2.1	$1.41
Long-Term/1985[a]	8.2	6.5	1.7	$1.72

[a] Floor areas used to calculate the average use and cost per square foot assume that homes weatherized in the long-term program are the same size as those weatherized in the interim program in 1983.

The first step in determining how well the Council's engineering estimates for residential weatherization savings agree with those estimated for Bonneville's program is to compare the estimates of post-retrofit space heating use. Figure 7-6 shows the post-program space heating use estimated by PRISM in Bonneville's evaluations compared to five engineering projections based on five different sets of input assumptions to the SUNDAY thermal simulation model. The five sets of input to SUNDAY are:

Set 1 65°F with 2,000 Btu per hour internal gains: The Council's current assumptions for long-term household behavior. Thermostat setting at 65°F for 24 hours per day. Efficient appliances generating 2,000 Btu per hour internal gains.

Set 2 65°F with 3,000 Btu per hour internal gains: Same as Set 1, except current appliance efficiencies are assumed to generate 3,000 Btu per hour of internal gains.

Set 3 68°F with 2,000 Btu per hour internal gains: Same as Set 1, except occupants are assumed to set their thermostats at 68°F for 24 hours per day.

Set 4 62°F with 3,000 Btu per hour internal gains: Occupants are assumed to set their thermostats at 62°F for 24 hours per day and use appliances with current efficiencies generating 3,000 Btu per hour of internal gains. The thermostat set point of 62°F assumes that either approximately 25 percent of the time or 25 percent of the heated area of the home has a thermostat setting of 55°F, and the remainder of the time or heated area of the home has a thermostat setting of 65°F.

Set 5 65°F with wood: Same as Set 4, except that occupants are assumed to use approximately two cords of wood per year as supplemental heating. A wood stove/fireplace insert conversion efficiency of 50 percent has been assumed resulting in approximately 15 million Btu (4,400 kilowatt-hours per hour) of useful heat.[17] Wood use is assumed to be proportional to monthly space heating needs, i.e., the months that have the greatest heating demands are the months of greatest wood use.

The engineering prediction of post-retrofit program use shown in Figure 7-6 is based on pre-program use as estimated in the program evaluation. The engineering estimate of post-program use was determined by assuming that the retrofit costs reported in the evaluations were used to purchase the same measures, in the same order and at the same cost as those identified in the Council's space heating supply curve for existing single-family houses.

As shown in Figure 7-6, the post-retrofit space heating use estimated by PRISM for the Bonneville weatherization program evaluations is higher than the engineering model estimates based on all five input assumption sets. The SUNDAY estimates that most closely match the PRISM estimates of post-retrofit use are based on Sets 1 and 3. The closest, Set 3, uses a three-degree higher thermostat setting both pre- and post-retrofit than is presently assumed by the Council. The other three input sets, which assume either lower amenity levels (i.e., lower thermostat settings) or supplemental wood use, underpredict post-retrofit use.

17. A Bonneville study of residential wood use in the region found that the occupants of single-family electrically heated homes reported approximately two cords of wood use per year on average.

Space Heating Use

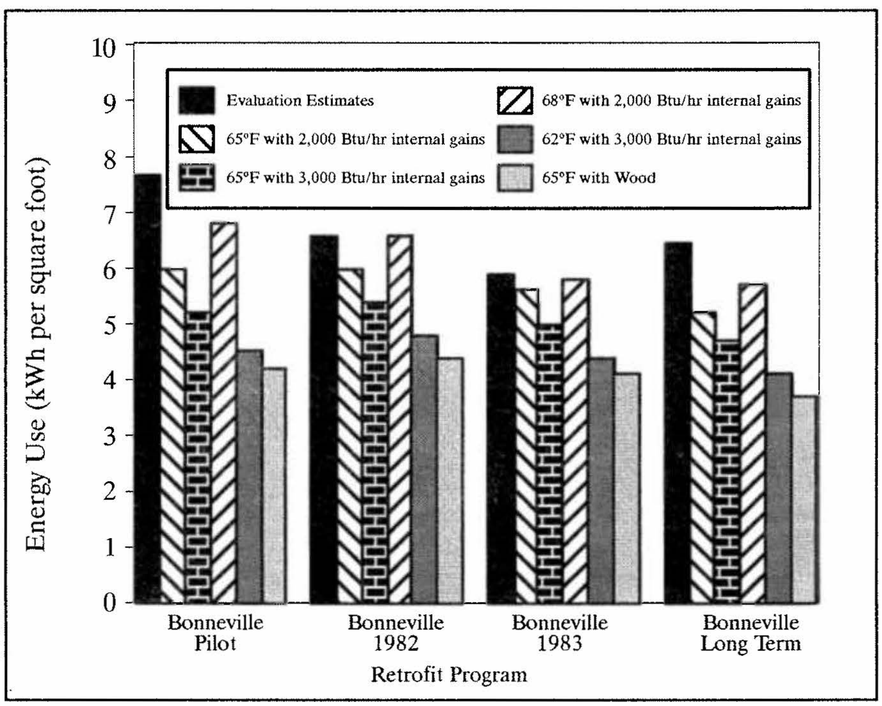


Figure 7-6
Post-Weatherization Space Heating Use

Weatherization Savings

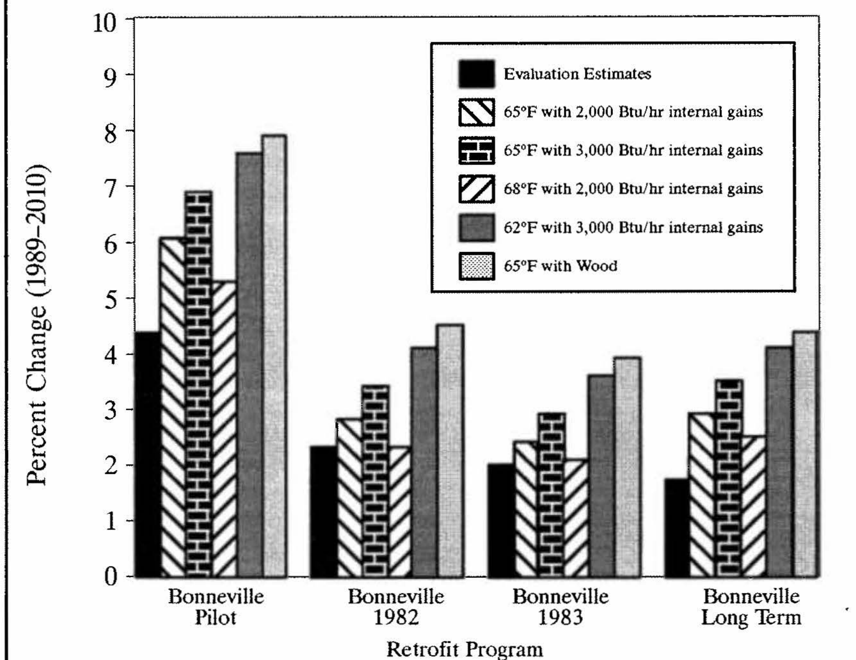


Figure 7–7
Weatherization Savings from Various Estimates

Figure 7–7 compares the estimated space heating savings that were obtained from PRISM for the Bonneville weatherization program to SUNDAY estimates of savings based on the five input assumption sets. In all cases, estimates of savings from SUNDAY are higher than those obtained from the PRISM estimates. As was the case with post–retrofit use, the two input sets that produce savings estimates that most closely agree with the PRISM estimates are Sets 1 and 3, with Set 3 once again being in best agreement. For all other input sets, which assume either lower amenity levels or supplemental wood, the SUNDAY estimates of savings are higher than the PRISM estimates.

If the PRISM estimates are accurate, and occupant behavior is projected to remain the same over the long term, then the Council should probably revise its assumptions on thermostat setting. However, prior to adopting a revised thermostat set point, several factors must be taken into consideration. First, it has been shown that PRISM systematically overestimates space heating energy use. This is due to the fact that a portion of the increased electricity use caused by colder winter weather results from greater lighting, water heating and cooking use. As the PRISM estimate of electricity used for heating is really an estimate of weather sensitive loads, it is possible and likely that PRISM is including at least a part of this electricity in its heating estimate. Consequently, it is very likely that both pre–retrofit and the post–retrofit use shown in Figure 7–6 based on PRISM are too high. If both pre– and post–retrofit use are overestimated by equivalent amounts, this would not affect savings estimates. Unfortunately, there is conflicting evidence on whether PRISM's overestimates of space heating use for well insulated buildings differs from its overestimates of space heating for buildings that are poorly insulated.[18]

Second, as stated previously, the SUNDAY estimates of both post–retrofit use and program savings are based on the presumption that participants installed the same measures, in the same order and at the same costs as those included in the Council's conservation supply curve for space heating in existing single–family homes. If measures were selected out of their least–cost order, then the PRISM estimates of savings would be less for the same expenditure. Indeed, Bonneville staff has observed that program participants have not always chosen the lowest cost conservation measures to improve efficiency. For aesthetic reasons, for example, many participants make expensive window replacements when a storm window would achieve the same level of efficiency. As a result, because these program participants have deviated from the idealized supply curve, both in terms of the measures selected and the costs of the measures, their post–retrofit use is

18. It presently appears that PRISM overstates the space heating use of well–insulated buildings more than it does poorly insulated structures. (See Lee, A.D. et. al. *Cost–effectiveness of Conservation Upgrades in Manufactured Homes*, PNL–6519, September 1988.)

higher than predicted, their savings are lower than predicted, and the savings appear to have higher levelized costs.[19] Consequently, the fact that SUNDAY estimates do not align perfectly with PRISM estimates of savings and post-retrofit use is not sufficient justification to indict either estimation technique.

A third issue is the effect of conservation on a consumer's electric bill, which will be lower following weatherization. This may lead to changes in behavior. For example, Figure 7-8 shows the measured space heating energy use in Washington RSDP houses compared to SUNDAY model projections based on four sets of alternative operating conditions described above and model inputs derived from occupant surveys and building audits. Each of the curves shows the predicted annual space heating use for houses as a function of heat loss rates. The two top curves assume efficient appliances and thermostat settings of either 68°F or 65°F. The bottom two curves show the predicted space heating for houses with inefficient appliances and thermostat settings of either 62°F or 65°F. These sets of assumptions bracket the measured use observed in the RSDP houses, shown by the solid line.

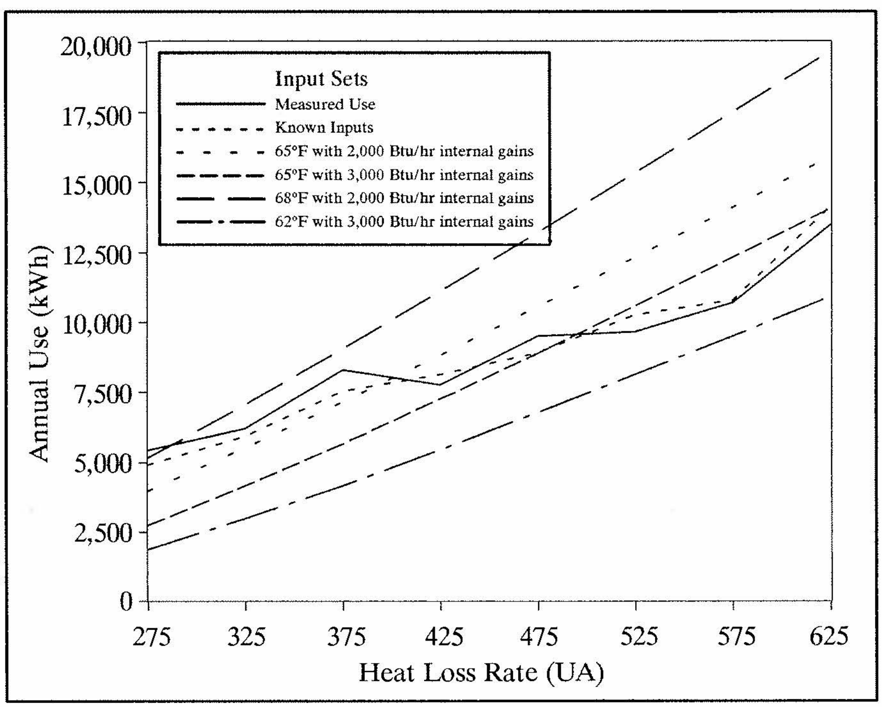
An interesting finding is that estimates of space heating use assuming efficient appliances and thermostat settings of either 65°F or 68°F are in better agreement with the measured use in well-insulated houses (low UAs); whereas, estimates assuming lower thermostat settings and/or inefficient appliances more closely match the measured use of high heat loss buildings.

These results appear to indicate that in more energy-efficient houses, occupants operate their houses more like the Council's assumed standard operating conditions, while in less well-insulated houses, they operate the home at reduced amenity levels (i.e., lower thermostat settings). Indeed, it is known that both the average measured temperature and occupant reported thermostat settings in the RSDP/MCS houses were higher than those of the control houses. This is consistent with economic theory and suggests that consumers in houses with low energy bills, such as those that are efficient, would choose a higher amenity such as relatively higher thermostat settings, and thus reduce the savings. Moreover, economic theory would also predict that even without weatherization, thermostat settings will tend to rise over time as electricity prices stabilize and individual incomes rise.

19. Bonneville has revised its Long-Term Weatherization Program financial assistance levels to encourage consumers to select measures that are more closely aligned with the idealized supply curve.

Space Heating Use

Figure 7-8
SUNDAY Predicted and Actual Use in Washington RSDP Houses Superimposed on Various Alternative Operating Conditions



Space Heating Conservation in New Residential Buildings

Figures 7-9, 7-10 and 7-11 show the technical space heating savings available under the Council's high forecast from new single-family and multifamily residences and from new manufactured houses at various costs. If the prevailing codes and building practices in the region had not changed since 1983, new single-family homes would have represented approximately 1,030 average megawatts of technical potential if savings costing less than 11 cents per kilowatt-hour could be achieved in all houses built between 1992 and 2010. Since 1983, when the Council adopted its first plan, the states of Oregon and Washington, and other jurisdictions in Idaho and Montana, have adopted energy codes equivalent to the Council's model conservation standards for new electrically heated residences. These code changes are anticipated to secure about 765 average megawatts of this technical potential, if they are completely enforced.[20] This leaves 270 average megawatts of technical potential yet to be secured through further code improvements and utility programs.[21] An additional 40 average megawatts of conservation is available from measures costing between 11 cents per kilowatt-hour and 15 cents per kilowatt-hour.

Under the Council's high forecast, savings costing less than 11 cents per kilowatt hour in multifamily dwellings represented approximately 65 average megawatts of technical potential beyond 1983 codes and building practices. Just under 70 percent (45 average megawatts) of this technical potential has been secured through the code improvements occurring between 1983 and 1992. The remaining 20 megawatts of technical potential are incorporated into the Council's model conservation standards for utility programs for new residential buildings.[22] An additional 10 average megawatts of conservation is available from measures costing between 11 and 15 cents per kilowatt-hour.

Savings costing less than 11 cents a kilowatt-hour from new manufactured housing represented about 280 average megawatts of technical potential beyond the prevailing building practices of 1983. Although the federal thermal efficiency standards for manufactured homes have not changed since 1974, market demand for more efficient units has resulted in improved efficiency.[23] As a consequence, an estimated 165 average megawatts of savings are now available at a cost below 11 cents per kilowatt-hour from measures beyond current (1992) construction practice in the Council's high forecast.[24]

The average cost of improving the thermal efficiency of new buildings beyond current codes is about 7.5 cents per kilowatt-hour when administrative costs and transmission and distribution adjustments are included. Figure 7-12 illustrates the savings secured through code improvements and changes in building practice that have occurred since 1983. The difference in the heights of the bars represents the savings that will be secured in new residential buildings constructed between 1992 and 2010 in the Council's high forecast through the improved codes if they are enforced. The remaining potential beyond 1992 building codes/practices requires further action.

Making new houses more efficient is a high priority for securing a least-cost energy future for the region. It is important to insulate houses fully at the time they are built or cost-effective savings can be lost. In addition, while the number of houses eligible for retrofitting will diminish over time, the number of houses that conservation can reach continues to grow as every new house is built.

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20. The state of Washington will begin enforcing an energy code equivalent to the Council's model conservation standards for new electrically heated residences in July 1991. The State of Oregon will begin enforcing an energy code equivalent to the Council's model conservation standards for new electrically heated residences in January 1992.

21. This is the amount of conservation included in the resource portfolio. For comparison, this is 120 average megawatts in the medium forecast.

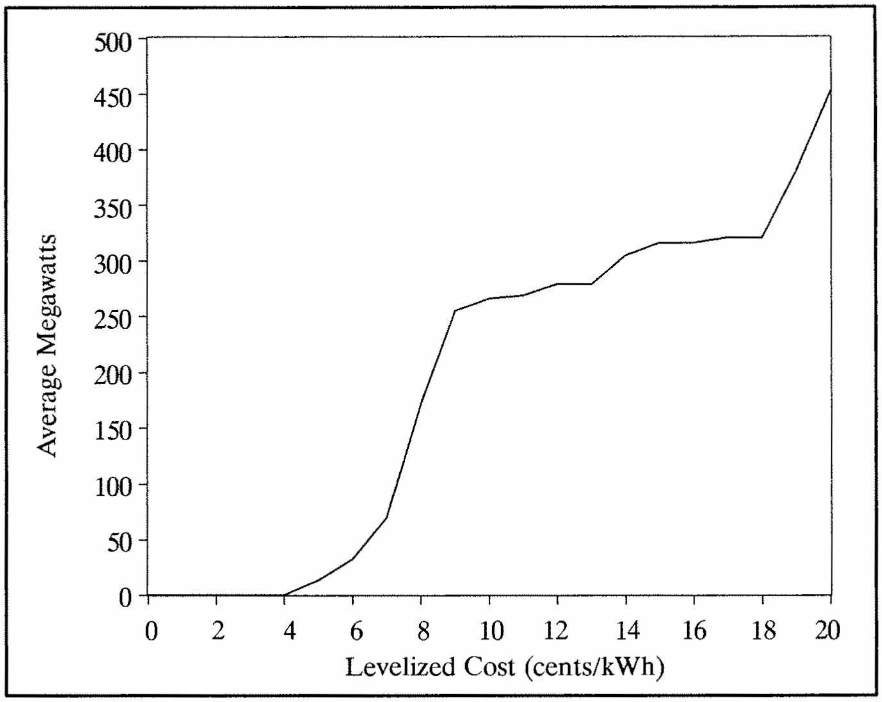
22. This value is also almost 20 average megawatts in the medium forecast.

23. The U.S. Department of Housing and Urban Development (HUD) was directed by Congress to update its thermal standards for manufactured housing in 1987. HUD has yet to release its proposal pursuant to this legislation.

24. There are approximately 170 average megawatts of savings available from new manufactured homes in the Council's medium forecast.

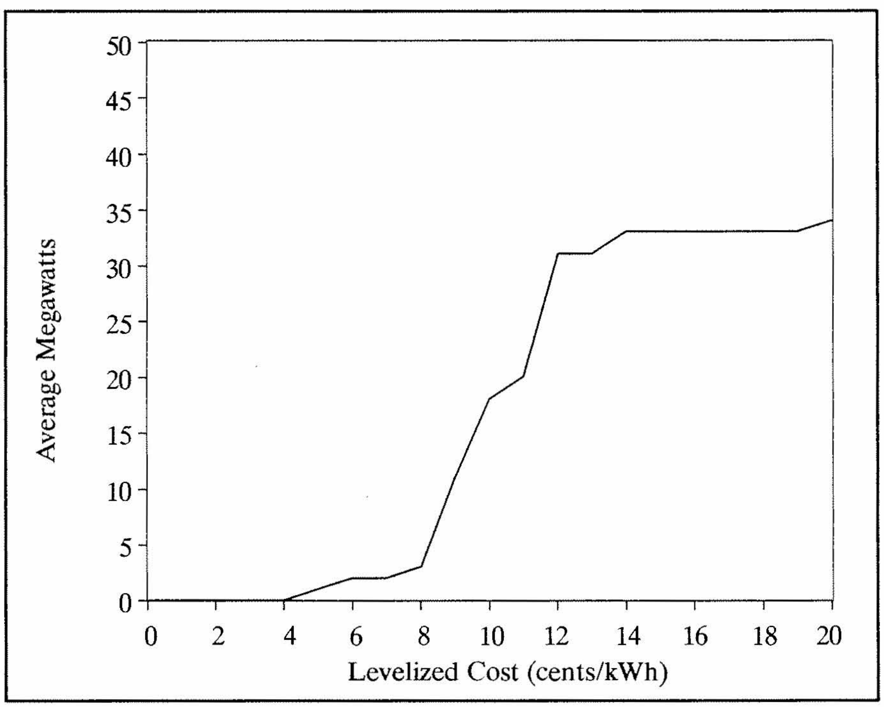
Conservation Potential

Figure 7-9
Technical Conservation from Space Heating Measures Beyond 1992 Codes/Practice in New Single-Family Dwellings



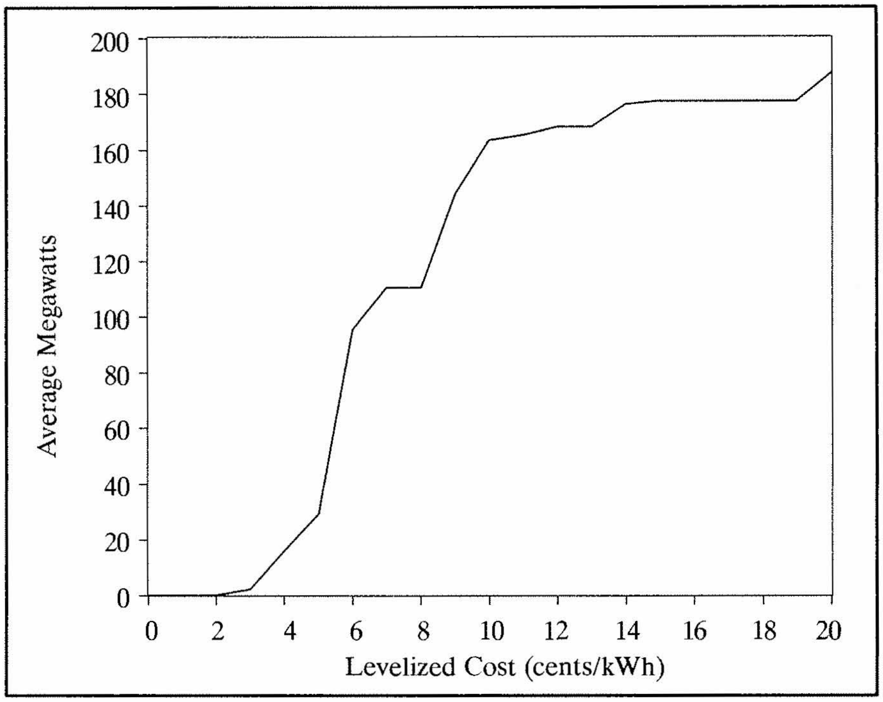
Conservation Potential

Figure 7-10
Technical Conservation from Space Heating Measures Beyond 1992 Codes/Practice in New Multifamily Dwellings



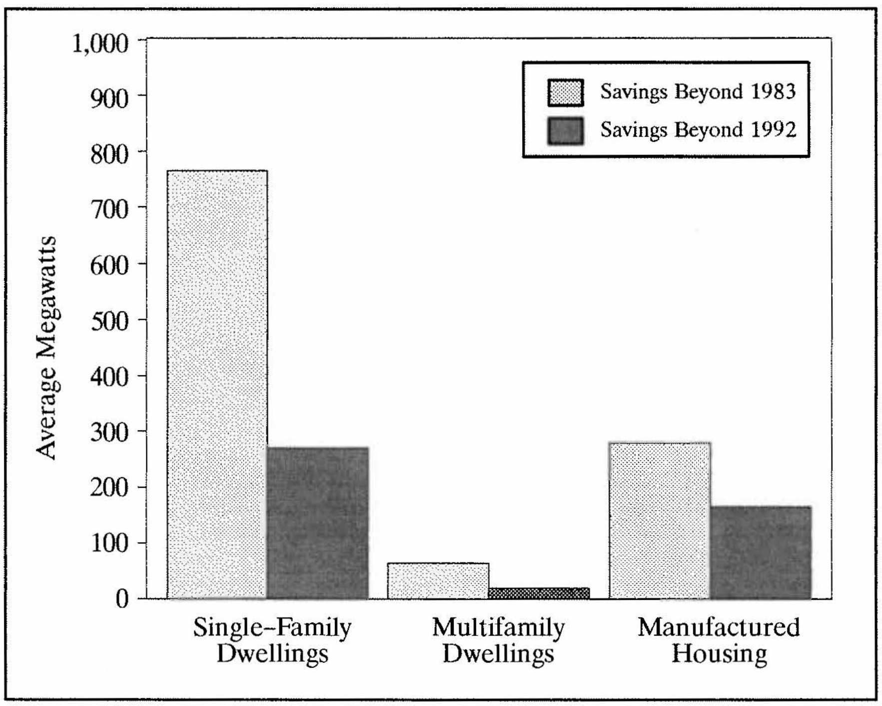
Conservation Potential

Figure 7-11
Technical Conservation from Space Heating Measures Beyond 1992 Codes/Practice in New Manufactured Housing



Conservation Potential

Figure 7-12
Technical Conservation from Space Heating Measures Beyond 1983 and 1992 Codes/Practice



The conservation potential available through improvements in the energy efficiency of new residential buildings was developed in five steps. These steps were to:

1. Establish the characteristics of current new residential construction.
2. Develop construction cost estimates for space heating conservation measures in new dwellings.
3. Assess the cost-effectiveness of space heating energy savings produced by efficiency improvements in new residential buildings.
4. Estimate the technical potential available from space heating energy conservation in new dwellings.
5. Estimate the achievable conservation potential available from space heating energy conservation in new dwellings.

The key sources of information used in this section come from research and programs operated in the region. Table 7-24 summarizes these data sources.

Separate estimates were prepared for single-family dwellings (up to four units and less than four stories), multifamily dwellings (five-plex and larger) and manufactured housing (e.g., mobile homes). A description of each of these steps, the data and major assumptions used and their sources follows.

Table 7-24
Key Data Sources for New Space Heating Measures

Residential Characteristics	
Pacific Northwest Residential Energy Survey	Insulation characteristics of new construction. House size and climate zone.
Housing Industries Dynamics Survey	Insulation characteristics of new construction. House size and climate zone.
Residential Standards Demonstration Project	Air change rates.
Residential Construction Demonstration Program	Manufactured housing current construction practice.
Northwest Residential Infiltration Study	Air change rates.
Battelle Pacific Northwest Laboratories/ Bonneville Power Administration	Current construction practice. Pacific Northwest manufactured housing and conservation upgrade possibilities.
Costs	
Bonneville Power Administration, Residential Standards Demonstration Project	Measure cost for single-family and multifamily homes.
Bonneville Power Administration, Residential Construction Demonstration Program	Measure cost for highly insulated walls (site built) and for manufactured homes, measure cost for heat recovery ventilation systems.
University of Washington Study	Measure cost (site built).
Manufactured Housing Institute Study	Costs of manufactured home measures.
U.S. Department of Housing and Urban Development	Costs of manufactured home measures.
Consumption and Savings	
Bonneville Power Administration, Residential Standards Demonstration Project	Calibration of simulation model energy consumption predictions.
Bonneville Power Administration, Residential Construction Demonstration Program	Calibration of simulation model energy consumption predictions.
Evaluation Reports from Weatherization Programs	Simulation model comparison.

Step 1. Establish the Characteristics of New Residential Construction

To determine the potential for improving the energy efficiency of new residential structures, it was first necessary to establish their current level of efficiency. In addition to identifying the level of insulation and type of windows commonly installed in new housing, other new home characteristics had to be ascertained, such as average floor area heated, number of stories, window area, "tightness" of the dwelling and foundation type. These characteristics significantly affect the amount of energy needed for space heating.

Tables 7-25 and 7-26 show by climate zone and building type the 1983 "base case" insulation levels assumed by the Council in its assessment of space heating conservation potential in new dwellings. The information on 1983 single-family and multifamily housing characteristics shown in Table 7-25 is derived from three sources. The first is a regional residential energy survey conducted for Bonneville in 1983 (Pacific Northwest Residential Energy Survey 1983, "PNRES '83"). This survey was used to estimate the average size of new dwellings. The second data source was the 1977 through 1983 annual survey of new home characteristics prepared by Housing Industry Dynamics (HID) for Bonneville. The HID survey data was used to determine the typical glass area and foundation types, and the most prevalent level of insulation found in new dwellings. In areas of the region that had adopted an energy code, the Council used the minimum requirements of those codes to represent construction practices.

As stated previously, building codes/practices have improved significantly since the Council adopted its first plan in 1983. In order to estimate the remaining potential for space heating conservation in new residential buildings it was necessary to update the 1983 "base case" to 1992 "current practice." For those areas in the region that enforce an energy code, the requirements of such codes served to establish the minimum thermal efficiency levels found in typical new single-family and multifamily dwellings. Table 7-26 shows the efficiency levels required by the 1990 revisions to the Oregon and Washington state codes.[25] This table also shows the expected annual space heating use for new residences built to the 1990 Oregon and Washington codes and to the current building practices assumed for climate Zone 3.

Information on the air tightness of new dwellings was obtained from the Residential Standards Demonstration Program (RSDP) sponsored by Bonneville. Data obtained in RSDP appeared to indicate that a house built between 1980 and 1983 experienced between 0.35 and 0.55 air changes per hour, depending on the test method used. Results of air tightness testing conducted through the Northwest Residential Infiltration Study (NORIS) sponsored by Bonneville indicate that the average infiltration rates for single-family detached housing built between 1980 and 1986 was approximately 0.40 to 0.45 air changes per hour. Research carried out under NORIS also found that the average infiltration rates for houses built under Bonneville's Super Good Cents program was approximately 0.30 air changes per hour in site-built homes and 0.25 air changes per hour in manufactured homes. The NORIS project found that, depending on the criteria used, from 20 to 50 percent of all of the homes tested, whether built to the Super Good Cents standards or not, would not meet the most current American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. standard for acceptable ventilation rates (ASHRAE Standard 62-89). Given these findings and the adoption of energy codes in Oregon and Washington that are equivalent to the Council's model standards, the Council will continue to assume the ASHRAE rate of 0.35 air changes per hour for current (1992) practice homes.

The base-case characteristics for new manufactured housing, shown in Table 7-25, were derived from information obtained from a Bonneville-sponsored study of current construction practices in the Northwest's manufacturing housing industry and data on the energy features of the most common models sold by manufacturers participating in Bonneville's Residential Construction Demonstration Program. The insulation levels assumed were also obtained from the same Bonneville studies. These levels exceed the requirements of the U.S. Department of Housing and Urban Development's current rules concerning the eligibility of manufactured homes for mortgage insurance under Title II of the National Housing Act.

Once the general characteristics of new dwellings had been identified, "typical" building designs were developed for detailed analysis of space heating conservation potential. Three typical single-family detached dwelling designs were developed to represent the mixture of house sizes and foundation types being constructed in the region. A single multifamily building design was chosen to represent new multifamily construction larger than four-plexes. Two manufactured home designs were selected to represent those typically being sold in the region. Table 7-27 summarizes the basic characteristics of the new dwellings used in the Council's assessment. These designs were selected as representative, based on features primarily related to their space heating requirements, such as foundation type, and secondarily on their architectural styles.

25. The 1990 session of the Washington State Legislature enacted legislation that will require new electrically heated homes constructed after July 1, 1991 to meet thermal efficiency standards that are equivalent to the Council's model conservation standards for new electrically heated residences. The State of Oregon also adopted revisions to its energy code in 1990 that are equivalent to the thermal performance requirements of the Council's model conservation standards for new electrically heated residences. These revisions go into effect January 1, 1992. The Council has included these savings in its demand forecast.

Table 7-25
New Residential Construction Base Case Efficiency Levels and Annual Space Heating Use Assumptions

Building Type	Climate Zone 1 Insulation Level	Climate Zone 1 Annual Use (kWh/sq. ft.)	Climate Zone 2 Insulation Level	Climate Zone 2 Annual Use (kWh/sq. ft.)	Climate Zone 3 Insulation Level	Climate Zone 3 Annual Use (kWh/sq. ft.)	Weighted Average Use (kWh/sq. ft.)
Single-Family Homes		6.8		9.7		8.2	7.3
▪ Roof (Attic)	R-30		R-30		R-38		
▪ Vaulted Ceiling	R-19/30		R-19/30		R-30		
▪ Walls	R-11		R-11		R-19		
▪ Underfloor	R-11/19		R-19		R-19		
▪ Windows	Double glazed (U-.90)		Double glazed (U-.90)		Double glazed (U-.65)		
▪ Air Tightness	0.35 ACH		0.35 ACH		0.35 ACH		
Multifamily Homes		3.6		5.9		7.0	3.7
▪ Ceiling/Roof	R-30		R-30		R-30		
▪ Walls	R-11		R-11		R-11		
▪ Underfloor	R-11/19		R-19		R-19		
▪ Windows	Double glazed (U-.90)		Double glazed (U-.90)		Double glazed (U-.65)		
▪ Air Tightness	0.35 ACH		0.35 ACH		0.35 ACH		
Manufactured Homes		8.8		12.7		14.9	10.2
▪ Ceiling/Roof	R-11		R-11		R-11		
▪ Walls	R-11		R-11		R-11		
▪ Underfloor	R-7		R-7		R-7		
▪ Windows	Double glazed (U-.90)		Double glazed (U-.90)		Double glazed (U-.90)		
▪ Air Tightness	0.35 ACH		0.35 ACH		0.35 ACH		

Table 7–26
New Residential Construction 1992 Energy Code Requirements, Construction Practices and Annual Space Heating Use

	Zone 1		Zone 2		Zone 3
	Oregon	Washington	Oregon	Washington	
Single–Family Dwellings					
▪ Roof (Attic)	38	38	38	38	38
▪ Vaulted	30	30	30	30	38
▪ Walls	21		21	24	19
▪ Underfloors	25	30	25	30	19
▪ Windows	R–2.5	R–2.5	R–2.5	R–2.5	2.0
▪ Exterior Doors	R–5	R–5	R–5	R–5	R–5
▪ Annual Use (kWh/sq. ft./yr.)	3.3	3.3	5.4	4.8	8.2
Multifamily Dwellings					
▪ Roof (Attic)	38	38	38	38	38
▪ Vault	30	30	30	30	30
▪ Walls	21	19	21	24	19
▪ Underfloors	25	30	25	30	19
▪ Windows	R–2.5	R–2.5	R–2.5	R–2.5	2.0
▪ Exterior Doors	R–5	R–5	R–5	R–5	R–5
▪ Annual Use (kWh/sq. ft./yr.)	1.3	1.3	2.6	2.3	4.5
Manufactured Housing					
▪ Roof (Attic)	R–14/19	R–14/19	R–14/19	R–14/19	R–14/19
▪ Vault	R–14/19	R–14/19	R–14/19	R–14/19	R–14/19
▪ Wall	R–11/19	R–11/19	R–11/19	R–11/19	R–11/19
▪ Underfloors	R–7/11	R–7/11	R–7/11	R–7/11	R–7/11
▪ Windows	R–1.3	R–1.3	R–1.3	R–1.3	R–1.3
▪ Exterior Doors	R–5	R–5	R–5	R–5	R–5
▪ Annual Use (kWh/sq. ft./yr.)	6.4		9.5		11.2

Table 7–27
Typical New Dwelling Characteristics

Characteristic	Single-Family Detached			Multifamily	Manufactured Housing	
Prototype Label	A	B	C	12 Units	A	B
Size—Gross Floor Area (sq. ft.)	1,344	1,848	2,356	840 sq. ft./unit	924	1,568
Foundation Type	Crawl space	Crawl space	Slab-on-grade Partial Basement	Crawl space	Skirted	Crawl space
Number of Stories	1	2-Split Level 1 with partial basement	2-Split Level 1 with partial basement	3-4 with garage	1	1
Window Area (sq. ft.)	174	220	310	1,140	116	196
Glass Area as a Percent of Floor Area	13%	12%	13% (of unit's floor area)	11.9%	12.6%	12.5%
Gross Wall Area						
▪ Above Grade	1,395	2,151	1,842	6,344	1,200	1,260
▪ Below Grade	—	—	584	—	—	—
Total Exterior Envelope Area (sq. ft.)	4,104	4,753	5,264	13,660	3,048	4,396

Step 2. Develop Construction Cost Estimates for Space Heating Conservation Measures in New Dwellings

In the development of the 1983 Power Plan, the Council conducted an extensive survey of conservation costs in new residential buildings. Pursuant to the Council's plan, Bonneville, in cooperation with the four Northwest states, initiated a regionwide demonstration program on energy-efficient new home construction called the Residential Standards Demonstration Program (RSDP). The Council analyzed the cost reports submitted by builders in this program. Except for one measure, infiltration control with mechanical ventilation, the median costs reported by participating builders generally agreed with those used by the Council in the 1983 plan. The conservation analysis presented here makes use of three sources of conservation measure cost in addition to the RSDP cost data. Cost data on highly insulated walls (beyond R–19) was obtained from builders who participated in Bonneville's Residential Construction Demonstration Program.[26] The estimated cost for several conservation measures was also obtained from a report prepared by researchers at the University of Washington who were charged with evaluating the cost-effectiveness of measures in the 1986 Washington State Energy Code and the Council's model conservation standards. The costs for high performance windows (R–3.0 and R–5.0) were derived from data collected in the Residential Construction Demonstration Program for new manufactured homes and the Competitek service of the Rocky Mountain Institute. The cost of achieving an R–3.0 window is reflective of adding either high performance "hard coat" or "soft coat" low emissivity glass to a wood or vinyl-framed window with clear glass and argon gas filling. This cost is estimated to be $1.56 per square foot of window area for single-family and multifamily housing and $1.85 per square foot for manufactured homes. This difference in incremental cost is due to differences in markups between material costs and retail price to the consumer. The cost of an R–5.0 window (estimated at $7.82 per square foot of window for all building types) reflects the cost of adding two layers of low emissivity film to a wood window that already has one layer of high performance low emissivity glass and argon gas filling.

All costs used in this analysis were adjusted to 1990 dollars using the GNP Implicit Price Deflator for fixed investment in residential construction. These costs include a 36-percent markup for builder overhead, profits and fees for single-family and multifamily housing. The costs

26. The cost reported in the Residential Construction Demonstration Program for R–40 double-wall construction was adjusted to account for the increase in building perimeter dimensions needed to maintain the same interior living areas. This added $0.30 per square foot of net exterior wall area to this measure's cost.

of measures installed in new manufactured homes reflect a 30-percent markup for dealer overhead and profit.

Not all space heating conservation measures have similar useful lives. Insulation and infiltration control measures (i.e., air/vapor barriers) installed in new single-family and multifamily dwellings are anticipated to last at least 70 years (i.e., about the life of the structure). These same measures installed in new manufactured houses are also expected to last the life of the building (i.e., 45 years). However, the Council has assumed that two measures, insulated doors and energy-efficient windows, must be repaired or replaced before the end of the life of the structure. The Council included the cost of repairing and/or replacing these two space heating conservation measures when calculating their levelized cost. Based on data obtained during the process of revising the Oregon energy code, it appears that, with modern sealants and manufacturing techniques, approximately 25 percent of the windows installed in new housing can be expected to fail during the first 70 years. The cost of replacing these windows was converted to present value. It was then determined that a 60-year measure life would provide the same present value. Insulated doors in new residential structures were assumed to be replaced at 30-year intervals at a cost equivalent to their initial capital cost.

The costs of improvements in the space heating efficiency of new manufactured housing used in this analysis are based on the results of the costs reported by manufacturers who participated in Bonneville's Residential Construction Demonstration Program (RCDP). In RCDP, 150 manufactured homes were built to the Council's model conservation standards. Three other studies were used to corroborate the preliminary cost information obtained through RCDP. Two studies, one prepared for the Manufactured Housing Institute (MHI), and the second prepared for the U.S. Department of Housing and Urban Development (HUD), reported costs for conservation measures based on national construction costs. The third study, conducted for Bonneville, obtained conservation measure cost data from manufacturers in the region using a survey. Tables 7-28 through 7-36 show the retail costs assumed by the Council for potential cost-effective space heating conservation measures for new single- and multifamily dwellings and manufactured housing.

Table 7–28
Costs and Savings from Conservation Measures in New Single–Family Dwellings, Zone 1—Portland
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	(kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,344 Square Feet									
Base Case UA	471	$0	$0	$0.00	8,896	6.6	0	0	$0
Insulated Door	460	$35	$35	$0.03	8,558	6.4	338	11	$60
Windows R–1.2 to R–2.5	382	$816	$852	$0.63	6,249	4.6	2,309	29	$1,058
Walls R–11 to R–19 ADV	344	$466	$1,318	$0.98	5,171	3.8	1,078	32	$1,580
Floors R–11 to R–19	325	$292	$1,610	$1.20	4,644	3.5	527	41	$1,907
Vault R–19 to R–30	319	$105	$1,715	$1.2	4,476	3.3	167	47	$2,024
Walls R–19 ADV to R–21 ADV	313	$145	$1,859	$1.38	4,314	3.2	162	67	$2,186
Attic R–30 to R–38 STD	308	$131	$1,990	$1.48	4,182	3.1	131	74	$2,332
Floors R–19 to R–30	292	$439	$2,428	$1.81	3,747	2.8	435	76	$2,823
Windows R–2.5 to R–3.0	282	$27	$2,701	$2.01	3,471	2.6	275	81	$3,155
Walls R–21 ADV to R–26 ADV	262	$594	$3,295	$2.45	2,950	2.2	521	86	$3,820
Attic R–38 STD to R–49 ADV	250	$379	$3,673	$2.73	2,653	2.0	29	96	$4,244
Vault R–30 to R–38	247	$160	$3,833	$2.85	2,583	1.9	70	170	$4,423
Walls R–26 ADV to R–40 DBW	231	$1,172	$5,006	$3.72	2,173	1.6	409	216	$5,735
Windows R–3.0 to R–5.0	210	$1,361	$6,366	$4.74	1,685	1.3	488	230	$7,399
Floors R–30 to R–38	204	$530	$6,896	$5.13	1,562	1.2	122	327	$7,992
Attic R–49 ADV to R–60 ADV	202	$353	$7,249	$5.39	1,496	1.1	65	406	$8,386
House Size—1,848 Square Feet									
Base Case UA	628	$0	$0	$0.00	12,981	7.0	0	0	$0
Insulated Door	617	$35	$35	$0.02	12,635	6.8	346	11	$60
Windows R–1.2 to R–2.5	518	$1,032	$1,068	$0.58	9,624	5.2	3,012	28	$1,322
Walls R–11 to R–19 ADV	457	$746	$1,813	$0.98	7,837	4.2	1,786	31	$2,157
Floors R–11 to R–19	447	$158	$1,972	$1.07	7,541	4.1	296	40	$2,334
Vault R–19 to R–30	443	$60	$2,032	$1.10	7,440	4.0	101	45	$2,402
Slab R–5 to R–10	439	$76	$2,108	$1.14	7,329	4.0	110	51	$2,486
Walls R–19 ADV to R–21 ADV	430	$231	$2,339	$1.27	7,057	3.8	272	64	$2,745

Table 7–28 (cont.)
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 1—Portland
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,848 Square Feet (cont.)									
Attic R-30 to R-38 STD	425	$147	$2,486	$1.35	6,901	3.7	155	71	$2,910
Floors R-19 to R-30	416	$238	$2,724	$1.47	6,652	3.6	249	72	$3,176
Windows R-2.5 to R-30	403	$344	$3,068	$1.66	6,275	3.4	376	75	$3,596
Walls R-21 ADV to R-26 ADV	371	$952	$4,020	$2.18	5,372	2.9	903	79	$4,661
Slab R-10 to R-15	369	$63	$4,082	$2.21	5,319	2.9	52	89	$4,731
Attic R-38 STD to R-49 ADV	356	$426	$4,508	$2.44	4,963	2.7	356	90	$5,208
Vault R-30 to R-38	354	$92	$4,601	$2.49	4,918	2.7	45	155	$5,311
Walls R-26 ADV to R-40 DBW	328	$1,877	$6,478	$3.51	4,210	2.3	707	200	$7,412
Windows R-3.0 to R-5.0	301	$1,720	$8,198	$4.44	3,522	1.9	688	206	$9,516
Floors R-30 to R-38	298	$287	$8,485	$4.59	3,447	1.9	75	289	$9,837
Attic R-49 ADV to R-60 ADV	295	$397	$8,882	$4.81	3,364	1.8	82	364	$10,281
House Size—2,356 Square Feet									
Base Case UA	721	$0	$0	$0.00	14,108	6.0	0	0	$0
Insulated Door	715	$18	$18	$0.01	13,940	5.9	167	12	$30
Basement Wall R-11 to R-21 W/TB	695	$191	$208	$0.09	13,345	5.7	594	24	$243
Windows R-1.2 to R-2.5	556	$1,455	$1,663	$0.71	9,242	3.9	4,103	29	$2,022
Walls R-11 to R-19 ADV	507	$596	$2,259	$0.96	7,875	3.3	1,368	32	$2,689
Floors R-11 to R-19	501	$102	$2,361	$1.00	7,693	3.3	181	42	$2,803
Vault R-19 to R-30	497	$71	$2,432	$1.03	7,580	3.2	112	47	$2,883
Slab R-5 to R-10	495	$24	$2,456	$1.04	7,547	3.2	32	54	$2,909
Walls R-19 ADV to R-21 ADV	488	$185	$2,641	$1.12	7,340	3.1	206	67	$3,116
Attic R-30 to R-38 STD	482	$157	$2,798	$1.19	7,182	3.0	157	75	$3,292
Floor R-19 to R-30	476	$153	$2,951	$1.25	7,029	3.0	153	75	$3,463
Windows R-2.5 to R-3.0	458	$485	$3,435	$1.46	6,527	2.8	501	79	$4,056
Walls R-21 ADV to R-26 ADV	432	$761	$4,196	$1.78	5,841	2.5	685	83	$4,907
Slab R-10 to R-15	432	$20	$4,216	$1.79	5,826	2.5	15	93	$4,929

Table 7–28 (cont.)
Costs and Savings from Conservation Measures in New Single–Family Dwellings, Zone 1—Portland
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	(kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—2,356 Square Feet (cont.)									
Attic R-38 STD to R-49 ADV	418	$456	$4,672	$1.98	5,458	2.3	367	93	$5,439
Vault R-30 to R-38	416	$108	$4,780	$2.03	5,407	2.3	50	161	$5,560
Walls R-26 ADV to R-40 DBW	395	$1,501	$6,281	$2.67	4,850	2.1	557	203	$7,240
Windows R-3.0 to R-5.0	357	$2,424	$8,705	$3.69	3,890	1.7	960	208	$10,205
Floors R-30 to R-38	356	$185	$8,890	$3.77	3,842	1.6	47	292	$10,411
Attic R-49 ADV to R-60 ADV	352	$424	$9,314	$3.95	3,75	41.6	88	363	$10,886

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.
STD—Standard framing.
DBW—Double wall construction.

Table 7-29
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 1—Seattle
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,344 Square Feet									
Base Case UA	471	$0	$0	$0.00	10,177	7.6	0	0	$0
Insulated Door	460	$35	$35	$0.03	9,792	7.3	38	10	$60
Windows R-1.2 to R-2.5	382	$816	$852	$0.63	7,155	5.3	2,636	25	$1,058
Walls R-11 to R-19 ADV	344	$466	$1,318	$0.98	5,926	4.4	1,230	28	$1,580
Floors R-11 to R-19	325	$292	$1,610	$1.20	5,327	4.0	598	36	$1,907
Vault R-19 to R-30	319	$105	$1,715	$1.28	5,139	3.8	188	42	$2,024
Walls R-19 ADV to R-21 ADV	313	$145	$1,859	$1.38	4,956	3.7	183	59	$2,186
Attic R-30 to R-38 STD	308	$131	$1,990	$1.48	4,808	3.6	148	66	$2,332
Floors R-19 to R-30	292	$439	$2,428	$1.81	4,316	3.2	492	67	$2,823
Windows R-2.5 to R-3.0	282	$272	$2,701	$2.01	4,004	3.0	313	71	$3,155
Walls R-21 ADV to R-26 ADV	262	$594	$3,295	$2.45	3,415	2.5	589	76	$3,820
Attic R-38 STD to R-49 ADV	250	$379	$3,673	$2.73	3,081	2.3	334	85	$4,244
Vault R-30 to R-38	247	$160	$3,833	$2.85	3,001	2.2	80	150	$4,423
Walls R-26 ADV to R-40 DBW	231	$1,172	$5,006	$3.72	2,537	1.9	464	191	$5,735
Windows R-3.0 to R-5.0	210	$1,361	$6,366	$4.74	1,980	1.5	557	202	$7,399
Floors R-30 to R-38	204	$530	$6,896	$5.13	1,840	1.4	140	286	$7,992
Attic R-49 ADV to R-60 ADV	202	$353	$7,249	$5.39	1,765	1.3	75	355	$8,386
House Size—1,848 Square Feet									
Base Case UA	628	$0	$0	$0.00	14,854	8.0	0	0	$0
Insulated Door	617	$35	$35	$0.02	14,457	7.8	396	10	$60
Window R-1.2 to R-2.5	518	$1,032	$1,068	$0.58	11,008	6.0	3,449	24	$1,322
Walls R-11 to R-19 ADV	457	$746	$1,813	$0.98	8,972	4.9	2,036	27	$2,157
Floors R-11 to R-19	447	$158	$1,972	$1.07	8,634	4.7	338	35	$2,334
Vault R-19 to R-30	443	$60	$2,032	$1.10	8,519	4.6	116	39	$2,402
Slab R-5 to R-10	439	$76	$2,108	$1.14	8,392	4.5	126	45	$2,486
Walls R-19 ADV to R-21 ADV	430	$231	$2,339	$1.27	8,081	4.4	311	56	$2,745

Table 7-29 (cont.)
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 1—Seattle
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,848 Square Feet (cont.)									
Attic R-30 to R-38 STD	425	$147	$2,486	$1.35	7,903	4.3	178	62	$2,910
Floors R-19 to R-30	416	$238	$2,724	$1.47	7,619	4.1	284	63	$3,176
Windows R-2.5 to R-3.0	403	$344	$3,068	$1.66	7,191	3.9	429	66	$3,596
Walls R-21 ADV to R-26 ADV	371	$952	$4,020	$2.18	6,170	3.3	1,021	70	$4,661
Slab R-10 to R-15	369	$63	$4,082	$2.21	6,111	3.3	59	80	$4,731
Attic R-38 STD to R-49 ADV	356	$426	$4,508	$2.44	5,711	3.1	400	80	$5,208
Vault R-30 to R-38	354	$92	$4,601	$2.49	5,661	3.1	51	138	$5,311
Walls R-26 ADV to R-40 DBW	328	$1,877	$6,478	$3.51	4,856	2.6	805	176	$7,412
Windows R-3.0 to R-5.0	301	$1,720	$8,198	$4.44	4,077	2.2	779	182	$9,516
Floors R-30 to R-38	298	$287	$8,485	$4.59	3,993	2.2	85	256	$9,837
Attic R-49 ADV to R-60 ADV	295	$397	$8,882	$4.81	3,900	2.1	93	322	$10,281
House Size—2,356 Square Feet									
Base Case UA	721	$0	$0	$0.00	16,136	6.8	0	0	$0
Insulated Door	715	$18	$18	$0.01	15,945	6.8	192	10	$30
Basement Walls R-11 to R-21 W/TB	695	$191	$208	$0.09	15,266	6.5	679	21	$243
Windows R-1.2 to R-2.5	556	$1,455	$1,663	$0.71	10,603	4.5	4,663	25	$2,022
Walls R-11 to R-19 ADV	507	$596	$2,259	$0.96	9,061	3.8	1,542	29	$2,689
Floors R-11 to R-19	501	$102	$2,361	$1.00	8,854	3.8	207	37	$2,803
Vault R-19 to R-30	497	$71	$2,432	$1.03	8,725	3.7	129	41	$2,883
Slab R-5 to R-10	495	$24	$2,456	$1.04	8,688	3.7	38	47	$2,909
Walls R-19 ADV to R-21 ADV	488	$185	$2,641	$1.12	8,451	3.6	236	59	$3,116
Attic R-30 to R-38 STD	482	$157	$2,798	$1.19	8,271	3.5	181	65	$3,292
Floors R-19 to R-30	476	$153	$2,951	$1.25	8,095	3.4	176	65	$3,463
Windows R-2.5 to R-3.0	458	$485	$3,435	$1.46	7,524	3.2	571	70	$4,056
Walls R-21 ADV to R-26 ADV	432	$761	$4,196	$1.78	6,744	2.9	779	73	$4,907
Slab R-10 to R-15	432	$20	$4,216	$1.79	6,726	2.9	18	81	$4,929

Table 7–29 (cont.)
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 1—Seattle
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—2,356 Square Feet (cont.)									
Attic R-38 STD to R-49 ADV	418	$456	$4,672	$1.98	6,313	2.7	413	83	$5,439
Vault R-30 to R-38	416	$108	$4,780	$2.03	6,257	2.7	56	145	$5,560
Walls R-26 ADV to R-40 DBW	395	$1,501	$6,281	$2.67	5,638	2.4	619	183	$7,240
Windows R-3.0 to R-5.0	357	$2,424	$8,705	$3.69	4,584	1.9	1,054	190	$10,205
Floors R-30 to R-38	356	$185	$8,890	$3.77	4,532	1.9	52	267	$10,411
Attic R-49 ADV to R-60 ADV	352	$424	$9,314	$3.95	4,435	1.9	97	331	$10,886

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.
STD—Standard framing.
DBW—Double wall construction.

Table 7-30
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 2—Spokane
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1344 Square Feet									
Base Case UA	471	$0	$0	$0.00	14,699	10.9	0	0	$0
Insulated Door	460	$35	$35	$0.03	14,201	10.6	499	8	$60
Windows R-1.2 to R-2.5	382	$816	$852	$0.63	10,745	8.0	3,455	19	$1,058
Walls R-11 to R-19 ADV	344	$466	$1,318	$0.98	9,108	6.8	1,637	21	$1,580
Floors R-11 to R-19	325	$292	$1,610	$1.20	8,307	6.2	802	27	$1,907
Vault R-19 to R-30	319	$105	$1,715	$1.28	8,052	6.0	254	31	$2,024
Walls R-19 ADV to R-21 ADV	313	$145	$1,859	$1.38	7,805	5.8	247	44	$2,186
Attic R-30 to R-38 STD	308	$131	$1,990	$1.48	7,605	5.7	201	49	$2,332
Floors R-19 to R-30	292	$439	$2,428	$1.81	6,936	5.2	669	49	$2,823
Windows R-2.5 to R-3.0	282	$272	$2,701	$2.01	6,507	4.8	429	52	$3,155
Walls R-21 ADV to R-26 ADV	262	$594	$3,295	$2.45	5,692	4.2	815	55	$3,820
Attic R-38 STD to R-49 ADV	250	$379	$3,673	$2.73	5,227	3.9	465	61	$4,244
Vault R-30 to R-38	247	$160	$3,833	$2.85	5,115	3.8	111	108	$4,423
Walls R-26 ADV to R-40 DBW	231	$1,172	$5,006	$3.72	4,472	3.3	644	137	$5,735
Windows R-3.0 to R-5.0	210	$1,361	$6,366	$4.74	3,684	2.7	788	142	$7,399
Floors R-30 to R-38	204	$530	$6,896	$5.13	3,483	2.6	200	200	$7,992
Attic R-49 ADV to R-60 ADV	202	$353	$7,249	$5.39	3,376	2.5	107	248	$8,386
House Size—1,848 Square Feet									
Base Case UA	628	$0	$0	$0.00	20,807	11.3	0	0	$0
Insulated Door	617	$35	$35	$0.02	20,302	11.0	505	8	$60
Windows R-1.2 to R-2.5	518	$1,032	$1,068	$0.58	15,871	8.6	4,431	19	$1,322
Walls R-11 to R-19 ADV	457	$746	$1,813	$0.98	13,198	7.1	2,673	21	$2,157
Floors R-11 to R-19	447	$158	$1,972	$1.07	12,751	6.9	447	26	$2,334
Vault R-19 to R-30	443	$60	$2,032	$1.10	12,598	6.8	153	29	$2,402
Slab R-5 to R-10	439	$76	$2,108	$1.14	12,431	6.7	167	34	$2,486
Walls R-19 ADV to R-21 ADV	430	$231	$2,339	$1.27	12,018	6.5	412	42	$2,745

Table 7–30 (cont.)
Costs and Savings from Conservation Measures in New Single–Family Dwellings, Zone 2—Spokane
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,848 Square Feet (cont.)									
Attic R-30 to R-38 STD	425	$147	$2,486	$1.35	11,783	6.4	235	47	$2,910
Floors R-19 to R-30	416	$238	$2,724	$1.47	11,407	6.2	376	47	$3,176
Windows R-2.5 to R-3.0	403	$344	$3,068	$1.66	10,839	5.9	568	50	$3,596
Walls R-21 ADV to R-26 ADV	371	$952	$4,020	$2.18	9,476	5.1	1,362	52	$4,661
Slab R-10 to R-15	369	$63	$4,082	$2.21	9,396	5.1	80	59	$4,731
Attic R-38 STD to R-49 ADV	356	$426	$4,508	$2.44	8,856	4.8	541	59	$5,208
Vault R-30 to R-38	354	$92	$4,601	$2.49	8,787	4.8	68	102	$5,311
Walls R-26 ADV to R-40 DBW	328	$1,877	$6,478	$3.51	7,695	4.2	1,092	130	$7,412
Windows R-3.0 to R-5.0	301	$1,720	$8,198	$4.44	6,620	3.6	1,075	132	$9,516
Floors R-30 to R-38	298	$287	$8,485	$4.59	6,503	3.5	117	185	$9,837
Attic R-49 ADV to R-60 ADV	295	$397	$8,882	$4.81	6,375	3.4	128	233	$10,281
House Size—2,356 Square Feet									
Base Case UA	721	$0	$0	$0.00	22,780	9.7	0	0	$0
Insulated Door	715	$18	$18	$0.01	22,530	9.6	250	8	$30
Basement Wall R-11 to R-21 W/TB	695	$191	$208	$0.09	21,644	9.2	887	16	$243
Windows R-1.2 to R-2.5	556	$1,455	$1,663	$0.71	15,527	6.6	6,117	19	$2,022
Walls R-11 to R-19 ADV	507	$596	$2,259	$0.96	13,468	5.7	2,058	21	$2,689
Floors R-11 to R-19	501	$102	$2,361	$1.00	13,193	5.6	276	27	$2,803
Vault R-19 to R-30	497	$71	$2,432	$1.03	13,020	5.5	172	31	$2,883
Slab R-5 to R-10	495	$24	$2,456	$1.04	12,970	5.5	50	35	$2,909
Walls R-19 ADV to R-21 ADV	488	$185	$2,641	$1.12	12,653	5.4	317	44	$3,116
Attic R-30 to R-38 STD	482	$157	$2,798	$1.19	12,411	5.3	242	49	$3,292
Floor R-19 to R-30	476	$153	$2,951	$1.25	12,175	5.2	235	49	$3,463
Windows R-2.5 to R-3.0	458	$485	$3,435	$1.46	11,399	4.8	776	51	$4,056
Walls R-21 ADV to R-26 ADV	432	$761	$4,196	$1.78	10,337	4.4	1,062	54	$4,907
Slab R-10 to R-15	432	$20	$4,216	$1.79	10,313	4.4	25	60	$4,929

Table 7-30 (cont.)
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 2—Spokane
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—2,356 Square Feet (cont.)									
Attic R-38 STD to R-49 ADV	418	$456	$4,672	$1.98	9,746	4.1	566	60	$5,439
Vault R-30 to R-38	416	$108	$4,780	$2.03	9,669	4.1	78	105	$5,560
Walls R-26 ADV to R-40 DBW	395	$1,501	$6,281	$2.67	8,815	3.7	854	133	$7,240
Windows R-3.0 to R-5.0	357	$2,424	$8,705	$3.69	7,348	3.1	1,467	136	$10,205
Floors R-30 to R-38	356	$185	$8,890	$3.77	7,275	3.1	73	191	$10,411
Attic R-49 ADV to R-60 ADV	352	$424	$9,314	$3.95	7,140	3.0	135	237	$10,886

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.
STD—Standard framing.
DBW—Double wall construction.

Table 7-31
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 3—Missoula
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,344 Square Feet									
Base Case UA	471	$0	$0	$0.00	17,270	12.8	0	0	$0
Insulated Door	460	$35	$35	$0.03	16,692	12.4	578	7	$60
Windows R-1.2 to R-2.5	382	$816	$852	$0.63	12,706	9.5	3,986	16	$1,058
Walls R-11 to R-19 ADV	344	$466	$1,318	$0.98	10,817	8.0	1,889	18	$1,580
Floors R-11 to R-19	325	$292	$1,610	$1.20	9,888	7.4	929	23	$1,907
Vault R-19 to R-30	319	$105	$1,715	$1.28	9,593	7.1	295	26	$2,024
Walls R-19 ADV to R-21 ADV	313	$145	$1,859	$1.38	9,307	6.9	286	38	$2,186
Attic R-30 to R-38 STD	308	$131	$1,990	$1.48	9,074	6.8	233	42	$2,332
Floors R-19 to R-30	292	$439	$2,428	$1.81	8,299	6.2	775	42	$2,823
Windows R-2.5 to R-3.0	282	$272	$2,701	$2.01	7,802	5.8	497	45	$3,155
Walls R-21 ADV to R-26 ADV	262	$594	$3,295	$2.45	6,860	5.1	942	47	$3,820
Attic R-38 STD to R-49 ADV	250	$379	$3,673	$2.73	6,324	4.7	536	53	$4,244
Vault R-30 to R-38	247	$160	$3,833	$2.85	6,195	4.6	129	93	$4,423
Walls R-26 ADV to R-40 DBW	231	$1,172	$5,006	$3.72	5,447	4.1	748	118	$5,735
Windows R-3.0 to R-5.0	210	$1,361	$6,366	$4.74	4,523	3.4	923	121	$7,399
Floors R-30 to R-38	204	$530	$6,896	$5.13	4,288	3.2	235	170	$7,992
Attic R-49 ADV to R-60 ADV	202	$353	$7,249	$5.39	4,161	3.1	126	211	$8,386
House Size—1,848 Square Feet									
Base Case UA	628	$0	$0	$0.00	24,388	13.2	0	0	$0
Insulated Door	617	$35	$35	$0.02	23,800	12.9	588	6	$60
Windows R-1.2 to R-2.5	518	$1,032	$1,068	$0.58	18,663	10.1	5,137	16	$1,322
Walls R-11 to R-19 ADV	457	$746	$1,813	$0.98	15,583	8.4	3,080	18	$2,157
Floors R-11 to R-19	447	$158	$1,972	$1.07	15,069	8.2	514	23	$2,334
Vault R-19 to R-30	443	$60	$2,032	$1.10	14,893	8.1	176	25	$2,402
Slab R-5 to R-10	439	$76	$2,108	$1.14	14,700	8.0	193	29	$2,486
Walls R-19 ADV to R-21 ADV	430	$231	$2,339	$1.27	14,225	7.7	475	36	$2,745

Table 7-31 (cont.)
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 3—Missoula
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,848 Square Feet (cont.)									
Attic R-30 to R-38 STD	425	$147	$2,486	$1.35	13,954	7.6	271	40	$2,910
Floors R-19 to R-30	416	$238	$2,724	$1.47	13,519	7.3	435	41	$3,176
Windows R-2.5 to R-3.0	403	$344	$3,068	$1.66	12,862	7.0	657	43	$3,596
Walls R-21 ADV to R-26 ADV	371	$952	$4,020	$2.18	11,287	6.1	1,576	45	$4,661
Slab R-10 to R-15	369	$63	$4,082	$2.21	11,194	6.1	93	51	$4,731
Attic R-38 STD to R-49 ADV	356	$426	$4,508	$2.44	10,569	5.7	625	51	$5,208
Vault R-30 to R-38	354	$92	$4,601	$2.49	10,490	5.7	79	88	$5,311
Walls R-26 ADV to R-40 DBW	328	$1,877	$6,478	$3.51	9,225	5.0	1,264	112	$7,412
Windows R-3.0 to R-5.0	301	$1,720	$8,198	$4.44	7,991	4.3	1,235	115	$9,516
Floors R-30 to R-38	298	$287	$8,485	$4.59	7,856	4.3	135	161	$9,837
Attic R-49 ADV to R-60 ADV	295	$397	$8,882	$4.81	7,708	4.2	148	202	$10,281
House Size—2,356 Square Feet									
Base Case UA	721	$0	$0	$0.00	26,728	11.3	0	0	$0
Insulated Door	715	$18	$18	$0.01	26,440	11.2	288	7	$30
Basement Wall R-11 to R-21 W/TB	695	$191	$208	$0.09	25,418	10.8	1,022	14	$243
Windows R-1.2 to R-2.5	556	$1,455	$1,663	$0.71	18,373	7.8	7,045	17	$2,022
Walls R-11 to R-19 ADV	507	$596	$2,259	$0.96	16,025	6.8	2,348	19	$2,689
Floors R-11 to R-19	501	$102	$2,361	$1.00	15,709	6.7	315	24	$2,803
Vault R-19 to R-30	497	$71	$2,432	$1.03	15,513	6.6	197	27	$2,883
Slab R-5 to R-10	495	$24	$2,456	$1.04	15,455	6.6	57	31	$2,909
Walls R-19 ADV to R-21 ADV	488	$185	$2,641	$1.12	15,095	6.4	361	38	$3,116
Attic R-30 to R-38 STD	482	$157	$2,798	$1.19	14,819	6.3	276	43	$3,292
Floor R-19 to R-30	476	$153	$2,951	$1.25	14,551	6.2	268	43	$3,463
Windows R-2.5 to R-3.0	458	$485	$3,435	$1.46	13,671	5.8	879	45	$4,056
Walls R-21 ADV to R-26 ADV	432	$761	$4,196	$1.78	12,463	5.3	1,208	47	$4,907
Slab R-10 to R-15	432	$20	$4,216	$1.79	12,435	5.3	28	52	$4,929

Table 7-31 (cont.)
Costs and Savings from Conservation Measures in New Single-Family Dwellings, Zone 3—Missoula
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—2,356 Square Feet (cont.)									
Attic R-38 STD to R-49 ADV	418	$456	$4,672	$1.98	11,787	5.0	648	53	$5,439
Vault R-30 to R-38	416	$108	$4,780	$2.03	11,698	5.0	89	91	$5,560
Walls R-26 ADV to R-40 DBW	395	$1,501	$6,281	$2.67	10,715	4.5	983	115	$7,240
Windows R-3.0 to R-5.0	357	$2,424	$8,705	$3.69	9,014	3.8	1,701	117	$10,205
Floors R-30 to R-38	356	$185	$8,890	$3.77	8,929	3.8	85	164	$10,411
Attic R-49 ADV to R-60 ADV	352	$424	$9,314	$3.95	8,772	3.7	157	204	$10,886

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.
STD—Standard framing.
DBW—Double wall construction.

Table 7-32
Costs and Savings from Conservation Measures in New Multifamily Dwellings, Dwelling Size—840 Square Feet, 1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
Zone 1—Portland									
Base Case	2,435	$0	$0	$0.00	2,666	3.2	0	0	$0
Insulated Door	2,402	$9	$9	$0.01	2,589	3.1	77	13	$15
Window R-1.2 to R-2.5	1,889	$446	$455	$0.54	1,480	1.8	1,109	33	$560
Floors R-11 to R-19	1,838	$66	$521	$0.62	1,375	1.6	105	47	$634
Vault R-19 to R-30	1,810	$40	$561	$0.67	1,318	1.6	57	52	$679
Walls R-11 to R-19	1,662	$213	$774	$0.92	1,029	1.2	289	55	$917
Walls R-19 to R-21	1,637	$52	$826	$0.98	982	1.2	48	82	$975
Floors R-19 to R-30	1,593	499	$925	$1.10	901	1.1	81	92	$1,086
Attic R-30 to R-38	1,584	$21	$945	$1.13	885	1.1	16	98	$1,109
Windows R-2.5 to R-3.0	1,516	$149	$1,094	$1.30	766	0.9	119	103	$1,291
Walls R-21 to R-26	1,429	$213	$1,307	$1.56	629	0.7	137	117	$1,529
Attic R-38 to R-49 ADV	1,407	$60	$1,367	$1.63	595	0.7	34	133	$1,596
Vault R-30 to R-38	1,394	$61	$1,428	$1.70	575	0.7	20	234	$1,664
Walls R-26 to R-40 DBW	1,308	$421	$1,848	$2.20	450	0.5	126	252	$3,240
Windows R-3.0 to R-5.0	1,171	$743	$2,591	$3.08	277	0.3	172	356	$6,480
Floors R-30 to R-38	1,153	$120	$2,711	$3.23	257	0.3	20	453	$6,480
Attic R-49 ADV to R-60 ADV	1,148	$56	$2,767	$3.29	251	0.3	6	703	$6,480
Zone 1—Seattle									
Base Case	2,435	$0	$0	$0.00	3,073	3.7	0	0	$0
Insulated Door	2,402	$9	$9	$0.01	2,987	3.6	86	11	$15
Windows R-1.2 to R-2.5	1,889	$446	$455	$0.54	1,726	2.1	1,261	29	$560
Floors R-11 to R-19	1,838	$66	$521	$0.62	1,607	1.9	119	42	$634
Vault R-19 to R-30	1,810	$40	$561	$0.67	1,542	1.8	65	46	$679
Walls R-11 to R-19	1,662	$213	$774	$0.92	1,218	1.4	325	49	$917
Walls R-19 to R-21	1,637	$52	$826	$0.98	1,163	1.4	54	72	$975
Floors R-19 to R-30	1,593	$99	$925	$1.10	1,070	1.3	93	80	$1,086
Attic R-30 to R-38	1,584	$21	$945	$1.13	1,052	1.3	18	84	$1,109
Windows R-2.5 to R-3.0	1,516	$149	$1,094	$1.30	913	1.1	139	88	$1,291
Walls R-21 to R-26	1,429	$213	$1,307	$1.56	749	0.9	165	97	$1,529

Table 7-32 (cont.)
Costs and Savings from Conservation Measures in New Multifamily Dwellings, Dwelling Size—840 Square Feet, 1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
Zone 1—Seattle (cont.)									
Attic R-38 to R-49 ADV	1,407	$60	$1,367	$1.63	708	0.8	41	110	$1,596
Vault R-30 to R-38	1,394	$61	$1,428	$1.70	684	0.8	24	194	$1,664
Walls R-26 to R-40 DBW	1,308	$421	$1,848	$2.20	532	0.6	152	208	$3,240
Windows R-3.0 to R-5.0	1,171	$743	$2,591	$3.08	328	0.4	204	301	$6,480
Floors R-30 to R-38	1,153	$120	$2,711	$3.23	304	0.4	23	385	$6,480
Attic R-49 ADV to R-60 ADV	1,148	$56	$2,767	$3.29	297	0.4	7	598	$6,480
Zone 2—Spokane									
Base Case	2,435	$0	$0	$0.00	4,970	5.9	0	0	$0
Insulated Door	2,402	$9	$9	$0.01	4,852	5.8	118	8	$15
Windows R-1.2 to R-2.5	1,889	$446	$455	$0.54	3,100	3.7	1,751	21	$560
Floors R-11 to R-19	1,838	$66	$521	$0.62	2,934	3.5	167	29	$634
Vault R-19 to R-30	1,810	$40	$561	$0.67	2,843	3.4	91	33	$679
Walls R-11 to R-19	1,662	$213	$774	$0.92	2,369	2.8	474	34	$917
Walls R-19 to R-21	1,637	$52	$826	$0.98	2,289	2.7	80	48	$975
Floors R-19 to R-30	1,593	$99	$925	$1.10	2,152	2.6	137	54	$1,086
Attic R-30 to R-38	1,584	$21	$945	$1.13	2,124	2.5	28	56	$1,109
Windows R-2.5 to R-3.0	1,516	$149	$1,094	$1.30	1,916	2.3	208	59	$1,291
Walls R-21 to R-26	1,429	$213	$1,307	$1.56	1,663	2.0	254	63	$1,529
Attic R-38 to R-49 ADV	1,407	$60	$1,367	$1.63	1,599	1.9	64	71	$1,596
Vault R-30 to R-38	1,394	$61	$1,428	$1.70	1,562	1.9	37	125	$1,664
Walls R-26 to R-40 DBW	1,308	$421	$1,848	$2.20	1,325	1.6	237	134	$3,240
Windows R-3.0 to R-5.0	1,171	$743	$2,591	$3.08	974	1.2	351	175	$6,480
Floors R-30 to R-38	1,153	$120	$2,711	$3.23	931	1.1	43	208	$6,480
Attic R-49 ADV to R-60 ADV	1,148	$56	$2,767	$3.29	918	1.1	13	323	$6,480
Zone 3—Missoula									
Base Case	2,435	$0	$0	$0.00	5,920	7.0	0	0	$0
Insulated Door	2,402	$9	$9	$0.01	5,784	6.9	136	7	$15

Table 7-32 (cont.)
Costs and Savings from Conservation Measures in New Multifamily Dwellings, Dwelling Size—840 Square Feet, 1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
Zone 3—Missoula (cont.)									
Windows R-1.2 to R-2.5	1,889	$446	$455	$0.54	3,779	4.5	2,005	18	$560
Floors R-11 to R-19	1,838	$66	$521	$0.62	3,586	4.3	193	25	$634
Vault R-19 to R-30	1,810	$40	$561	$0.67	3,481	4.1	105	28	$679
Walls R-11 to R-19	1,662	$213	$774	$0.92	2,932	3.5	549	29	$917
Walls R-19 to R-21	1,637	$52	$826	$0.98	2,839	3.4	93	42	$975
Floors R-19 to R-30	1,593	$99	$925	$1.10	2,679	3.2	160	46	$1,086
Attic R-30 to R-38	1,584	$21	$945	$1.13	2,646	3.2	33	47	$1,109
Windows R-2.5 to R-3.0	1,516	$149	$1,094	$1.30	2,402	2.9	245	50	$1,291
Walls R-21 to R-26	1,429	$213	$1,307	$1.56	2,098	2.5	303	53	$1,529
Attic R-38 to R-49 ADV	1,407	$60	$1,367	$1.63	2,022	2.4	76	59	$1,596
Vault R-30 to R-38	1,394	$61	$1,428	$1.70	1,977	2.4	45	102	$1,664
Walls R-26 to R-40 DBW	1,308	$421	$1,848	$2.20	1,684	2.0	294	108	$3,240
Windows R-3.0 to R-5.0	1,171	$743	$2,591	$3.08	1,244	1.5	439	139	$6,480
Floors R-30 to R-38	1,153	$120	$2,711	$3.23	1,190	1.4	54	167	$6,480
Attic R-49 ADV to R-60 ADV	1,148	$56	$2,767	$3.29	1,174	1.4	16	259	$6,480

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.
STD—Standard framing.
DBW—Double wall construction.

Table 7-33
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 1—Portland
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—924 Square Feet									
Base Case	373	$0	$0	$0.00	7,241	7.8	0	0	$0
Floors R-7 to R-11 Cut-In	343	$83	$83	$0.09	6,314	6.8	926	8	$93
Attic R-14 to R-19 Blown	338	$26	$109	$0.12	6,152	6.7	162	14	$122
Vault R-14 to R-22 Blown	329	$54	$164	$0.18	5,875	6.4	27	17	$183
Attic R-19 to R-30 Blown	324	$57	$221	$0.24	5,713	6.2	161	31	$247
Floors R-11 to R-22 Cut-In	304	$240	$461	$0.50	5,091	5.5	621	35	$516
Vault R-22 to R-30 Blown	299	$54	$516	$0.56	4,963	5.4	128	38	$577
Vault R-30 to R-38 Blown	296	$54	$570	$0.62	4,854	5.3	109	45	$638
Attic R-30 to R-38 Blown	294	$42	$612	$0.66	4,794	5.2	59	63	$684
Floors R-22 to R-33 Cut-In	283	$240	$852	$0.92	4,463	4.8	331	65	$953
Walls R-11 to R-19	255	$597	$1,449	$1.57	3,662	4.0	800	67	$1,622
Walls R-19 to R-21 ADV	251	$94	$1,544	$1.67	3,540	3.8	122	70	$1,727
Windows R-1.2 to R-2.5	203	$1,423	$2,967	$3.21	2,182	2.4	1,358	95	$3,320
Windows R-2.5 to R-3.0	196	$215	$3,182	$3.44	1,999	2.2	183	106	$3,560
Attic R-38 to R-49 Blown	194	$57	$3,239	$3.51	1,968	2.1	30	169	$3,624
Windows R-3.0 to R-5.0	180	$907	$4,146	$4.49	1,611	1.7	356	232	$4,639
Floors R-33 to R-44 Cut-In	179	$240	$4,386	$4.75	1,564	1.7	47	463	$4,908
House Size—1,568 Square Feet									
Base Case	566	$0	$0	$0.00	12,063	7.7	0	0	$0
Floors R-7 to R-11 Cut-In	516	$141	$141	$0.09	10,457	6.7	1,607	7	$158
Attic R-14 to R-19 Blown	504	$59	$200	$0.13	10,077	6.4	379	13	$224
Vault R-14 to R-22 Blown	493	$69	$269	$0.17	9,722	6.2	355	17	$301
Attic R-19 to R-30 Blown	481	$130	$399	$0.25	9,353	6.0	369	31	$446

Table 7–33 (cont.)
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 1—Portland
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,568 Square Feet (cont.)									
Floors R-11 to R-22 Cut-In	447	$408	$806	$0.51	8,294	5.3	1,058	34	$902
Vault R-22 to R-30 Blown	442	$69	$875	$0.56	8,133	5.2	161	38	$979
Vault R-30 to R-38 Blown	437	$69	$944	$0.60	7,991	5.1	141	43	$1,056
Attic R-30 to R-38 Blown	432	$94	$1,038	$0.66	7,852	5.0	139	60	$1,161
Floors R-22 to R-33 Cut-In	414	$408	$1,446	$0.92	7,280	4.6	572	64	$1,618
Walls R-11 to R-19	387	$585	$2,031	$1.29	6,477	4.1	802	65	$2,272
Walls R-19 to R-21 ADV	383	$92	$2,123	$1.35	6,354	4.1	122	67	$2,375
Windows R-1.2 to R-2.5	300	$2,405	$4,528	$2.89	3,978	2.5	2,377	90	$5,066
Windows R-2.5 to R-3.0	289	$363	$4,890	$3.12	3,656	2.3	321	101	$5,472
Attic R-38 to R-49 Blown	286	$130	$5,020	$3.20	3,582	2.3	74	157	$5,617
Windows R-3.0 to R-5.0	262	$1,533	$6,553	$4.18	2,950	1.9	632	217	$7,332
Floors R-33 to R-44 Cut-In	259	$408	$6,961	$4.44	2,866	1.8	83	440	$7,788

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.

Table 7–34
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 1—Seattle
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—924 Square Feet									
Base Case	373	$0	$0	$0.00	8,290	9.0	0	0	$0
Floors R-7 to R-11 Cut-In	343	$83	$83	$0.09	7,229	7.8	1,061	7	$93
Attic R-14 to R-19 Blown	338	$26	$109	$0.12	7,045	7.6	184	12	$122
Vault R-14 to R-22 Blown	329	$54	$164	$0.18	6,729	7.3	316	15	$183
Attic R-19 to R-30 Blown	324	$57	$221	$0.24	6,545	7.1	184	28	$247
Floors R-11 to R-22 Cut-In	304	$240	$461	$0.50	5,838	6.3	707	30	$516
Vault R-22 to R-30 Blown	299	$54	$516	$0.56	5,692	6.2	146	33	$577
Vault R-30 to R-38 Blown	296	$54	$570	$0.62	5,567	6.0	125	39	$638
Attic R-30 to R-38 Blown	294	$42	$612	$0.66	5,499	6.0	68	55	$684
Floors R-22 to R-33 Cut-In	283	$240	$852	$0.92	5,122	5.5	377	57	$953
Walls R-11 to R-19	255	$597	$1,449	$1.57	4,209	4.6	913	59	$1,622
Walls R-19 to R-21 ADV	251	$94	$1,544	$1.67	4,070	4.4	139	61	$1,727
Windows R-1.2 to R-2.5	203	$1,423	$2,967	$3.21	2,533	2.7	1,536	84	$3,320
Windows R-2.5 to R-3.0	196	$215	$3,182	$3.44	2,325	2.5	208	94	$3,560
Attic R-38 to R-49 Blown	194	$57	$3,239	$3.51	2,290	2.5	35	148	$3,624
Window R-3.0 to R-5.0	180	$907	$4,146	$4.49	1,882	2.0	408	203	$4,639
Floors R-33 to R-44 Cut-In	179	$240	$4,386	$4.75	1,828	2.0	54	405	$4,908
House Size—1,568 Square Feet									
Base Case	566	$0	$0	$0.00	13,812	8.8	0	0	$0
Floors R-7 to R-11 Cut-In	516	$141	$141	$0.09	11,976	7.6	1,836	6	$158
Attic R-14 to R-19 Blown	504	$59	$200	$0.13	11,549	7.4	427	12	$224
Vault R-14 to R-22 Blown	493	$69	$269	$0.17	11,145	7.1	404	15	$301
Attic R-19 to R-30 Blown	481	$130	$399	$0.25	10,722	6.8	423	27	$446

Table 7–34 (cont.)
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 1—Seattle
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,568 Square Feet (cont.)									
Floors R-11 to R-22 Cut-In	447	$408	$806	$0.51	9,500	6.1	1,222	29	$902
Vault R-22 to R-30 Blown	442	$69	$875	$0.56	9,315	5.9	184	33	$979
Vault R-30 to R-38 Blown	437	$69	$944	$0.60	9,154	5.8	161	38	$1,056
Attic R-30 to R-38 Blown	432	$94	$1,038	$0.66	8,995	5.7	159	53	$1,161
Floors R-22 to R-33 Cut-In	414	$408	$1,446	$0.92	8,339	5.3	657	55	$1,618
Walls R-11 to R-19	387	$585	$2,031	$1.29	7,417	4.7	922	57	$2,272
Walls R-19 to R-21 ADV	383	$92	$2,123	$1.35	7,277	4.6	140	59	$2,375
Windows R-1.2 to R-2.5	300	$2,405	$4,528	$2.89	4,595	2.9	2,681	80	$5,066
Windows R-2.5 to R-3.0	289	$363	$4,890	$3.12	4,233	2.7	362	89	$5,472
Attic R-38 to R-49 Blown	286	$130	$5,020	$3.20	4,149	2.6	84	139	$5,617
Windows R-3.0 to R-5.0	262	$1,533	$6,553	$4.18	3,434	2.2	715	192	$7,332
Floors R-33 to R-44 Cut-In	259	$408	$6,961	$4.44	3,340	2.1	94	388	$7,788

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.

Table 7–35
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 2—Spokane
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—924 Square Feet									
Base Case	373	$0	$0	$0.00	12,292	13.3	0	0	$0
Floors R-7 to R-11 Cut-In	343	$83	$83	$0.09	10,903	11.8	1,388	5	$93
Attic R-14 to R-19 Blown	338	$26	$109	$0.12	10,661	11.5	242	9	122
Vault R-14 to R-22 Blown	329	$54	$164	$0.18	10,246	11.1	415	11	$183
Attic R-19 to R-30 Blown	324	$57	$221	$0.24	10,004	10.8	242	21	$247
Floors R-11 to R-22 Cut-In	304	$240	$461	$0.50	9,063	9.8	941	23	$516
Vault R-22 to R-30 Blown	299	$54	$516	$0.56	8,869	9.6	194	25	$577
Vault R-30 to R-38 Blown	296	$54	$570	$0.62	8,700	9.4	169	29	$638
Attic R-30 to R-38 Blown	294	$42	$612	$0.66	8,608	9.3	92	40	$684
Floors R-22 to R-33 Cut-In	283	$240	$852	$0.92	8,099	8.8	510	42	$953
Walls R-11 to R-19	255	$597	$1,449	$1.57	6,859	7.4	1,240	43	$1,622
Walls R-19 to R-21 ADV	251	$94	$1,544	$1.67	6,669	7.2	190	44	$1,727
Windows R-1.2 to R-2.5	203	$1,423	$2,967	$3.21	4,542	4.9	2,128	60	$3,320
Windows R-2.5 to R-3.0	196	$215	$3,182	$3.44	4,248	4.6	294	66	$3,560
Attic R-38 to R-49 Blown	194	$57	$3,239	$3.51	4,198	4.5	50	103	$3,624
Windows R-3.0 to R-5.0	180	$907	$4,146	$4.49	3,618	3.9	580	142	$4,639
Floors R-33 to R-44 Cut-In	179	$240	$4,386	$4.75	3,542	3.8	77	283	$4,908
House Size—1,568 Square Feet									
Base Case	566	$0	$0	$0.00	19,707	12.6	0	0	$0
Floors R-7 to R-11 Cut-In	516	$141	$141	$0.09	17,331	11.1	2,376	5	$158
Attic R-14 to R-19 Blown	504	$59	$200	$0.13	16,773	10.7	558	9	$224
Vault R-14 to R-22 Blown	493	$69	$269	$0.17	16,244	10.4	529	11	$301
Attic R-19 to R-30 Blown	481	$130	$399	$0.25	15,689	10.0	555	21	$446

Table 7-35 (cont.)
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 2—Spokane
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,568 Square Feet (cont.)									
Floors R-11 to R-22 Cut-In	447	$408	$806	$0.51	14,075	9.0	1,614	22	$902
Vault R-22 to R-30 Blown	442	$69	$875	$0.56	13,829	8.8	246	25	$979
Vault R-30 to R-38 Blown	437	$69	$944	$0.60	13,614	8.7	215	28	$1,056
Attic R-30 to R-38 Blown	432	$94	$1,038	$0.66	13,402	8.5	211	40	$1,161
Floors R-22 to R-33 Cut-In	414	$408	$1,446	$0.92	12,529	8.0	873	41	$1,618
Walls R-11 to R-19	387	$585	$2,031	$1.29	11,301	7.2	1,228	42	$2,272
Walls R-19 to R-21 ADV	383	$92	$2,123	$1.35	11,113	7.1	188	44	$2,375
Windows R-1.2 to R-2.5	300	$2,405	$4,528	$2.89	7,451	4.8	3,662	59	$5,066
Windows R-2.5 to R-3.0	289	$363	$4,890	$3.12	6,944	4.4	507	64	$5,472
Attic R-38 to R-49 Blown	286	$130	$5,020	$3.20	6,827	4.4	117	99	$5,617
Windows R-3.0 to R-5.0	262	$1,533	$6,553	$4.18	5,829	3.7	998	138	$7,332
Floors R-33 to R-44 Cut-In	259	$408	$6,961	$4.44	5,697	3.6	131	279	$7,788

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.

Table 7-36
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 3—Missoula
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—924 Square Feet									
Base Case	373	$0	$0	$0.00	14,513	15.7	0	0	$0
Floors R-7 to R-11 Cut-In	343	$83	$83	$0.09	12,887	13.9	1,626	4	$93
Attic R-14 to R-19 Blown	338	$26	$109	$0.12	12,604	13.6	283	8	$122
Vault R-14 to R-22 Blown	329	$54	$164	$0.18	12,119	13.1	485	10	$183
Attic R-19 to R-30 Blown	324	$57	$221	$0.24	11,836	12.8	283	18	$247
Floor R-11 to R-22 Cut-In	304	$240	$461	$0.50	10,741	11.6	1,096	19	$516
Vault R-22 to R-30 Blown	299	$54	$516	$0.56	10,515	11.4	226	21	$577
Vault R-30 to R-38 Blown	296	$54	$570	$0.62	10,320	11.2	195	25	$638
Attic R-30 to R-38 Blown	294	$42	$612	$0.66	10,213	11.1	106	35	$684
Floor R-22 to R-33 Cut-In	283	$240	$852	$0.92	9,623	10.4	590	36	$953
Walls R-11 to R-19	255	$597	$1,449	$1.57	8,187	8.9	1,436	37	$1,622
Walls R-19 to R-21 ADV	251	$94	$1,544	$1.67	7,967	8.6	220	38	$1,727
Windows R-1.2 to R-2.5	203	$1,423	$2,967	$3.21	5,472	5.9	2,496	51	$3,320
Windows R-2.5 to R-3.0	196	$215	$3,182	$3.44	5,127	5.5	344	56	$3,560
Attic R-38 to R-49 Blown	194	$57	$3,239	$3.51	5,069	5.5	58	88	$3,624
Windows R-3.0 to R-5.0	180	$907	$4,146	$4.49	4,394	4.8	675	121	$4,639
Floors R-33 to R-44 Cut-In	179	$240	$4,386	$4.75	4,304	4.7	90	242	$4,908
House Size—1,568 Square Feet									
Base Case	566	$0	$0	$0.00	23,161	14.8	0	0	$0
Floors R-7 to R-11 Cut-In	516	$141	$141	$0.09	20,388	13.0	2,773	4	$158
Attic R-14 to R-19 Blown	504	$59	$200	$0.13	19,741	12.6	647	8	$224
Vault R-14 to R-22 Blown	493	$69	$269	$0.17	19,129	12.2	613	10	$301
Attic R-19 to R-30 Blown	481	$130	$399	$0.25	18,486	11.8	643	18	$446

Table 7-36 (cont.)
Costs and Savings from Conservation Measures in New Manufactured Housing, Zone 3—Missoula
1990 Dollars, 0.35 ach Assumed as Current Practice

Conservation Measure	UA Btu/F	Incremental Cost	Cumulative Cost	Cost ($/sq. ft.)	Annual Use (kWh/yr.)	Annual Use (kWh/sq. ft.)	Annual Savings (kWh/yr.)	Levelized Cost (mills/kWh)	Present Value ($)
House Size—1,568 Square Feet (cont.)									
Floors R-11 to R-22 Cut-In	447	$408	$806	$0.51	16,618	10.6	1,868	19	$902
Vault R-22 to R-30 Blown	442	$69	$875	$0.56	16,335	10.4	284	21	$979
Vault R-30 to R-38 Blown	437	$69	$944	$0.60	16,086	10.3	248	24	$1,056
Attic R-30 to R-38 Blown	432	$94	$1,038	$0.66	15,843	10.1	244	34	$1,161
Floors R-22 to R-33 Cut-In	414	$408	$1,446	$0.92	14,836	9.5	1,006	36	$1,618
Walls R-11 to R-19	387	$585	$2,031	$1.29	13,418	8.6	1,418	37	$2,272
Walls R-19 to R-21 ADV	383	$92	$2,123	$1.35	13,201	8.4	218	38	$2,375
Windows R-1.2 to R-2.5	300	$2,405	$4,528	$2.89	8,952	5.7	4,249	50	$5,066
Windows R-2.5 to R-3.0	289	$363	$4,890	$3.12	8,367	5.3	585	55	$5,472
Attic R-38 to R-49 Blown	286	$130	$5,020	$3.20	8,232	5.2	135	86	$5,617
Windows R-3.0 to R-5.0	262	$1,533	$6,553	$4.18	7,077	4.5	1,154	119	$7,332
Floors R-33 to R-44 Cut-In	259	$408	$6,961	$4.44	6,925	4.4	152	240	$7,788

NOTE: UA—Measure of resistance to heat loss.
Btu/F—British thermal units per degree of Fahrenheit.
ACH—Air changes per hour.
ADV—Advanced framing.

Step 3. Estimate the Cost-Effectiveness of Space Heating Energy Savings Produced by Efficiency Improvements in New Residential Buildings

Once typical new dwelling designs were selected, the Council used a computer simulation model to estimate potential space heating energy savings that could be produced by each conservation measure. This model, SUNDAY, is also used to estimate savings from weatherization measures (see discussion above). As discussed in Step 3 in the residential weatherization section above, this model accurately predicts sub-metered space heating consumption in houses with a wide range of insulation levels.

The absolute value (in kilowatt-hours per year) of the space heating energy savings produced by adding an individual conservation measure is a function of the existing thermal efficiency level of the building. The less efficient the existing building, the larger the savings that will be obtained from installing the same measure.

To assess the savings that could be produced by installing each space heating conservation measure, it is necessary to take into account the interaction of all of the measures. This was done by determining each measure's benefit (i.e., change in heat loss rate) and cost (i.e., present-value dollars per square foot). The savings produced by each potentially cost-effective measure were then analyzed under the assumption that all measures with higher benefit-to-cost ratios had already been installed in the house.

Figure 7-13 illustrates how the heating requirements of a typical house built to 1986 building practices and the model conservation standards for new electrically heated residences might be met. Heating requirements are met by solar heat, internal gains (the amount of heat released indoors by people and appliances), and the furnace, which can be supplemented by heat from wood burning stoves or other sources. The typical house reflects average conditions for a house that is heated primarily with electricity. If the house were heated primarily with wood, the contribution from wood would be much larger, but electrical savings would still be significant as long as electricity was the marginal fuel.

When determining the electrical savings of measures applied to a current-practice house, at least the following three policy considerations must be evaluated: the treatment of wood heating, internal temperature settings for the whole house, and internal gains.[27] The Council assumed no wood heating when evaluating measure savings in new residential buildings. The Council used a constant thermostat setting of 65°F for the whole house to represent a combination of higher temperatures when the house was occupied and the occupants active, and a lower nighttime setback. Finally, the Council assumed a cadre of efficient appliances, reflecting appliances that would be in place for most of the life of the house, and are present in the region throughout most of the Council's plan.

Appliances currently in place in houses are less efficient than new appliances, but contribute more usable heat to the house, and thus cut space heating loads. This is reflected in Figure 7-13, where internal gains are larger in the current practice house.

The Council reassessed the planning assumptions described above and feels that these assumptions should be maintained for the following reasons. First, there is no assurance that occupants of houses built to the standards will continue to use wood heat. Changing wood prices, income levels, wood availability and environmental regulations all could reduce the use of wood heating, leaving the electrical system vulnerable to mass "fuel switching" to electricity, an action that would be difficult if not impossible to plan resources for. Second, the Northwest Power Act defines conservation as an efficiency improvement, not a change in lifestyle. Current behavior of consumers to close off rooms or lower thermostats may represent curtailment rather than conservation as defined in the Act. Such behavior is not expected to continue after cost-effective efficiency improvements are made. Third, more efficient appliances are clearly cost-effective resources and will be the norm in the next decade, especially in new houses. Appliance manufacturers have testified that, even

27. These items are discussed here in terms of the calculated savings per measure. Under Step 5, these items are discussed in terms of differences between the demand forecast estimates of space heating loads and estimates from the engineering model.

Heating Sources

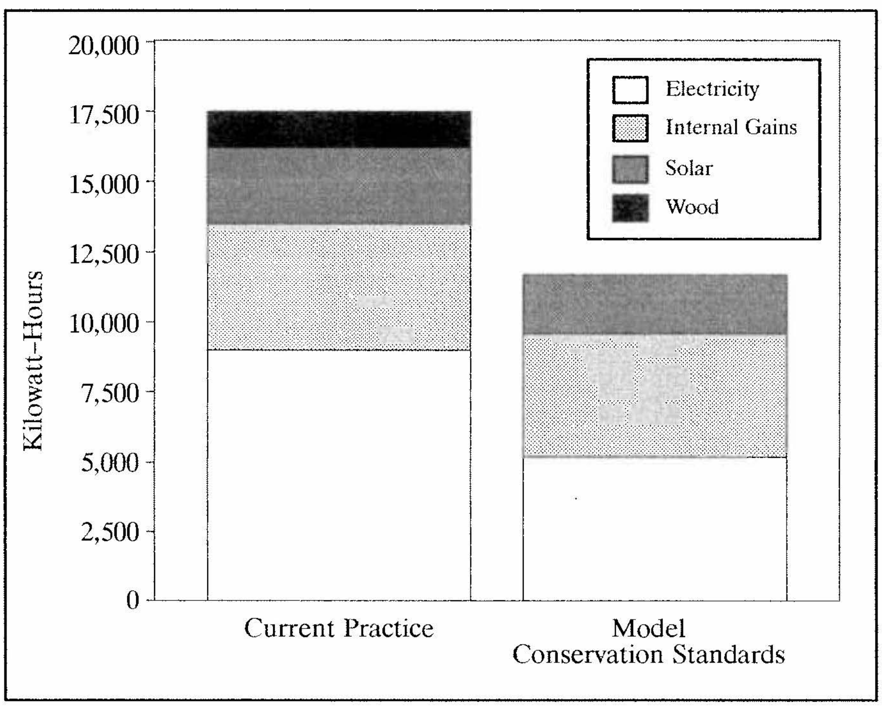


Figure 7-13
Residential Heating Sources

without appliance standards such as those adopted in 1987 by Congress, new appliances will be much more efficient. Therefore, the Council's estimates reflect less heat escaping from these appliances to heat the house. Finally, the adoption of planning assumptions different from these would subject the region to greater planning uncertainties than the present set of assumptions. If the energy-efficiency requirements of the standards are made less stringent, because it is assumed consumers will continue to close off rooms and heat with wood, the degree of uncertainty the region must plan for increases.

Tables 7-28 through 7-36 show the levelized cost, annual energy use and energy savings produced by the addition of each measure for each dwelling type, building design and for representative climate types found in the region (Zone 1-Portland and Seattle, Zone 2-Spokane and Zone 3-Missoula). The levelized costs shown for single-family and multifamily buildings are based on a 70-year physical life and a financing cost of approximately 9 percent nominal.[28] Levelization was done using an 8.15 percent nominal (3 percent real, with 5 percent inflation) discount rate. The levelized cost shown for manufactured housing is based on a 45-year economic life and levelization at the same nominal financing and discount rate used for single-family and multifamily housing. For planning purposes, it has been assumed that the efficiency improvements in single-family and multifamily houses and manufactured housing will be obtained via a combination of codes, marketing and incentive programs financed through Bonneville, public utilities and the region's investor-owned utilities.

The Council has established two model conservation standards for new residences heated with electricity. The standard for utility programs for new residential buildings, pursuant to the requirements of the Act, require these programs to secure all regionally cost-effective conservation savings.

As shown in Tables 7-29 and 7-32, the installation of some measures not currently included in the reference paths for the Council's model conservation standards for new electrically heated buildings[29] appear to be regionally cost-effective. These measures include the use of R-26 advanced-framed walls and the use of R-49 advanced-framed attic insulation in climate zones 1 and 2 and the use of R-15 slab edge insulation and R-3.0 windows in all climate zones. While the Council has not included these measures in its model standard for new electrically heated buildings for these climate zones, these measures or their equivalents should be secured through the Council's model conservation standard for utility programs for new residential buildings. These measures, which are included in the Council's resource portfolio, represent commercially available and reliable resources.

Step 4. Estimate the Regional Conservation Potential Available from Space Heating Conservation in New Dwellings

The next step in the Council's development of a regional supply curve for space heating conservation potential requires combining the engineering estimates of individual house savings by climate zone to establish a regional total. Because each measure saves a different amount of energy in each house design and in each location, an aggregate supply curve must be developed that represents the weighted average savings for all measures in comparable dwelling types.

Each of the three single-family dwelling designs was assigned a weight based on its foundation type, size and window area. The specific weight assigned to each design approximately reflects that design's share of the new housing stock additions expected over the forecast period. This was also done for the two manufactured housing designs. Building type weighting was unnecessary for multifamily space heating, because only one multifamily design was used. It should be noted that the Council's forecasting model defines all units up to and including four-plexes as "single-family dwellings." Consequently, the weights selected are designed to achieve a much smaller average size for new single-family houses (i.e., 1,400 square feet of floor area) than if they been selected on the basis of the more conventional definition of a single-family home (one- and two-family dwellings) used to establish the model conservation standards. The average size of typical new one- and two-family dwellings recently constructed in the region is between 1,600 and 1,800 square feet of floor area.

Once each building design's weight was established, the average savings by climate type were calculated for all designs. These savings then were aggregated to the regional level based on the share of new electrically heated dwellings expected to be constructed in each climate over the forecast period. Table 7-37 shows the weight assigned each building design and climate type. Tables 7-38 through 7-40 show the weighted average use, cost and savings available from new single-family, multifamily and manufactured houses at levelized costs less than 20 cents per kilowatt-hour (equivalent to 200 mills per kilowatt-hour).

28. As noted in the introduction, finance costs are taken from the system models and reflect a sponsorship mixed among Bonneville and investor-owned utilities.

29. See Chapter 12, Table 12-1.

Table 7–37
Weighting Factors Used to Aggregate Individual Building and Location Savings to Region

Building Type	Weight	Mean Size		
Single–Family Dwellings (less than five–plex)				
▪ 1,344 square feet—Single Story	90%			
▪ 1,848 square feet—Two Story	9%			
▪ 2,356 square feet—One Story with Basement	1%	1,400 square feet		
Multifamily Dwellings (five–plex and larger)				
▪ 12–Unit	100%	840 square feet/unit[b]		
Manufactured Housing				
▪ 924 Single Wide	14%			
▪ 1,568 Double Wide	86%	1,475 square feet[b]		
		Weight		
Zone	HDD[a]	Single–Family Homes	Multifamily Homes	Manufactured Housing
▪ Zone 1—Portland	4,786	19%	21%	20%
▪ Zone 1—Seattle	5,444	68%	75%	44%
▪ Zone 2—Spokane	6,818	10%	3%	27%
▪ Zone 3—Missoula	7,773	3%	2%	9%
▪ Region Average HDD		5,535	5,380	5,892

[a] HDD—Heating degree days at 65°F based on Typical Meteorological Year (TMY) weather tape used to estimate savings. TMY weather tapes vary slightly from published long–term averages.

[b] Table 7-42 shows the mean size of new units used in the forecast model. The unit sizes shown here were scaled to match those assumed in the forecast model.

Table 7-38
Regionally Weighted Savings and Costs in New Single-Family Dwellings

Levelized Cost (mills/kWh)	Capital Cost Total	($/sq. ft.)	Annual Use (kWh/yr.)	(kWh/sq. ft.)	Relative Use (% of base)	Annual Savings (kWh/yr.)	Present Value	Average R-Value
0	$0	$0.00	11,116	7.9	100	0	$0	8.49
10	$5	$0.00	11,049	7.9	99	68	$8	8.52
20	$161	$0.12	10,173	7.3	92	943	$212	8.96
30	$1,313	$0.94	6,698	4.8	60	4,419	$1,576	11.50
40	$1,615	$1.16	6,045	4.3	54	5,072	$1,915	12.19
50	$1,869	$1.34	5,607	4.0	50	5,509	$2,201	12.69
60	$2,059	$1.48	5,348	3.8	48	5,768	$2,415	13.01
70	$2,500	$1.80	4,841	3.4	43	6,275	$2,909	13.72
80	$3,172	$2.29	4,139	2.9	36	6,978	$3,680	14.91
90	$3,627	$2.62	3,718	2.6	32	7,398	$4,195	15.70
100	$3,707	$2.67	3,653	2.6	32	7,464	$4,285	15.84
110	$3,722	$2.68	3,641	2.6	31	7,475	$4,302	15.85
120	$3,803	$2.74	3,586	2.5	31	7,530	$4,397	15.95
130	$3,803	$2.74	3,586	2.5	31	7,530	$4,397	15.95
140	$4,027	$2.91	3,457	2.4	30	7,660	$4,660	16.20
150	$4,135	$2.99	3,397	2.4	30	7,719	$4,781	16.33
160	$4,135	$2.99	3,397	2.4	30	7,719	$4,781	16.33
170	$4,187	$3.02	3,372	2.4	30	7,744	$4,839	16.38
180	$4,187	$3.02	3,372	2.4	30	7,744	$4,839	16.38
190	$4,934	$3.57	3,062	2.1	27	8,054	$5,675	17.13
200	$5,841	$4.24	2,687	1.9	23	8,429	$6,777	18.26

Table 7–39
Regionally Weighted Savings and Costs in New Multifamily Dwellings

Levelized Cost (mills/kWh)	Capital Cost		Annual Use		Relative Use (% of base)	Annual Savings (kWh/yr.)	Present Value	Average R-Value
	Total	($/sq. ft.)	(kWh/yr.)	(kWh/sq. ft.)				
0	$0	$0.00	3,085	3.7	100	0	$0	5.61
10	$0	$0.00	3,079	3.7	99	5	$1	5.61
20	$16	$0.02	2,967	3.5	96	118	$2 4	5.71
30	$368	$0.44	1,958	2.3	64	1,127	$454	6.93
40	$468	$0.56	1,711	2.0	55	1,374	$575	7.27
50	$725	$0.86	1,302	1.6	42	1,782	$863	8.06
60	$792	$0.94	1,210	1.4	39	1,875	$938	8.26
70	$798	$0.95	1,203	1.4	39	1,881	$945	8.28
80	$838	$1.00	1,161	1.4	37	1,924	$990	8.38
90	$1,049	$1.25	964	1.1	31	2,121	$1,238	8.90
100	$1,234	$1.47	820	1.0	26	2,264	$1,444	9.37
110	$1,273	$1.52	790	0.9	25	2,294	$1,509	9.46
120	$1,362	$1.62	731	0.9	23	2,354	$1,609	9.69
130	$1,364	$1.62	730	0.9	23	2,355	$1,610	9.69
140	$1,399	$1.67	709	0.8	22	2,375	$1,719	9.76
150	$1,399	$1.67	709	0.8	22	2,375	$1,719	9.76
160	$1,399	$1.67	709	0.8	22	2,375	$1,719	9.76
170	$1,401	$1.67	708	0.8	22	2,376	$1,719	9.76
180	$1,421	$1.69	699	0.8	22	2,386	$1,806	9.79
190	$1,421	$1.69	699	0.8	22	2,386	$1,806	9.79
200	$1,467	$1.75	681	0.8	22	2,403	$1,857	9.86

Table 7–40
Regionally Weighted Savings and Costs in New Manufactured Housing

Levelized Cost (mills/kWh)	Capital Cost Total	($/sq. ft.)	Annual Use (kWh/yr.)	(kWh/sq. ft.)	Relative Use (% of base)	Annual Savings (kWh/yr.)	Present Value	Average R-Value
0	$0	$0.00	15,006	10.2	100	0	$0	7.81
10	$152	$0.10	12,916	8.8	86	2,090	$170	8.63
20	$299	$0.20	12,030	8.2	80	2,976	$334	9.04
30	$535	$0.36	11,144	7.6	75	3,862	$599	9.45
40	$980	$0.67	9,941	6.8	66	5,066	$1,096	10.19
50	$1,304	$0.89	9,256	6.3	62	5,750	$1,459	10.62
60	$2,655	$1.81	7,116	4.8	49	7,890	$2,971	12.43
70	$2,977	$2.04	6,669	4.5	46	8,337	$3,331	12.89
80	$2,977	$2.04	6,669	4.5	46	8,337	$3,331	12.89
90	$3,984	$2.72	5,551	3.8	37	9,455	$4,458	14.27
100	$4,587	$3.13	4,955	3.4	32	10,051	$5,132	15.14
110	$4,687	$3.19	4,866	3.3	31	10,140	$5,245	15.30
120	$4,817	$3.28	4,768	3.2	31	10,238	$5,390	15.42
130	$4,817	$3.28	4,768	3.2	31	10,238	$5,390	15.42
140	$5,207	$3.55	4,515	3.1	30	10,491	$5,826	15.78
150	$5,259	$3.58	4,481	3.0	29	10,525	$5,885	15.84
160	$5,283	$3.60	4,468	3.0	29	10,538	$5,911	15.87
170	$5,283	$3.60	4,468	3.0	29	10,538	$5,911	15.87
180	$5,283	$3.60	4,468	3.0	29	10,538	$5,911	15.87
190	$5,283	$3.60	4,468	3.0	29	10,538	$5,911	15.87
200	$5,918	$4.03	4,172	2.8	27	10,834	$6,621	16.46

Step 5. Estimate the Realizable Conservation Potential from New Residential Space Heating Efficiency Improvements

In order to establish the proportion of technically available space heating conservation that realistically can be achieved, two adjustments must be made to the engineering savings estimates. First, to ensure consistency with the Council's load forecast, the conservation resource based on engineering estimates of current space heating energy use must be adjusted or scaled to account for the forecasting model's estimate of current space heating use. The forecast model estimates shown here assume higher consumer amenity levels in the year 2010 than are present today. This is consistent with the Council's forecast, which projects that consumers will increase their amenity levels by the year 2010. This results in higher space heating use than would otherwise be shown in Table 7-41.

Table 7-41 compares the average space heating energy use by dwelling type for houses built to 1992 practice, as estimated by the Council's forecasting model for the year 2010 in the medium forecast and the engineering estimate. The engineering estimates and the forecasting model estimates of space heating use in new homes agree reasonably well.

The Council's forecasting model does not explicitly assume a specific average dwelling unit size. However, the forecasting model's present implicit assumptions regarding average size for existing dwellings are shown in Table 7-42. Based on survey data, it appears that average new multifamily dwellings (five-plex and larger) and manufactured houses being built today typically are larger than the forecasting model assumes for all existing multifamily dwellings and manufactured houses. However, new single-family housing (less than five-plexes) appears to be the same size as the existing single-family stock. To account for this fact, the forecasting model's projected use for new multifamily units and manufactured homes shown in Table 7-41 has been scaled by the ratio of the size of new stock to existing stock. Similarly, the engineering model's estimates of cost and energy savings from conservation actions in new multifamily dwellings and manufactured homes shown in Table 7-41 also were scaled to match the forecast model's assumptions regarding new unit size. This was done by multiplying the engineering estimates of use, cost and savings by the ratio of average unit size implicitly assumed in the forecast model to the average floor area of new dwelling units. No size adjustment was made for new single-family dwellings because their size appears to be consistent with the existing stock.

The Council's engineering estimates of space heating energy use in new dwellings and the forecasting model contain similar underlying assumptions regarding appliance efficiency and family size. In order to match current (1992) consumption, the forecasting model must use current (1992) appliance efficiencies. However, because the Council anticipates substantial efficiency improvements in appliance energy use within the next five to 10 years, the Council's engineering and forecast model estimates of space heating use in 2010 assumes the presence of more efficient appliances.

Table 7-41
Forecast Model versus Engineering Estimate for Space Heating in New Dwellings Built to 1992 Codes/Practice Regional Average Use in 2010

Building Type	Forecasting Model (kWh/yr.)	Forecasting Model (kWh/sq. ft./yr.)	Engineering Estimate (kWh/yr.)	Engineering Estimate (kWh/sq. ft./yr.)
Single-Family Dwelling	5,035	3.6	5,080	3.6
Multifamily Dwelling	1,475	1.4	1,430	1.4
Manufactured Housing	10,300	7.0	11,145	7.6

Table 7-42
Forecasting Model Dwelling Size versus Average New Dwellings (Square Feet)

Building Type	Model Existing Stock	New Stock	Ratio of New Stock to Model
Single-Family Dwelling	1,400	1,400	1.00
Multifamily Dwelling	840	1,030	1.23
Manufactured Housing	985	1,475	1.50

Because waste heat offsets the need for space heating, more efficient appliances mean larger space heating energy requirements. Had the Council assumed less efficient appliances in its engineering and forecasting model estimates, the regional average space heating energy used in new single-family houses built in 2010 would fall about 1.0 kilowatt-hours per square foot. Thus, failure to recognize the installation of efficient appliances in this same house by the year 2010 would result in an underestimate of space heating energy needs by 1,400 kilowatt-hours per year in the average single-family house.[30]

Table 7-43 shows the technical conservation potential in the Council's high forecast from improvements in space heating efficiency in new single-family and multifamily dwellings and manufactured houses from a 1983 code/construction practice base. Table 7-44 shows the potential in the Council's medium forecast. Tables 7-45 and 7-46 show the technical potential in the Council's high and medium forecast from a base that incorporates the more efficient 1992 codes and building practices as the base. Table 7-47 shows the number of new electrically heated residences for all Council forecasts by dwelling type.

30. Due to the decreased need for space heating in houses built with all regionally cost-effective space heat conservation measures, increases in appliance efficiency would result in a smaller increase in space heating needs. This is estimated to be just over 1,100 kilowatt-hours per year.

Table 7-43
Potential Savings above 1983 Practice from Space Heating in New Residential Buildings
Average Megawatts in High Forecast 1992-2010

Levelized Cost (cents/kWh) Nominal	Real	Single-Family Dwellings	Multifamily Dwellings	Manufactured Housing	Total
0	0	0	0	0	0
1.0	0.5	75	0	35	110
2.0	1.0	140	0	60	200
3.0	1.5	565	5	90	660
4.0	2.0	665	15	125	805
5.0	2.5	730	35	145	910
6.0	3.1	770	40	210	1,020
7.0	3.6	850	40	225	1,100
8.0	4.1	955	45	225	1,225
9.0	4.6	1,020	55	260	1,335
10.0	5.1	1,030	60	275	1,365
11.0	5.6	1,030	65	280	1,370
12.0	6.1	1,040	75	280	1,395
13.0	6.6	1,040	75	280	1,395
14.0	7.1	1,060	75	290	1,425
15.0	7.6	1,070	75	290	1,435
16.0	8.1	1,070	75	290	1,435
17.0	8.6	1,070	75	290	1,435
18.0	9.1	1,070	75	290	1,435
19.0	9.7	1,120	75	290	1,485
20.0	10.2	1,175	75	300	1,550

Table 7-44
Potential Savings above 1983 Practice from Space Heating in New Residential Buildings
Average Megawatts in Medium Forecast 1992-2010

Levelized Cost (cents/kWh) Nominal	Real	Single-Family Dwellings	Multifamily Dwellings	Manufactured Housing	Total
0	0	0	0	0	0
1.0	0.5	30	0	40	70
2.0	1.0	60	0	65	125
3.0	1.5	245	5	95	345
4.0	2.0	290	15	130	435
5.0	2.5	320	35	150	505
6.0	3.1	340	40	220	600
7.0	3.6	375	40	235	650
8.0	4.1	420	40	235	695
9.0	4.6	450	50	270	770
10.0	5.1	455	55	290	800
11.0	5.6	460	60	290	810
12.0	6.1	460	70	295	825
13.0	6.6	470	70	295	835
14.0	7.1	470	70	300	840
15.0	7.6	470	70	305	845
16.0	8.1	470	70	305	845
17.0	8.6	475	70	305	850
18.0	9.1	475	70	305	850
19.0	9.7	495	70	305	870
20.0	10.2	520	75	315	910

Table 7–45
Potential Savings above 1992 Practice from Space Heating in New Residential Buildings
Average Megawatts in High Forecast 1992–2010

Levelized Cost (cents/kWh) Nominal	Real	Single-Family Dwellings	Multifamily Dwellings	Manufactured Housing	Total
0	0	0	0	0	0
1.0	0.5	0	0	0	0
2.0	1.0	0	0	0	0
3.0	1.5	0	0	0	0
4.0	2.0	0	0	15	15
5.0	2.5	15	0	30	45
6.0	3.1	30	0	95	125
7.0	3.6	70	0	110	180
8.0	4.1	170	5	110	285
9.0	4.6	255	10	145	410
10.0	5.1	265	20	165	450
11.0	5.6	270	30	165	465
12.0	6.1	280	30	170	480
13.0	6.6	280	30	170	480
14.0	7.1	305	35	175	515
15.0	7.6	315	35	180	530
16.0	8.1	315	35	180	530
17.0	8.6	320	35	180	535
18.0	9.1	320	35	180	535
19.0	9.7	380	35	180	595
20.0	10.2	450	35	190	675

Table 7–46
Potential Savings above 1992 Practice from Space Heating in New Residential Buildings
Average Megawatts in Medium Forecast 1992–2010

Levelized Cost (cents/kWh) Nominal	Real	Single–Family Dwellings	Multifamily Dwellings	Manufactured Housing	Total
0	0	0	0	0	0
1.0	0.5	0	0	0	0
2.0	1.0	0	0	0	0
3.0	1.5	0	0	0	0
4.0	2.0	0	0	20	20
5.0	2.5	5	0	30	35
6.0	3.1	15	0	100	115
7.0	3.6	30	5	115	150
8.0	4.1	75	5	115	195
9.0	4.6	110	10	150	270
10.0	5.1	120	20	170	310
11.0	5.6	120	20	175	315
12.0	6.1	125	30	175	330
13.0	6.6	125	30	175	330
14.0	7.1	135	30	185	350
15.0	7.6	140	30	185	355
16.0	8.1	140	30	185	355
17.0	8.6	140	30	185	355
18.0	9.1	140	30	185	355
19.0	9.7	170	30	185	355
20.0	10.2	200	30	195	425

Table 7–47
Number of New Electrically Heated Dwellings 1992 to 2010

Dwelling Type	High	Medium–High	Medium	Medium–Low	Low
Single–Family Dwellings	1,259,700	754,000	562,600	417,400	193,700
Multifamily Dwellings	388,800	348,000	350,600	345,000	270,200
Manufactured Housing	257,900	289,200	269,400	245,700	159,000

Electric Water Heating Conservation

The energy used to heat water represents the second largest end use of electricity in the residential sector. Figure 7–14 shows the technical potential for improving the efficiency of residential water heating at various costs of electricity. These savings represent better insulated water heaters, pipe wraps, a technology that pushes the hot water remaining in the pipes back into the water heater after hot water is drawn (called a 'hot water saver'), and more efficient appliances that use hot water (e.g., clotheswashers, dishwashers and showerheads). An additional 190 average megawatts of technical conservation potential, not shown in Figure 7–14, is available from water-heating heat-pumps with heat recovery ventilation.

The cost-effective technical potential identified by the Council for electric water heaters and water consuming appliances (not including 190 average megawatts from heat-pump heat-recovery-ventilators) is about 700 average megawatts in the high-demand forecast and 562 average megawatts in the medium forecast at measure costs between 0 and 11 cents per kilowatt-hour. The average cost of improving the efficiency of electric water heaters is 4 cents per kilowatt-hour, even when administrative costs and transmission and distribution adjustments are incorporated. Water heating conservation measures, costing between 11 and 15 cents per kilowatt-hour, represent the second block of water heating conservation, and supply an additional 86 average megawatts of conservation in the high demand forecast. Finally, a measure that saves both water heating and space heating energy, a water-heating heat pump with heat recovery ventilation, can also save an additional 190 average megawatts of energy at a levelized cost of about 8 cents per kilowatt-hour.

The Council's assessment of the conservation potential available from improved residential water heating efficiency involved three steps. These were to:

1. Estimate the cost and savings potential available from improved water heating efficiency beyond the 1990 federal standard.
2. Develop conservation supply functions for the total potential.
3. Calibrate savings to the Council's forecast.

The key data for this information comes from research and programs operated in the region. These are summarized in Table 7–48.

Conservation Potential

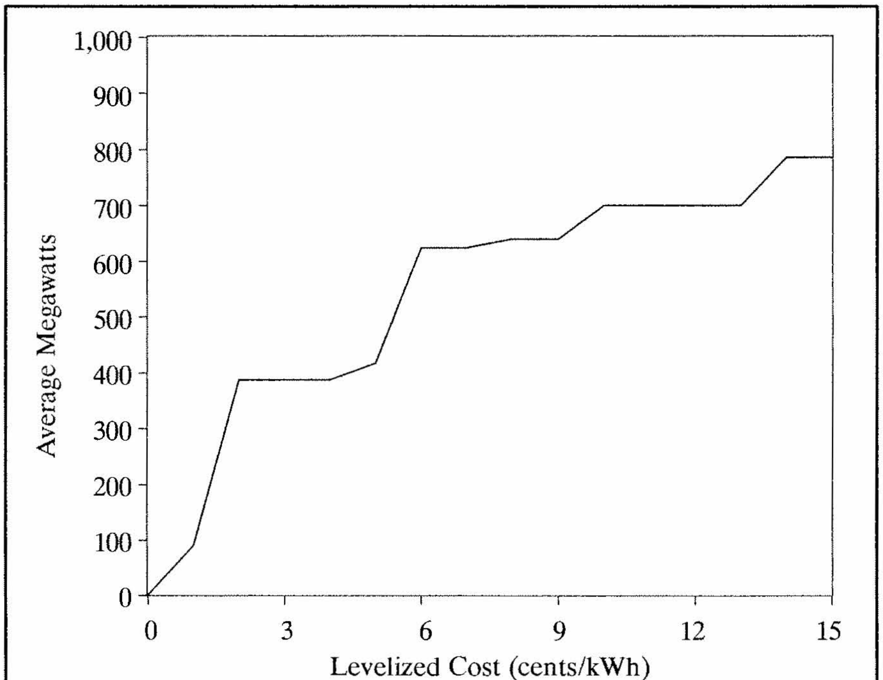


Figure 7–14
Technical Conservation Potential from Residential Water Heating Measures

Table 7–48
Key Data Sources for Water Heating Measures Costs

Costs	
U.S. Department of Energy	Costs of efficient dishwashers and clotheswashers
Oregon Department of Energy	Costs of efficient showerheads
Bonneville Power Administration's Water Heating Program	Costs of wraps
Pacific Power and Light's Appliance Advisory Group	Costs of bottom boards
Bonneville Power Administration Study	Costs of thermal traps and pipe wraps
Puget Sound Power and Light	Costs of efficient water heaters
Consumption and Savings	
Hood River Conservation Project	Household water heater consumption
Residential Standards Demonstration Program	Household water heater consumption
End-Use Load and Conservation Assessment Program	Household water heater consumption
Seattle City Light Evaluations	Savings for bottom boards, thermal traps/pipe wraps and efficient tanks
Bonneville Power Administration Studies	Savings for bottom boards, thermal traps/pipe wraps and efficient tanks
U.S. Department of Energy	Savings for efficient tanks

Step 1. Estimate the Cost and Savings Potential Available from Improved Water Heating Efficiency

The amount of energy consumed for water heating depends on two factors: standby losses and variable use. Standby losses refer to the energy that is used during storage to keep the water hot. They are determined by the temperature of the water relative to the air temperature surrounding the tank and the insulation levels of the hot water storage tank and supply piping. Variable use is the amount of hot water actually used in the household. Variable use differs substantially among households, depending on the habits and number of occupants, and the stock of appliances that use hot water (such as clotheswashers and dishwashers), as well as the temperature of the hot water and the cold water that enters the tank.

In 1987, the National Appliance Energy Conservation Act was passed that regulates the maximum energy consumption of a variety of household appliances, including electric water heaters, refrigerators and freezers. For electric water heaters, the appliance standards regulate the standby losses from the water heater tank. The level of the national standard is about the level or slightly more efficient than the level set by Oregon and Washington for water heaters sold in their states. The federal standard became effective in 1990, and a review of the standard by the secretary of the U.S. Department of Energy to see if it should be strengthened is required by 1992. The estimates of conservation potential for water heater tanks developed here are based on going beyond the current federal standard and setting a more stringent standard equivalent to the level of some of the most efficient tanks produced today. It is envisioned that a revision to the federal standard, as well as other acquisition efforts, such as programs to get showerheads and other measures, will be able to secure savings beginning in 1995.

The base use of water heaters from which conservation potential could be estimated was derived by reviewing research. Table 7–49 summarizes available data on standby losses from conventional (typically R–5) tanks. Water heat was directly submetered in all field studies. Laboratory tests on individual units and U.S. DOE's analysis had lower standby losses than those found in field tests. The average value of the full sample is 1,580 kilowatt-hours per year. This value was compared to an estimate of standby losses from the current federal standard, which was derived from U.S. DOE's Engineering Analysis Document. Since the current federal standard requires more efficient tanks than those shown in Table 7–49, their standby losses should be lower. U.S. DOE's work indicates that standby losses from the federal standard are on the order of 720 kilowatt-hours per year for a 70° temperature rise. This lower base was used as the estimate of base case use in both the forecast of electricity demand and the estimate of conservation savings when the federal standard becomes effective in 1990. This level is much lower than assumed in previous calculations. Bonneville is currently conducting laboratory studies to determine the standby loss of a tank that meets the 1990 federal standard. This analysis will incorporate that work in a future revision. In addition, draft work conducted for the End-Use Loads and Conservation Assessment Program (ELCAP) on a sample of new homes, built about 1986, indicates standby use of approximately 1,100 kilowatt-hours per year. All these estimates will need to be reviewed and reconciled when they become final.

Variable use for the pre-conservation situation was estimated from studies that reported the gallons of hot water used per person or per household. Table 7-50 summarizes the empirical data. Hot water demand was actually measured in some cases, while in others it was calculated. The average use per person per day is about 18 gallons, which is used in this analysis.

In recent years, considerable end use monitored data has been collected on total electricity consumption for water heating in the Northwest. Table 7-51 summarizes such data collected through the Hood River Conservation Project, which monitored existing houses in Hood River, Oregon, the Residential Standards Demonstration Project, which monitored new water heaters in new houses, and the End-Use Loads and Conservation Assessment Program (ELCAP), which monitored use in pre-1983 existing households. The new houses are more representative of use with the federal standards in place, since the new houses were built primarily in Washington and Oregon, which already have standards that approximate the federal standard. Energy consumption is shown as a function of household size.

The number of occupants per house according to the forecast is about 2.7 occupants per household in the early years. Using 48 gallons per household per day and 720 kilowatt-hours for standby losses, puts consumption at about 4,108 kilowatt-hours per household. This is in the range of monitored use in both the Hood River and RSDP samples for this household size, although it is closer to the RSDP estimates, and seems to be an appropriate estimate of base case electric water heating consumption.

The only two measures evaluated to reduce standby consumption were more efficient tanks than the 1990 federal standard, and a bottom board. Savings from wrapping an efficient tank were not known, and assumed to be relatively small since standby losses are reduced significantly after the more efficient tank is adopted. A project by Bonneville is currently underway to evaluate this, and its information will be incorporated into future revisions. Thermal traps are assumed to be already incorporated into the better tank, and therefore they do not appear as a separate standby loss conservation measure.

Savings for demand reduction measures were evaluated assuming an 80°F temperature difference between the temperature setting of the tank and the inlet water temperature. Savings from standby loss measures assumed a 70°F temperature difference between the temperature setting of the tank and the ambient air temperature surrounding the tank.

Efficient Tanks

Savings from an efficient tank were adapted from work done for U.S. DOE in 1982 for appliance standards. This analysis indicated that moving from a tank with an energy factor of 0.88 to an energy factor of 0.95 saved about 350 kilowatt-hours per year. Costs for this measure were taken from Puget Sound Power and Light, which has been actively promoting an efficient water heater program for a number of years. Its costs are assumed to reflect long-term costs of a regionwide water heating efficiency program.

Table 7-49
Data on Standby Losses from Conventional Water Heater Tanks

Source	Standby (kWh/yr.)	N	Notes
Seattle City Light	1,610	26	All unwrapped, submetered
Biemer/Auburg '84	1,375	1	Laboratory tests
Goldstein/Clear	1,468		Calculated for 1960-1980 vintage tanks
Ek '82 (#36)	1,483	1	Laboratory test
Ecotope '82	1,995	91	Some wrapped, many different locations
Ecotope Heat Pump Study	1,731	39	Median standby losses in three cities are weighted by climate zone's contribution to regional population
U.S. DOE Engineering Analysis Document	1,415		Calculated
Average	1,580		

Table 7–50
Variable Demand Use for Hot Water

Source	Gallons per Year per Person	N	Notes
Lawrence Berkeley Laboratories	5,582		
Natural Resources Defense Council	5,411		Calculated
Seattle City Light	6,019	26	Calculated
Ecotope Heat Pump Study	7,680	38	Submetered participants selected on basis of family size and high water use
Bavir	7,094		Regression results from submetered sample
Long Island Light Company	6,788	257	Submetered
Average	6,429		

Table 7–51
Measured Consumption of Electric Water Heaters

	ELCAP Base Sample		Hood River Conservation Project		Residential Standards Demonstration Project	
Occupants per Household	Consumption (kWh/yr.)	Sample Size	Consumption (kWh/yr.)	Sample Size	Consumption (kWh/yr.)	Sample Size
1	2,633	18	2,843	25	2,764	30
2	3,575	82	4,173	78	3,812	109
3	5,321	34	5,756	26	4,817	93
4	5,544	44	6,253	35	5,541	133
5	6,032	17	7,582	9	5,688	34
6	7,232	7	9,504	6	6,730	18
7	6,930	3	—	—	8,143	8

Bottom Boards

Savings from bottom boards were taken from field tests by Seattle City Light and a laboratory test by Bonneville. Both of these studies indicated about 35 kilowatt-hours worth of savings from insulating the bottom of the tank. Costs are taken from Pacific Power and Light.

Clotheswashers and Dishwashers

Conservation measures for variable use include clotheswashers and dishwashers that use hot water more efficiently, energy-saving showerheads, and a device called a ‘hot water saver.’ The costs and savings available from efficient clotheswashers and dishwashers were taken from work done for the U.S. Department of Energy in support of a rulemaking to investigate whether more efficient standards should be set for these appliances. The DOE study showed that by using measures that were less than 11 cents per kilowatt-hour, more efficient clotheswashers would save about 143 kilowatt-hours per year, and more efficient dishwashers would save 105 kilowatt-hours per year. In addition, the DOE study and work done for Pacific Power and Light indicated that going to horizontal axis, front-loading washing machines would reduce energy consumption to about 185 kilowatt-hours per year, which is a savings of 345 kilowatt-hours per year beyond the other efficiencies. This type of machine is much more efficient because it uses much less water. The clothes are cycled through a tub half full of water rather than completely full. This is the only measure that fell between 11 and 15 cents per kilowatt-hour. It constitutes the second tier of conservation savings.

Efficient Showerheads

Costs and savings from energy-saving showerheads in new houses are based primarily on work done in Oregon and on research into hot water use during showers. An Oregon survey found that new showerheads had an average flow rate of about 3.2 gallons per minute. Oregon has a standard that requires 3.0 gallons per minute, and Washington recently adopted legislation limiting maximum flow levels to 3 gallons per minute starting in 1990 and to 2.5 gallons per minute starting in 1993. Work done for Bonneville indicated wide consumer acceptance of energy saving shower heads. In addition, there is good availability from manufacturers of showerheads below 3 gallons per minute. The Appliance Efficiency Group, which is a group of utilities and interested parties trying to arrive at uniform efficiency requirements for their appliance programs, recently adopted 2.5 gallons per minute at 60 psi or the maximum flow for showerheads distributed through their programs in the near term. The group committed to investigate setting a second, lower level that would become effective in a few years. Because this second level is likely and because the 2.5 standard is a maximum and the average will be better, this analysis assumes that showerheads will be at about 2.3 gallons per minute. Savings are based on installing showerheads with flow rates of 2.3 gallons per minute in new houses with electric water heat instead of showerheads with flow rates of 3.0 gallons per minute.

In existing houses, the efficient showerhead will replace one that doesn't necessarily meet code. There is very little data to document the average flow rates from existing houses in the Northwest. This analysis assumes that existing showerheads use an average of about 4.5 gallons per minute and that they will be replaced with showerheads using 2.3 gallons per minute on average. For both new and existing houses, it was assumed that showers last for an average of 10 minutes, and that half the water consumed is hot. In addition, it was assumed that the average shower use is one shower per person every two days.

Incremental costs of the efficient showerhead were taken from the Oregon survey and doubled to reflect the fact that many new homes would need two showerheads. No incremental installation costs were attached to the more efficient showerhead in new housing, since there would have been installation costs for a standard showerhead anyway. The total cost of the efficient showerhead was used for showerheads in existing housing and again doubled to reflect more than one showerhead per house. Installation costs for existing houses were assumed to be about $50.

Hot Water Saver

A device called a 'hot water saver' was also evaluated. This device saves energy by pushing the warm water left in the pipes after water is drawn back into the tank. It effectively replaces the warm water left in the pipes with cold. The hot water saver was evaluated as a conservation measure in new single family and manufactured housing units.

Savings from the hot water saver can vary significantly depending on the hot water draw schedule in the house, the length of piping, the number of people, and other factors. The hot water saver was field tested in Richland, Washington in the early 1980s. Data from approximately 20 houses indicated 13 percent savings off a base use of 5,580 kilowatt-hours per year, or 700 kilowatt-hours per year savings. These savings are normalized for the same amount of water use between control and test days, which were alternate days. Less hot water was used during the test days. If savings were not normalized for this, they would be about 1,100 kilowatt-hours. The hot water saver is also accepted by the California Energy Commission as a method to meet its building energy budgets. Based on a number of laboratory tests the Energy Commission conducted, and on judgment, it gives the hot water saver a credit of 15 percent savings off total water heating use. The Council's estimates of use for single-family houses would be about 4,200 kilowatt-hours per year and a 15 percent savings would be about 630 kilowatt-hours per year.

From these studies, savings could reasonably be expected to be between 600 and 1,100 kilowatt-hours per year. The Council selected the normalized savings from the field tests of 700 kilowatt-hours per year as expected savings. However, this had to be adjusted to reflect the fact that the field test houses had more occupants than those across the region. This resulted in an estimate of 525 kilowatt-hours per house in single-family houses. While the hot water saver saves energy from the portion of use labeled 'variable' use, it does interact with space heating savings. (This interaction is described in more detail at the end of the residential section of this chapter.) This drops savings to about 300 kilowatt-hours per year.

Costs of the unit are taken from the manufacturer at about $120 to the wholesaler or builder. We added $25 additional plumbing costs, or about 1/2 hour. The unit is quite easy to install. To this total cost of $145, the Council added a 36 percent markup for the builder's overhead, profit and fees, as is done for all conservation measures in new housing. This resulted in a final price of $197.

The only information on lifetime was from tests done by Oakridge National Laboratory. They did accelerated testing to represent about 13 years worth of use and found no degradation. Twenty years seems plausible, given the sturdiness of the components contained in the product.

Lifetimes

The lifetimes of the water heater and bottom board are 12 years, the dishwasher and clothes washer are 10 years, and showerheads and the hot water saver are 20 years.

Solar Water Heaters and Heat Pump Water Heaters

Solar water heaters are used in this analysis to represent either solar water heaters or heat pump water heaters. Either technology significantly reduces the electricity used to heat water. The costs and percent savings for solar water heaters is taken from the Council's staff issue paper entitled *Assessment of the Potential for the Direct Application of Renewable Resources* (publication number 89-39). It appears that solar water heaters would approach the cost-effectiveness threshold of 11 cents per kilowatt-hour in households with large hot water demand, such as those represented by greater than five people per household. Heat pump water heaters appear even less cost-effective at this time unless they are used as heat recovery ventilators, which is discussed next.

Heat Pump Water Heaters with Heat Recovery Ventilation

Since the mid-1980s several firms in the United States and Canada have been developing a technology that attempts to reduce the consumption of electricity for water heating while suppling ventilation to the home. This technology recovers the waste heat in air exhausted from the home using a heat pump to heat hot water. The best of these systems has achieved coefficients of performance (COPs) of 2.5 in actual field testing. Unlike the air-to-air heat recovery ventilators, exhaust air heat pumps do not require supply air ducts nor special frost protection mechanisms. Moreover, some exhaust air heat pump systems can provide supplemental space heating at COPs near 3.0., and thus provide additional savings.

Although the most efficient exhaust air heat recovery heat pump costs nearly $1,500, the actual incremental cost of an exhaust air heat recovery heat pump is estimated to be between $1,000 and $1,200. This incremental cost takes into consideration four factors. Two factors that reduce the incremental cost of these units and two factors which increase their incremental cost. First, because of their slower recovery periods most manufactures of exhaust air heat recovery heat pumps employ an 80 gallon storage tank to ensure an adequate hot water supply. The identical size efficient (EF=0.93) resistance water heater costs approximately $325, while a "quick recovery" 52-gallon efficient (EF=0.95) resistance water heater costs approximately $210. Thus, the offset for replacement of the standard electric resistance water heater ranges from $210 to $325, depending upon the tank size being replaced. Second, because these units can be substituted for the exhaust ventilation fan and automatic controls now required by the MCS/Super Good Cents, their incremental cost can be offset by a $100 to $150 "credit" for the avoided cost of the fan and controls. The two factors that act to increase these units' incremental cost compared to a standard resistance water heater are their higher installation cost and higher annual maintenance cost. The installation cost of an exhaust air heat recovery heat pump are estimated to be slightly higher ($155 compared to $120) than a standard electric resistance water heater to reflect the cost of adding a condensate drain, exhaust grills and duct work. These units have air filters to keep their evaporator coils from fouling with dust. These must be changed two times per year at an expected average cost of $5 per year. It is assumed that a standard electric resistance water heater has no annual maintenance cost.

Water heating use is strongly correlated to the number of occupants in a household. Therefore, any measure that improves the efficiency of heating water will be more economical in larger households than in homes with fewer occupants. This is clearly the case for exhaust air heat pumps. Table 7-52 shows the levelized cost of energy saved for households with varying numbers of occupants. These costs are derived after accounting for other, cheaper conservation measures that are identified in this chapter.

This table shows that for households with three or more members (or unusually large hot water use) where the exhaust air heat recovery heat pump is replacing either a 52 or 80 gallon tank, the use of such systems is regionally cost-effective. Based on survey data, it appears that the average number of occupants in new single-family, detached dwellings and in new manufactured homes equals or exceeds three people.

In the Council's high forecast, approximately 2,071,400 new electric water heaters are expected to be installed. Of these, 1,259,700 are expected to be installed in new electrically heated single-family homes and 257,900 new electrically heated manufactured homes. Assuming that only half of these homes could cost-effectively install exhaust air heat recovery heat pumps where there is an average of at least three people per home, then the technical potential for this resource is:

$$[(\text{Number of units}/\ 2) * \text{kWh savings/unit}]\ /\ 8{,}760{,}000\ \text{kWh/MWa} = \text{Total MW}$$

$$[(1{,}259{,}700 + 257{,}900)/\ 2) * 2184\ \text{kWh/yr.}]\ /\ 8{,}760{,}000 = 189\ \text{MWa}$$

In order to estimate the realizable potential for this resource, it has been assumed that only 85 percent of those new electrically heated single-family and manufactured homes with three or more occupants will install exhaust air heat recovery heat pumps. This assumption results in a total realizable potential of 190 average megawatts by the year 2010 in the Council's high forecast. In the Council's medium forecast, the realizable potential for this resource is approximately 90 average megawatts.

Table 7-52
Levelized Cost of Water Heating Energy Savings from Exhaust Air Heat Recovery Heat Pumps by Household Size

Occupants	Cost[a] (1990 $)	Cost[b] (1990 $)	Annual Use (kWh/yr.)	Savings (kWh/yr.)	Levelized (Mills/kWh[c])	Cost (Mills/kWh[d])
1	$1,010	$1,175	1,440	864	229	264
2	$1,010	$1.175	2,540	1,524	130	150
3	$1,010	$1,175	3,640	2,184	91	105
4	$1,010	$1,175	4,740	2,844	70	80
5	$1,010	$1,175	5,840	3,504	57	65
6	$1,010	$1,175	6,940	4,164	48	55

a Incremental cost above an 80 gallon EF = 0.93 tank with $150 ventilation system cost credit.

b Incremental cost above a 52 gallon EF = 0.95 tank with $100 ventilation system cost credit.

c Based on incremental cost over 80 gallon tank.

d Based on incremental cost over 52 gallon tank.

Summary Calculations

The assumptions described above for each measure led to the cost-effectiveness calculation for each measure shown in Table 7-53, except for the heat pump heat recovery ventilator, which was calculated above. This table assumes an average household with 2.4 occupants, which is the forecast value for out-years of the forecast. Savings for standby loss conservation measures have been reduced to reflect the interaction between internal gains from water heaters and space heating electricity consumption. This is described in the section that follows the analysis of refrigerator and freezer conservation potential. The table shows the marginal cost of each water heating conservation measure, starting with a tank that meets the federal appliance standard for 1990. Except for solar water heaters, none of the measures exceeds 11 cents per kilowatt-hour, even after taking into account the interactive effect with space heating, except the horizontal-axis clothes washer, which falls in the 11 to 15 cents per kilowatt hour band.

Step 2. Develop Conservation Supply Functions for Technical and Achievable Potential

The savings for each measure were multiplied by the number of units existing in 2010 to which that measure applied. The number of electric water heaters was taken as the number of units existing in 2010. The number of electric water heaters that appears in the forecast between 1995 and 2010 would over count the number of water heaters in 2010, since the average lifetime of water heaters is shorter than the 15 years between 1995 and 2010, and consequently some replacements would be occurring. The savings from showerheads are assumed to be limited by the number of new houses likely to be built between 1995 and 2010 with electric water heaters. The number of clotheswashers and dishwashers is assumed to track the number of electric water heaters in 2010 with saturations of 78 percent and 50 percent respectively.

Step 3. Calibrate the Supply Curve to the Council's Forecast and Incorporate Behavioral Impacts on the Savings Estimates

The engineering and field measurements described above predict a base water heater use of about 3,770 kilowatt-hours per year for 2.4 people per house. As mentioned above, these figures represent standby losses at the level of the federal standard. Since the consumption of the average water heater at the avoided cost cut-off is about 2,500 kilowatt-hours per year, the cost-effective relative efficiency improvement holding behavior constant is 0.67. In the medium demand forecast, base case use in 2010 at the frozen efficiency level of the federal standard is about 3,790 kilowatt-hours per year. For purposes of the supply curve, the difference between the forecast base case use and the engineering base-case use is so small that no calibration was necessary.

Table 7-53
Measure Costs and Savings for Water Heaters

Conservation Measure	Measure Capital Cost	Measure Present Value Cost	Savings with Interaction[a] (kWh/yr.)	Levelized Cost (cents/kWh)
Base Use = 3,770 kWh/year (EF = .88)				
Tank @ EF=.88	$0	$0	0	0
New Showerhead (3.0 to 2.3 gpm)	$15	$17	380	0.6
Existing Showerhead (4.5 to 2.3 gpm)	$80	$90	930	1.3
Efficient Dishwasher	$18	$35	105	4.4
Efficient Clotheswasher	$28	$55	143	5.1
Efficient 0.95 Tank	$70	$120	288	5.5
Bottom Board	$10	$17	29	7.8
New Single-Family Water Saver	$197	$220	304	9.6
Horizontal Axis Clotheswasher	$200	$385	345	14.0

[a] This reflects the reduced savings from standby loss measures due to the interaction with electric space heating.

This relative efficiency change was incorporated in the forecast, and energy consumption was estimated after all measures were installed. Savings for the average water heater are the difference between base use of 3,790 kilowatt-hours and use after the conservation measures are installed. Because there are different penetration rates on each measure, and measures can only be applied if the appliance is present (e.g., a dishwasher), the savings-weighted penetration rate is 0.66.

The amount of conservation available in the high demand forecast can then be estimated as the number of new water heaters, times the weighted penetration rate, times the estimate of cost-effective savings. The megawatts available in the medium and high demand forecast at various costs is presented in Table 7-54. These savings do not include the savings from heat pump heat recovery ventilators, calculated in the text above.

Table 7-54
Conservation Available from Water Heaters

Levelized Cost (cents/kWh)		Cumulative Technical Potential (average megawatts)	
Nominal	Real	High Forecast	Medium Forecast
0	0	0	0
1	.5	89	57
2	1	386	324
3	1.5	386	324
4	2	386	324
5	2.5	415	347
6	3	622	510
7	3.5	622	510
8	4	638	523
9	4.5	638	523
10	5	699	562
11	5.5	699	562
12	6	699	562
13	6.5	699	562
14	7	785	614
15-20	7.5-10	785	614

Conservation in Other Residential Appliances

Approximately one-quarter of the electricity currently consumed in the residential sector is used to operate refrigerators, freezers, stoves and lights. This section describes the conservation assessment for refrigerators that contain freezers (hereafter called refrigerators), freezers, clothesdryers and residential lighting.

Refrigerators and Freezers

The Council estimates 113 average megawatts of technical savings are available from conservation in refrigerators and freezers in the high-demand forecast and 89 in the medium forecast. All the measure included in this estimate are beyond the 1993 Federal standard. They are considered to be relatively high-cost conservation, since the inexpensive measures will probably be used to attain the level of the 1993 standard, and are therefore part of the second block of conservation resources.

The average megawatts currently identified for refrigerators and freezers represent significantly less than the available conservation presented in the 1986 Power Plan and the Draft 1991 Power Plan. Most of this reduction results from the National Appliance Energy Conservation Act, discussed below, which regulates the minimum efficiency of new appliances. The savings estimated in the draft have essentially been incorporated in the forecast of electricity demand as reduced use. This change illustrates the effectiveness of appliance standards at acquiring conservation resources.

The savings identified by the Council are based on cost-effective efficiency improvements that go beyond federal legislation. The National Appliance Energy Conservation Act was passed by Congress and signed by President Reagan in early 1987. It sets an initial maximum energy consumption level for refrigerators and freezers (as well as other home appliances) that becomes effective for any unit sold in or after 1990. The federal law also requires a review of these initial standards for refrigerators and freezers by 1990. The Department of Energy reviewed the standards and adopted more stringent levels to become effective in 1993. Currently, the Council's forecast of electricity demand incorporates the 1993 standard. This is the base case against which further efficiency improvements are measured.

Analysis indicates that efficiency improvements beyond the 1993 federal standard are achievable. The conservation resource this represents is modeled as the current "golden carrot" effort, that makes a standard change feasible. The golden carrot is a program that uses utility incentives to encourage manufacturers to produce equipment that is significantly more efficient than the standard. The plan assumes this program becomes effective starting in 1997, and will eventually result in revised standards becoming effective in 2000.

While refrigerators and freezers that comply with the requirements of the golden carrot program are not widely commercially available, an alternative design refrigerator that approximates this energy use can be purchased today, but only at a high price because it is handmade.

The Council used two steps to evaluate the savings available from refrigerator and freezer efficiency improvements. These were to:

1. Estimate the cost and savings potential available from improved refrigerator and freezer efficiency.
2. Develop technical and achievable conservation potential and calibrate the conservation potential to the Council's forecast.

The key data used in this analysis is from the U.S. Department of Energy proceedings on refrigerator and freezer efficiency improvements.

Step 1. Estimate the Costs and Savings Potential Available from Improved Refrigerator and Freezer Efficiency

The potential for saving energy from improved refrigerator and freezer operating efficiencies is well documented. The U.S. Department of Energy and the California Energy Commission have reviewed the option of appliance efficiency standards over the last decade. The Department of Energy has done a recent study on efficiency improvements to refrigerators and freezers. The savings and cost information from that study are used here. The measures represent options that could be manufactured into appliances by the early 1990s.

In this analysis, an 18-cubic-foot automatic defrost refrigerator with a top-mounted freezer was used as the prototype to represent refrigerators. Both a 15-cubic-foot manual defrost upright freezer and a 17-cubic-foot chest freezer were used to represent freezers. About 61 percent of the refrigerators sold in the region have top-mounted (as opposed to side-by-side) freezers. Automatic defrost units represent approximately 70 to 80 percent of the refrigerators sold today. About 50 percent of freezers sold are uprights, and about 50 percent are chest styles.

To get a feel for how the various standards affect consumption, take the example of the typical refrigerator. The Association of Home Appliance Manufacturers estimates that the average unit of this sort sold in 1983 consumed about 1,156 kilowatt-hours per year. The 1990 federal standard requires that this same refrigerator consume no more than about 950 kilowatt-hours per year, and the 1993 standard requires about 690 kilowatt-hours per year. The golden carrot program is likely to target about 500 kilowatt-hours per year as the use for the typical refrigerator. This is the level used to present savings for the 11-15 cents per kilowatt-hour block of conservation.

This analysis evaluates cost-effectiveness from the perspective of the region. Table 7-55 presents cost and savings information for the prototype 18-cubic-foot refrigerator. Savings and levelized costs include the interaction of appliance efficiency improvements with space heating requirements, described more fully in the following section.

The costs and savings for measures that can be applied to the prototype upright and chest freezers appear in Table 7-56. As with refrigerators, this information is taken from the U.S. Department of Energy technical documentation.

Step 2. Develop Conservation Supply Functions for Technical and Achievable Potential Consistent with the Council's Forecast

Savings costing less than 11 cents per kilowatt-hour are already secured in the 1993 federal code. Therefore, savings in this section only reflect going beyond the 1993 code and capturing savings in the 11 to 15 cents per kilowatt-hour range. These are included in the second block of conservation. The savings from conservation measures in refrigerators and freezers is evaluated consistently with the values carried in the forecasting model.

The Council's forecasting model was used to estimate the base case use of refrigerators and freezers in the year 2010 with efficiencies frozen at the 1993 federal standards. In the medium demand forecast, new refrigerators use about 687 kilowatt-hours per year and freezers use about 500 kilowatt-hours per year for the average refrigerator and freezer purchased in the region.

Table 7–55
Measure Cost and Savings for Prototype Refrigerator[a]

	Use (kWh/yr.)	Measure Cost	Cumulative Cost	Levelized Cost (cents/kWh)[b]
Current Federal Code for 1990	947	$0	$0	0
Foam Insulation in Door Compressor EER[c] 5.0	787	$11.24	$11.24	1.3
Improved Foam Insulation (k=0.11)	745	$7.27	$18.51	3.2
Compressor EER 5.3	714	$13.12	$31.63	7.9
Efficient Fans, 2" Door Insulation with Improved Foam (k=0.10)	637	$50.74	$82.38	12.2
Adaptive Defrost, Evacuated Panels (k=0.05)	515	$102.97	$185.35	156.3

a Analysis is for an 18-cubic-foot automatic defrost refrigerator with a top-mounted freezer.

b Adjusted for space heat interaction.

c EER—Energy-Efficiency Ratio.

Table 7–56
Measure Cost and Savings for Prototype Freezers

	Use (kWh/yr.)	Measure Capital Cost	Levelized Cost (cents/kWh)[a]
Upright[b]			
▪ Base Case	777	$0	0
▪ Compressor EER 5.0[c]	606	$15.19	1.2
▪ Improved Foam Insulation	544	$7.63	1.6
▪ Compressor EER 5.3	511	$13.07	5.2
▪ Door Insulation 2" and Better Foam	453	$28.12	6.4
▪ Evacuated Panel	343	$51.40	6.2
Chest[d]			
▪ Base Case	600	0	0
▪ Compressor EER 5.0, Foam Insulation in Lid	475	$11.25	1.2
▪ Improved Foam Insulation	442	$4.68	1.9
▪ Compressor EER 5.3	415	$13.01	6.4
▪ 2.5" Lid, Better Foam Insulation	370	$25.55	7.5
▪ Evacuated Panel, 2.5" Sides	315	$52.07	12.5

a Adjusted for space heat interaction.

b Analysis is for a 15-cubic-foot upright freezer with manual defrost.

c EER—Energy-Efficiency Ratio.

d Analysis for a 17-cubic-foot chest freezer with manual defrost.

For refrigerators, a base use of 675 kilowatt-hours per year and a conservation cut-off of 515 kilowatt-hours per year resulted in a total technical potential:

TS	=	N x S x I ÷ C
	=	4,812,000 x (687 - 515) x 0.8 ÷ 8,760,000
	=	75 average megawatts

Where:		
TS	=	total savings from refrigerators, expressed in average megawatts
N	=	number of refrigerators purchased 1997 to 2010
S	=	savings from each refrigerator, in kilowatt-hours per refrigerator (pre-conservation use minus-post conservation use)
I	=	loss of savings due to interaction with the space heating system
C	=	conversion from kilowatt-hours to average megawatts (8,760,000 kilowatt-hours per average megawatt)

For freezers, a base case use of 500 kilowatt-hours per year and a conservation cut-off of 329 kilowatt-hours per year, resulted in a total technical potential:

TS	=	N x S x I ÷ C
	=	2,204,000 x (504-329) x 0.87 ÷ 8,760,000
	=	38 average megawatts

Where:		
TS	=	total savings from freezers, expressed in average megawatts
N	=	number of freezers purchased 1997 to 2010
S	=	savings from each freezer in kilowatt-hours per refrigerator (pre-conservation use minus-post conservation use)
I	=	loss of savings due to interaction with the space heating system
C	=	conversion from kilowatt-hours to average megawatts (8,760,000 kilowatt-hours per average megawatt)

The achievable portion is considered to be 90 percent of technical potential.

Clothesdryers

In support of efficiency standards for residential appliances, the U.S. Department of Energy investigated improvements that could be made to residential clothesdryers. The analysis shown below is taken from the draft technical documentation used by the Department of Energy.

Table 7-57 displays the information collected by the department. Annual usage has been scaled to reflect the number of dryer loads per year in the Northwest, compared to the national testing procedure. Using this scaled savings, it appears only one measure, automatic termination based on moisture or temperature, is cost-effective. If this level is adopted, about 6 average megawatts could be secured. However, this assumes that the measure is not already widely used in clothesdryers currently sold. It is likely that many new clothesdryers already incorporate automatic termination, and therefore the savings were not used in the portfolio analysis.

Table 7–57
Measure Cost and Savings for Clothesdryers

Measure	Measure Capital Cost	Use (kWh/yr.)	Levelized Cost (cents/kWh)
Base Case	0	532	0
Automatic Termination	$8	468	7
1" Cabinet Insulation	$11	459	29
Recycle Exhaust	$50	431	47
Heat Pump Clothesdryer (off base)	$300	170	21

In addition, there are two advanced technologies that could save significant amounts of electricity, if they became commercially available. These are heat pump clothesdryers and microwave clothesdryers. Both heat pump and microwave clothesdryers are in the prototype stage in this country, although small versions of the heat pump clothes dryer are used to some extent in Europe. The key disadvantages of each unit are that the heat pump dryer requires longer to dry than a conventional clothes dryer, and the microwave dryer cannot dry materials with metal threads, although it can dry clothes with metal buttons and zippers. On the other hand, the microwave unit dries clothes more quickly than a conventional dryer, and appears to be easier on fabric. If heat pump clothesdryers were used instead of the conservation measures listed in Table 7-57, they would save about 60 average megawatts at about 21 cents per kilowatt-hour. Since this resource is not yet commercially available in the United States and is expensive, it is not considered at this time. Microwave clothesdryers would save about 15 average megawatts of energy at a cost of about 8 cents per kilowatt hour. Since they are not yet commercially available, they are not included in the resource stack. However, they appear promising, and should be targeted for development if possible.

Residential Lighting

Great strides have been made in developing lighting technologies to replace traditional incandescent bulbs in a residential setting. The typical replacement is to put a compact fluorescent (bulb and ballast) into the existing incandescent socket. There are now compact fluorescents that are similar to incandescent bulbs in color, but that use significantly less energy. For example, a 75-watt incandescent bulb is typically replaced with an 18-watt fluorescent bulb and ballast to achieve similar light levels. This means a significant savings every time the light is turned on.

Compact fluorescents are currently commercially available, but there is an emerging lighting technology that might prove more efficient and inexpensive in the future. This technology is essentially an electronic signal that excites gasses common in all bulbs to create light. The first prototype versions have succeeded in producing as much light as a 150-watt incandescent, with similar color, in a similar sized and shaped bulb. These are projected to be about half the cost of the compact fluorescents. Since these are not yet commercially available, this section focuses on the compact fluorescent.

There are some problems with the new compact fluorescents. First, they have a high first cost, about $20 instead of the $0.66 cost of incandescent bulbs. Even though they last much longer, there is sticker price shock when the consumer sees them in the market place. Second, they are not yet widely available in stores that sell light bulbs, such as grocery stores. Probably because of the high first cost, a large market has not developed for these bulbs, even though they save energy. Third, the compact fluorescent, which is larger than the incandescent, may not fit in the existing socket because of the configuration of many lamp shades and lamp harps. Finally, there currently are no compact fluorescents that have light output equal to a 100-watt incandescent or greater and will easily fit into existing fixtures. In order to achieve more light output, the fluorescent bulb must get larger, which will further limit its application in existing fixtures and sockets.

In terms of program design, there are slightly different problems. For example, administrative costs could overwhelm cost-effective savings, if fluorescent bulbs were the only reason for a visit to a house. However, if the bulbs were installed while the utility was also doing other things in the house, they would remain cost-effective. In addition, there are questions about the longevity of savings. A fluorescent bulb may last 9,000 hours, but at the end of this life, how can the electric system be assured that the fluorescent will be replaced in kind, instead of with a low-first-cost incandescent that fits the same socket?

These problems can be resolved. The program questions can be resolved during program design, but they must be kept in mind. The prior set of technical questions essentially means that the resource size may not be as large as once thought, since there are households where no incandescents will be replaced and others where very few will be accommodated.

On the other hand, there also are some benefits to the compact fluorescents. They do not need replacement nearly as often, and consequently maintenance is minimal. This is especially important in hard-to-reach places, such as stairwells, and in areas where the lights burn long hours.

In this chapter, compact fluorescents are used to simply illustrate the types of savings available from efficient lighting. As other efficiency technologies become widespread and cost-effective, they should also be used in programs.

There were two steps used to estimate the savings available from efficient residential lighting. They were to:

1. Estimate the levelized cost of improving the efficiency of residential lighting.
2. Develop technical and achievable conservation potential.

Step 1. Estimate the Levelized Cost of Improving the Efficiency of Residential Lighting

In this analysis, an 18-watt compact fluorescent replacing a 75-watt incandescent is used to represent a typical levelized cost for the generic installation of compact fluorescents for incandescents in new and existing housing. The general question is whether this measure has a low enough levelized cost to warrant further evaluation of the total conservation potential. As seen below, since it passes this test in new and existing housing, the average wattage reductions expected per house are used to estimate regional potential. This analysis assumes the compact fluorescent is placed into an incandescent socket. In new housing there is the opportunity to put the compact fluorescents into fixtures that are optically designed for this type of bulb. This should enhance the visual performance of the compact fluorescents. The costs of these fixtures can be expensive relative to incandescent. However, since they ensure that the replacement bulb will also be a compact fluorescent instead of an incandescent, it is worth an effort, such as bulk purchasing, to try to bring costs down. This should be investigated by programs in the Northwest. Another advantage of efficient lighting in new homes is that the lights can be placed in rooms with high usage, such as kitchens and apartment hallways, where they result in a quicker payback to the consumer.

Energy savings are based on data collected for Pacific Power and Light Company. In a study examining the potential for retrofitting compact fluorescents into existing houses, the utility collected information on the number of lamps that could be converted, the number of hours the lights were on, and other information on occupant attitudes. While not regionally representative, this data is the only monitored source of information available. It is used to estimate the cost-effectiveness and size of the conservation resource.

Pacific Power and Light found that an average of three bulbs could be replaced per house. Only two of these bulbs were monitored for their hours of usage, but these were on an average of two hours per day. In the example used here of an 18-watt fluorescent replacing a 75-watt incandescent, the savings are then 42 kilowatt-hours per year, per bulb. However, as described in the next section, some of the savings from making the lighting more efficient are lost, because the space heater has to operate more frequently. In an electrically heated house, about 50 percent of the savings are lost, but only about 45 percent of the houses in the region are electrically heated. This results in a total net loss of about 22 percent. Instead of 42 kilowatt-hours per year being saved, only 33 kilowatt-hours are saved. This lower figure is used in the cost-effectiveness evaluation and in the estimate of total regional megawatts.

The lifetime of a compact fluorescent is about 10,000 hours, but this is tested assuming longer on-times than two hours per day. Consequently, the 10,000 hours is assumed to be shortened to 9,000 hours. This implies a lifetime of 12 years if the lamp is on only two hours per day.

The cost of compact fluorescents has dropped significantly over the years. Currently, the retail cost of an 18-watt compact fluorescent, including the ballast, is about $18, according to information from the Rocky Mountain Institute and various discussions with lighting professionals. This price can be reduced if the unit is purchased in bulk. For example, distributor costs are closer to $10 to $15. There may be some incremental installation cost, since the first one that is installed may be installed by the utility. For initial purposes, assume that the installation cost is $1 per bulb if installation occurs when the utility is conducting other business at the house; for example, the utility might be conducting weatherization audits, replacing a water heater or installing a showerhead. The net cost of the compact fluorescent must be reduced to reflect the cost of replacing the incandescents because they last only 850 to 1,000 hours, while the fluorescent lasts 9,000 to 10,000 hours. This means not incurring a $0.66 cost for an incandescent bulb 10 times over the life of the compact fluorescent. This analysis assumes the cost of incandescent bulbs is $0.50, since many purchases are made when the bulbs are on sale.

Using these assumptions, the levelized cost of the compact fluorescent is about 8 cents per kilowatt-hour and, therefore, cost-effective if administrative costs are kept fairly low.

Step 2. Estimate Technical and Achievable Conservation Potential

In order to estimate the impact on the region, if a full effort were made to install compact fluorescents in new existing houses, two more data points are needed. First, what is the average wattage reduction when a compact fluorescent replaces an incandescent? Second, to how many households does the retrofit apply?

Pacific Power and Light's experience indicates that an average 50 watts were saved for each incandescent bulb replaced. The Council's forecast shows 2.95 million pre-1990 households (includes single-family, multifamily and manufactured houses) surviving until 2010. This information, combined with an average on-time of two hours per day, three applicable fixtures per house, and the average interaction with space heating of about 22 percent loss in savings, represents a technical potential of 28 average megawatts in existing housing. Achievable savings area assumed to be 85 percent of this or 24 average megawatts.

There are approximately 3.28 million new households built between 1992 and 2010 in the high-demand forecast and 1.92 million in the medium forecast. Currently there is no known source of data for how many fixtures can be fluorescent in a new house or how many hours they are on. The following are simply some rough estimates to make a first cut at the regional costs and savings. Since there are more opportunities for putting compact fluorescents into new houses than existing houses, the plan assumes that four fixtures can be replaced (averaged over single-family, multifamily and manufactured houses). These are assumed to result in an average 50-watt reduction, operating about four hours per day. Using these assumptions for new houses, this indicates a promising resource on the order of 87 average megawatts in the high forecast and 51 average megawatts in the medium forecast. Assuming 85 percent penetration rate for the achievable potential results in 74 average megawatts in the high and 43 in the medium forecast. In the ISAAC model, these savings are assumed to accrue on the following schedule: 15 percent in 1991, 30 percent in 1993, 50 percent in 1994 and 85 percent from 1995 on.

Electric Cooktops and Ovens

A number of technologies to improve the efficiency of traditional electric resistance cooking and baking have been developed over the last few years. In cooktops, radiant cooking can reduce the energy used by traditional electric resistance units. This is primarily because heat already stored in the resistance element is wasted when the cooked food is removed and the element is turned off. However, the cost of radiant cooktops is quite expensive relative to traditional cooktops, while the savings are not large, resulting in levelized costs that are too expensive to consider further.

A pervasive technology that has saved some of the energy used by ovens is the microwave oven. Since it heats food directly, instead of the cooking vessel and surrounding air, it is much more efficient than a tradition oven. However, it is already in widespread use and therefore can't be considered further conservation. Reductions due to bi-radiant ovens could produce further savings, but questions remain surrounding their use. This is a technology that is a promising resource.

The Interaction Between Internal Gains and Electric Space Heat

A house is warmed by a combination of internal and external heat sources. Internal heat comes from incidental or waste heat given off by appliances and people (usually called "internal gains") and from the space heater. The external source of heat is primarily radiant energy from the sun (usually called "solar gains"). These heating sources are in balance, and if the heat produced by any one of them decreases, more heat must be added from the other components to keep the house at the same temperature. This section explains the interaction between the waste heat given off by appliances and the heat supplied by the space heater.[31]

If the efficiency of an appliance, such as a refrigerator located inside the heated space, improves, the unit both uses less energy and gives off less waste heat. This change in turn causes the space heater to use more electricity, in order to keep the house at the same temperature it was before the improvement in the refrigerator's efficiency occurred.

The balance between the decrease in electricity consumption by the refrigerator and the increase in use for extra space heating depends on many factors. One prominent factor is the insulation level of the house. The better insulated a dwelling, the less useful is the waste heat from the appliance. For example, the space heater must produce about an additional 5 kilowatt-hours per year for every 10 kilowatt-hours per year saved by the appliance efficiency improvement, assuming all of the following: the appliance is located in the heated space, electricity is the space heating fuel, no air conditioning is installed, and the house is not fully insulated. In other words, only 50 percent of the savings from improving appliance efficiency would be realized. This estimate accounts for periods of the year, such as summer, when additional space heat is not necessary.

This estimate must be tempered by other intervening variables to calculate the average expected impact on the Northwest electrical system from improved appliance efficiencies. First, the appliance must be one that produces internal gains. Many do not. For example, about half the electric freezers in the region are located outside heated areas. Waste heat generated from freezers (and other appliances) that are outside the heated shell of the house does not contribute to internal gains. Consequently, any efficiency improvements in appliances located outside the house would be fully realized as 100-percent energy savings and would not require that additional heat be provided by the furnace.

31. Solar gains are considered constant in this discussion.

Second, a number of electrical appliances that do produce internal gains, such as refrigerators, are located in houses that do not use electricity for their space heating. In this case, the full amount of electricity saved by improving the appliance's efficiency is realized by the region's electrical system.

Finally, the reduction of internal gains benefits the house if air-conditioning equipment is installed. In this case, less cooling needs to be provided in the summer to offset the internal gains from inefficient appliances.

For water heaters, only the standby use of hot water held in the tank (for units located in the house) is an internal gain. Variable hot water demand does not contribute significantly to internal gains, even though it uses electricity.[32] Consequently, only efficiency improvements in standby use for tanks located in the house increase the heat needed from the space heater.

When all of these factors are considered, electricity used for space heating must make up, on average in the region, about 17 percent, 20 percent, 13 percent and 22 percent of the savings from standby losses on water heaters, refrigerators, freezers and lights, respectively. These figures were used to devalue the savings obtainable from these appliances in the preceding cost-effectiveness evaluations.

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Commercial Sector

Of the estimated conservation resource, the commercial sector accounts for roughly half of the total. At the same time, the commercial sector represents the most diverse and perhaps the least understood of all the sectors. It includes buildings ranging from 1,000 square foot convenience stores to 50-story office towers and energy uses ranging from computers to supermarket refrigerators. These two facts alone make the commercial sector a particularly difficult, yet critically important part of estimating the conservation resource in the region.

Because of the complexity of the sector, much less precision is possible for estimating the conservation potential, when compared to the residential sector. For example, while three prototype residential buildings may encompass a majority of the energy-consuming characteristics in residential buildings, the 10 prototypes in the commercial analysis, each modeled twice as new and existing buildings, only start to reflect the wide range of energy-consuming characteristics found in commercial buildings.

This section describes the current energy uses in the sector, the process used to evaluate the conservation potential, and a comparison with conservation program experience.

Summary

In 1989, the commercial sector consumed approximately 22 percent of the region's total energy sales or about 3,768 weather adjusted average megawatts. If loads grow at high levels, commercial energy consumption could more than double by the year 2010 to 7,900 average megawatts. This sector's energy consumption is dominated by lighting (33 percent), space heating (27 percent), ventilation (15 percent) and cooling (8 percent). Further detail on the current estimates by end use are provided in Volume II, Chapter 6.

Figure 7-15 shows the amount of existing and new commercial sector conservation available in the high forecast. The combined total of technical conservation potential for the sector is over 1,850 average megawatts for measures costing 11 cents per kilowatt-hour or less. This makes the commercial sector conservation resource one of the largest resources in the portfolio and approximately 45 percent of the entire conservation resource potential. However, this amounts to less than 25 percent of the projected commercial electric energy demand in the year 2010. The resource is split fairly evenly between existing buildings with 800 average megawatts and new commercial buildings at 710. The total also includes 350 average megawatts of potential savings available if all of the existing stock were brought up to the same efficiency levels as new buildings during a renovation or remodel of the building.

The Council assumes that these cost-effective efficiency improvements in existing and new commercial buildings will be acquired through new programs and code improvements over the next 20 years. Therefore, the conservation potential estimates used for the resource portfolio analysis do not include savings secured by the 1986 Oregon and Washington energy codes and changes in practice. Efficiency improvements resulting from changes in codes and practice are reflected in the forecast through a reduction in loads of over 830 average megawatts. While these savings are not explicitly counted here, they represent a significant amount of energy that would make the total potential savings from 1983 practice almost 2,700 average megawatts.

In addition to the resources described above, there are an estimated 250 additional average megawatts potential from commercially available measures that cost between 11 and 15 cents per kilowatt-hour. Many of these technologies are available but expensive today; but with the rapid change in technology in this sector, it is likely that many will become less expensive in the near future. This is especially true in the lighting end use where solid state electronics are revolutionizing the powering and control of electric lighting equipment.

Figures 7-16 and 7-17 show the amount of commercial sector conservation available at various costs in existing and new buildings.

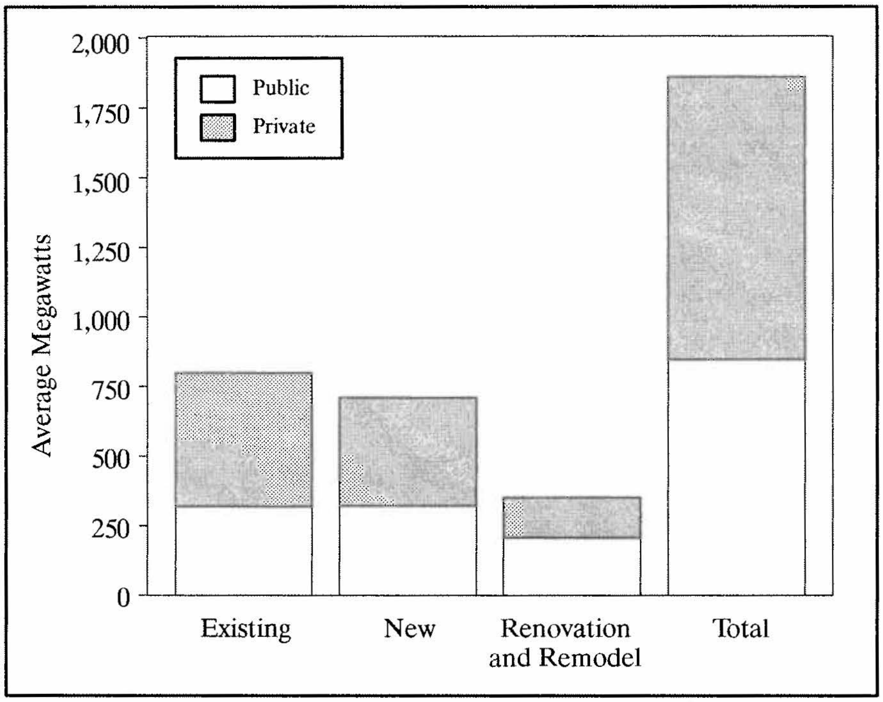
Savings from existing commercial buildings are available at an average cost of 5 cents per kilowatt-hour. Savings from new commercial buildings are available at an average cost of about 4 cents per kilowatt-hour. These levelized costs escalate to 6 and 5 cents per kilowatt-hour, respectively, if administrative costs and transmission and distribution adjustments are included.

The Council's estimate of conservation savings from the commercial sector involved the following four steps:

1. Identify the current regional average consumption for typical existing and new commercial buildings.
2. Evaluate cost-effective efficiency improvements in existing and new commercial buildings.
3. Develop estimates of conservation potential in new and existing commercial buildings that are consistent with the Council's load forecasts.
4. Estimate the amount of conservation potential achievable in new and existing commercial buildings.

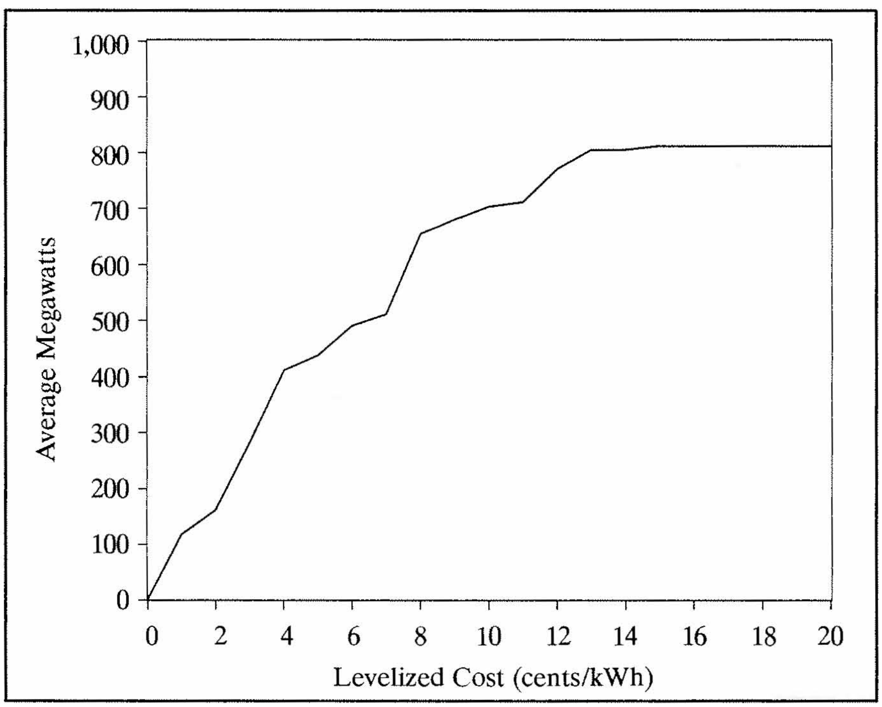
Conservation Potential

Figure 7-15
Technical Potential for Commercial Buildings



Conservation Potential

Figure 7-16
Technical Conservation Potential for New Commercial Buildings



Conservation Potential

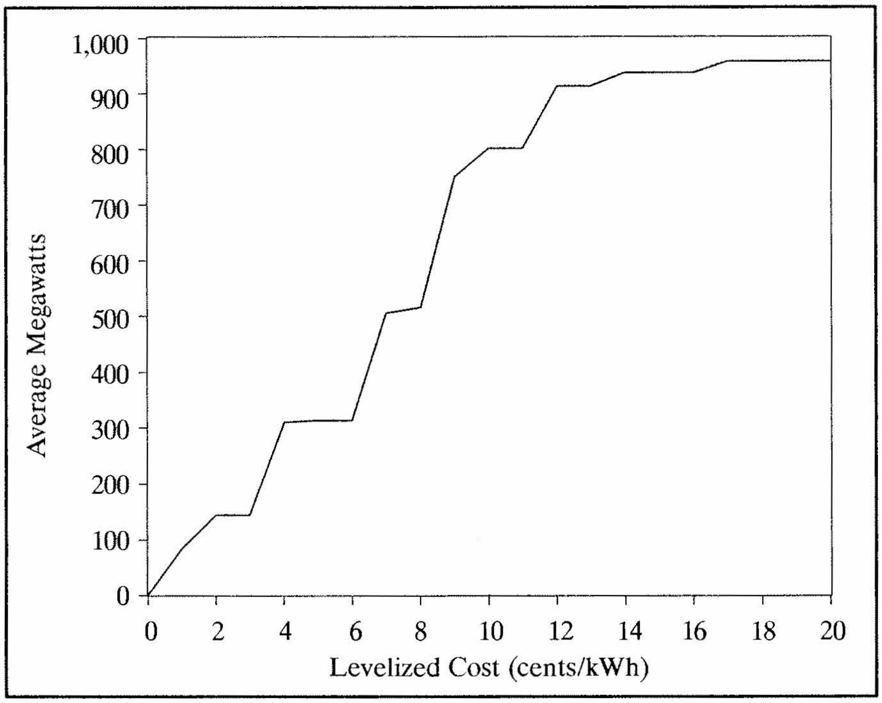


Figure 7-17
Technical Conservation Potential for Existing Commercial Buildings

Step 1. Identify the Current Regional Average Consumption for Typical Existing and New Commercial Buildings

The Council's commercial sector forecasting model contains representations of 10 building categories. Table 7-58 shows the annual energy use for all-electric[33] commercial buildings that comprised the stock in 1979, as estimated by the Council's forecast. This table also presents billing data information collected by Energuard and by the Commercial Audit Program (CAP). These two programs combined have large sample sizes for many of the building types. There is fair agreement between the forecast estimates and data from billing records. However, there is a large discrepancy for the forecast's restaurant category, because the forecast includes all types of restaurants, including sit-down and fast-food, while the billing data is from fast-food restaurants only. Fast-food restaurants have very high energy use per square foot, because they usually are quite small and serve a large number of meals per day. The warehouse category also has a large variance between one of the billing data samples and the forecast. This could be due to small sample size. It should be remembered that, while there is reasonable agreement between the forecast and billing data for average values, for most of these building categories, there can be tremendous variations in use among buildings.

To convey the relative importance of each building type in the analysis, the last column of Table 7-58 shows the percent of total electricity consumption for existing buildings in 1989, by building type. These percentages account for the fact that not all end uses require electricity as their fuel. Office and retail buildings are far and above the most crucial building types for determining electricity consumption in existing commercial buildings. These two building types alone represent almost 50 percent of projected electricity consumption.

In comparing the billing data shown in Table 7-58 and the forecast model assumptions, three factors should be kept in mind. First, the buildings with billing data from the Commercial Audit Program and Energuard shown in Table 7-58 were not selected to be statistically representative of the average. Second, the annual use data from these sources represents each building's total energy use,

33. The term all-electric means that every end use in the building uses electricity as the fuel. The electricity consumption of the average building will be lower, since some end uses, for example, space heating, water heating or cooking, can be fueled by gas. ASHRAE stands for the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. This organization sets various standards for building practices based on consensus.The Council's model conservation standards code for commercial buildings has been translated into model energy code format and is published in the 1990 Northwest Energy Code.

Table 7-58
Summary of Annual Energy Use for Existing Commercial Buildings Located in the Region (All-Electric Buildings)

Building Type (Sample Size = N)	Commercial Audit Program (kWh/sq. ft./yr.)	Energuard Data (kWh/sq. ft./yr.)	ELCAP[a] (kWh/sq. ft./yr.)	Council's Forecast (1979 Stock) (kWh/sq. ft/yr.)	Building Type's Percent of Total Electricity Consumption in 1989
Office	28[b] (N=579)	27 (N=157)	21 (N=14)	24	29%
Retail	21 (N=681)	22 (N=581)	13 (N=17)	18	18%
Grocery	57[b] (N=198)	61 (N=336)	76 (N=6)	70	10%
Restaurant			43 (N=6)	38	5%
▪ Fast-Food	133 (N=47)	116 (N=20)			
Hotel/Motel	26 (N=61)	23 (N=6)	—	19	3%
Health		29 (N=30)	—	20	5%
▪ Hospital	81[c] (N=22)				
School	24[c] (N=61)	20 (N=146)	9 (N=2)	22	8%
College		Inc. in "Schools"[d]	7 (N=1)	20	3%
Warehouse	12 (N=43)	20 (N=77)	8 (N=12)	23	5%
Other		22 (N=41)	7 (N=3)	16	15%
Total					100%

[a] Consumption data from End-use Load and Conservation Assessment Project commercial summaries.

[b] Consumption data for this building type was augmented by information from the Public Utility Regulatory Policies Act of 1978.

[c] Consumption data for this building type was augmented by information from the Institutional Buildings Program (IBP) and the Institutional Conservation Program (ICP).

[d] Colleges included in schools category for the Energuard Data.

regardless of the fuel source. Total energy use is then converted to kilowatt-hours per square foot. Since many of these buildings use natural gas or fuel oil for some end uses, the conversion efficiencies of these fuels are included in the figures. In contrast, the figures from ELCAP and the Council's forecast shown here assume that all energy requirements of the building are supplied by electricity. Third, the year of operation for the buildings in the sample is mostly prior to 1985, and the forecast figures use 1979 as the operating year. Finally, the ELCAP numbers include some new buildings in these summaries, although the majority of the buildings are pre-1980 stock.

The ELCAP data presents some unique opportunities for further comparisons, because of the detailed end-use monitored data available. Unfortunately, the sample sizes monitored for most of the building types are so small that it is difficult to draw any conclusions from the group. However, the sample sizes for office and retail are large enough to permit some aggregation and draw some conclusions. Due to the sample selection procedure and limited size of even these groups. it would be careless to generalize these conclusions to the rest of the regional stock, but it is useful to compare the monitored data with both the forecast output and the engineering prototype analysis used to generate the supply curves.

Table 7-59 presents a comparison of the ELCAP data, prototype engineering analysis and the forecast estimates for a number of end uses in new and existing office and retail buildings. Since the ELCAP offices average less than 50,000 square feet, the ELCAP buildings must be compared more with the UIC small prototypes than with the large prototype. Interestingly enough, the agreement between the forecast and the ELCAP data is fairly good for most end uses. However, neither UIC prototype seems to agree very well with the forecast or the ELCAP data by end-use, even though the UIC prototypes were calibrated to other samples of commercial buildings. It is important to note that the UIC numbers represent resistance heat while both the ELCAP sample and the forecast have a fraction of buildings that use heat pumps. While the exact impact of the heat pumps is not known, one would expect that the space heating numbers from the UIC work would be higher than the ELCAP or forecast numbers. Given that lighting affects both heating and cooling, this difference has implications on the HVAC interactions of lighting measures for the total electrically heated building stock.

Table 7–59
EUI Summary Table—Existing Office Buildings

Building Type	Small Office	ComBase Offices	Public Utility Offices	Medium Office	Large Office
Developer	UIC	ELCAP N=7	NPPC/Forecast	ASHRAE	UIC
Prototype	1980 Base	Mean Pre-1980	1979 All Electric	Average All Cases	1980 Base
Floor Area (sq. ft.)	4,880	9,150	N/A	48,664	408,000
End Use	Energy Consumption (kWh/sq. ft.)				
Space Heat	10.3	7.2	5.7	2.6	14.2
Space Cool	2.0	2.1	2.9	4.1	1.7
HVAC Auxiliary	1.2	2.7	3.8	2.8	5.3
Hot Water	0.5	1.4	0.3	0.3	0.2
Internal Lighting	5.8	9.4	8.9	6.4	10.1
External Lighting	1.3	2.8	—	—	0.4
Vertical Transport	0.3	0.1	—	1.4	0.9
Misc. Equipment	2.3	2.5	2.6	2.0	2.2
Total	23.7	27.5	24.4	19.4	35.0

New Office Buildings

Building Type	Small Office	ComBase Offices	Public Utility Offices	Medium Office	Large Office
Developer	UIC	ELCAP	NPPC/Forecast	ASHRAE	UIC
Prototype	1989 All Electric	Mean Post-1979	1990 All Electric	Average All Cases	1989 All Electric
Floor Area (sq. ft.)	4,880	11,915	N/A	48,664	408,000
End Use	Energy Consumption (kWh/sq. ft.)				
Space Heat	7.8	3.2	5.9	2.6	5.3
Space Cool	1.6	1.7	6.1	3.6	0.6
HVAC Auxiliary	2.0	4.4	4.4	2.8	1.8
Hot Water	0.5	0.6	0.3	0.3	0.2
Internal Lighting	4.7	6.1	7.6	6.4	7.3
External Lighting	1.3	1.4	—	—	0.4
Vertical Transport	0.3	0.1	—	1.4	0.5
Misc. Equipment	3.3	3.0	3.3	2.0	3.1
Total	21.5	20.4	27.8	19.0	19.2

Table 7-59 (cont.)
Existing Retail Buildings

Building Type	Small Retails	ComBase Retails	Public Utility Retails	Large Retails
Developer	UIC	ELCAP	NPPC/Forecast	UIC
Prototype	Base Line	Mean Pre-1980	1979 All Electric	Base Line
Floor Area (sq. ft.)	13,125	26.565	N/A	120,000
End Use	Energy Consumption (kWh/sq. ft.)			
Space Heat	4.8	2.7	3.1	2.5
Space Cool	0.9	0.9	3.9	0.5
HVAC Auxiliary	1.0	0.6	4.9	3.3
Hot Water	0.4	0.5	0.2	0.2
Internal Lighting	7.8	6.3	6.3	13.8
External Lighting	0.9	0.7	—	0.3
Vertical Transport	0.0	0.0	—	0.6
Misc. Equipment	1.1	1.8	2.1	1.2
Total	16.8	13.6	20.5	22.4

New Retail Buildings

Building Type	Small Retails	ComBase Retails	Public Utility Retails	Large Retails
Developer	UIC	ELCAP	NPPC/Forecast	UIC
Prototype	1989 All Electric	Mean Post-1979	1990 All Electric	1989 All Electric
Floor Area (sq. ft.)	13,125	2,867	N/A	120,000
End Use	Energy Consumption (kWh/sq. ft.)			
Space Heat	1.1	3.1	3.1	0.0
Space Cool	0.7	0.6	3.9	0.7
HVAC Auxiliary	1.6	1.0	4.9	4.2
Hot Water	0.4	0.4	0.2	0.2
Internal Lighting	8.4	3.8	6.3	12.5
External Lighting	0.8	2.3	—	0.3
Vertical Transport	—	—	—	0.6
Misc. Equipment	1.1	1.1	2.2	0.6
Total	14.1	12.3	20.5	19.1

The ELCAP data for new buildings other than office and retail is even more limited, and other data sets are difficult to find as well. Table 7-60 shows energy use data that is available from new commercial buildings. The Council's forecast assumptions on new commercial buildings built to 1980 practice appear first in Table 7-60. These buildings are assumed to meet the level of ASHRAE 90-80A, that represents the level of Oregon and Washington state building codes in 1980. The second column shows available data from work done by a Bonneville contractor and from work at the Oregon Department of Energy on billing information in recently built commercial buildings.

This can be compared to billing data collected primarily through the Commercial Audit Program, which is shown in the third column. The final column in Table 7–60 shows the percent of electricity consumption in the year 1989 represented by each building type. Again, offices and retail stores are the most important building types, accounting for over 45 percent of total electricity consumption. These building types are followed in importance by restaurants and groceries.

The comparison of values in Table 7–60 needs to be qualified. First, the forecast figures for both 1980 practice and estimated 1989 practice assume an all-electric building; consequently, fuel conversion efficiencies are not incorporated. In contrast, the average use figures for current practice buildings are for total energy and include fuel conversion efficiencies. Second, the sample size of energy consumption in new buildings is very small, except for offices and retail, and buildings were not selected to represent the region.

In comparing data for new commercial buildings, it is important to understand that there have been significant changes in this portion of the sector that make it difficult to model. Changes in energy-use patterns in areas such as Seattle that have recently experienced strong economic growth can greatly influence the total energy consumption of a building. In addition, increased use of computers, both desktop and central, have increased the total consumption and shifted a great deal of heating into a cooling requirement. Both of these trends, as well as other effects, have altered the way that the buildings behave, making it difficult to model from either a forecasting or engineering perspective.

Figure 7–18 compares predicted or modeled energy use with metered use for offices from several different data sets, including the Seattle Major Projects Evaluation and Energy Edge. With this small a sample, it is very difficult to predict the absolute usage of a small sample of buildings. Further work needs to be completed to refine both the models and our understanding of the factors that drive the buildings' energy use.

Table 7–60
Summary of Annual Energy Use for New Commercial Buildings Located in the Region
(All-Electric Buildings)

	1980 Practice from Forecast (kWh/sq. ft./yr.)	Sample of Current Practice (Approximately 1980 Construction) (Sample Size = N) (kWh/sq. ft./yr.)		Building Type's Percent of Total Electricity Consumption in 1989
		Oregon Survey	Commercial Audit Program	
Office	30	19 (N = 14)	21 (N = 159)	25%
Restaurant	28	—		4%
▪ Fast-Food	N/A		141 (N = 16)	
Retail	23	22 (N = 8)	20 (N = 135)	20%
Grocery	62	44 (N = 1)	70 (N = 46)	12%
Warehouse	17	18 (N = 1)	15 (N = 5)	5%
School	18	16 (N = 3)	12 (N = 2)	5%
College	20	22 (N = 1)	—	3%
Health	14	—	—	5%
Hotel/Motel	13	—	23 (N = 12)	4%
Miscellaneous	16	28 (N = 2)	—	17%
Total				100%

New Office Buildings Energy Use

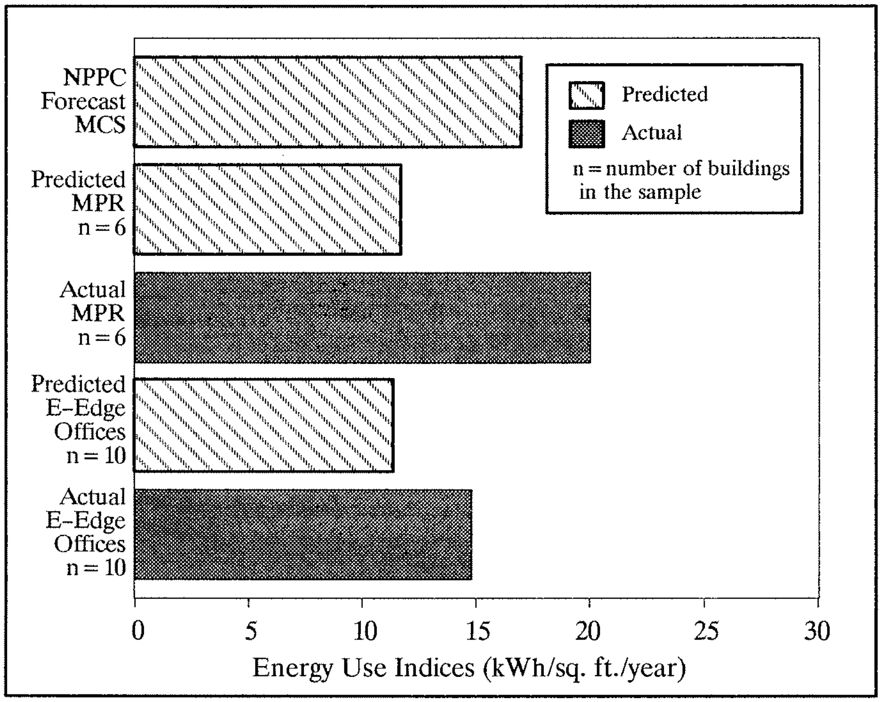


Figure 7–18
Preliminary Comparison of Energy Use Indices for New Office Buildings

Step 2. Evaluate the Efficiency Improvement Available in Existing and New Commercial Buildings

For both new and existing buildings, the estimates of cost–effective efficiency changes, and costs to achieve these changes are based primarily on work done for Bonneville by United Industries Corporation (UIC). This work develops base–case energy use, savings and costs from adding conservation measures for 10 prototype buildings. For existing commercial buildings, each prototype is modeled to reflect existing stock in 1979. To represent new commercial buildings, each prototype was modified to reflect how a new building of this prototype would have been built in 1980 as well as to 1989 current practice. The base–case use of each building prototype was calibrated to billing data available for that building type. For existing buildings these values came primarily from the Commercial Audit Program. For new buildings the consumption was calibrated most closely to the ELCAP data.

While the underlying analysis for the existing building sector continues to be the Commercial Building Prototype Review (1988), the new building sector analysis was completely revised based on the Analysis of Commercial Model Conservation Standards Study (November 1990). This new work contains significantly updated costs and energy savings estimates that were unavailable at the time that the draft plan was published. Therefore, all of the prototypical buildings in the new sector were completely revised. Because there was no similar new work for existing buildings, only the office and retail sectors were revised from previous analysis.

For both existing and new buildings, the UIC work estimated initial costs from a variety of sources including standard cost estimating tools, local distributor quotes and program data where available. Savings from installing conservation measures were estimated using an hourly simulation model. Because commercial conservation measures can have significant interaction with one another, it is generally necessary to use a fairly detailed model to determine the net savings from an individual measure. For example, making lighting more efficient can save electricity both from the lights and from the cooling load of the building. But if the building has a greater heating load than cooling load, then more heating will be required when the more efficient lights are installed. Because of these and other interactions, savings that are evaluated from installing one individual measure can be under– or overestimated compared to the savings that can be achieved when a package of conservation measures is installed.

To the extent possible, the savings estimates take into account the interaction of the package of measures installed in the building. The UIC work was used to determine the interaction terms for all of the prototypes except office and retail in existing buildings. Interaction terms for these two prototypes were taken from a study of lost-opportunity resources in renovations and remodels in the commercial sector. The primary reason for using the different set of interaction terms lies specifically in the large building prototypes in these sectors. The UIC work predicted interaction terms that appeared to be too large for these types of buildings and the renovation/remodel study was thought to provide a more realistic assessment of these terms.

For new buildings, interaction terms were modeled directly for both electric resistance and heat pump heating systems and weighted according to an estimate of the market share for each. In addition, since a large fraction of the building stock is heated with fossil fuels, the electric interaction becomes positive due to the lack of an electric space heating penalty. Again, these interaction terms were weighted according to estimated market shares with the resistance and heat pump heating systems.

Measures analyzed for all prototype buildings fall primarily into the following end uses: lighting, heating, ventilation and air conditioning, and domestic hot water. Where appropriate, the prototypes included an analysis of refrigeration conservation measures as well. Lighting measures include efficient lamps and ballasts, more efficient fixtures and advanced control systems. Heating, ventilating and cooling improvements included such measures as economizers to use outside air to cool, variable air volume controls and radiant heaters, where applicable. Building structure measures, such as roof and wall insulation, and more efficient windows also were modeled. Refrigeration improvements were taken from a study done for Bonneville by ADM Associates. Refrigeration savings applied only to grocery stores and restaurants.

As with any prototype work, some of the measures applied to the prototype building would not apply to a particular building, if an audit were done on it. Conversely, there may be measures that are not included in the prototype analysis that can be applied to the audited building. Essentially, the measures used in the prototype analysis are simply a proxy for the costs and savings that one could expect to achieve in the great variety of buildings the prototype represents. However, the actual measures that are installed to secure the savings may vary significantly from those in the prototype analysis.

Since the initial UIC work was completed in 1987, there have been a number of technological improvements that allow greater levels of efficiency to be achieved, particularly in the lighting sector. For new buildings, the new UIC work includes a comprehensive analysis of current technology. However, because of the limitations on the data available for existing buildings a detailed look at lighting was performed for the office and retail sectors only. Tables 7-61 through 7-70 list the individual measures for lighting, HVAC and domestic hot water for prototypes for new buildings. Tables 7-71 through 7-74 list the individual measures for office and retail prototype existing buildings.

For the new prototypes, the UIC work analyzed a package of measures that are included if the buildings were built to the Council's new model conservation standards code. The MCS code was based on ASHRAE standard 90.1-1989 and the lighting requirements of the Department of Energy's Standards for Non-Residential Buildings. These standards were both developed as national consensus standards and therefore do not necessarily include measures that would fall into the optimal order. Therefore, the requirements of the MCS were modeled as a package that was assumed to come in before any other measures.

Table 7-61
New Large Office

Prototype Summary		Block 1 Summary	
Location	Seattle	Cutoff (mills/kWh)	110
Floor Area	408,000	Cumulative Cost ($/sq. ft.)	$2.84
Regional Weighting	0.146	Cumulative Savings (kWh/sq. ft.)	5.94
Deflator (1989-January 1990)	1.000	Average Levelized Cost (mills/kWh)	40.1
Program Life	45	Average Cost ($/kW)	$4,186
Base Efficiency Light Operating Hours	4,250	**Block 2 Summary**	

Prototype Weightings						Block 2 Summary	
	Fuel Choice		Interactions			Cutoff (mills/kWh)	150
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net	Cumulative Cost ($/sq. ft.)	$2.84
						Cumulative Savings (kWh/sq. ft.)	5.94
Electric Resistance	70%	88%	-0.4	0.10	0.70	Average Levelized Cost (mills/kWh)	40.1
Electric Heat Pump	10%	13%	-0.2	0.20	1.00	Incremental Cost ($/sq. ft.)	$0.00
Gas	20%	—	0	0.10	1.10	Incremental Savings (kWh/sq. ft.)	0.00
Total	100%	100%			0.81	Incremental Cost ($/kW)	$0

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	22.5	2.2
All	1989 Base Case	—	—	—	—	—	—	—	—	—	19.3	1.7
All	MCS Package[c]	1.69	0.34	-0.003	30	20	0.40	1.69	0.40	19.9	17.6	1.3
LGT[d]	Occupancy Sensors	1.23	0.22	0.000	15	34	0.49	2.92	0.89	25.7	16.5	0.9
LGT[d]	E.L. Exit Signs[e]	0.13	0.07	-0.001	30	40	0.06	3.05	0.96	26.3	16.4	0.9
LGT[d]	Ambient/Task Lighting	1.45	0.33	0.012	30	45	0.78	4.49	1.73	32.4	15.1	0.4
ENV[f]	Very Low-E Windows	1.35	0.71	0.000	30	62	1.00	5.85	2.74	39.3	13.7	0.4
HVC[g]	Variable Speed Drive	0.09	0.05	0.000	15	94	0.10	5.94	2.84	40.1	13.6	0.4
LGT[d]	Daylight Dimming	0.13	0.28	0.000	15	382	0.61	6.07	3.45	47.7	13.5	0.4
HVC[g]	Evaporative Cooling	0.16	0.56	0.000	15	647	1.23	6.23	4.68	63.1	13.3	0.4

Table 7–61 (cont.)
New Large Office

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code*.

[d] LGT—Lighting.

[e] Electroluminescent Exit Signs.

[f] ENV—Envelope.

[g] HVC—Heating, Ventilating and Air-Conditioning.

Table 7–62
New Large Retail

Prototype Summary	
Location	Seattle
Floor Area	120,000
Regional Weighting	0.059
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	5,100

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$5.32
Cumulative Savings (kWh/sq. ft.)	5.72
Average Levelized Cost (mills/kWh)	78.2
Average Cost ($/kW)	$8,159

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$5.32
Cumulative Savings (kWh/sq. ft.)	5.72
Average Levelized Cost (mills/kWh)	78.2
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	20%	50%	0	0.03	1.03
Electric Heat Pump	20%	50%	0	0.03	1.03
Gas	60%	—	0	0.03	1.03
Total	100%	100%			1.03

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	20.0	2.5
All	1989 Base Case	—	—	—	—	—	—	—	—	—	19.1	2.5
All	MCS Package[c]	2.34	0.23	0.064	30	73	2.05	2.34	2.05	73.3	16.8	2.0
LGT[d]	E.L. Exit Signs[e]	0.09	0.04	-0.001	30	30	0.03	2.43	2.08	71.8	16.7	2.0
LGT[d]	T-8 w/Electronic Ballast	1.47	0.20	0.023	30	52	0.92	3.90	2.99	64.4	15.2	1.7
LGT[d]	Halogen IR Lamps	1.81	0.04	0.043	1	108	2.33	5.72	5.32	78.2	13.4	1.4
HVC[f]	Evaporative Cooling	0.18	0.69	0.000	15	703	1.52	5.90	6.85	97.5	13.2	1.4

Table 7-62 (cont.)
New Large Retail

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] LGT—Lighting.

[e] Electroluminescent Exit Signs.

[f] HVC—Heating, Ventilating and Air-Conditioning.

Table 7–63
New Small Office

Prototype Summary	
Location	Seattle
Floor Area	4,880
Regional Weighting	0.141
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	2,600

Block 1 Summary	
Cutoff (mills/kWh)	100
Cumulative Cost ($/sq. ft.)	$3.42
Cumulative Savings (kWh/sq. ft.)	6.79
Average Levelized Cost (mills/kWh)	42.2
Average Cost ($/kW)	$4,407

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$5.21
Cumulative Savings (kWh/sq. ft.)	7.88
Average Levelized Cost (mills/kWh)	55.5
Incremental Cost ($/sq. ft.)	$1.80
Incremental Savings (kWh/sq. ft.)	1.09
Incremental Cost ($/kW)	$14,449

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	20%	50%	–0.54	0.12	0.58
Electric Heat Pump	20%	50%	–0.19	0.12	0.93
Gas	60%	—	0.00	0.12	1.12
Total	100%	100%			0.97

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	20.9	2.2
All	1989 Base Case	—	—	—	—	—	—	—	—	—	19.4	1.8
All	MCS Package[c]	1.36	0.49	–0.003	30	38	0.61	1.36	0.61	38.0	18.1	1.4
HVC[d]	Heat Pump	2.28	0.13	0.000	10	15	0.40	3.64	1.01	23.3	15.9	1.4
LGT[e]	E.L. Exit Signs[f]	0.16	0.07	–0.001	30	30	0.06	3.80	1.07	23.6	15.7	1.3
LGT[e]	Ambient/Task Lighting	1.35	0.36	0.008	30	45	0.73	5.15	1.80	29.3	14.5	0.8
LGT[e]	Daylight Dimming Electronic Ballast	1.08	0.45	0.000	15	78	0.99	6.23	2.79	37.7	13.5	0.4
ENV[g]	R-19 Ceiling Insulation	0.08	0.06	0.000	30	82	0.08	6.31	2.88	38.3	13.5	0.4
ENV[g]	Add R-5 Wall Insulation	0.48	0.38	0.000	30	95	0.54	6.79	3.42	42.2	13.0	0.4

Table 7-63 (cont.)
New Small Office

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
ENV[g]	Window U=0.59	0.35	0.36	0.000	30	122	0.50	7.14	3.92	46.1	12.6	0.4
HVC[d]	Economizer	0.69	0.43	0.000	11	147	1.21	7.83	5.13	55.0	11.9	0.4
ENV[g]	R-19 to R-25 Ceiling	0.05	0.06	0.000	30	140	0.08	7.88	5.21	55.5	11.9	0.4
ENV[g]	Window U=0.52	0.52	0.74	0.000	30	171	1.05	8.40	6.26	62.6	11.4	0.4
ENV[g]	Window U=0.46	0.65	1.05	0.000	30	191	1.48	9.05	7.74	71.8	10.7	0.4
ENV[g]	R-25 to R-30 Ceiling	0.03	0.05	0.000	30	220	0.07	9.07	7.81	72.3	10.7	0.4
ENV[g]	R-30 to R-38 Ceiling	0.03	0.08	0.000	30	295	0.11	9.11	7.92	73.0	10.7	0.4

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] HVC—Heating, Ventilating and Air-Conditioning.

[e] LGT—Lighting.

[f] Electroluminescent Exit Signs.

[g] ENV—Envelope.

Table 7–64
New Small Retail

Prototype Summary	
Location	Seattle
Floor Area	13,124
Regional Weighting	0.089
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	4,000

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$2.52
Cumulative Savings (kWh/sq. ft.)	4.59
Average Levelized Cost (mills/kWh)	46.2
Average Cost ($/kW)	$4,819

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$2.52
Cumulative Savings (kWh/sq. ft.)	4.59
Average Levelized Cost (mills/kWh)	46.2
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	20%	50%	–0.28	0.08	0.80
Electric Heat Pump	20%	50%	–0.14	0.08	0.94
Gas	60%	—	0	0.08	1.08
Total	100%	100%			1.00

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	15.6	2.1
All	1989 Base Case	—	—	—	—	—	—	—	—	—	13.9	2.1
All	MCS Package[c]	0.61	0.29	–0.106	30	-337	-2.47	0.61	0.00	0.0	13.3	2.0
LGT[d]	Daylight Dimming	0.78	0.07	0.000	15	16	0.15	1.40	0.15	9.0	12.6	1.8
LGT[d]	E.L. Exit Signs[e]	0.08	0.03	–0.001	30	31	0.03	1.47	0.18	10.1	12.6	1.8
LGT[d]	Halogen IR Lamps	0.90	0.01	0.009	1	48	0.51	2.38	0.69	24.3	11.8	1.6
LGT[d]	T-8 w/Electronic Ballast	1.88	0.43	0.034	30	67	1.51	4.26	2.20	43.4	10.1	1.1
HVC[f]	Heat Pump	0.33	0.10	0.000	10	82	0.32	4.59	2.52	46.2	9.7	1.1

Table 7–64 (cont.)
New Small Retail

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code*.

[d] LGT—Lighting.

[e] Electroluminescent Exit Signs.

[f] HVC—Heating, Ventilating and Air-Conditioning.

Table 7–65
New Warehouse

Prototype Summary	
Location	Seattle
Floor Area	18,025
Regional Weighting	0.047
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	3,120

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$0.94
Cumulative Savings (kWh/sq. ft.)	2.86
Average Levelized Cost (mills/kWh)	27.7
Average Cost ($/kW)	$2,894

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$1.07
Cumulative Savings (kWh/sq. ft.)	2.93
Average Levelized Cost (mills/kWh)	30.6
Incremental Cost ($/sq. ft.)	$0.13
Incremental Savings (kWh/sq. ft.)	0.08
Incremental Cost ($/kW)	$14,507

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	40%	80%	–0.1	0.10	1.00
Electric Heat Pump	10%	20%	–0.1	0.10	1.00
Gas	50%	—	0	0.10	1.10
Total	100%	100%			1.05

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	9.9	1.0
All	1989 Base Case	—	—	—	—	—	—	—	—	—	8.2	1.0
All	MCS Package[c]	0.97	0.11	–0.017	30	–26	–0.30	0.97	0.00	0.0	7.3	0.6
LGT[d]	Occupancy Sensors	0.57	0.04	0.000	10	19	0.13	1.54	0.13	7.1	6.7	0.4
HVC[e]	Heat Pump	0.44	0.03	0.000	10	20	0.10	1.98	0.23	9.9	6.3	0.4
LGT[d]	E.L. Exit Signs[f]	0.09	0.04	–0.001	30	29	0.03	2.07	0.26	10.7	6.2	0.4
LGT[d]	Ambient/Task Lighting	0.18	0.07	–0.000	30	43	0.09	2.25	0.36	13.3	6.0	0.3
LGT[d]	Daylight Dimming	0.11	0.05	0.000	15	86	0.12	2.36	0.47	16.8	5.9	0.3
ENV[g]	Add R-5 Wall Insulation	0.32	0.23	0.000	30	85	0.32	2.68	0.79	24.8	5.5	0.3
ENV[g]	R-19 Roof Insulation	0.14	0.11	0.000	30	92	0.15	2.82	0.94	28.1	5.2	0.2

Table 7–65 (cont.)
New Warehouse

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
ENV[g]	R-19 to R-25 Roof Insulation	0.08	0.09	0.000	30	139	0.13	2.90	1.07	31.0	5.1	0.2

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] LGT—Lighting.

[e] HVC—Heating, Ventilating and Air-Conditioning.

[f] Electroluminescent Exit Signs.

[g] ENV—Envelope.

Table 7–66
New School

Prototype Summary	
Location	Seattle
Floor Area	67,784
Regional Weighting	0.063
Deflator (1989–January 1990)	1..000
Program Life	45
Base Efficiency Light Operating Hours	2,534

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$1.35
Cumulative Savings (kWh/sq. ft.)	2.14
Average Levelized Cost (mills/kWh)	52.8
Average Cost ($/kW)	$5,511

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	25%	50%	–0.68	0.00	0.32
Electric Heat Pump	25%	50%	–0.34	0.00	0.39
Gas	50%	—	0	0.00	1.00
Total	100%	100%			0.68

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$1.54
Cumulative Savings (kWh/sq. ft.)	2.26
Average Levelized Cost (mills/kWh)	57.3
Incremental Cost ($/sq. ft.)	$0.20
Incremental Savings (kWh/sq. ft.)	0.12
Incremental Cost ($/kW)	$14,309

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	12.0	1.3
All	1989 Base Case	—	—	—	—	—	—	—	—	—	17.2	1.8
All	MCS Package[c]	0.65	0.15	0.008	30	56	0.43	0.65	0.00	0.0	16.6	1.5
LGT[d]	E.L. Exit Signs[e]	0.14	0.07	–0.002	30	35	0.06	0.79	0.06	6.1	16.5	1.5
ENV[f]	R-25 Roof Insulation	0.19	0.10	0.000	30	67	0.15	0.97	0.20	17.6	16.3	1.5
ENV[f]	Very Low-E Windows	0.22	0.13	0.000	30	72	0.19	1.19	0.39	27.6	16.1	1.5
ENV[f]	R-19 Wall Insulation	0.37	0.25	0.000	30	79	0.35	1.56	0.74	39.8	15.7	1.5
ENV[f]	R-19 + R-5 Wall Insulation	0.28	0.20	0.000	30	84	0.28	1.84	1.02	46.5	15.4	1.5
HVC[g]	Variable Speed Drive on Pumps and Fans	0.18	0.09	0.000	15	92	0.20	2.03	1.22	50.7	15.2	1.5

Table 7–66 (cont.)
New School

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
ENV[f]	R-25 to R-30 Roof	0.11	0.09	0.000	30	92	0.12	2.14	1.35	52.8	15.1	1.5
ENV[f]	R-30 to R-38 Roof	0.12	0.14	0.000	30	137	0.20	2.26	1.54	57.3	15.0	1.5

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] LGT—Lighting.

[e] Electroluminescent Exit Signs.

[f] ENV—Envelope.

[g] HVC—Heating, Ventilating and Air-Conditioning.

Table 7–67
New Grocery

Prototype Summary		**Block 1 Summary**	
Location	Seattle	Cutoff (mills/kWh)	110
Floor Area	26,052	Cumulative Cost ($/sq. ft.)	$3.81
Regional Weighting	0.037	Cumulative Savings (kWh/sq. ft.)	15.86
Deflator (1989–January 1990)	1.000	Average Levelized Cost (mills/kWh)	20.2
Program Life	45	Average Cost ($/kW)	$2,104
Base Efficiency Light Operating Hours	7,150	**Block 2 Summary**	

Prototype Weightings							
	Fuel Choice		Interactions			Cutoff (mills/kWh)	150
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net	Cumulative Cost ($/sq. ft.)	$4.52
						Cumulative Savings (kWh/sq. ft.)	16.31
Electric Resistance	30%	75%	-0.22	0.08	0.86	Average Levelized Cost (mills/kWh)	23.3
Electric Heat Pump	10%	25%	-0.11	0.08	0.97	Incremental Cost ($/sq. ft.)	$0.71
Gas	60%	—	0	0.08	1.08	Incremental Savings (kWh/sq. ft.)	0.44
Total	100%	100%			1.00	Incremental Cost ($/kW)	$14,121

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	63.6	2.2
All	1989 Base Case	—	—	—	—	—	—	—	—	—	68.1	1.8
All	MCS Package[c]	0.00	0.00	0.000	30	0	0.00	0.00	0.00	0.0	69.2	1.8
REF[d]	Floating Head Press	2.85	-0.26	0.000	10	-24	-0.80	2.85	-0.80	-23.7	66.3	1.8
REF[d]	Anti–Sweat Timer	4.40	0.08	0.000	10	5	0.26	7.25	-0.55	-6.3	61.9	1.8
REF[d]	Hot Gas Defrost	2.41	0.06	0.000	10	6	0.19	9.66	-0.36	-3.2	59.5	1.8
LGT[e]	E.L. Exit Signs[f]	0.09	0.04	-0.001	30	28	0.03	9.75	-0.33	-2.9	59.4	1.8
REF[d]	Efficient Evaporating Fans	1.94	0.23	0.000	10	31	0.71	11.69	0.38	2.7	57.5	1.8
REF[d]	Mechanical Subcooling	0.69	0.10	0.000	10	39	0.32	12.37	0.70	4.8	56.8	1.8

Table 7-67 (cont.)
New Grocery

End Use	Description	Measure: Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Building: Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
REF[d]	Refrigerated Case Covers	1.47	0.24	0.000	11	40	0.69	13.84	1.39	8.5	55.4	1.8
LGT[e]	T-8 w/Electronic Ballast	2.02	0.54	0.061	30	100	2.42	15.86	3.81	20.2	53.5	1.5
LGT[e]	Halogen IR Lamps	0.44	0.01	0.019	1	135	0.71	16.31	4.52	23.3	53.0	1.5
REF[d]	Liquid Pressure Amplifier	0.61	0.95	0.000	10	402	2.94	16.92	7.46	37.0	52.4	1.5

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] REF—Refrigerated Case Covers.

[e] LGT—Lighting.

[f] Electroluminescent Exit Signs.

Table 7-68
New Fast Food

Prototype Summary	
Location	Seattle
Floor Area	2,624
Regional Weighting	0.033
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	6,237

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$2.95
Cumulative Savings (kWh/sq. ft.)	10.94
Average Levelized Cost (mills/kWh)	22.6
Average Cost ($/kW)	$2,358

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$2.95
Cumulative Savings (kWh/sq. ft.)	10.94
Average Levelized Cost (mills/kWh)	22.6
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	20%	50%	–0.59	0.02	0.43
Electric Heat Pump	20%	50%	–0.21	0.02	0.81
Gas	60%	—	0	0.02	1.02
Total	100%	100%			0.86

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	65.2	2.7
All	1989 Base Case	—	—	—	—	—	—	—	—	—	67.3	1.9
All	MCS Package[c]	3.25	1.17	–0.037	30	16	0.64	3.25	0.00	0.0	64.1	1.4
HVC[d]	Heat Pump	6.05	0.33	0.000	10	14	1.03	9.30	1.03	9.3	58.0	1.4
LGT[e]	E.L. Exit Signs[f]	0.18	0.08	–0.002	30	31	0.07	9.48	1.10	9.7	57.9	1.4
LGT[e]	T-8 w/Electronic Ballast	1.46	0.39	0.036	15	106	1.85	10.94	2.95	22.6	56.6	1.1

Table 7-68 (cont.)
New Fast Food

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code*.

[d] HVC—Heating, Ventilating and Air-Conditioning.

[e] LGT—Lighting.

[f] Electroluminescent Exit Signs.

Table 7–69
New Hospital

Prototype Summary	
Location	Seattle
Floor Area	272,000
Regional Weighting	0.061
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	4,505

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$2.24
Cumulative Savings (kWh/sq. ft.)	2.96
Average Levelized Cost (mills/kWh)	63.7
Average Cost ($/kW)	$6,649

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$2.24
Cumulative Savings (kWh/sq. ft.)	2.96
Average Levelized Cost (mills/kWh)	63.7
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	40%	100%	–0.8	0.20	0.40
Electric Heat Pump	0%	0%	–0.4	0.20	0.80
Gas	60%	—	0	0.20	1.20
Total	100%	100%			0.88

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	60.2	2.0
All	1989 Base Case	—	—	—	—	—	—	—	—	—	43.0	1.9
All	MCS Package[c]	0.66	0.18	0.014	30	80	0.63	0.66	0.63	80.3	42.3	1.5
LGT[d]	E.L. Exit Signs[e]	0.15	0.07	–0.002	30	33	0.06	0.80	0.68	71.4	42.2	1.4
LGT[d]	Ambient/Task Lighting	0.29	0.05	0.001	15	39	0.13	1.09	0.82	62.8	42.1	1.4
ENV[f]	R-19 + R-5 Wall Insulation	0.29	0.10	0.000	30	40	0.14	1.38	0.96	58.1	41.8	1.4
ENV[f]	Very Low-E Windows	0.62	0.21	0.000	30	40	0.30	2.00	1.25	52.6	41.2	1.4
LGT[d]	Halogen IR Lamps	0.12	0.00	0.000	1	52	0.08	2.13	1.33	52.6	41.1	1.3
LGT[d]	Daylight Dimming	0.20	0.08	–0.000	15	67	0.16	2.32	1.49	53.8	41.1	1.3

Table 7–69 (cont.)
New Hospital

End Use	Description	Measure: Net Savings (kWh/sq. ft.)	Measure: Capital Cost ($/sq. ft.)	Measure: Annual O&M ($/sq. ft.)	Measure: Measure Life (yr.)	Measure: Levelized Cost (m/kWh)	Measure: Cost PV ($/sq. ft.)	Building: Cumulative Savings (kWh/sq. ft.)	Building: Cumulative PV ($/sq. ft.)	Building: Cumulative Cost (m/kWh)	Building: Total EUI[a] (kWh/sq. ft.)	Building: Efficient LPD[b] (w/sq. ft.)
LGT[d]	T-8 w/Electronic Ballast	0.63	0.20	0.018	30	100	0.76	2.96	2.24	63.7	40.8	1.1
LGT[d]	Occupancy Sensors	0.18	0.11	0.000	10	164	0.34	3.13	2.59	69.4	40.7	1.1

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] LGT—Lighting.

[e] Electroluminescent Exit Signs.

[f] ENV—Envelope.

Table 7–70
New Hotel

Prototype Summary	
Location	Seattle
Floor Area	277,200
Regional Weighting	0.037
Deflator (1989–January 1990)	1.000
Program Life	45
Base Efficiency Light Operating Hours	3,021

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$0.67
Cumulative Savings (kWh/sq. ft.)	5.09
Average Levelized Cost (mills/kWh)	11.1
Average Cost ($/kW)	$1,156

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$0.67
Cumulative Savings (kWh/sq. ft.)	5.09
Average Levelized Cost (mills/kWh)	11.1
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	25%	50%	–.04	0.10	0.70
Electric Heat Pump	25%	50%	–.02	0.10	0.90
Gas	50%	—	0	0.10	1.10
Total	100%	100%			0.95

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1980 Base	—	—	—	—	—	—	—	—	—	22.8	1.7
All	1989 Base Case	—	—	—	—	—	—	—	—	—	20.4	1.9
All	MCS Package[c]	3.02	0.11	–0.006	30	–1	–0.02	3.02	–0.02	–0.6	17.4	1.0
LGT[d]	Compact Fluorescents	1.02	0.06	–0.012	11	–12	–0.14	4.04	–0.16	–3.4	16.5	0.7
ENV[e]	R-11 Wall Insulation	0.21	0.04	0.000	30	23	0.06	4.26	–0.10	–2.0	16.3	0.7
HVC[f]	Variable Speed Drive on Pumps and Fans	0.16	0.03	0.000	15	30	0.06	4.41	–0.05	–0.9	16.2	0.7
LGT[d]	E.L. Exit Signs[g]	0.16	0.07	–0.000	30	47	0.09	4.58	0.04	0.8	16.0	0.6
ENV[e]	Very Low-E Windows	0.52	0.32	0.000	18	102	0.63	5.09	0.67	11.1	15.5	0.6

Table 7–70 (cont.)
New Hotel

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] MCS (model conservation standards) Package represents the Council's recommended code published in the *1990 Northwest Energy Code.*

[d] LGT—Lighting.

[e] ENV—Envelope.

[f] HVC—Heating, Ventilating and Air-Conditioning.

[g] Electroluminescent Exit Signs.

Table 7–71
Existing Large Office

Prototype Summary	
Location	Seattle
Floor Area	408,000
Regional Weighting	0.146
Deflator (1989–January 1990)	1.393
Program Life	30
Base Efficiency Light Operating Hours	4,250

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$9.40
Cumulative Savings (kWh/sq. ft.)	15.54
Average Levelized Cost (mills/kWh)	54.5
Average Cost ($/kW)	$5,297

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$9.40
Cumulative Savings (kWh/sq. ft.)	15.54
Average Levelized Cost (mills/kWh)	54.5
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	$0

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	40%	80%	-0.4	0.20	0.80
Electric Heat Pump	10%	20%	-0.2	0.20	1.00
Gas	50%	—	0	0.20	1.20
Total	100%	100%			1.02

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1979 Stock	—	—	—	—	—	—	—	—	—	30.8	2.4
LGT[c]	100-watt Incandescent to 34-watt	0.57	0.21	-0.022	30	-46	-0.29	0.57	-0.29	-46.0	30.3	2.3
HVC[d]	Temperature Reset, Multizone	1.36	0.02	0.000	11	3	0.04	1.93	-0.25	-11.6	28.9	2.3
HVC[d]	R-6 Roof Insulation	0.21	0.03	0.000	30	15	0.04	2.15	-0.21	-9.0	28.7	2.3
LGT[c]	T-8 w/Magnetic Ballast	4.46	1.40	0.000	30	35	1.76	6.60	1.54	21.0	25.1	1.2
LGT[c]	T-8 w/Electronic Ballast	0.84	0.30	0.000	15	65	0.60	7.44	2.15	26.0	24.4	1.0
LGT[c]	Daylight Photocell Dimming	0.36	0.15	0.000	15	74	0.30	7.80	2.44	28.2	24.1	0.9
HVC[d]	Variable Air Volume	7.74	2.60	0.000	11	81	6.95	15.55	9.40	54.5	16.3	0.9

Table 7-71 (cont.)
Existing Large Office

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] LGT—Lighting.

[d] HVC—Heating, Ventilating and Air-Conditioning.

Table 7–72
Existing Large Retail

Prototype Summary	
Location	Seattle
Floor Area	120,000
Regional Weighting	0.059
Deflator (1989–January 1990)	1.3934
Program Life	30
Base Efficiency Light Operating Hours	5,100

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$5.52
Cumulative Savings (kWh/sq. ft.)	11.29
Average Levelized Cost (mills/kWh)	44.1
Average Cost ($/kW)	$4,284

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$5.52
Cumulative Savings (kWh/sq. ft.)	11.29
Average Levelized Cost (mills/kWh)	44.1
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	40%	80%	–0.09	0.16	1.07
Electric Heat Pump	10%	20%	–0.06	0.16	1.10
Gas	50%	—	0	0.16	1.16
Total	100%	100%			1.12

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1979 Stock	—	—	—	—	—	—	—	—	—	22.2	2.7
LGT[c]	Efficient Incandescent	1.93	0.29	–0.013	15	13	0.27	1.93	0.27	12.7	20.3	2.4
HVC[d]	Reduce Minimum Output Air	1.12	0.07	0.000	9	18	0.23	3.06	0.50	14.8	19.2	2.4
ENV[e]	Roof Insulation	1.75	0.31	0.000	30	20	0.39	4.81	0.89	16.6	17.5	2.4
DHW[f]	Tank Insulation	0.01	0.00	0.000	10	39	0.01	4.82	0.89	16.7	17.5	2.4
LGT[c]	T-8 w/Electronic Ballast—Sales	6.05	2.08	0.002	15	64	4.32	10.87	5.21	43.2	11.6	1.3
LGT[c]	T-8 w/Electronic Ballast—Storage	0.41	0.13	0.002	15	66	0.30	11.29	5.51	44.0	11.2	1.2
ENV[e]	Caulking and Weatherstripping	0.01	0.00	0.000	10	99	0.01	11.29	5.52	44.1	11.2	1.2

Table 7–72 (cont.)
Existing Large Retail

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
ENV[e]	Wall Insulation	1.06	1.58	0.000	30	168	1.97	12.35	7.49	54.6	10.2	1.2
HVC[d]	Radiant Heaters	0.03	0.04	0.000	10	398	0.11	12.38	7.60	55.3	10.1	1.2

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] LGT—Lighting.

[d] HVC—Heating, Ventilating and Air-Conditioning.

[e] ENV—Envelope.

[f] DHW—Domestic Hot Water.

Table 7–73
Existing Small Office

Prototype Summary	
Location	Seattle
Floor Area	4,880
Regional Weighting	0.141
Deflator (1989–January 1990)	1.3934
Program Life	30
Base Efficiency Light Operating Hours	2,600

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$3.37
Cumulative Savings (kWh/sq. ft.)	6.40
Average Levelized Cost (mills/kWh)	47.4
Average Cost ($/kW)	$4,610

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$9.62
Cumulative Savings (kWh/sq. ft.)	11.12
Average Levelized Cost (mills/kWh)	77.9
Incremental Cost ($/sq. ft.)	$6.25
Incremental Savings (kWh/sq. ft.)	4.72
Incremental Cost ($/kW)	$11,603

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	40%	80%	–0.54	0.12	0.58
Electric Heat Pump	10%	20%	–0.19	0.12	0.93
Gas	50%	—	0.00	0.12	1.12
Total	100%	100%			0.88

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1979 Stock	—	—	—	—	—	—	—	—	—	22.7	2.2
LGT[c]	Incandescent to 34–watt Fluorescent	0.49	0.30	–0.032	15	–33	–0.18	0.49	–0.18	–33.0	22.3	2.0
HVC[d]	Reduce Outside Air	1.42	0.02	0.000	15	3	0.04	1.91	–0.14	–6.6	20.9	2.0
ENV[e]	Roof Insulation	1.05	0.34	0.000	30	36	0.42	2.96	0.28	8.6	19.8	2.0
DHW[f]	Tank Insulation	0.08	0.01	0.000	10	41	0.04	3.05	0.32	9.5	19.7	2.0
LGT[c]	T–8 w/Electronic Ballast	1.62	0.76	0.010	30	66	1.19	4.67	1.52	29.2	18.6	1.3
ENV[e]	Low–E Glass	1.74	1.49	0.000	30	96	1.86	6.40	3.37	47.4	16.8	1.3
HVC[d]	Optimum Start Timer	0.70	0.43	0.000	15	113	0.88	7.10	4.25	53.9	16.1	1.3
LGT[c]	Daylight Dimming	0.33	0.21	0.000	15	117	0.42	7.43	4.67	56.7	15.9	1.2

Table 7-73 (cont.)
Existing Small Office

End Use	Description	Measure: Net Savings (kWh/sq. ft.)	Measure: Capital Cost ($/sq. ft.)	Measure: Annual O&M ($/sq. ft.)	Measure: Measure Life (yr.)	Measure: Levelized Cost (m/kWh)	Measure: Cost PV ($/sq. ft.)	Building: Cumulative Savings (kWh/sq. ft.)	Building: Cumulative PV ($/sq. ft.)	Building: Cumulative Cost (m/kWh)	Building: Total EUI[a] (kWh/sq. ft.)	Building: Efficient LPD[b] (w/sq. ft.)
HVC[d]	Heat Pump Air Conditioner Compressor Replacement	2.81	1.78	0.000	15	117	3.65	10.24	8.32	73.2	13.1	1.2
HVC[d]	Economizer	0.88	0.63	0.000	15	133	1.30	11.12	9.62	77.9	12.2	1.2
DHW[f]	Cock Timer	0.01	0.01	0.000	15	202	0.03	11.14	9.65	78.1	12.2	1.2
LGT[c]	3 Tube Parabolic Fix	0.51	1.04	-0.006	30	204	1.15	11.64	10.80	83.5	11.7	1.0

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] LGT—Lighting.

[d] HVC—Heating, Ventilating and Air-Conditioning.

[e] ENV—Envelope.

[f] DHW—Domestic Hot Water.

Table 7–74
Existing Small Retail

Prototype Summary	
Location	Seattle
Floor Area	13,124
Regional Weighting	0.089
Deflator (1989–January 1990)	1.3934
Program Life	30
Base Efficiency Light Operating Hours	4,000

Block 1 Summary	
Cutoff (mills/kWh)	110
Cumulative Cost ($/sq. ft.)	$3.42
Cumulative Savings (kWh/sq. ft.)	6.81
Average Levelized Cost (mills/kWh)	45.3
Average Cost ($/kW)	$4,404

Block 2 Summary	
Cutoff (mills/kWh)	150
Cumulative Cost ($/sq. ft.)	$3.42
Cumulative Savings (kWh/sq. ft.)	6.81
Average Levelized Cost (mills/kWh)	45.3
Incremental Cost ($/sq. ft.)	$0.00
Incremental Savings (kWh/sq. ft.)	0.00
Incremental Cost ($/kW)	N/A

Prototype Weightings

	Fuel Choice		Interactions		
Base Year HVAC Interactions	% All	% Electric	Heat	Cool	Net
Electric Resistance	40%	80%	–0.31	0.11	0.80
Electric Heat Pump	10%	20%	–0.21	0.11	0.94
Gas	50%	—	0	0.11	1.11
Total	100%	100%			0.97

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
All	1979 Stock	—	—	—	—	—	—	—	—	—	16.5	1.9
ENV[c]	Roof Insulation—Sales	2.37	0.58	0.000	30	27	0.72	2.37	0.72	27.4	14.1	1.9
LGT[d]	Efficient Incandescent	0.89	0.23	–0.004	15	36	0.36	3.26	1.08	29.8	13.4	1.7
DHW[e]	Tank Insulation	0.03	0.01	0.000	10	40	0.01	3.29	1.09	29.9	13.3	1.7
LGT[d]	T-8 w/Electronic Ballast—Sales	2.12	0.59	0.001	15	53	1.24	5.41	2.33	38.8	11.5	1.2
HVC[f]	Heat Pump Air Conditioner Compressor Replacement	1.13	0.41	0.000	15	68	0.85	6.54	3.18	43.8	10.4	1.2
LGT[d]	T-8 w/Electronic Ballast—Storage Dreg	0.15	0.03	0.002	15	69	0.12	6.69	3.29	44.4	10.3	1.1
ENV[c]	Roof Insulation—Storage	0.11	0.10	0.000	30	100	0.13	6.81	3.42	45.3	10.2	1.1

Table 7–74 (cont.)
Existing Small Retail

		Measure						Building				
End Use	Description	Net Savings (kWh/sq. ft.)	Capital Cost ($/sq. ft.)	Annual O&M ($/sq. ft.)	Measure Life (yr.)	Levelized Cost (m/kWh)	Cost PV ($/sq. ft.)	Cumulative Savings (kWh/sq. ft.)	Cumulative PV ($/sq. ft.)	Cumulative Cost (m/kWh)	Total EUI[a] (kWh/sq. ft.)	Efficient LPD[b] (w/sq. ft.)
ENV[c]	Low-E Windows—Sales	0.35	0.59	0.000	30	188	0.73	7.16	4.16	52.3	9.8	1.1
HVC[f]	Heat Recovery Exhaust	0.35	0.66	0.000	14	369	1.44	7.51	5.60	67.1	9.5	1.1

[a] EUI—Energy Use Index

[b] LPD—Lighting Power Density

[c] ENV—Envelope.

[d] LGT—Lighting.

[e] DHW—Domestic Hot Water.

[f] HVC—Heating, Ventilating and Air-Conditioning.

Table 7-75 shows the savings percentages, if all measures costing less than 11 cents per kilowatt-hour are added to the prototypes that represent existing buildings. The table also shows the pre-conservation consumption estimate for each prototype building, which reflects the 1979 stock. These savings can be compared to savings estimates from Puget Power's retrofit program collected for the 1986 Power Plan. Puget's information is shown in Table 7-76. Some of the prototype buildings in Table 7-75 result in estimates of savings and use close to those reported by Puget Power, while others are quite different. Some of the differences may stem from the representativeness of the prototypes. For example, the hospital prototype does not encompass general health care buildings, such as doctors' offices and laboratories, while Puget Power's audit program may have included these. The vintage of the buildings in Puget Power's program also is unknown compared to this analysis. Finally, it is not clear how the cost of measures recommended in Puget Power's program compares with the 11 cents per kilowatt-hour levelized cost used to cut off the conservation measures in the prototype analysis. It appears that significant savings can be achieved by retrofitting existing buildings, from 12 percent to more than 40 percent of the energy used.

Table 7-77 shows cost and savings information similar to Table 7-75 for new buildings.

A significant problem that surfaces from the prototype analysis is that, in some cases, the prototypes used for the conservation analysis poorly represent the building categories used in the load forecast. For example, a fast food restaurant was modeled as the restaurant prototype, but the restaurant category in the forecast includes fast food restaurants, cafeterias and leisure dining. Extra care was taken to make the prototypes for offices and retail stores consistent with the categories used in the load forecast, because these are the most important building types. However, limited information prevented this kind of extensive modeling on some of the other building types. In particular, there was no prototype modeled for the college sector or the miscellaneous category in the UIC work. For this reason, the costs and savings for these two buildings must be estimated using simplified techniques.

The college building category was represented as a mix of the other building prototypes. The college sector was a weighted mix of prototypes that including: 40 percent school, 30 percent office, 10 percent restaurant, 20 percent hotel. The miscellaneous building category was estimated by weighting all of the other building prototypes.

Another problem that is created by the prototype analysis stems from the year used as the base case. Table 7-77 indicates the cost-effective savings available from existing buildings in 1979 and new buildings built in 1989. However, between 1979 and 1989, some retrofit activity has diminished the conservation resource in existing buildings, and new buildings built after 1980 already will be complying with new energy codes that were adopted after 1980. For existing commercial buildings, the savings that already have occurred through retrofitting are estimated using the forecasting model. The forecast estimates that an average 25 percent or 270 average megawatts of the cost-effective savings available in Table 7-77 already have occurred by 1989 for the existing stock. Since this estimate is derived using the forecasting model, it is consistent with the forecast's estimates of fuel saturations. The fact that 25 percent of the savings already is achieved also means that some of the costs also have been incurred. The simplifying assumption made in this analysis is that the very cheapest measures were used to achieve the 25 percent savings that occurred between 1979 and 1989. The average savings summarized in this chapter incorporate the reduction in savings and increase in cost from retrofit activity that has occurred since 1979.

For new commercial buildings, the prototype analysis included modeling of both 1980 and 1989 new building construction practice and therefore allowed direct calculation of the savings and costs after improvements from 1980 to 1989. While these improvements are not reported as part of the resource, they represent over 550 average megawatts already captured if uniformly implemented. Since these codes (but only with partial compliance) are represented in the load forecasts as reduced load, they are not reported as a potential resource to be compared in the portfolio. It is important to note that this estimate of savings from existing codes assumes that the energy related portions of those codes, such as lighting budgets and insulation, are being enforced. If these codes currently are not enforced, much of the conservation that is already counted as secured will be lost.

Table 7-75
Costs and Percent Savings for Conservation in Existing Commercial Buildings—Prototype Analysis[a]

	Percent Savings	Average Levelized Cost of Measures (mills/kWh)	Base-Case Use (kWh/sq. ft./yr.)
Office	37%	51	27
Retail	35%	45	19
Fast Food	29%	61	123
Warehouse	42%	30	12
Hospital	12%	18	64
Schools	41%	39	21
Grocery	25%	33	58
Hotel	23%	37	28

[a] These values are for an all-electric building.

Table 7-76
Retrofit Savings from Existing Commercial Buildings: Puget Power's Program[a]

Building Type (Sample Size = N)	Percent Savings from Average Use	Average Use of Program Buildings (Pre-retrofit) (kWh/sq. ft./yr.)
Office (N=62)	30%	26
Retail (N=11)	16%	25
Grocery (N=36)	23%	62
Restaurant (N=10)	22%	89
Hotel (N=2)	16%	24
Hospital (N=30)	28%	29
School (N=28)	17%	24
Warehouse (N=4)	26%	16
Other (N=8)	21%	22
Average savings = 22 percent		
Average savings weighted by building type = 22 percent		

[a] Program offers measures, such as heating, ventilating and air-conditioning modifications, glazing and insulation, lighting measures and some process modifications.

Table 7-77
Costs and Percent Savings for Conservation in New (1989) Commercial Buildings Prototype Analysis[a]

	Percent Savings	Average Levelized Cost of Measures (mills/kWh)	Base Case Use (kWh/sq. ft.)
Office	33%	41	19
Retail	32%	59	16
Fast Food	16%	23	67
Warehouse	34%	28	8
Hospital	7%	64	43
Schools	12%	53	17
Grocery	23%	20	68
Hotel	25%	11	20

[a] These values are based on an all-electric building.

Step 3. Develop Estimates of Technical Realizable Potential for Conservation in New and Existing Commercial Buildings, Consistent with the Load Forecast

The total regional savings available from conservation potential in new and existing buildings was estimated using the Council's commercial sector forecasting models, as described below.

First, this sector's demand was forecast assuming efficiency improvements were made to existing buildings through 1989 and new buildings are built to existing state building codes. Then the percent improvement represented by the 11 cents per kilowatt-hour conservation cutoff was imposed on each building type, and the demand for electricity was re-estimated. The difference between projected demand at current 1989 efficiencies and demand with the technical conservation improvements represented the total technical conservation.

In the Council's high forecast, approximately 800 average megawatts are achievable in existing buildings and 710 average megawatts in new commercial buildings. As mentioned above, the Council is committed to further reviewing measures that can be applied to these prototype buildings, which is likely to increase savings. Tables 7-78 and 7-79 show the total technical conservation that is available at a given cost in the high and medium demand forecasts. While the total amount of savings at 11 cents per kilowatt-hour is taken directly from the forecast, the shape of the curve is taken from an aggregation of the prototypes. Consequently, it should be viewed as an approximation only.

In addition to the 800 average megawatts of technical potential in existing buildings there is another 350 average megawatts of potential if every building was brought to all cost-effective measures during a major renovation or remodel between 1992 and 2010. This assumes that because of the drastic changes to the building, it will be possible to bring the building up to the same levels of efficiency as new buildings for the same cost.

Tables 7-78 and 7-79 indicate that there is approximately another 250 average megawatts of savings between 11 cents per kilowatt-hour and 15 cents per kilowatt hour for existing, new and renovated/remodeled buildings. While the curve is definitely flattened out at this point, it is not clear whether this is a real effect or more a function of the limitations of the UIC work. As mentioned earlier, technology changes, particularly in lighting, may provide additional savings in this higher cost block. The Council is committed to pursuing this issue in more detail, as more information on the newer technologies becomes available.

Table 7–78
Technical Conservation from Existing Commercial Buildings

Levelized Cost		Total Cumulative Megawatts	
Nominal	Real	High	Medium
1	0.5	83	65
2	1.0	142	112
3	1.5	142	112
4	2.0	308	242
5	2.5	311	244
6	3.0	311	244
7	3.5	503	394
8	4.0	514	403
9	4.5	748	587
10	5.0	799	627
11	5.5	799	627
12	6.0	911	714
13	6.5	911	714
14	7.0	936	735
15	7.5	936	735
16	8.0	936	735
17	8.5	956	750
18	9.0	956	750
19	9.0	956	750
20	9.0	956	750

Step 4. Estimate the Amount of Conservation Potential Achievable in New and Existing Commercial Buildings

Because of the inability to uniformly enforce codes or achieve full installations in all structures, the Council assumes that 85 percent of the technical potential is achievable in new and existing structures. In addition, the Council also assumes that it will take time to build the infrastructure necessary to acquire the resource. For this reason, both the new and the existing programs are assumed to ramp in over a five year period before reaching the full achievable levels. Because of the unique nature of renovations and remodels, the Council assumes that 2 percent of the floor space per year is available for treatment under this category. This effectively limits the achievable amount of the renovation and remodel resource to 36 percent of the technical potential which is further reduced to the 85 percent level to account for institutional and other barriers.

Table 7-79
Technical Conservation from New Commercial Buildings

Levelized Cost		Total Cumulative Megawatts	
Nominal	Real	High	Medium
1	0.5	116	72
2	1.0	160	100
3	1.5	279	175
4	2.0	410	257
5	2.5	436	273
6	3.0	489	306
7	3.5	509	318
8	4.0	653	408
9	4.5	678	424
10	5.0	701	438
11	5.5	709	443
12	6.0	769	481
13	6.5	803	481
14	7.0	803	502
15	7.5	810	502
16	8.0	810	507
17	8.5	810	507
18	9.0	810	507
19	9.0	810	507
20	9.0	810	507

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Industrial Sector

In 1989, firm sales to the industrial sector were 6,935 average megawatts, which is about 40 percent of firm loads. About one-third of total industrial demand for electricity is consumed by the direct service industries, which are mainly the aluminum industry, and some chemical and other primary metal producers that buy electricity directly from the Bonneville Power Administration. The largest consumers among the non-direct service industries are lumber and wood products, pulp and paper, chemicals, food processing and primary metals.

A model to estimate non-aluminum industrial savings that was developed for Bonneville is used to estimate savings in this chapter. In the high and medium demand forecasts, the model derives 265 average megawatts of technical potential from existing industries at a cost of about 2 cents per kilowatt-hour. This still rounds to 2 cents per kilowatt-hour, even if administrative costs and transmission and distribution adjustments are incorporated. Conservation from new and expanding loads in the high demand forecast are 270 average megawatts at a cost of about 2 cents per kilowatt-hour. This remains about 2 cents per kilowatt-hour, if administrative costs and transmission and distribution adjustments are made. In the medium forecast, about 75 average megawatts are available.

All of these savings are from measures that cost less than 11 cents per kilowatt-hour. In addition, the Council has identified approximately 335 average megawatts in the high, and 235 average megawatts in the medium demand forecasts as a second block of conservation. The derivation of these resources is described later. Figure 7-19 depicts the amount of conservation available at various costs.

Conservation from the direct service aluminum industries is being secured through the conservation modernization program. Consequently, these savings are not available for further development and are not included in this chapter.

Assessing the technical and economic potential for industrial conservation presents a more difficult problem than in any other sector. Not only are industrial uses of electricity more diverse than in other sectors, but the conservation potential is also more site-specific. Moreover, because energy use frequently plays a major role in industrial processes, many industries consider energy-use data proprietary.

In prior power plans, the conservation estimates were based primarily on a survey asking individual plant managers to estimate conservation potentials in their specific plant. The surveys were coordinated by industry trade associations, such as Northwest Pulp and Paper Association and the Industrial Customers of Northwest Utilities. Data reports from specific firms were masked to protect proprietary data. However, the current estimates are based on a new model, which incorporated information from the survey, as well as from other data sources. This chapter briefly describes the analysis. The model used to derive the conservation estimates was developed for Bonneville. Significant portions of the material presented in this section are taken from materials presented by Bonneville in summarizing the contractor's work.

The model developed for Bonneville and data used to drive it are currently undergoing review and revision. This effort is intended to take a broad look at all data sources and add them to the analysis. When this effort is completed, the Council will likely adopt the new estimates in future plan revisions.

The steps used to evaluate conservation were to:

1. Evaluate measures that can be applied to the industrial sector, using existing data.
2. Calibrate to the electricity demand forecast for current and expected loads.
3. Compare the results to program information.

The key data sources for the industrial sector typically come from programs operated in the region. These are listed in Table 7-80.

Step 1. Evaluate Applicable Conservation Measures

The model used to derive conservation estimates in the industrial sector investigates conservation measures based on seven specific end uses, which are called service demands. An energy conservation measure is a specific equipment replacement or operating change that reduces the energy used in a particular service demand.

The seven service demands and corresponding conservation measures are:

Lighting

The lighting measures include the replacement of incandescent bulbs with fluorescent bulbs, replacement of fluorescent ballasts with electronic ballasts and the conversion of mercury vapor lights to high-pressure sodium or metal halide lighting. Lighting controls are included with some measures.

Air-Conditioning

The single air-conditioning measure is the installation of an economizer on an air-conditioning system.

Processing Heating

The single process heating measure is insulation on steam pipe. This measure has limited applicability, because the process heat for most firms comes from fossil fuels.

Conservation Potential

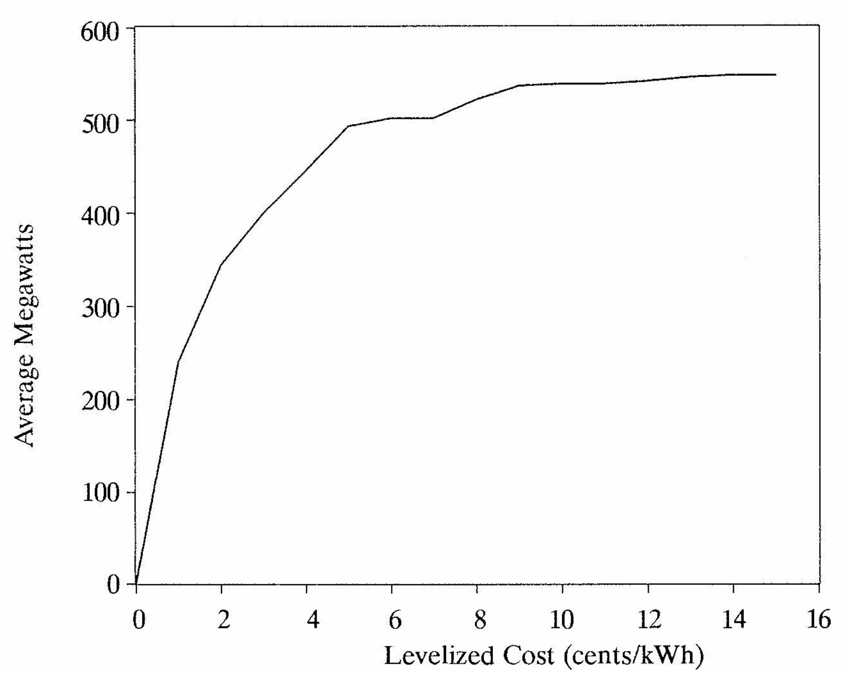

Figure 7–19 Technical Conservation Potential from the Industrial Sector

Table 7–80
Key Sources for the Industrial Sector

Bonneville's Industrial Test Program	Cost and savings of measures
Dunn and Bradstreet Industrial Survey	Consumption broken down by end use
Motors Study	Cost and savings of motors
Survey of Industrial Customers	Consumption and savings potential
Energy Analysis and Diagnostic Center	Savings from specific plants
Oregon Department of Energy Audits	Costs and savings from specific plants

Compressed Air

The available measures include a leak reduction program, a reduction in operating pressure and the use of electronic controllers.

Pumping

Measures considered to reduce the electricity used in pumping include pump downsizing, variable speed drives, flow restricting nozzles and oversized piping.

Refrigeration

The refrigeration measures include the reduction of condensing pressure, options to increase suction pressure, the use of automatic controls and various measures to reduce air infiltration.

Motors

The single type of motor measure is the replacement of a standard–efficiency motor with a high–efficiency motor. Since the cost and percentage savings of motors are a function of the size of the motor and the feasibility of rewinding the incumbent motor, separate measures are identified for five size ranges.

The data used for each measure includes the cost of the measure and the cost of the incumbent equipment replaced by the measure. Annual operating and maintenance costs for each measure also are used. The energy savings for a measure are characterized as a percentage reduction that can be achieved by substituting the measure for the incumbent equipment. The energy savings for each measure depend on the annual operating hours for each industry and the percentage of time during plant operating hours that the measure is actually saving energy.

The data to develop the conservation measures came from several sources. The most important are the reports produced by the Industrial Test Program. This program performed 10 energy audits in each of the food, wood products and pulp and paper industries.

Data in the 1985 supply curve report completed for the Council by Synergic Resources Corporation and used to estimate conservation in the 1989 supplement also was used. Most of the motors data came from the 1987 report by Seton, Johnson & Odell, Inc., which estimated the conservation potential in lost opportunities for the industrial sector in the Pacific Northwest. Many other data sources also were used.

The model does not assume that all measures are available to all industries, not only because the industry may not have the applicable service demand, but because efficient equipment may already be installed. In these cases, there is no further conservation potential.

Step 2. Calibrate to the Demand Forecast

The next step is to apply the conservation measures to the forecast's electricity loads by industry. The load forecast is used to derive current electricity use and predicted load growth by industry. The 10 industries included in this assessment are displayed in Table 7-81.

The model has been criticized as not incorporating all information available on conservation measures. This would include both individual measures that are currently recommended in audits and a comprehensive systems approach to improving efficiency. At least the first criticism should be addressed by an assessment currently underway by Bonneville to enhance the model and the data used in the model. These efforts were not completed in time to include in this power plan.

In the model, SIC 50 was created to estimate savings from all industrial loads not counted in any of the other nine industries listed above. The aluminum smelters are virtually the only plants served directly by Bonneville, which are excluded from the model.

The forecast electricity use for each industry is allocated to service and subservice demands, and conservation measures are identified for each demand. The allocations of energy use to service and subservice demands are derived from the Dun & Bradstreet Major Industrial Plant Database (MIPD). This data comes from surveys of larger energy-intensive firms.

For example, motors constitute one service demand, and motors in the 21 to 50 horsepower range constitute a subservice demand within the motors service demand. Measure 702, in the model, replaces standard-efficiency motors with high-efficiency motors in the 21 to 50 horsepower size range. The implementation of measure 702 will reduce electricity use by about 5 percent in the available portion of the subservice demand. It is currently assumed that 25 percent of the energy used by motors in the 21 to 50 horsepower subservice demand cannot be reduced by measure 702, because it is estimated that this percentage

Table 7-81
Industries in the Industrial Supply Curve Model

Standard Industrial Classification Code (SIC)	Industry
10	Mining Industries (composite of SICs 10-14)
20	Food and Kindred Products
24	Lumber and Wood Products
26	Paper and Allied Products
28	Chemicals and Coal Products
29	Petroleum and Coal Products
32	Stone, Clay and Glass Products
33	Primary Metals Industries
37	Transportation Equipment
50	Minor Industries

of the subservice demand is already served by high-efficiency motors, and no further improvement is possible.

Step 3. Compare Model Results to Programs

There are a number of reasons to expect that the savings and costs generated by this analysis are conservative. First, the measures considered in this model are very specific equipment change-outs. Major process changes are not considered, because the available data sources did not consider major process changes in the energy audits. Major process changes can create significant conservation opportunities.

Second, the data sources used to develop this supply curve had little information on measures in the upper cost brackets, so the lack of costly conservation opportunities in the supply curve is due more to data deficiencies than to a genuine shortage of expensive ways to trim electricity use in the industrial sector.

Third, this supply curve probably underestimates the savings potential and overestimates the costs of savings from new facilities. All measure cost and savings data are based on the cost of substituting the more efficient measures for existing equipment in existing plants. More savings may be available at a lower cost, if they are acquired when a plant is built rather than later as retrofits. However, no data is in hand on this issue.

Finally, measure costs are based on the full cost of the measure, excluding the salvage value of existing equipment. This will create a high levelized cost relative to a cost with salvage values included. It was also assumed that measures were installed before normal retirement of existing equipment. This is not because we expect the program to be operated in such a manner as an overall policy, but to allow for this type of activity to occur on an occasional basis, as required. In addition, it is a conservative estimate of costs and savings of the resource. This means that the full cost of the efficient measure was used instead of the incremental cost between the efficient and inefficient version. If this assumption were changed to reflect only incremental costs, the average cost would fall slightly from 2.3 to 1.9 cents per kilowatt-hour, and an additional 100 average megawatts of technical conservation potential would fall below the 11 cents per kilowatt-hour avoided cost in the medium forecast scenario. The timing of this resource's acquisition would be determined by the schedule of industrial plant renovations and change-outs.

In addition to these known conservatisms and in comparison to information collected by the Oregon Department of Energy and to audits conducted by the Energy Analysis and Diagnostic Center nationwide, the percent savings from the model are fairly low. The current analysis indicates savings potential at about 6 percent of non-direct service industry loads. The Oregon Department of Energy data set includes information from 111 site visits to individual plants, and the Energy Analysis and Diagnostic Center data set includes information from 750 audits. Both of these indicate an average savings from recommended conservation measures that is about 10 percent. These recommended conservation measures did not span the full cost-effectiveness range to 11 cents per kilowatt-hour and were based on a lower avoided cost. If audits had tried to identify all measures up to 11 cents per kilowatt-hour, more savings would have been identified. For example, the Energy Analysis and Diagnostic Center data base only identified measures with less than a two-year payback.

These program results were discussed in advisory committee meetings. It was decided to retain the current model estimates as a conservative estimator of savings, instead of moving now to an estimate based on these audits. However, it also was agreed that these audit results warranted further investigation, and that future program results and information will prove invaluable in helping refine the size of future conservation estimates. Such an effort is currently underway. Programs will be the primary source of information for further revisions to the supply curves. If 10 percent savings based on program experience were used instead of the 6 percent savings calculated from the model, an additional 340 average megawatts would be available in the high demand forecast. These additional resources make up the second block of industrial conservation. Their costs were assumed to be double those of the first block of conservation.

The results of the analysis described above led to the savings in Table 7-82. About 540 average megawatts were identified as cost-effective resources at an average cost of about 2 cents per kilowatt-hour, after incorporating adjustments for administrative costs and transmission and distribution credits.

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Table 7-82
Industrial Sector Technical Conservation Potential

Levelized Cost (cents/kWh)		New and Expanding Loads (MWa)		
Nominal	Real	High Forecast	Medium Forecast	Existing (MWa)
0	0	0	0	0
1	0.5	121	33	118
2	1	175	48	168
3	1.5	203	57	196
4	2	226	62	219
5	2.5	251	70	241
6	3	256	70	245
7	3.5	256	73	245
8	4	266	73	255
9	4.5	273	75	263
10	5	274	75	264
11	5.5	274	75	264
12	6	276	76	265
13	6.5	278	77	267
14	7	279	77	268
15	7.5	279	77	268

Irrigation Sector

In 1989, the region's irrigated agriculture consumed about 640 average megawatts of electricity, about 4 percent of the region's total consumption. The technical potential for conservation measures, evaluated with a marginal measure not exceeding a cost of 11 cents per kilowatt-hour, is about 45 average megawatts. Virtually all of this resource comes from making existing loads more efficient. These savings are available at an average cost of about 5 cents per kilowatt-hour, even if administrative costs and transmission and distribution adjustments are incorporated. Figure 7-20 depicts irrigation sector conservation available at various costs.

The conservation resource in public utility service areas is estimated to be about 40 percent of the total potential, with about 60 percent in the private utility service areas. This split is based on the proportion of total irrigation loads in the Council forecast, not including Bureau of Reclamation loads.

The Council's assessment of conservation potential for this sector involved the following two steps:

1. Evaluate the end-use conservation measures to be included in the supply curve analysis.
2. Estimate realizable conservation potential, by using the cost and potential savings data available from the Irrigation Sector Energy Planning Model.

Step 1. Evaluate the End-Use Conservation Measures to be Included in the Analysis

In the 1986 Power Plan, the Council relied on estimates of conservation potential in irrigated agriculture provided by a Bonneville contractor. At the time, the research represented the most complete picture of energy conservation opportunities in the region's irrigation sector. Since that time, Bonneville's irrigation research contractor has updated its analytical studies in order to better characterize the irrigation sector. This effort has produced improved base line data, which the Council used to prepare its assessment of the conservation potentials in this sector. The primary effect of this updated information is a reduction in the potential savings previously estimated for the 1986 irrigation supply curve. These adjustments were made for the 1989 supplement and are included in the current estimate.

Conservation Potential

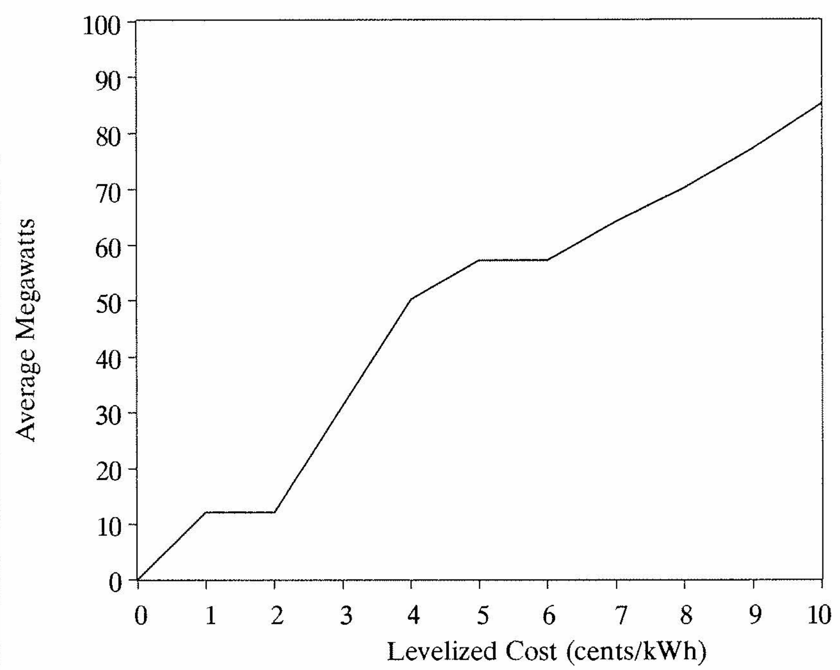

Figure 7-20
Technical Conservation Potential from the Irrigation Sector

A major reason for this reduction from the 1986 plan is evidence from the Bonneville Irrigation Conservation Program that indicates at this time irrigators are unwilling to adopt use of low pressure measures on many hand-move and sideroll systems. While Bonneville is sponsoring research on low pressure nozzles for application in these systems, at this time there is sufficient uncertainty about when significant penetration of this measure would occur.

In addition, based on survey results, irrigators are continuing to take conservation actions at a greater rate than previously assumed, thereby reducing the amount of potential conservation available.

The conservation opportunities considered in the irrigation supply curve estimates include:

- low pressure irrigation on center pivot systems;
- fittings redesign;
- main-line modifications;
- improved scheduling; and
- energy-efficient motors.

Low pressure irrigation involves using sprinkler or spray application devices designed to operate at lower pressures than conventional sprinkler devices. These low pressure devices can be divided into three major types: low pressure spray heads, low pressure impact sprinklers and drop tubes.

The fittings of an irrigation system include valves, elbow joints and other components used to connect the irrigation pump to the pipes of the system and to connect the pipes within the system to each other. Fittings redesign involves using larger tapered fittings to replace valves and elbows that are too small or that change abruptly in size and direction.

Main line modification involves increasing the size of the system's main line, resulting in decreased energy losses due to friction. This redesign generally can be accomplished most economically by installing a second main line pipe parallel to the existing one.

Improved scheduling involves the improvements in both timing and amount of water applications. This reduces water use without reducing crop yields, and energy use is reduced due to a decrease in pumping requirements. Scheduling is the cornerstone of a basic comprehensive management approach to efficient water and energy management, with all other conservation measures being necessary components. Research results indicate that scheduling is easier to implement on center pivot systems than on hand-move and sideroll systems. Recently, the question has been raised whether scheduling really saves electricity. Savings from scheduling depend upon farmers overwatering in the base case, which is not well documented. In addition, an evaluation of Bonneville's Irrigated Agriculture Conservation Program indicated that scheduling may save energy in normal water years, but not when extreme conditions exist. In very dry years, water is a limited resource, and scheduling may simply improve the crop, since water is applied at appropriate times, but not save energy since overwatering is constrained. Due to the significant questions surrounding whether scheduling saved energy, it was not included as part of the resource at this time.

Energy-efficient electric motors are those that are manufactured with materials and designs that reduce the level of energy losses compared to standard electric motors. The electric motors are used to operate water pumps. Recently, implementors of Bonneville's irrigation program have cast doubts on the ability of energy-efficient motors to survive under the type of conditions that exist in the fields. Some have argued that energy-efficient motors are less able than a standard motor to withstand the voltage imbalances that occur in the field, and, therefore, their longevity is significantly shortened. In addition, some argue that when an energy-efficient motor is rewound, it is most commonly not done to energy-efficiency levels, and therefore the savings are lost over the long term. These questions need to be investigated further to document the extent of the problem and whether some of the new generation of energy-efficient motors might perform better. Due to these questions, we counted the savings from energy-efficient motors, about 13 average megawatts, as part of the second block of conservation.

Step 2. Estimate Conservation Potential

Conservation supply estimates for the irrigation sector were developed using the Irrigation Sector Energy Planning model. The model combines both engineering and economic principles to derive energy savings and levelized costs per kilowatt-hour for conservation investments. The average megawatts available at various costs are displayed in Table 7-83.

The model uses a number of base line data inputs, including estimates of crop-specific acreages in 11 subbasins in the region; type of irrigation systems used; pumping lift; pumping plant efficiencies; estimates of water application volumes to specific crops by irrigation system type; and system operating pressures. The model also uses rough estimates of conservation measures believed to have been applied on existing acreages and subtracts these estimated savings prior to calculating the remaining conservation potential. The Irrigation Sector Energy Planning model has incorporated new information from Bonneville's Stage I irrigation system audits and irrigator surveys that indicates that irrigators have increased conservation achievements over previous estimates assumed in the model.

In a test of the model to estimate the base line energy use for 1985 regional irrigation loads, the Irrigation Sector Energy Planning model estimates were within 3 percent of the load estimated from 1985 billing records. This indicates a high degree of confidence for this part of the model.

Table 7-83
Irrigation Sector Technical Conservation Potential

	Average Megawatts		
Levelized Cost (cents/kWh)	Existing Land	New Land	Total
0	0	0	0
1	0	0	0
2	13	1	14
3	34	1	35
4	42	1	43
5	42	1	43
6	42	1	43
7	42	1	43
8	42	1	43
9	44	1	45
10	44	1	45
11	44	1	45

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